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VIA HAND DELIVERY

June 29, 2009

RECEIVED
JUN 30 2009
CONNECTICUT
SITING COUNCIL

Honorable Daniel Caruso
Chairman
Connecticut Siting Council
10 Franklin Square
New Britain, CT 06051

Re: **Docket F-2009**

Dear Chairman Caruso:

Enclosed are an original and 20 copies of The United Illuminating Company's responses to the CEAB's interrogatories.

Please do not hesitate to call me should you have any questions concerning this filing.

Very truly yours,

Bruce L. McDermott

cc: Service List (via electronic mail)

10705\1228\2242146.1

Interrogatory CEAB-1

Q-CEAB-1: Please provide a detailed description of the methodology by which the energy and peak load forecasts contained in your initial filing in this proceeding were prepared.

A-CEAB-1: The energy forecast and the system peak load forecasts use different models and are used for different purposes. The energy forecast is used for financial planning purposes whereas the system peak load forecast is used to plan for the sufficiency of T&D infrastructure.

The energy forecast was developed by starting with the previous year's weather corrected sales. Net load additions and deletions based on UI's Economic Development Forecast were added to the previous year's weather adjusted sales. For years with minimal or no projected economic development activity, a fixed forecast sales figure was used. Next, historic sales growth figures were used to predict sales growth by customer class. Next, the forecasted sales in leap years were adjusted to account for the additional one day of sales. Finally, additional adjustments were made for the reduction in sales due to (C&LM) and Distributed Generation (DG).

The 2009 System Peak Load Forecast methodology used a multi-model econometric-based forecast of UI sales, by customer class, based on UI's historical sales data, and third party data for economic and demographic drivers. The sales forecast was then converted to a system peak forecast using UI-specific system load factor forecasts.

The first step used in developing the system peak load forecast was to weather normalize the historical sales-by-class data. UI uses a kWh sales-by-class weather normalization methodology that used non-linear, multiple regression models that related monthly actual billed kWh sales-by-class to billing-cycle-adjusted monthly average temperature.

The temperature data were "adjusted" for billing cycles by using the average of the temperature of the billing cycle month and the prior month. This "adjusted" temperature more closely matches the temperature of the sales period corresponding to the billing cycle-affected monthly sales data.

Two different weather normalization methodologies were employed – one for normalizing historic sales, as described above, and one for normalizing historic peak loads. The historic peak loads were normalized using regression models that related MW System Peak Loads to the temperature humidity index (THI). The weekday system peak loads were normalized by regressing the 12-hour average THI for the period June 1 through August 31. The qualifying weekday system peaks were defined by the resulting 12-hour average THI that exceeded 70. The peak normalization developed both a "90/10" (extreme weather) as well as a "50/50" (normal weather) System Peak Load normalized value.

Monthly sales-by-customer class normalized data are compressed into quarterly datasets in order to minimize the use of intervention variables and more easily facilitate the use of lagging variables.

A large set of economic and demographic data were analyzed for statistically-significant relationships with the weather normalized energy sales data by customer class (also tested for statistically significant lags). All variables that were ultimately used were highly significant (i.e., 80% Confidence Level[1] or better).

Multiple regression models were then employed to estimate sales-by-customer class forecasts using the weather normalized data. The modeling approach employed economic and demographic data. The process tests the statistical significance of these data in explaining growth in normalized historical quarterly energy sales. Several datasets and sources were tested in this process using regression techniques. Only the variables that best explain sales-by-customer class growth are used in the final forecast models.

The Sales Forecasts were converted to System Peak Load Forecasts expressed on a "50/50" and "90/10" planning probability by using a forecast of the system load factor. First, the quarterly sales forecasts were converted to system energy requirements using a system loss factor to adjust for system energy losses. The system energy requirements were then converted to system peak load using a

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[1] The confidence level describes the uncertainty of a sampling method, the higher the percentage the greater the confidence.

Once the Base Peak Load Forecast was developed the impact of C&LM, DG and new large customer loads were added. UI's latest ten-year forecast of C&LM from the data used for the UI January 2009 Integrated Resource Plan for Connecticut (IRP) was utilized in developing the load scenarios. The System Peak Load Forecast included only the load impacts from the energy efficiencies programs. UI chose to exclude Load Response Programs (LRPs) in the System Peak Load Forecast since the future dispatch and use of the LRPs remains uncertain, given the multiple recent changes to ISO-NE's planned dispatch of these resources. This exclusion of the Load Response Programs (LRP) resources was a change since the LRP resources were included in the 2008 forecast for the Connecticut Siting Council. ISO-NE's recent iterations, to the conditions under which the LRPs would be dispatched, would impact the LRPs' predictability and usefulness to UI's system. Also, most, if not all of the LRP measures are expected to become part of the ISO-NE Forward Capacity Market (FCM) by 2012. Due to the uncertainty of their current dispatch, and their likely incorporation in the FCM in 2012, UI excluded the LRPs for consideration as a long term resource for planning purposes.

UI also forecasted a significant impact from DG programs. UI's latest forecast of new DG sources includes only the new annual incremental increases from those units in UI's service territory that have received approval for grants under Public Act 05-01, *An Act Concerning Energy Independence*. Existing DG units installed as part of the monetary grant program, and their impact to the UI System Peak Load are included in the historical data set used to develop the System Peak Load Forecast. Only 50% of the currently planned DG capacity is assumed to be installed in this year's System Peak Load Forecast due to the volatile economic conditions and the cancellation of many planned projects in all industries.

Identified new large customer load data is used to develop load scenarios with the new loads added to the forecast models' results. The identified new large customer loads included a peak load contribution, the time of year they are anticipated to connect to UI's system, the substation that would provide electric service, and a probability of their connection. A portion of the new loads are considered part of normal system growth and are considered as included in the econometric model-based forecast. UI's system has a history of customer growth and the regular gain and loss of individual customers. These historical trends become part of the forecast system growth rates by the use of the historical data and econometric models. To reduce the potential of double-counting these new loads (i.e., adding new loads to the econometric model-based results that were already embedded in the growth rates), the new loads were screened to eliminate the new loads that were consistent with normal system growth based on the size, customer class and location.

The final UI System Peak Load forecast was finally calculated from the Base Peak Load Forecast combined with the impacts from the C&LM, DG and new large loads.

<u>Interrogatory CEAB-2</u>

The United Illuminating Company
Docket No. F2009

Witness: Mike Ghilani

Q-CEAB-2: Please provide the number of MW and customers in your service territory that are currently enrolled in ISO-NE Demand Response Programs.

A-CEAB-2: There are approximately 200 customers and 60 MW of capacity in UI's service territory that are currently enrolled in the ISO-NE 30 Minute Real-Time Demand Response program.

Interrogatory CEAB-3

The United Illuminating Company
Docket No. F2009

Witness: Mike Ghilani

Q-CEAB-3: Please provide the number of MW and customers in your service territory that (a) cleared in FCA2 as a real-time demand response or profiled response customer, or (b) cleared in FAC2 as an "other demand resource" (ODR) customer.

A-CEAB-3: UI cleared approximately 95 MW of Active Real-Time Demand Response in our service territory, from approximately 180 customers, in FCA-2. UI also cleared 42.76 MW for Other Demand Resources (Energy Efficiency). The total number of customers for energy efficiency is not applicable.

Interrogatory CEAB-4

Q-CEAB-4: Please describe and show the calculations underlying the load factor forecasts found in CL&P's Table 2-1, UI's Exhibit 1, and CMEEC's Table 1.

A-CEAB-4: The load factor forecasts found in UI's Exhibit 1 is calculated by taking the average System Energy Requirements and dividing by either the normal or extreme weather system peak. The calculation is:

$$\text{Load Factor} = \frac{\text{(System Energy Requirements in GWHrs)}}{\text{(1000 * 8760 hours * System Peak in MW)}}$$

As stated on p. 3 of UI's filing, the Sales Forecast presented in Exhibit 1 is used for budgeting and financial planning purposes. Also, as stated on p. 5 of UI's filing, the Peak Load Forecast is a derivative of a sales forecast that uses a different forecasting methodology than the revenue-focused Sales Forecast. A projected load factor is also used in the forecasting methodology to derive the Peak Load Forecast. The system peak load forecast for the normal weather scenario is based on a normal weather load factor forecast that ranges from 47.1 – 47.2%. The system peak load forecast for the extreme weather scenario is based on an extreme weather load factor forecast of 44.2 – 44.3%.

Q-CEAB-5: Please provide a copy of your ten year plan for infrastructure improvements in Connecticut.

A-CEAB-5: The following provides the infrastructure improvements necessary to support UI's ten-year plan.

The United Illuminating Ten Year Transmission Planning Study identified projects that are required to assure continued reliable service to our customers in the 2009 – 2018 timeframe. These projects are grouped into three categories of reliability drivers that establish need. These reliability-based project categories are:

1. Distribution Capacity – New 115/ 13.8 kV distribution substations that are required to provide capacity in an area that has been forecast to have a deficiency of available substation capacity based on the 90/10 peak demand load forecast. Feasible distribution solutions are identified and exhausted before the need for a new substation is considered. These distribution solutions seek to take advantage of available capacity on nearby distribution circuits through 13.8 kV feeder level load transfers, or they look to add capacity, where practical, at existing 115/ 13.8 kV substations.
2. Aging Infrastructure – Component replacement/upgrade projects or larger scale substation rebuild projects that are required to assure the reliable operation of the electric system, based on the condition of the equipment, its impact on system performance and the increased failure risks associated with aging infrastructure.
3. Standards Compliance – Projects that are required to meet national and regional transmission planning reliability standards. As a Transmission Owner (TO) and member of New England Power Pool (NEPOOL), UI is required to meet reliability standards defined by the North American Electric Reliability Council (NERC), Northeast Power Coordinating Council (NPCC), and the Independent System Operator – New England (ISO-NE). Projects identified in this category are primarily driven by transmission reliability standards related to the thermal, voltage, short circuit and stability performance of the transmission system as impacted by UI's transmission elements.

The following list of transmission infrastructure reliability projects in the 2009 -2018 timeframe are considered to be planned, proposed or conceptual in nature. Planned projects have received Connecticut Siting Council (CSC) approval, if required, and are in the detail engineering design phase preparing for construction. Proposed projects have been identified by UI as the recommended solution and are in detailed study or in the CSC approval process, as required. Conceptual projects have an identified need that requires further detail analysis, and further solution development and evaluation.

Projects currently under construction or recently completed are not included in this listing. These include:

1. Trumbull 115/13.8 kV Substation - Placed into service in June 2008.
2. Middletown-Norwalk 345 kV Reliability Project (M-N Project) - Placed in-service in December 2008.
3. Mix Avenue Substation 115 kV Oil Circuit Breaker Replacement - Placed in service in December 2008.
4. Ash Creek 115 kV Disconnect Switch Replacements – Placed into service March 2009.

Reliability Projects: Distribution Capacity

Project	**Reliability Project Type**	**Projected In-Service Year**	**Status** (Conceptual, Proposed, Planned)
Union Avenue 115/ 26.4 kV Substation (a.k.a., "Metro-North")	Distribution Capacity	2010	Planned
Broadway 115/ 13.8 kV Substation Expansion Project	Distribution Capacity	2010	Planned
New Shelton 115/ 13.8 kV Substation	Distribution Capacity	2013	Conceptual

Interrogatory CEAB-5

Reliability Projects: Aging Infrastructure

Project	**Reliability Project Type**	**Projected In-Service Year**	**Status** (Conceptual, Proposed, Planned)
New Haven Area 115 kV High Pressure Fluid Filled (HPFF) Cable Pumping Plant Technology Upgrade	Aging Infrastructure	2011	Conceptual
East Shore 115 kV Asset Replacement	Aging Infrastructure	2011-2015	Conceptual
Substation Control House Expansions – Substations TBD	Aging Infrastructure	2011-2013	Conceptual
Grand Avenue 115 kV Switching Station Modernization Project	Aging Infrastructure	2012	Planned
115 kV Oil Circuit Breaker Replacement Program	Aging Infrastructure	2012-2015	Conceptual
Baird 115/ 13.8 kV Substation Rebuild	Aging Infrastructure	2013	Conceptual
Sackett 115/ 13.8 kV Substation Rebuild	Aging Infrastructure	2014	Conceptual
New Haven Area 115 kV Low Pressure Oil Filled (LPOF) Underground Cable System Replacement	Aging Infrastructure	2018	Conceptual

Reliability Projects: Standards Compliance

Project	**Reliability Project Type**	**Projected In-Service Year**	**Status** (Conceptual, Proposed, Planned)
East Shore 115 kV Capacitor Bank Transient Recovery Voltage (TRV) Mitigation	Standards Compliance	2010	Planned
Water Street Substation 115 kV Circuit Breaker Fault Duty Mitigation	Standards Compliance	2010	Planned
North Haven 115 kV Capacitor Bank Transient Recovery Voltage (TRV) Mitigation	Standards Compliance	2011	Conceptual
West River 115 kV Switching Station Fault Duty Mitigation	Standards Compliance	2011	Conceptual
Sackett 115 kV Capacitor Bank Transient Recovery Voltage (TRV) Mitigation	Standards Compliance	2012	Conceptual
Devon Tie 115 kV Switching Station Bulk Power System (BPS) Compliance Upgrades	Standards Compliance	2012	Conceptual
Naugatuck Valley 115 kV Reliability	Standards Compliance	2013	Conceptual
Pequonnock 115 kV Circuit Breaker Fault Duty Mitigation	Standards Compliance	2013	Conceptual

<u>Interrogatory CEAB-6</u>

The United Illuminating Company
Docket No. F2009

Witness: Christian Bilcheck

Q-CEAB-6: Please indicate which of the transmission improvements described in your initial filings in this proceeding are to serve planned or anticipated generating facilities.

A-CEAB-6: There are no transmission improvements described in UI's initial filings in this proceeding that are to serve planned or anticipated generating facilities. However, transmission improvements at UI substations will be required to interconnect the following generation projects that are currently under development:

1. Ansonia Generation LLC
2. PSEG Connecticut - New Haven Harbor Generation

Interrogatory CEAB-7

The United Illuminating Company
Docket No. F2009

Witness: Mike Ghilani
Page 1 of 1

Q-CEAB-7: Please compare your assumptions for CL&M impacts in both your 50/50 and 90/10 cases, in terms of MWh and peak MW savings, to the levels in the Reference Case and Expanded Energy Efficiency in Connecticut Case described in the electric distribution companies' 2009 IRP Filing submitted January 1, 2009.

A-CEAB-7: See the table below. Note that the CSC filing erroneously included the expanded EE (earlier version) energy and should have only included the reference level EE. Additionally, the capacity shown in the CSC filing takes into account capacity from prior year measures that have expired whereas the IRP capacity does not.

						Megawatts					
Document	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
CSC-50/50	5.14	11.47	12.39	11.06	10.45	9.56	9.30	8.26	7.10	7.39	92.11
CSC-90/10	5.14	11.47	12.39	11.06	10.45	9.56	9.30	8.26	7.10	7.39	92.11
2009 IRP Ref EE	10.10	11.07	12.48	11.84	10.76	9.68	9.47	9.61	9.76	9.89	104.64
2009 IRP Expanded EE	10.77	14.74	21.14	24.84	25.43	23.67	23.13	22.61	22.76	22.88	211.98

						Gigawatt-Hours					
Document	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
CSC-50/50	80.00	118.00	138.00	160.00	129.00	129.00	130.00	131.00	132.00	133.00	1,280.00
2009 IRP Ref EE	73.25	90.09	86.43	71.16	63.56	56.37	57.17	58.12	58.89	59.62	674.66
2009 IRP Expanded EE	85.78	133.96	161.64	166.15	154.34	140.12	134.94	135.89	136.66	137.39	1,386.88

<u>Interrogatory CEAB-8</u>

Q-CEAB-8: Please provide the forecast of impacts resulting from distributed generation (DG) projects for which the Department of Public Utility Control has approved grants pursuant to the DG Grant Program in the period 2009-2018 on (a) total system energy requirements and (b) summer peaks. Please provide a list of the DG units and their anticipated in-service dates.

Q-CEAB-8: See tables below.

Distributed Generation Incremental Impacts											
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
MW	2.47	10.68	6.09	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.24
GWh	46.0	126.0	147.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	323

Interrogatory CEAB-8

Monetary Grant - Operational Units (CSC 4/1/09 Filing)

Customer Name	Docket	Project Type	Fuel Type	Operating Strategy	Project Location	Project Size kW	Grant Award Status	Date Operational
Fairfield University	06-05-12	CHP	Natural Gas	Baseload Generation	SWCT - Fairfield	4,600	Paid	Dec-07
Southern Connecticut Gas	07-11-33	CHP	Natural Gas	Baseload Generation	SWCT - Orange	71.6	Pending	Aug-08
Town of Fairfield	07-03-07	Fuel Cell	Natural Gas	Baseload Generation	SWCT - Fairfield	200	Paid	Jul-08

	kW
Total CHP Units	4,672
Total Fuel Cell Untis	200
Total All Units	4,872

Monetary Grant - Forcasted Units (CSC 4/1/09 Filing)

Customer Name	Docket	Project Type	Fuel Type	Operating Strategy	Project Location	Project Size kW	Grant Award Status	Date Operational
GNH WPCA	07-03-23	CHP	Natural Gas	Baseload Generation	SWCT - New Haven	708	Approved	Dec-08
Sargent	06-12-22	CHP	Natural Gas	Baseload Generation	SWCT - New Haven	500	Approved	Dec-08
YMCA-MLFD	07-07-18	CHP	Natural Gas	Baseload Generation	SWCT - Milford	49	Approved	Dec-08
Woodview Elderly Housing	08-01-18	CHP	Natural Gas	Baseload Generation	SWCT - East Haven	73	Approved	Dec-08
Lord Chamberlin	08-09-07	CHP	Natural Gas	Baseload Generation	SWCT - Stratford	148	Approved	Jan-09
U.S. Surgical Corp.	07-06-51	CHP	Natural Gas	Baseload Generation	SWCT - North Haven	4,797	Approved	Jan-09
Latex Foam	07-04-19	CHP	Natural Gas	Baseload Generation	SWCT - Shelton	1,500	Approved	Apr-10
Schick	07-05-16	CHP	Natural Gas	Baseload Generation	SWCT - Milford	5,207	Approved	Jun-10
YMCA-BPT	07-07-21	CHP	Natural Gas	Baseload Generation	SWCT - Bridgeport	49	Approved	Jul-10
YMCA-HMDN	07-07-19	CHP	Natural Gas	Baseload Generation	SWCT - Hamden	49	Approved	Jul-10
YMCA-NH	07-07-20	CHP	Natural Gas	Baseload Generation	SWCT - New Haven	69	Approved	Jul-10
Yale University	07-04-21	CHP	Natural Gas	Baseload Generation	SWCT - New Haven	14,486	Approved	Dec-10
St. Raphael's	07-06-78	CHP	Natural Gas	Baseload Generation	SWCT - New Haven	1,784	Approved	Jan-11
Sikorsky Aircraft	08-08-43	CHP	Natural Gas	Baseload Generation	SWCT - Stratford	10,363	Draft	Sep-11
US Micro Hydro	08-03-24	Hydro	Water	Baseload Generation	SWCT - New Haven	36	Approved	Jul-11

	kW
Total CHP Units	39,783
Total Hydro Units	36
Total All Units	39,819

Capacity used for CSC 4/1/09 Filing

Year	Operational Capacity (kW)	Forecasted Capacity (kW)	Adjusted Forecasted Capacity (kW)	Operational & Adjusted Forecasted (kW)
2007	4,600			
2008	272	1,331	665.315	
2009		4,945	2472.6	2,472.6
2010		21,360	10680	10,680.0
2011		12,183	6091.58	6,091.6
Total	4,871.60	39,819	19,909.50	19,244.18

Monetary Grant - Operational Units (6/15/09)

Customer Name	Docket	Project Type	Fuel Type	Operating Strategy	Project Location	Project Size kW	Grant Award Status	Date Operational
Fairfield University	06-05-12	CHP	Natural Gas	Baseload Generation	SWCT - Fairfield	4,600	Paid	Dec-07
Southern Connecticut Gas	07-11-33	CHP	Natural Gas	Baseload Generation	SWCT - Orange	71.6	Pending	Aug-08
Town of Fairfield	07-03-07	Fuel Cell	Natural Gas	Baseload Generation	SWCT - Fairfield	200	Paid	Jul-08
YMCA-MLFD	07-07-18	CHP	Natural Gas	Baseload Generation	SWCT - Milford	49	Approved	Dec-08
Woodview Elderly Housing	08-01-18	CHP	Natural Gas	Baseload Generation	SWCT - East Haven	73	Approved	Dec-08
U.S. Surgical Corp.	07-06-51	CHP	Natural Gas	Baseload Generation	SWCT - North Haven	2,994	Approved	Dec-08
U.S. Surgical Corp.	07-06-52	CHP	Natural Gas	Baseload Generation	SWCT - North Haven	1,803	Approved	Mar-09
						kW		
					Total CHP Units	9,591		
					Total Fuel Cell Untis	200		
					Total All Units	9,791		

Monetary Grant - Forcasted Units (6/15/09)

Customer Name	Docket	Project Type	Fuel Type	Operating Strategy	Project Location	Project Size kW	Grant Award Status	Date Operational
GNH WPCA	07-03-23	CHP	Natural Gas	Baseload Generation	SWCT - New Haven	708	Approved	Jun-09
Sargent	06-12-22	CHP	Natural Gas	Baseload Generation	SWCT - New Haven	500	Approved	Jul-09
Lord Chamberlin	08-09-07	CHP	Natural Gas	Baseload Generation	SWCT - Stratford	148	Approved	Jul-09
Latex Foam	07-04-19	CHP	Natural Gas	Baseload Generation	SWCT - Shelton	1,600	Approved	Apr-10
Schick	07-05-16	CHP	Natural Gas	Baseload Generation	SWCT - Milford	5,207	Approved	Jun-10
YMCA-BPT	07-07-21	CHP	Natural Gas	Baseload Generation	SWCT - Bridgeport	49	Approved	Jul-10
YMCA-HMDN	07-07-19	CHP	Natural Gas	Baseload Generation	SWCT - Hamden	49	Approved	Jul-10
YMCA-NH	07-07-20	CHP	Natural Gas	Baseload Generation	SWCT - New Haven	69	Approved	Jul-10
Yale University	07-04-21	CHP	Natural Gas	Baseload Generation	SWCT - New Haven	14,486	Approved	Dec-10
St. Raphael's	07-06-78	CHP	Natural Gas	Baseload Generation	SWCT - New Haven	1,784	Approved	Jan-11
Sikorsky Aircraft	08-08-43	CHP	Natural Gas	Baseload Generation	SWCT - Stratford	10,363	Approved	Sep-11
US Micro Hydro	08-03-24	Hydro	Water	Baseload Generation	SWCT - New Haven	36	Approved	Jul-11
						kW		
					Total CHP Units	34,864		
					Total Hydro Units	36		
					Total All Units	34,900		

Updated Capacity 6/15/09

Year	Operational Capacity (kW)	Forecasted Capacity (kW)	Adjusted Forecasted Capacity (kW)	Operational & Adjusted Forecasted (kW)
2007	4,600			
2008	3,388			
2009	1,803	1,357	678.3	2,481.3
2010		21,360	10680	10,680.0
2011		12,183	6091.58	6,091.6
Total	9,790.83	34,900	17,449.88	19,252.88

Interrogatory CEAB-9

The United Illuminating Company
Docket No. F2009

Witness: Mike Ghilani
Page 1 of 1

Q-CEAB-9: Please provide the effective Load Factor for C&LM programs described on in your 2009 Filing for both history and forecast, and compare to the system-wide Load Factor shown in Exhibit 1.

A-CEAB-9: See table below.

Load Factor			
Year	50/50	90/10	CLM
1998			
1999			
2000	55%	53%	
2001	55%	52%	60%
2002	55%	52%	51%
2003	54%	51%	45%
2004	54%	52%	65%
2005	54%	51%	62%
2006	51%	48%	57%
2007	50%	48%	73%
2008	49%	46%	71%
2009	49%	46%	83%
2010	47%	44%	93%
2011	45%	42%	79%
2012	43%	40%	69%
2013	41%	39%	67%
2014	41%	38%	67%
2015	40%	38%	69%
2016	40%	37%	69%
2017	39%	37%	69%
2018	39%	37%	69%

CLM Load Factor = kWh saved / (8760 x peak kW saved)

Interrogatory CEAB-25

The United Illuminating Company
Docket No. F2009

Witness: Mike Ghilani

Q-CEAB-25: Please provide the forecast of conservation and load management (CL&M) impacts from the "additional Aggressive C&LM programs" referenced on p. 8 of UI's "Report to the CSC on Loads and Transmission Resources, April 1, 2009" (the UI filing) that ultimately was not used to adjust the Peak Load Forecast. Please provide the data annually in the following form (a) total system energy requirements, (b) summer peak in the following format: (i) total C&LM, (ii) conservation impacts only, and (iii) load impacts only.

A-CEAB-25: See the tables below for the aggressive CLM energy and capacity savings. Note that the expanded (aggressive) EE energy savings was erroneously included in the forecast.

					Megawatts						
Document	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
2009 IRP Expanded EE	10.77	14.74	21.14	24.84	25.43	23.67	23.13	22.61	22.76	22.88	211.98

					Gigawatt-Hours						
Document	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
2009 IRP Expanded EE	85.78	133.96	161.64	166.15	154.34	140.12	134.94	135.89	136.66	137.39	1,386.88

The 2009 IRP did not have a scenario that assumed any "additional aggressive" demand response. The IRP included UI's current level of demand response up to May 2010 and then assumed the capacity obligation from the first two forward capacity auctions.

Interrogatory CEAB-26

The United Illuminating Company	Witness: Mike Ghilani Robert Manning
Docket No. F2009	Page 1 of 2

Q-CEAB-26: Exhibit 1 of the UI filing states in footnote 3 that the data contained in it include C&LM, DG and potential new large customer planned loads identified by UI Economic Development, while Exhibit 2 of the UI filing states in footnote 1 that the data contained in it excludes C&LM, DG and potential new large customer planned loads identified by UI Economic Development. Please provide the annual forecasts implied by these two exhibits shown separately for each category: (a) C&LM, (b) DG and (c) potential large customer planned loads.

A-CEAB-26: (a) The annual forecast of C&LM reflected in Exhibit 1 is provided in the Table below.

Year	Incremental Impact from C&LM (MW)	Incremental Impact from C&LM Grossed-up to System Level (MW)
2009	5.14	5.34
2010	11.47	11.92
2011	12.39	12.88
2012	11.06	11.49
2013	10.45	10.86
2014	9.56	9.94
2015	9.30	9.66
2016	8.26	8.58
2017	7.10	7.38
2018	7.39	7.68

There was no impact from C&LM reflected in Exhibit 2.

(b) The annual forecast of DG reflected in Exhibit 1 is provided in the Table below.

Year	Incremental Impact from DG (MW)	Incremental Impact from DG Grossed-up to System Level (MW)
2009	2.47	2.57
2010	10.68	11.10
2011	6.09	6.33
2012	-	-
2013	-	-
2014	-	-
2015	-	-
2016	-	-
2017	-	-
2018	-	-

There was no impact from DG reflected in Exhibit 2.

(c) The annual forecast of potential large customer planned load in Exhibit 1 is provided in the Table below.

Year	Incremental Impact of Potential Large Customer Planned Load (MW)	Incremental Impact of Potential Large Customer Planned Load Grossed-up to System Level (MW)
2009	8.29	8.61
2010	20.47	21.28
2011	18.91	19.65
2012	12.37	12.85
2013	4.47	4.64
2014	-	-
2015	0.69	0.72
2016	-	-
2017	-	-
2018	-	-

There was no impact from potential large customer planned load additions reflected in Exhibit 2.

Interrogatory CEAB-27

The United Illuminating Company
Docket No. F2009

Witness: Mike Ghilani
Page 1 of 1

Q-CEAB-27: Page 12: Please provide the status of the EE Potential study the company and ECMB have had prepared on their behalf, including the approximate EE potential of the study for UI and the reason for delay in implementation CEAB 28. In relation to the statement quoted in (3) above concerning the development of adequate in-state renewable resources, please indicate the renewable projects that have been selected to date for long-term contracts under project 150, including their planned capacity and in-service dates.

A-CEAB-27: See the tables below regarding project 150 status. The EE potential study is being performed under the direction of the ECMB and has not been finalized. Please direct any questions regarding the estimated completion date and reason for delay to the ECMB.

Executed and Approved Project 150 Contracts

Project	Capacity (MW)	In Service
South Norwalk Renewable Generation	30	6/1/2011
Stamford Hospital Fuel Cell CHP	4.8	after 10/1/09
Watertown Renewable Power	15	12/31/2011
Clearview Renewable Energy	30	12/1/2011
Clearview East Canaan Energy	3	6/1/2010
Plainfield Renewable Energy	30	7/1/2011
Waterbury Hospital Fuel Cell CHP	2.4	after 6/9/09
DFC-ERG Milford	9	5/29/2010

Projects Awarded in Round 3, Pending Execution

Project	Capacity (MW)	In Service
DFC-ERG Bloomfied	3.65	10/15/2010
Bridgeport Fuel Cell Park	14.93	1/1/2011
DFC-ERG Trumbull	3.4	11/15/2010
DFC-ERG Glastonbury	3.4	12/15/2010
Cube	3.36	9/30/2010

Q-CEAB-28: Please provide in table format an illustration of the Peak Load Forecast Methodology described on pages 5-9 using historical year values for each step in the process, e.g., 2001 and/or 2005. In your answer please include an explanation of the factors that produced the extreme actual System Peak values in 2001 and 2005.

A-CEAB-28: The Peak Load Forecast Methodology described on pages 5-9 of UI's filing is illustrated in the tables below. Step 1 of the process takes actual historic energy sales by customer class and weather normalizes the energy sales using the average monthly temperature. The output of Step 1 is weather normalized sales by customer class.

Step	Input	Process	Output
1	Historic Energy Sales by Customer Class	Weather Normalization using Average Monthly Temperature	Weather Normalized Sales by Customer Class

The output of Step 1 is the input to Step 2. Step 2 of the process takes the weather normalized sales by customer class and uses the econometric model by customer class to produce the forecast of quarterly sales as the output.

Step	Input	Process	Output
2	Weather Normalized Sales by Customer Class	Econometric Model by Customer Class development	Forecast of Quarterly Sales

The output of Step 2 is the input to Step 3. Step 3 sums the forecast of quarterly sales into an annual sales forecast.

Step	Input	Process	Output
3	Forecast of Quarterly Sales	Summation of Quarterly Sales Forecast by Customer Class	Annual Sales

The output of Step 3 is the input to Step 4. Step 4 converts the annual sales (customer level) into system energy requirements (the UI 'envelope') by increasing the energy requirements to account for losses on the system.

Step	Input	Process	Output
4	Annual Sales	Loss Factor used to increase energy requirements to account for system losses	System Energy Requirements

Step 5 of the process is the weather normalization process of system peaks. The output of Step 5 (Weather Normalized Peak for Normal and Extreme Weather) is based on a model that relates the twelve-hour average Temperature Humidity Index (THI) to historical summer weekday peak loads. 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 as well as for extreme conditions.

Step	Input	Process	Output
5	Historic System Peaks	Weather Normalization using 12-hour average THI	Weather Normalized Peak for Normal and Extreme Weather

The outputs of Steps 4 and 5 are used as inputs into Step 6. The output of Step 6 results in the historic load factors for both normal and extreme weather. The calculation is a result of dividing the average load (system energy requirements divided by 8,760 hours) by the peak load.

Step	Input	Process	Output
6	System Energy Requirements and Peak Load	Calculation of Historic Load Factors for Normal and Extreme Weather	Historic Load Factors for Normal and Extreme Weather

The output of Step 6 (historic load factors for normal and extreme weather) is the input to Step 7. Step 7 utilizes the historic load factors to create the forecast of load factors for both normal and extreme weather.

Step	Input	Process	Output
7	Historic Load Factors for Normal and Extreme Weather	Analysis of historic load factors to create forecast of load factors	Forecasted Load Factors for Normal and Extreme Weather

Step 8 uses the output of Steps 4 and 7 as its input. This step takes the system energy requirements and divides by the number of hours in a year and the forecast of normal and extreme weather load factors to derive a base system peak forecast for normal and extreme weather.

Step	Input	Process	Output
8	System Energy Requirements & System Load Factor	Divide by 8,760 hours & System Load Factor	Base System Peak Forecast

The output of Step 8 is one of the inputs to Step 9. Other inputs to Step 9 include the forecast of C&LM, DG and new large customer loads. These inputs are summed (C&LM and DG are offsets to system peak load) to develop the system peak load forecast.

Step	Input	Process	Output
9	Base System Peak Forecast, C&LM, DG & New Large Customer Loads	Summation of inputs	System Peak Load Forecast

Step 5 above is the process that was used to produce the extreme weather peaks based on the actual System Peak values. An example is presented in the two tables below using the 2001 and 2005 System Peaks as requested. The extreme weather adjusted peak is based on a model that relates the twelve-hour average THI to historical summer weekday peak loads. 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 as well as for extreme conditions.

Year	Hour of Peak	System Peak	12-hour Average THI at Hour of System Peak	Extreme Weather (90/10) 12-hour Average THI	Difference between Extreme Weather 12-hour Average THI and 12-hour Average THI at Hour of System Peak
2001	16	1,324[2]	80.467	80.4	-0.067
2005	16	1,346	78.5	80.4	1.9

[2] Reflects the value in revised Exhibit 1.

Year	System Peak (1)	Difference between Extreme Weather 12-hour Average THI and 12-hour Average THI at Hour of System Peak (2)	Weather Adjustment (MW/THI) (3)	System Peak Adjustment (2) * (3) (MW) (4)	Extreme Weather (90/10) System Peak (1) + (4)
2001	1,324	-0.067	36.48	-2.4	1,322
2005	1,346	1.87	43.74	81.8	1,428