The United Illuminating Company
157Church Street
P.O. Box 1564
New Haven, CT 06506-0901
203.499.2000

April 1, 2009

Mr. S. Derek Phelps
Executive Director
Connecitcut Siting Council
10 Franklin Square
New Britain, CT 06051

ORIGINAL

RE: Docket No. F-2009 – Connecticut Siting Council Review of the Ten-Year Forecast of Connecticut Electric Loads and Resources

Dear Mr. Phelps:

The United Illuminating Company (UI) hereby submits an original and twenty (20) copies of an Update to its Load Forecast and Transmission Planning in order to assist the Connecticut Siting Council in its Hearings pursuant to Section 16-50r of the General Statutes of Connecticut.

Respectfully submitted,

THE UNITED ILLUMINATING COMPANY

by Michael A. Coretto
Michael A. Coretto
Senior Director – Retail Access &
Regulatory Strategy

cc: Service List

Report to the Connecticut Siting Council on Loads and Transmission Resources

April 1, 2009

The United Illuminating Company
157 Church Street
New Haven, CT 06506

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Section I. Load Forecast Update

This section presents the results and a summary of the methodology for The United Illuminating Company's ("UI" or "Company") most recent ten-year energy sales forecast (Sales Forecast) and ten-year system peak load forecast (Peak Load Forecast). The Sales Forecast is used for budgeting and financial planning purposes. The Peak Load Forecast is used by the Connecticut Siting Council ("Council" or "CSC") for resource planning purposes in Connecticut. The two forecasts use different forecasting methodologies chosen to fulfill their intended purpose.

Sales Forecast Purpose & Methodology

The primary purpose of the Sales Forecast is to accurately project monthly sales-by-class which is then converted to a revenue forecast using electric service rates by class. The principal output of the Sales Forecast is monthly energy sales. UI utilizes the ten-year Sales Forecast for a number of purposes. A key reason for the Sales Forecast is to project the energy sales as the basis for predicting revenue over the next 12 to 24 months. The UI Sales Forecast produces monthly forecasted energy sales weather-adjusted to "normal weather" or average weather conditions.

Weather has a large impact on both sales and peak load. Any analysis of the actual historical sales and peak load must consider the weather conditions under which those sales and peak loads occurred. The Company's sales forecasting process begins by weather-adjusting the actual, customer-class specific, historical sales data to the sales that would have been experienced under normal weather, using heating degree days (HDD) and cooling degree days (CDD) based on a standard of 65 degrees Fahrenheit for the transition from heating-based to cooling-based sales.

The sales forecasting process then moves to the creation of a Base Energy Sales Forecast which reflects the projected sales from UI's existing base of customers. The Base Sales Forecast development employs focused analytical processes that weather-adjusts and evaluates the most recent energy sales history of its customers, trends in the local and state economies and the sales forecast team's interpretations of how these factors are likely to impact UI's future monthly sales.

The impact to the sales from Conservation and Load Management (C&LM) and Distributed Generation (DG) currently on the UI system are embedded in the historical data used to develop the Base Energy Sales Forecast, and therefore, the future impact of these resources is accounted for in the Base Energy Sales Forecast results. UI adds to the Base Energy Sales Forecast the projected future annual impact of incremental additions of new C&LM and DG to account for the future additions of these resources. In addition, UI adds an estimate of sales resulting from specific, new customers projected by UI's Economic Development group. The addition of new customers is another variable that can materially impact sales and peak loads. UI's Economic Development group creates regular projections of new customer additions and deletions to the system based on their interaction with municipalities, Account Managers, potential developers and businesses. These new loads include expansions of existing UI customers, redevelopment of existing areas and new "green field" construction. UI's final Sales Forecast results from the summation of the normal weather-adjusted Base Energy Sales Forecast and new large customer sales along with the decrement to sales due to projected C&LM and DG.

Peak Load Forecast Purpose & Methodology

The purpose of the peak load forecast shown in Exhibit I is to allow the Council to effectively forecast and evaluate the demand and supply balance in Connecticut. The primary output of UI's Peak Load Forecast is the forecast of system peak loads under both normal and extreme weather conditions. Normal weather or average weather, also referred to as a 50/50 forecast, means the data provides a 50% confidence, from a statistical perspective, that forecasted normal weather-adjusted system peak will be exceeded 50% of the time on the peak load day, due to weather conditions. Extreme weather, also referred to as a 90/10 forecast, means the data provides a 90% confidence, from a statistical perspective, that the forecasted extreme weather-adjusted system peak will be exceeded only 10% of the time on the system peak day, due to weather conditions. In other words, the forecasted 90/10 peak load will be reached or exceeded once every ten years.

The UI Peak Load Forecast is a derivative of a quarterly sales forecast and a projected load factor. The forecast of quarterly sales used for the Peak Load Forecast is strictly an interim calculation step that utilizes a different forecasting methodology than the revenue-focused Sales Forecast described above. The Peak Load Forecast is derived from weather-adjusted sales that use an average monthly temperature methodology to weather-adjust the sales. This is different than the method used in the revenue-focused Sales Forecast described in the prior section. For the Peak Load Forecast development, the Company first uses customer-class specific regression models to weather-adjust the historic sales data to equivalent sales that would be seen under normal weather conditions based on 30-years of historical weather data. The normal weather-adjusted sales data is then used to develop a series of econometric models for each major customer class which relates the sales to economic and demographic drivers, obtained from independent sources. The parameters used in the individual econometric models vary by the customer class. The models are then used to produce forecasts of quarterly sales for each major customer class under normal weather conditions.

Next, UI calculates the weather-adjusted historical system peak loads, for both normal weather and extreme weather conditions. The weather-adjustment for historic peak loads is based on a model that relates the twelve-hour average Temperature Humidity Index (a mathematical formula that combines temperature and humidity into a single number) to historical summer weekday peak loads (THI Model). The THI Model is then used to adjust historic peak loads to the loads that would have been seen under normal or average temperature and humidity conditions and for extreme conditions.

The weather-adjusted sales and peak loads are used to calculate historical load factors for both normal and extreme weather conditions. The historical load factor information is then used to translate the annual sales (based on a summation of the forecasts of quarterly sales by customer class) into a Base Load Forecast for both normal and extreme weather-adjusted conditions. The Base Load Forecast reflects the forecasted peak load resulting from UI's existing levels of C&LM, DG and existing base of customers. Similar to the Sales Forecast, the Company accounts for projected new C&LM and DG and new large customer loads separately. UI's final Peak Load Forecast results from the summation of the Base Load Forecast and new large customer loads along with the impact due to incremental additions of new C&LM and DG.

<u>Changes to 2009 Forecasts Methodologies</u>

This year, the Company has incorporated a number of refinements to further enhance its peak load forecasting methodology. As described above, and similar to the last few years, this year's long-range peak forecasting models utilize econometric models to forecast data by customer classes. However, in 2009, the Company has increased the number of separately forecasted customer classes used to develop the Peak Load Forecast and expanded the number and regional focus of the economic and demographic drivers used in developing the models for each customer class. The Company believes these enhancements improve the quality of the resulting Peak Load Forecast this year in an effort to capture the recent historical and forecasted impacts of the current economic downturn.

Normal Weather-Adjusted Historical and Forecasted Data

The data shown in Exhibit 1 includes actual historical data for system energy requirements, sales and peak load. Exhibit 1 also includes historical and forecasted sales and peak load adjusted to normal weather conditions. UI is a summer peaking utility due primarily to the air conditioning loads on its system. During recent history, between 1999 and 2008, UI has experienced lower normal weather-adjusted sales growth as compared to its normal weather-adjusted peak load growth (i.e., 1.5% sales growth versus a 13.2% peak load growth in the past nine-years). This is attributed to air-conditioning loads that have increased to accommodate the comfort requirements and to counter the additional heat output and space conditioning demands of computers and electronics. It should be noted that in four of the last nine years of historical data (1999, 2001, 2002 and 2006), the actual peak load has exceeded the normal weather-adjusted peak load. This exceedance is consistent with the design of the normal weather adjustment, in that, typical variations in weather alone will cause the normal weather-adjusted value to be exceeded 50% of the time on the peak load day. This recent history of peak loads reinforces the need for the Company to consider extreme weather in its Peak Load Forecasts. The forecast of the normal weather-adjusted peak load projects a continued growth of 12.8% between 2008 and 2018. However, the forecast of sales projects a decline of -11.2% during the same period due to the small incremental sales increases from the existing customer base and new customers being more than overcome by the sales reductions resulting from incremental C&LM and DG additions. The Sales Forecast is lower than last year's forecast due to the impacts of the current economic conditions on the primary components of the forecast. The normal weather-Adjusted Peak Load Forecast is slightly higher than last year's forecast (22 MW higher in year 2017). The reason this year's forecast is not lower as would be expected based on current economic conditions, is due to the fact that last year's forecast included the impact of additional Aggressive C&LM, which at the time of the filing was under review by the Department of Public Utility Control ("DPUC"). Ultimately, funding for these new Aggressive C&LM programs was not approved, and therefore they are not included as decrements in this year's Peak Load Forecast.

Extreme Weather-Adjusted Historical and Forecasted Data

In addition to the normal weather-adjusted data, Exhibit 1 also shows historical and forecasted peak loads adjusted to extreme weather conditions. The 1999 to 2008 historical data in Exhibit 1 shows a growth in the extreme weather-adjusted historical Peak Loads that is slightly more than the growth seen in the historical normal weather-adjusted Peak Loads (i.e., 13.8% growth in extreme weather peak load versus 13.2% growth in the normal weather peak load). The Company's extreme weather-adjusted Peak Load Forecast shows a growth of 13.2% during the period from 2008 to 2018. This forecasted growth is significantly lower than last year's forecast due the impacts of the current economic conditions.

The ability to predict when extreme weather will occur or the exact amount of economic activity that will be realized is difficult. Therefore, prudent planning requires that the possibility of the effects of extreme weather (temperature and humidity) 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 from the normal and extreme weather-adjusted results are intended to provide a plausible range of futures. No single forecast will be accurate throughout the forecast period. When extreme weather occurs, regardless of the timing, the system infrastructure must be in place to serve the load safely and reliably[1].

UI Peak Load Scenario for ISO-NE Regional Transmission Planning

In addition to this filing to the Council, the Company must also file a forecast of peak loads to the Independent System Operator-New England ("ISO-NE") as input to ISO-NE's regional planning process. A preliminary forecast of peak loads that the Company intends to provide to ISO-NE is provided for informational purposes in Exhibit 2. This Peak Load Scenario excludes all C&LM, DG and potential new large customer loads in order to be consistent with the ISO-NE treatment of loads and resources in their regional planning.

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 four years old, the full potential of the DG sections is only now beginning to come to pass. The implementation of the Act, carried out by the DPUC, provides monetary grants to offset the capital cost of installing DG. Despite these capital grants, the decision of whether or not such an installation is economically attractive is unique to each

[1] The purpose of the peak load forecast shown in Exhibit I is to allow the Council to effectively forecast and evaluate the demand and supply balance in Connecticut.

customer. As such, the remaining number of installations that may occur under the Act is difficult to predict.

Since the inception of the program, approximately 9.8 Megawatts of DG capacity have become operational in the UI service territory while additional grants totaling 35.1 Megawatts of capacity have been approved. The in-service dates for these additional units are under the control of the owners, but all of these units are scheduled to be operational over the next few years. In development of the sales and system peak forecasts shown in Exhibit 1, these units have all been included as offsets to load.

The DPUC has recently evaluated this grant program for cost effectiveness to the ratepayers and, as a result of this evaluation, has decided to end the program. The change to the monetary grant program took effect for all projects that submitted applications on or after October 14, 2008.

Conservation & Load Management

New England's energy markets continue to develop and evolve, and the Electric Distribution Companies continue to be active participants in the development of the ISO-NE stakeholder process to refine the markets. The new Forward Capacity Market ("FCM") allows market participants to enter their peak demand savings into the capacity market during the Transition Period and bid them into the full FCM. Market participants earn capacity payments for qualifying resources, such as distributed generation, energy efficiency, load management or load response. This is the first time in the United States that reduction in demand through energy efficiency and demand response programs was considered as electrical capacity equivalent to supply-side generation sources. Additional electrical capacity "produced" through the implementation of efficiency and load management measures becomes a resource, which can then be bid to ISO-NE on a level playing field with new generation.

UI has entered peak demand savings from energy efficiency and load management projects into the Transition Period FCM on behalf of the Connecticut Energy Efficiency Fund and has successfully bid capacity in the first two capacity auctions.

PA 07-242, An Act Concerning Electricity and Energy Efficiency ("2007 Act") required the Companies to begin an integrated resource planning ("IRP") process. On January 1, 2009, the Companies submitted their second IRP plan to the CEAB. If implemented by the Department, this plan would result in a significant increase in energy-efficiency projects/installations over the planning horizon. The 2007 Act also established several initiatives and programs designed to significantly reduce electric power supply costs caused by inadequate transmission and generation in Connecticut's power infrastructure. The 2007 Act provides C&LM incentives that are intended to encourage consumers to conserve electricity, manage their electric load and to install energy-efficient equipment.

The strategic focus of UI's programs is the result of a multi-level collaborative process involving UI and a diverse group of stakeholders. These stakeholders include: the Department, the ECMB, Connecticut state government, consumer and business interests, national and regional environmental and energy efficiency organizations, design professionals and energy services providers.

UI participates in national and regional activities to develop a long-range focus for energy efficiency. The organizations include the Consortium for Energy Efficiency ("CEE"), the American Council for an Energy-Efficient Economy ("ACEEE"), Northeast Energy Efficiency Partnerships ("NEEP") and other utility and public benefit fund organizations. The activities include market baseline research, development of efficiency standards, exchange of programmatic ideas and concepts and the assessment of the need for incentives. These efforts have produced many of the energy efficiency concepts and measures upon which the programs are based.

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 Corporation (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 accommodate area load growth, 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 to approximately 14% of energy in 2010 to 27% of energy in 2020 for all Classes of renewables. New England's requirements for generation from renewable resources are projected by ISO-NE to be ramping up from approximately 9,000 GWh in 2008 to approximately 25,000 GWh in 2020.[2]

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 renewable needs 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.[3]

In January 2007, the Council granted a certificate of environmental compatibility and public need for the Trumbull 115/13.8-kV Substation Project. The Trumbull Substation Project, which was completed June 2008, addressed reliability and capacity issues in the greater Trumbull area.

In April 2005, the Council granted a certificate of environmental compatibility and public need for the Middletown-Norwalk (M-N) Project. As a result of the M-N Project, which went in to service December 2008, the 345-kV transmission loop into Southwest Connecticut was completed, thereby improving customer reliability and reducing transmission congestion costs. The M-N Project provides infrastructure capable of allowing greater access to more of New

[2] ISO-NE Regional System Plan Update, October 2008.
[3] ibid

England's competitively priced generation, which should result in lower energy costs to all of Connecticut's consumers as well as the continued reliable operation of the electric system.

UI's planned transmission system modifications are listed in Exhibit 3 and are outlined below.

To address reliability, substation capacity and voltage support issues in the greater New Haven area, UI has received Declaratory Ruling from the Council for the following projects:

- Broadway 115/13.8-kV Substation Expansion Project
- Union Avenue – Metro North 115/26.4-kV Substation Project

The Broadway 115/13.8-kV Substation Expansion Project and the Union Avenue – Metro North 115/26.4-kV Substation Project are expected to be completed by June 2010 and August 2010 respectively.

Recently the Council also provided Declaratory Ruling approval of UI's proposed Grand Avenue 115-kV Switching Station Modernization Project, which addresses reliability compliance issues in the greater New Haven area. The Grand Avenue 115-kV Switching Station Modernization Project is expected to be in service by 2012.

As discussed in Section I of this report, the forecasted system peak load growth is significantly lower than last year's forecast due to the impacts of the current economic conditions. Based on the new forecast, the need for the following new 115/13.8-kV substations, which were presented in last year's report, have slipped beyond the ten year horizon – Hamden, Fairfield, New Haven II, North Branford and Orange.

UI has other transmission infrastructure upgrades under internal review, such as the Shelton Substation Project, a new 115/13.8-kV substation, needed to address distribution reliability and capacity issues related to substation thermal overloads and voltage collapse concerns in the greater Shelton area. UI anticipates making a filing with the Council for this project later in 2009, which is projected to be in service in 2013 (representing a change from 2010 as presented in last year's report).

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 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 43 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. UI anticipates making a filing with the CSC for the Naugatuck Valley 115-kV Reliability Improvement Project in 2010, which is expected to be in service in 2013.

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 2013. In 2009, UI, CL&P and ISO-NE are expected to complete the necessary studies to provide a conceptual solution for the Pequonnock 115 kV Fault Duty Mitigation Project. UI anticipates making a filing with the CSC for this project in 2010.

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 3 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 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 the Company 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

History

									Normal Weather Adjustment					Extreme Weather Adjustment		
Year	Total Sys. Req. (GWh)	Annual Change (Pct.)	Actual Sales (GWh)	Annual Change (Pct.)	Actual System Peak (MW)	Annual Change	Load Factor (Pct.)	Weather Adjusted Sales (GWh)	Annual Change (Pct.)	Weather Adjusted System Peak (MW)	Annual Change	Load Factor (Pct.)	Weather Adjusted System Peak (MW)	Annual Change	Load Factor (Pct.)
1998	5,728	1.7%	5,452	1.4%	1,143	-2.6%	57%	5,485	1.2%	-	-	-	-	-	-
1999	5,943	3.8%	5,652	3.7%	1,273	11.4%	53%	5,625	2.6%	1,219	-	-	1,289	-	-
2000	5,977	0.6%	5,654	0.0%	1,153	-9.4%	59%	5,708	1.5%	1,236	1.4%	55%	1,292	0.3%	53%
2001	6,010	0.6%	5,724	1.2%	1,318	14.3%	52%	5,689	-0.3%	1,259	1.8%	55%	1,322	2.3%	52%
2002	6,051	0.7%	5,781	1.0%	1,300	-1.4%	53%	5,684	-0.1%	1,259	0.0%	55%	1,318	-0.2%	52%
2003	6,071	0.3%	5,772	-0.2%	1,274	-2.0%	54%	5,734	0.9%	1,285	2.0%	54%	1,351	2.5%	51%
2004	6,205	2.2%	5,952	3.1%	1,201	-5.8%	59%	5,952	3.8%	1,300	1.2%	54%	1,364	0.9%	52%
2005	6,360	2.5%	6,106	2.6%	1,346	12.1%	54%	5,995	0.7%	1,353	4.0%	54%	1,428	4.7%	51%
2006	6,149	-3.3%	5,919	-3.1%	1,456	8.2%	48%	5,979	-0.3%	1,377	1.8%	51%	1,456	2.0%	48%
2007	6,119	-0.5%	5,917	0.0%	1,298	-10.9%	54%	5,929	-0.8%	1,389	0.8%	50%	1,464	0.6%	48%
2008	5,912	-3.4%	5,729	-3.2%	1,301	0.3%	52%	5,709	-3.7%	1,379	-0.7%	49%	1,467	0.2%	46%
1998 - 2008 growth		3.2%		5.1%		13.9%			4.1%		-			-	
1999 - 2008 growth		-0.5%		1.4%		2.2%			1.5%		13.2%			13.8%	

Forecast

			Normal Weather Scenario					Extreme Weather Scenario		
Year	Total Sys. Req. (GWh)	Annual Change (Pct.)	Weather Adjusted Sales (GWh)	Annual Change (Pct.)	System Peak (MW)	Annual Change	Load Factor (Pct.)	System Peak (MW)	Annual Change	Load Factor (Pct.)
2009	5,876	-0.6%	5,591	-2.1%	1,383	0.2%	49%	1,473	0.4%	46%
2010	5,705	-2.9%	5,428	-2.9%	1,386	0.2%	47%	1,476	0.2%	44%
2011	5,656	-0.9%	5,382	-0.9%	1,431	3.2%	45%	1,524	3.2%	42%
2012	5,609	-0.8%	5,336	-0.8%	1,506	5.2%	43%	1,604	5.2%	40%
2013	5,531	-1.4%	5,263	-1.4%	1,535	1.9%	41%	1,635	2.0%	39%
2014	5,479	-1.0%	5,213	-1.0%	1,538	0.2%	41%	1,639	0.2%	38%
2015	5,433	-0.8%	5,169	-0.8%	1,541	0.2%	40%	1,643	0.3%	38%
2016	5,410	-0.4%	5,147	-0.4%	1,548	0.5%	40%	1,651	0.5%	37%
2017	5,358	-1.0%	5,098	-1.0%	1,555	0.4%	39%	1,659	0.5%	37%
2018	5,331	-0.5%	5,072	-0.5%	1,556	0.1%	39%	1,661	0.1%	37%
2008 - 2018 growth		-9.8%		-11.2%		12.8%			13.2%	

1. System Requirements are sales plus losses and Company use.
2. Load Factor = System Requirements (MWh) / (8760 Hours X System Peak (MW)).
3. All forecasts include C&LM, DG & potential new large customer planned loads identified by UI Economic Development.
4. System Peak Load for 1998 had insufficient data available to calculate normalized values with a methodology consistent with later years.

EXHIBIT 2 Peak Load Scenario for ISO-NE Regional Planning Process

The United Illuminating Company

Peak Load Scenario for ISO-NE's Regional Transmission Planning Process
(Final forecasts to be provided to ISO-NE)

Forecast

	Normal Weather Scenario			Extreme Weather Scenario		
Year	System Peak (MW)	Annual Change		System Peak (MW)	Annual Change	
2009	1,382	0.2%		1,472	0.4%	
2010	1,387	0.3%		1,477	0.4%	
2011	1,431	3.2%		1,525	3.2%	
2012	1,505	5.1%		1,603	5.1%	
2013	1,540	2.3%		1,640	2.3%	
2014	1,553	0.8%		1,654	0.8%	
2015	1,565	0.8%		1,667	0.8%	
2016	1,581	1.0%		1,684	1.0%	
2017	1,595	0.9%		1,699	0.9%	
2018	1,604	0.6%		1,709	0.6%	
2008 - 2018 growth			16.3%			16.5%

1. All forecasts exclude C&LM, DG & potential new large customer planned loads identified by UI economic development, consistent with ISO-NE CELT load forecasting methodology.

EXHIBIT 3 Transmission System Planned Modifications

Report to the Connecticut Siting Council

List of Planned Transmission Projects for which Certificate Applications are being contemplated, may be subject to Declaratory Ruling, or have already been filed

Projects for which Certificate Applications are being Contemplated	kV	Date of Completion
1. Installation of new 115/13.8-kV substation in Shelton	115	2013
2. Naugatuck Valley 115-kV Reliability Improvement Project	115	2013
3. Pequonnock 115-kV Fault Duty Mitigation Project	115	2013

Projects which have Received CSC Declaratory Ruling Approval		
1. Broadway 115/13.8-kV Substation Expansion Project	115	2010
2. Union Avenue – Metro North 115/26.4-kV Substation Project	115	2010
3. Grand Avenue 115-kV Switching Station Modernization Project	115	2012