BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

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	)	
UNITIL ENERGY SYSTEMS, INC.	)	**DOCKET NO. DE 09-____**
Petitioner	)	
	)	

PETITION FOR APPROVAL OF DISTRIBUTED ENERGY RESOURCES INVESTMENT PROPOSAL AND PROPOSED TARIFF

Pursuant to the provisions of RSA Chapter 374-G, Unitil Energy Systems, Inc., ("UES" or "Company") submits this Petition to the New Hampshire Public Utilities Commission ("Commission") requesting:

1. approval of UES' proposed two-stage framework for review of its Distributed Energy Resources ("DER") investment proposal;
2. approval of UES proposed DER project screening process;
3. approval of UES' proposed DER rate recovery mechanism and DER Tariff, Schedule DERIC, which would be activated with an initial rate filing later this year; and
4. approval of UES' proposed 2009 DER program, which consists of four energy management and distributed generation projects.

In support of its Petition, UES states the following:

Petitioner

UES is a New Hampshire corporation and public utility primarily engaged in the distribution of electricity in the capital and seacoast regions of New Hampshire.

Background

Pursuant to RSA Chapter 374:G, electric public utilities may make investments in distributed energy resources ("DER"), as defined and limited in the statute, and, through an appropriate rate filing, seek rate recovery for such investments. Specifically, the law authorizes rate recovery for utility investments in DER that "provide energy diversity by eliminating, displacing or better managing energy deliveries from the centralized bulk power grid." For such investments, RSA 374:G provides for an expedited rate approval process and the potential for incentive returns for DER investments.

UES' DER investment proposal consists of a proposed two-stage framework for regulatory review of the Petition, a proposed DER screening process, a proposed rate recovery mechanism and tariff, and four specific projects for Commission approval:
1) Time-of-Use/Demand Response (TOU/DR) Pilot Program designed to investigate the costs and benefits associated with three distinct demand reduction programs. Two of these programs will investigate TOU rates incorporating low, medium and high-cost time based rates with a critical peak price (CPP) that can be initiated during periods of extreme electricity demand. The third program is a non-TOU program that entails a utility-controlled thermostat that requires no intervention from the customer. The pilot will be conducted jointly in UES' affiliate Fitchburg Gas and Electric Light Company's Massachusetts and UES' New Hampshire service territories in order to achieve maximum efficiency at the lowest cost to the ratepayers of either state. The Company is intending to file for grant funding for up to 50 percent of the project costs from the United States Department of Energy under the Smart Grid Investment Grant Program;

2) a Solar Domestic Hot Water (DHW) system to replace the existing electric DHW system at Crutchfield Place, a 105 unit low income multifamily property in downtown Concord owned and managed by the Concord Housing Authority in Concord, NH;

3) a Solar Photovoltaic ("PV") investment to install 202 panels of BP Solar SX 3195, 195 watt or equivalent on the new Stratham Fire House in Stratham, NH; and

4) an investment contributing to the School Administrative Unit (SAU) 16 of Exeter's project to provide more efficient energy to the school system. This project will employ two forms of alternative, distributed energy generation: installation of a 100 kilowatt (kW) photo voltaic (PV) solar array mounted on the roof of the new SAU 16 high school building; and the installation of one Capstone microturbine combined heat and power unit at the administrative offices located at 30 Linden Street, Exeter, NH.

Description of Exhibits

Attached to this Petition are the following Exhibits:

Exhibit – GRG-1: Testimony and Schedules of George R, Gantz.

Exhibit – HJA-1: Testimony and Schedules of Howard J. Axelrod.

Exhibit – CLC-1: Testimony and Schedules of Cindy L. Carroll.

Exhibit – JCE -1: Testimony and Schedules of Justin C. Eisfeller.

Proposed Tariffs

UES' proposed tariffs are included with this filing and are provided in clean and redline format. UES requests approval of these proposed tariffs.

Request for Approvals

UES respectfully requests that the Commission issue a final order containing the following findings of fact, conclusions and approvals:

1. FIND that UES' proposed two-stage framework for review of its Distributed Energy Regulatory ("DER") investment proposal is reasonable;
2. FIND that UES' proposed DER rate recovery mechanism and DER Tariff, Schedule DERIC are reasonable and in the public interest;
3. FIND that UES proposed DER project screening process is a reasonable methodology for determining the Benefit/Cost of DER projects;
4. FIND that UES' proposed 2009 DER program, which consists of four energy management and distributed generation projects, is in the public interest;
5. CONCLUDE that, based upon the above Findings, UES Petition should be approved as filed;
6. GRANT APPROVAL of the tariff changes requested herein.

Conclusion

For all of the foregoing reasons, UES requests that the Commission grant it the approvals requested in this Petition, and for such other relief as the Commission may deem necessary and proper.

Respectfully submitted,

UNITIL ENERGY SYSTEMS, INC.
By its Attorney:

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Chief Regulatory Attorney
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August 5, 2009

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DOMESTIC DELIVERY SERVICE
SCHEDULE D (continued)

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge: All energy delivered under this Schedule shall be subject to the External Delivery Charge as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

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LOW INCOME ENERGY ASSISTANCE PROGRAM

Customers taking service under this rate may be eligible to receive discounts under the statewide low-income electric assistance program ("LI-EAP") authorized by the New Hampshire Public Utilities Commission. Eligibility for the LI-EAP shall be determined by the Community Action Agencies. Customers participating in the LI-EAP will continue to take service under this rate, but will receive a discount as provided under this Tariff as applicable.

ELECTRICITY CONSUMPTION TAX

All customers shall be obligated to pay the Electricity Consumption Tax in accordance with New Hampshire Statute RSA Chapter 83-E, which may be revised from time to time, in addition to all other applicable rates and charges under this Tariff. The Electricity Consumption Tax shall appear separately on all customer bills.

TERMS OF PAYMENT

The charges for service hereunder are net, billed monthly and due within 25 days following the date postmarked on the bill, as specified in the Terms and Conditions for Distribution Service, which is a part of this Tariff. Amounts not paid prior to the due date shall be subject to interest on past due accounts, as provided in Appendix A of the Terms and

GENERAL DELIVERY SERVICE
SCHEDULE G (continued)

MINIMUM CHARGE

The Minimum Charge per month or fraction thereof will be as follows:

Large General Service Schedule G1:

The Minimum Charge per month shall be no less than the Customer Charge for each type of service installed plus a capacity charge based upon a minimum demand and/or demand ratchet as defined under the Determination of Demand provision of this Schedule.

Regular General Service Rates G2, G2 kWh meter, Uncontrolled (Quick Recovery) Water Heating, and Space Heating:

The Minimum Charge per month shall be the Customer Charge for each type of service installed.

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OUTDOOR LIGHTING SERVICE
SCHEDULE OL (continued)

MONTHLY KWH PER LUMINAIRE

For billing purposes on Energy based charges and adjustments, the monthly kWh figures shown in the table above under Distribution Charges - Monthly: Luminaire shall be used for each luminaire type.

OTHER FIXTURES AND EQUIPMENT

Lighting fixtures other than that specified herein will be provided only at prices and for a contract term to be mutually agreed upon between the Company and the Customer.

MINIMUM CHARGE

The minimum charge per month, or fraction thereof, per lamp shall be the Distribution Charge: Luminaire.

ADJUSTMENTS

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DISTRIBUTED ENERGY RESOURCES INVESTMENT CHARGE
SCHEDULE DERIC

The Distributed Energy Resources Investment Charge ("DERIC"), as specified on Calculation of the Distributed Energy Resources Investment Charge, shall be billed by the Company to all customers taking Delivery Service from the Company. The purpose of the DERIC is to recover, on a fully reconciling basis, the costs of the Company's investments in distributed energy resources.

The DERIC shall be established annually based on a forecast of includable costs, and shall include a full reconciliation with interest for any over- or under-recoveries occurring in the prior year(s). Interest shall be calculated at the prime rate, with said prime rate to be fixed on a quarterly basis and to be established as reported in THE WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used. The Company may file to the change the DERIC at any time should significant over- or under-recoveries occur or be expected to occur.

Any adjustment to the DERIC shall be in accordance with a notice filed with the Commission setting forth the amount of the proposed charge and the amount of the increase or decrease. The notice shall further specify the effective date of such charge, which shall not be earlier than forty-five (45) days after the filing of the notice, or such other date as the Commission may authorize. The annual adjustment to the DERIC shall be derived in the same manner as that provided by Calculation of the Distributed Energy Resources Investment Charge.

The DERIC shall be calculated according to the formula below.

$DERIC_x = (RR_x - OR_x + LBR_x + RA_{x-1} + I_x) / FkWh_x$; where

$DERIC_x$ = The annual Distributed Energy Resources Investment Charge for the year "x". "x" is the forecast year.

RR_x = The projected annual Revenue Requirement for the recovery of the investment and operation and maintenance costs of the Company's distributed energy resource investments approved by the Commission pursuant to RSA 374:G. The annual revenue requirement shall consist of the return on rate base and associated income taxes, along with depreciation and amortization expense, operation and maintenance expenses and taxes other than income taxes.

OR_x = The projected annual Offset Revenues received from any source that the Company is able to secure to support the cost of its investments.

**DISTRIBUTED ENERGY RESOURCES INVESTMENT CHARGE
SCHEDULE DERIC**

LBR_x = The projected calculated lost base revenue in year x resulting from the implementation of approved distributed energy resource investments.

RAx_{-1} = The annual Reconciliation Adjustment defined as the difference between (a) the actual annual Revenue Requirement, Offset Revenues, and LBR in the previous year, and (b) the revenue actually collected in the previous year. Interest calculated on the average monthly balance shall also be included in the RA. Interest shall be calculated at the prime rate, with said prime rate to be fixed on a quarterly basis and to be established as reported in THE WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used.

I_x = The estimated interest in the forecast period, calculated as defined above.

$FkWh_x$ = The forecasted kWh is the forecasted amount of electricity to be distributed to the Company's distribution customers for the year "x".

CALCULATION OF THE
DISTRIBUTED ENERGY RESOURCES INVESTMENT CHARGE

1.	(Over)/under Recovery - Beginning Balance January 1, 2010	to be filed
2.	Estimated Total Costs (January 2010 - December 2010)	to be filed
3.	Estimated Interest (January 2010 - December 2010)	to be filed
4.	Costs to be Recovered (L.1 + L.2 + L.3)	to be filed
5.	Estimated Calendar Month Deliveries in kWh (January 2010 - December 2010)	to be filed
6.	Distributed Energy Resources Investment Charge ($/kWh) (L.4/L.5)	to be filed

Authorized by NHPUC Order No. in Case No. , dated

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UNITIL ENERGY SYSTEMS, INC

DIRECT TESTIMONY OF

GEORGE R. GANTZ

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DE 09-___

AUGUST 5, 2009

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LIST OF SCHEDULES

I. INTRODUCTION

Q. Please state your name, title and business address.

A. My name is George R. Gantz. I am the Senior Vice President of Distributed Energy Resources for Unitil Service Corp. and an officer of Unitil Energy Systems, Inc. ("UES" or "Company"). My business address is 6 Liberty Lane West, Hampton, New Hampshire.

Q. Please summarize your qualifications and current position.

A. I have been employed by Unitil since 1983. During that time I have held various positions with increasing responsibilities in areas including pricing, legislative and regulatory affairs, power supply planning and acquisition, marketing and business development, customer services, communications and strategic planning. I have appeared many times as a witness before this Commission as well as the Massachusetts Department of Public Utilities, the Maine Public Utilities Commission and the Federal Energy Regulatory Commission. I graduated from Stanford University with a B.S. in Mathematics and Honors Humanities in 1973. I have also been active in leadership roles in various organizations including the Business and Industry Association, The United Way of North Central Massachusetts and the Fitchburg State College Foundation.

In July 2009, Unitil undertook a reorganization under which I was reassigned from the Customer Services and Communications functions and given leadership for the energy efficiency, demand response, distributed generation and smart grid initiatives.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of SB451, codified as RSA 374:G, to discuss the regulatory process under RSA 374:G and to introduce UES' proposal for ratemaking under RSA 374:G. UES believes that implementing this innovative statute is an important milestone for the Company and for the state of New Hampshire. Distributed Energy Resources ("DER") offer the promise of more cost-effective electric energy supply and delivery and increased efficiency in our production and utilization of energy. Achieving this promise will require significant innovation and sustained investments. With this filing UES hopes to accelerate the process and begin a long term initiative to find and deploy an increasing portfolio of cost-effective DER projects in its service area.

In my testimony I will cover the following:

- Goals and Objectives for UES' DER initiative
- Overview of RSA 374:G requirements
- Proposal for an efficient, two-step regulatory process
- Step One: Filing for Commission Approval
- Step Two: Rate Recovery

The other witnesses in this proceeding include: Dr. Howard J. Axelrod of Energy Strategies Inc., who will describe in detail the screening process and screening model UES has developed for use in qualifying proposed DER projects for investment and rate recovery; Justin C. Eisfeller, Unitil's Director of Measurement and Control, who will provide information relative to the company's proposed Time-of-Use / Smart Grid pilot program; and Cindy L. Carroll, Unitil's Director of Business Services, who will discuss the three other project proposals being included in this filing:

Solar Hot Water Installation for Crutchfield Place (Concord Housing Authority)
Solar PV Installation at the Stratham Fire Station
Solar PV and Micro CHP in the Exeter School District

Q. Please explain how the proposed Time of Use / Smart Grid pilot program relates to what the Company's Massachusetts affiliate has proposed to the Department of Public Utilities?

A. The Time of Use / Smart Grid pilot program is being proposed as a joint program of both UES and its Massachusetts affiliate Fitchburg Gas and Electric Light Company (FG&E). FG&E filed the proposal in Massachusetts as a "Smart Grid Pilot" in April 2009 in compliance with the Green Communities Act. That proceeding is now underway with approval expected in October. The joint proposal allows the companies to gain the benefits of conducting a broader pilot program with a larger and more robust statistical sampling plan at lower cost to our customers in either state.

Q. Is the Company making a proposal for grant funding of its Time of Use / Smart Grid pilot program under the Department of Energy Smart Grid Investment Grant program?

A. Yes, the Company is filing an application to the DOE for the Time of Use / Smart Grid Pilot Program in order to help defray the costs of the program to our customers. The application is being filed on August 6th with anticipated award announcement in October. This grant program is competitive and the level of interest nationally is quite high, so the outcome of the application is unknown. The proposal included in this filing and testified to by Mr. Eisfeller does not assume that the Company is awarded grant funding from DOE.

II. GOALS AND OBJECTIVES FOR UES'S DER INITIATIVE

Q. What are UES' guiding goals and objectives in undertaking its DER initiative?

A. It is the Company's goal to promote an accelerated deployment of energy efficiency and local generation in order to displace central station generation and the fuels on which it relies – thereby providing customers with cost-effective and environmentally sound energy options. In addition, UES seeks to promote the orderly transition and transformation of the electric grid to a so-called "smart grid" in a cost – effective manner. Finally, we view DER as a potentially more cost-effective option for maintaining and improving distribution reliability and performance than traditional distribution investments.

Q. Are there other benefits that can be derived from DER investments?

A. Yes, there are. The DER projects that UES is pursuing are designed to reduce or control peak demand, promote energy conservation, or generate electricity close to the source of the demand. By substituting a DER solution for conventional generation investment and imported energy supply, more of the dollars expended will be directed to local businesses, thereby maximizing the economic impact of each dollar spent by UES. DER projects will also help reduce our dependence on fossil fired generation.

Q. What does UES seek from the Commission in these proceedings?

A. This is UES' first application pursuant to RSA 374-G. It is our hope that the Commission in this proceeding will act favorably on the following proposals:

1. To authorize the two-stage DER regulatory framework we are proposing;
2. To approve our proposed DER rate recovery mechanism and DER Tariff, Schedule DERIC, which would be activated with an initial rate filing later this year;
3. To approve the DER project screening process we are proposing in this proceeding; and

4. To approve UES' proposed 2009 DER program, which consists of four innovative energy management and distributed generation projects.

III. OVERVIEW OF RSA 374:G REQUIREMENTS

Q. Please provide an overview of RSA 374:G.

A. As the Commission is aware, RSA 374:G became effective on September 9, 2008. A copy is provided for reference as Schedule GRG-1. The new law allows electric public utilities to make investments in DER as defined and limited in the statute, and requires the New Hampshire Public Utilities Commission to provide rate recovery for such investments. Specifically, the law authorizes rate recovery for utility investments in DER that "provide energy diversity by eliminating, displacing or better managing energy deliveries from the centralized bulk power grid". In essence, RSA 374:G allows electric utilities to either directly invest in or subsidize customer investments in a range of DER technologies, systems or processes that are cost effective, have environmental and economic development impacts and improve the reliability and security of the overall electrical system. For such investments, RSA 374:G provides for an expedited rate approval process and the potential for incentive returns for DER investments.

While RSA 374:G does allow distribution utilities to make investments in DER technologies and applications, it also contains certain limits particularly with respect to generation technologies. For example, the energy from utility-owned generation may only be used to displace energy for system losses or company use. This effectively limits this option to about four percent of the Company's kilowatt-hour throughput. In addition, generation projects must be smaller than 5 megawatts, and the total generation capacity may not exceed six percent of the company's system peak load, a limit of about 18 megawatts for UES. In addition, generation must be either renewable, or fueled with natural gas, in which case it must meet stringent emission limitations and additional restrictions on deployment levels.

While Chapter 374-G provides some clarity as to the types of DER investments that UES can make within the above categories, and outlines the broad criteria that the Commission should consider in its review process, it does not specify the regulatory process and rate recovery mechanism in any detail, nor does it delineate a precise cost/benefit test or evaluation process. These are matters left to the distribution utilities to propose and the Commission to decide.

IV. PROPOSAL FOR AN EFFICIENT TWO-STEP REGULATORY PROCESS

Q. What instruction does RSA 374-G provide regarding the regulatory process to be followed by a distribution utility and the Commission?

A. Section I of RSA 374-G:5 establishes the basic information required in a utility filing; Section II requires a pre-determination by the Commission of public interest; and Section III is a directive to the Commission to allow rate recovery for authorized and prudently incurred investments.

While 374-G:5 Section II does not stipulate the precise criteria that the Commission must use in pre-approving a utility's DER investments, it does require a finding of public interest based on the balancing of nine factors addressing economic cost benefit, environmental benefits and economic development. The provisions require the company to address cost and benefits to the utility ratepayers, to the participating customer and to the company's Default Service customers.

Section 374-G:5 Section III requires that investments being included in rates must be prudently incurred. An appropriate standard for a prudent investment would be meeting a public interest test – this implies that if the public interest test in Section II, relating to cost/benefit, environmental impact and economic development, is satisfied, then the investment would be prudent.

Section III also indicates that "authorized and prudently incurred investments shall be recovered." The inclusion of the word "authorized" implies that rate recovery will be provided for projects that have been approved, i.e. "authorized," by the Commission pursuant to the satisfaction of the public interest test.

In a single, contemporaneous filing, it is hard to see how the Commission could pre-approve the projects and simultaneously authorize recovery of prudently incurred costs in rates – unless the company had already made the investments. This would, of course, mean that the company would have funded the projects prior to Commission approval, putting the company at risk that one or more or all of the DER projects in which it had invested would fail to meet the Commission's standard of public interest.

Q. How does UES propose to implement RSA 374-G:5 in a manner that is consistent with the requirements and administratively efficient?

A. We think there is an approach that meets the requirements of RSA 374-G:5 in a reasonable and administratively manageable way. This will involve a bifurcated two-step process. In the first step the company files with the Commission, prior to making the actual investments, a detailed description of each DER project along with the required information needed to satisfy the public interest test. The Commission would then decide whether each project as presented meets or does not meet the public interest test. Essentially, the Commission would be authorizing the company to proceed with the project - and to recover the DER investments when incurred. The company would make a subsequent rate filing to recover the costs for DER projects that had been previously approved. In the cost recovery review process, the company would need to verify that project had met the designed objectives within a reasonable time frame and within the anticipated budget range.

Q. Does RSA 374-G specify when a utility should apply for DER rate recovery?

A. RSA 374-G:5 is written in such a way that a utility could file for each and every DER investment it makes. However, since the scale of particular investments is expected to be small and possibly spread out throughout a calendar year, it could be an administrative nightmare for all parties if separate DER filings are made for each and every DER investment. We think it would be far more efficient to implement the two-step approach described above as an annual process.

V. STEP ONE: FILING FOR COMMISSION APPROVAL

Q. Describe the elements of the initial DER project approval filing.

A. UES' DER project approval filing provides information on the proposed DER projects for the current year, along with sufficient information for the Commission to make a determination as to whether the proposed project is in the public interest.

Q. How will the Company demonstrate that proposed DER projects are in the public interest?

A. UES has developed an analytical screening process, described in detail by Dr. Axelrod, that is designed to address the questions posed by Section G:5 Section II items *a* through *i* regarding:

- Cost/benefit for participating customers, default customers and system-wide customers.

- Other tangible benefits including reduced environmental impacts, enhanced system reliability and diversity and increased regional economic output.

The Company's filing will describe each project and present an estimated cost along with the technical assessment of expected project performance, lifetime, etc. The output of the screening analysis will be presented and any additional factors or considerations relevant to the Commission's deliberation will be provided.

Q. Will there be any differences in the treatment of utility-owned and customer-owned DER investment?

A. RSA 374-G provides for two possible types of utility DER investment:

1. Traditional investment in utility owned technologies such as on-site distributed generation, energy storage technologies, and demand response and load control systems.
2. Utility investment in Customer Owned DER projects.

We propose that the public interest criteria for either utility or customer-owned projects be the same. There will be differences, however, in the allocations of costs and benefits. Specifically, it is anticipated that many customer-owned projects will involve some customer contribution to the project. The level of customer contribution will be an important factor impacting the level of net benefits to other UES customers.

Q. How does UES propose to determine the level of its investment in Customer-Owned DER?

A. While there are several possible approaches to determining the level of investment that the utility may make in a customer-owned DER project, UES proposes the following three-step process as a guideline. First, we would determine the level of benefit available to the Company and its distribution customers for the proposed project, excluding the benefits that would flow directly to the participating customer. Based on the expected project life and the Company's overall cost of capital, we would then calculate the level of investment those benefits would justify. Next we would look at the project's economics from the customer perspective. If those economic benefits are large we could seek to reduce the utility investment to balance the relative net benefits between the participant and all other customers. In the third step, we would look at the upfront financial requirement facing the customer and factor in the customer's ability and/or motivation to implement the project given an up-front financial threshold, the potential for other sources of funding and other factors. Ultimately, the goal will be to achieve a reasonable allocation of costs and benefits and an appropriate sharing of risks and responsibilities.

Q. Please address the requirements of RSA 374-G subsection I.

A. Section G:5 I identifies six filing requirements:

a) A detailed description and economic evaluation
b) A discussion of cost, benefits and risks
c) A description of any equipment specifications
d) A showing of efforts to involve local businesses
e) Evidence of environmental compliance
f) Copy of customer contracts

The Company believes its initial filing provides plans in sufficient detail as to satisfy the first four requirements. Item e) is a matter of compliance which the Company will document as necessary in the rate recovery reconciliation process. Similarly, the actual customer contracts would be a matter of compliance and filed in the rate recovery reconciliation filing, although the nature of that contract would be discussed in the DER program approval filing. In this current filing, we have included Memoranda of Understanding with the three host customers – the MOUs will guide the development of the definitive customer agreements which will be filed with the rate filing.

VI. STEP TWO: RATE RECOVERY

Q. Please explain the basis for UES' proposed rate recovery mechanism?

A. RSA 374 Section G5:III, provides electric utilities the opportunity to recover both prudently incurred investments and associated expenses for authorized DER projects. The statute also says that investments "shall be recovered under this section in a utility's base distribution rates as a component of rate base, and cost recovery shall include the recovery of depreciation, a return on investment, taxes, and other operating and maintenance expenses directly associated with the investment, net of any offsetting revenues received by the utility directly attributable to the investment." In addition, Section IV stipulates that "the Commission may add an incentive to the return on equity component as it deems appropriate to encourage investment in distributed energy resources."

These provisions define clearly the elements of the revenue requirement to be included in the rate calculations. However, in the context of UES' proposed bifurcated regulatory process, we are proposing that the rate calculation and inclusion of DER investments in rates occur once annually.

Q. Please describe the proposed cost recovery process.

A. UES proposes to recover the costs associated with its approved DER investments through a fully reconciling rate under the proposed DER Tariff, Schedule DERIC, which is attached to my testimony as Schedule GRG-2. The DER Investment Charge ("DERIC") would be included in the Company's distribution rates for billing purposes. The rate calculation, as described in the Tariff, will be based on a revenue requirement calculation that factors in the investments the Company will be making in approved DER projects, recovered over the useful life of the investment, as well as the associated mobilization, operating and maintenance, and monitoring, verification and reporting costs. The revenue requirements will be tracked on a monthly basis and reconciled annually.

Q. Please explain the proposed revenue requirements calculation.

A. The revenue requirement begins with the capital investment in DER equipment being made by the Company. This investment will be tracked separately in the Company's plant records system. The accounting process will also provide for the calculation of depreciation and depreciation reserve as well as deferred income taxes and deferred tax reserves under tax normalization, all in accordance with standard utility accounting methods. The net investment and a provision for working capital provide the basis for calculating the rate base value, on which the return is calculated. The Company proposes to use the capital structure and debt costs for the previous year from the form F-1 Supplemental Quarterly Financial and Sales Information that is on file with the Commission, with the inclusion of a return on equity from the Company's most recent base rate case. This will be adjusted for the effective income tax-rate to provide a pre-tax return value. This is a simple, straightforward, easily audited method.

In addition to the return component, the calculated revenue requirement will include depreciation, other taxes (if any), mobilization, operating and maintenance, and monitoring, verification and reporting costs incurred by the Company. Until such time as the company implements revenue decoupling, a factor for lost base revenues (LBR) associated with the operation of the approved DER projects will also be included. This calculation will be available monthly and filed with the annual reconciliation filing.

Q. How will the rate be calculated?

A. The Company proposes to calculate a single DERIC for an annual period on the basis of an updated, pre-filed budget for the previously approved DER projects during the upcoming period. The estimated revenue requirement will be calculated based on the capital and expenses already incurred and expected to be incurred in the coming year. That figure will be divided by forecasted retail distribution sales to all customers. This will provide a single rate in cents/kilowatt-hour to be charged to all customers.

As the year proceeds, the Company will maintain a calculation of the actual revenue requirement, based on projects completed and expenses incurred. This will be matched against revenues received from the DERIC for that month. Over- or under-collections will be accumulated and deferred to the subsequent year, with interest at the prime rate.

When the rate for the subsequent period is calculated, any over- or under-collection will be netted with the forecast revenue requirement in the calculation of the rate.

All of the calculations included in the revenue requirement calculations and reconciliation will be transparent and will track to specific accounting entries so that the process can be easily audited and verified. The Company will use accounting procedures similar to those it presently uses in its energy efficiency programs. These procedures ensure that costs are properly allocated and accounted for.

Q. Assuming the Commission approves this two-phased DER rate recovery process, what are the filing dates that you propose?

A. We recommend moving towards an annual cycle that would involve making the DER project filings in the second quarter, with approval in three months. The rate recovery reconciliation filing would follow by mid-November, 45 days in advance of the proposed rate effective date of January 1.

Q. What is the anticipated budget for the DER projects being filed with the Commission in this filing?

A. The attached Schedule GRG-3 provides the anticipated budget for the four DER projects included in this filing. As indicated, the proposed DER budget for these projects includes an estimate of $761,241 in capital investments and an estimate of $577,346 for other operating expenses. The total outlay for these programs over the next year is therefore about $1.3 million. The calculated benefit for this expenditure is $2,980,710.

The expenditures for the Crutchfield, Stratham and Exeter DER projects are direct capital investments. In the case of the TOU / Smart Grid Pilot, we are proposing to recover this as an expense item, consistent with the pilot nature of the project and its one-year time horizon. In addition, for this project we are excluding internal staff time for purposes of proposed rate recovery in both Massachusetts and New Hampshire. Finally, we have not assumed any contribution of funding from the DOE SGIG grant for which we are applying – in the event our grant application is successful, the costs to be recovered from ratepayers would be reduced by half.

In addition to the direct project costs, we have included in the budget an estimated entry for the external consulting costs associated with the initial development and start-up of the DER proposals, as well as an estimate of the costs for the ongoing program management and reporting. The costs associated with these activities are incremental for the company, directly attributable to the DER projects and of an ongoing nature, and therefore appropriate for inclusion in the rate recovery mechanism.

VII. CONCLUSION

Q. Does that complete your testimony?

A. Yes, it does.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 374-G
ELECTRIC UTILITY INVESTMENT IN DISTRIBUTED ENERGY RESOURCES

Section 374-G:1

374-G:1 Purpose. – Distributed energy resources can increase overall energy efficiency and provide energy diversity by eliminating, displacing, or better managing energy deliveries from the centralized bulk power grid, in keeping with the objectives of RSA 362-F:1. It is therefore in the public interest to stimulate investment in distributed energy resources in New Hampshire by encouraging New Hampshire electric public utilities to invest in distributed energy resources including clean and renewable generation benefiting the transmission and distribution system under state regulatory oversight.

Source. 2008, 373:1, eff. Sept. 9, 2008.

Section 374-G:2

374-G:2 Definitions; Exclusions. –

I. The following definitions shall apply in this chapter except as otherwise provided:

(a) ""Commission" means the public utilities commission.

(b) ""Distributed energy resources" means electric generation equipment, including clean and renewable generation, energy storage, energy efficiency, demand response, load reduction or control programs, and technologies or devices located on or inter-connected to the local electric distribution system for purposes including but not limited to reducing line losses, supporting voltage regulation, or peak load shaving, as part of a strategy for minimizing transmission and distribution costs as provided in RSA 374-F:3, III.

II. ""Distributed energy resources" in this chapter shall exclude electric generation equipment interconnected with the local electric distribution system at a single point or through a customer's own electrical wiring that is in excess of 5 megawatts.

Source. 2008, 373:1, eff. Sept. 9, 2008.

Section 374-G:3

374-G:3 Electric Generation Equipment Funded by Public Utility; Requirements. – Any electric generation equipment funded in part by a public utility under this chapter is subject to the following requirements:

I. The energy produced by electric generation equipment owned by the public utility shall be used as an offset to distribution system losses or the public utility company's own use;

II. The energy produced by electric generation equipment utilizing a non-renewable fuel source that is owned by a customer, or sited on a customer's property shall be used to displace the customer's own use;

III. The energy produced by electric generation equipment utilizing a renewable fuel source that is owned by a customer, or sited on the consumer's premises shall be used to displace the customers own use; however, if energy is occasionally generated in excess of the customer's energy requirements, it may be credited to the customer's account in a subsequent period.

IV. Any biomass-fueled generation shall meet the emission requirements to qualify as eligible biomass technology under RSA 362-F:2, VIII.

V. Any fossil-fuel fueled generation shall produce combined heat and power with a minimum energy efficiency of 60 percent, measured as usable thermal and electrical output in BTUs divided by fuel input in BTUs, shall be installed as an integrated combined heat and power application, and shall meet the following emission standards (in lbs/MW-H): NOx--0.07; CO--0.10; VOCs--0.02. A credit to meet the emission standard may be applied at the rate of one MW-H for each 3.4 million BTUs of heat recovered.

VI. These requirements apply in addition to and do not preempt or replace any emission standards or permitting requirements applicable to a given generation facility under any other applicable state or federal law.

Source. 2008, 373:1, eff. Sept. 9, 2008.

Section 374-G:4

374-G:4 Investments in Distributed Energy Resources. –

I. Notwithstanding any other provision of law to the contrary, as provided in RSA 374-G:5, a New Hampshire electric public utility may invest in or own distributed energy resources, located on or inter-connected to the local electric distribution system.

II. Distributed electric generation owned by or receiving investments from an electric utility under this section shall be limited to a cumulative maximum in megawatts of 6 percent of the utility's total distribution peak load in megawatts.

III. In addition, once the cumulative generation authorized under this chapter for a given public utility reaches 3 percent of the utility's total distribution peak load in megawatts, then that utility shall not be allowed to add any additional non-renewable generation under this chapter, until the cumulative renewable generation installed pursuant to this chapter, as a percentage of total generation installed pursuant to this chapter, shall equal or exceed twice the sum of the then-applicable percentage requirements for class I and class II under RSA 362-F:3.

Source. 2008, 373:1, eff. Sept. 9, 2008.

Section 374-G:5

374-G:5 Rate Filing; Authorization. –

I. A New Hampshire electric public utility may seek rate recovery for its investments in distributed energy resources from the commission by making an appropriate rate filing. At a minimum, such filing shall include the following:

(a) A detailed description and economic evaluation of the proposed investment.

(b) A discussion of the costs, benefits, and risks of the proposal with specific reference to the factors listed in paragraph II, including an analysis of the costs, benefits, and rate implications to the participating customers, to the company's default service customers, and to the utility's distribution customers.

(c) A description of any equipment or installation specifications, solicitations, and procurements it has or intends to implement.

(d) A showing that it has made reasonable efforts to involve local businesses in its program.

(e) Evidence of compliance with any applicable emission limitations.

(f) A copy of any customer contracts or agreements to be executed as part of the program.

II. Prior to authorizing a utility's recovery of investments made in distributed energy resources, the commission shall determine that the utility's investment and its recovery in rates, as proposed, are in the public interest. Determination of the public interest under this section shall include but not be limited to consideration and balancing of the following factors:

(a) Whether the expected value of the economic benefits of the investment to the utility's ratepayers over the life of the investment outweigh the economic costs to the utility's ratepayers.

(b) The efficient and cost-effective realization of the purposes of the renewable portfolio standards of RSA 362-F and the restructuring policy principles of RSA 374-F:3.

(c) The costs and benefits to any participating customer or customers.

(d) The costs and benefits to the company's default service customers.

(e) The energy security benefits of the investment to the state of New Hampshire.

(f) The environmental benefits of the investment to the state of New Hampshire.

(g) The economic development benefits and liabilities of the investment to the state of New Hampshire.

(h) The effect on the reliability, safety, and efficiency of electric service.

(i) The effect on competition within the region's electricity markets and the state's energy services market.

III. Authorized and prudently incurred investments shall be recovered under this section in a utility's base distribution rates as a component of rate base, and cost recovery shall include the recovery of depreciation, a return on investment, taxes, and other operating and maintenance expenses directly associated with the investment, net of any offsetting revenues received by the utility directly attributable to the investment.

IV. The commission may add an incentive to the return on equity component as it deems appropriate to encourage investments in distributed energy resources.

V. The commission shall approve, disapprove, or approve with conditions a utility rate filing under this section within 90 days of its filing. The commission may extend this deadline to 6 months at its discretion for any filing involving an investment in excess of $1,000,000. The commission may also extend the deadline at its discretion for failure of the applicant to respond to data requests on an expedited timeline.

Source. 2008, 373:1, eff. Sept. 9, 2008.

Section 374-G:6

374-G:6 Exemption; Rural Electric Cooperatives. – The requirements for commission authorization for recovery of investments under RSA 374-G:5 shall not apply to rural electric cooperatives for which a certificate of deregulation is on file with the commission.

Source. 2008, 373:1, eff. Sept. 9, 2008.

Section 374-G:7

374-G:7 Exclusion. – Any renewable generating equipment funded in part by a distribution utility under this chapter shall not be included in the calculation of the total rated generating capacity under RSA 362-A:9, I for purposes of limiting net energy metering.

Source. 2008, 373:1, eff. Sept. 9, 2008.

**DISTRIBUTED ENERGY RESOURCES INVESTMENT CHARGE
SCHEDULE DERIC**

The Distributed Energy Resources Investment Charge ("DERIC"), as specified on Calculation of the Distributed Energy Resources Investment Charge, shall be billed by the Company to all customers taking Delivery Service from the Company. The purpose of the DERIC is to recover, on a fully reconciling basis, the costs of the Company's investments in distributed energy resources.

The DERIC shall be established annually based on a forecast of includable costs, and shall include a full reconciliation with interest for any over- or under-recoveries occurring in the prior year(s). Interest shall be calculated at the prime rate, with said prime rate to be fixed on a quarterly basis and to be established as reported in THE WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used. The Company may file to the change the DERIC at any time should significant over- or under-recoveries occur or be expected to occur.

Any adjustment to the DERIC shall be in accordance with a notice filed with the Commission setting forth the amount of the proposed charge and the amount of the increase or decrease. The notice shall further specify the effective date of such charge, which shall not be earlier than forty-five (45) days after the filing of the notice, or such other date as the Commission may authorize. The annual adjustment to the DERIC shall be derived in the same manner as that provided by Calculation of the Distributed Energy Resources Investment Charge.

The DERIC shall be calculated according to the formula below.

$DERIC_x = (RR_x - OR_x + LBR_x + RA_{x-1} + I_x)/ \; FkWh_x$; where

$DERIC_x$ = The annual Distributed Energy Resources Investment Charge for the year "x". "x" is the forecast year.

RR_x = The projected annual Revenue Requirement for the recovery of the investment and operation and maintenance costs of the Company's distributed energy resource investments approved by the Commission pursuant to RSA 374:G. The annual revenue requirement shall consist of the return on rate base and associated income taxes, along with depreciation and amortization expense, operation and maintenance expenses and taxes other than income taxes.

OR_x = The projected annual Offset Revenues received from any source that the Company is able to secure to support the cost of its investments.

Authorized by NHPUC Order No. ______ in Case No. DE _____ dated ______________

**DISTRIBUTED ENERGY RESOURCES INVESTMENT CHARGE
SCHEDULE DERIC**

LBR_x = The projected calculated lost base revenue in year x resulting from the implementation of approved distributed energy resource investments.

RAx_{-1} = The annual Reconciliation Adjustment defined as the difference between (a) the actual annual Revenue Requirement, Offset Revenues, and LBR in the previous year, and (b) the revenue actually collected in the previous year. Interest calculated on the average monthly balance shall also be included in the RA. Interest shall be calculated at the prime rate, with said prime rate to be fixed on a quarterly basis and to be established as reported in THE WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used.

I_x = The estimated interest in the forecast period, calculated as defined above.

$FkWh_x$ = The forecasted kWh is the forecasted amount of electricity to be distributed to the Company's distribution customers for the year "x".

**CALCULATION OF THE
DISTRIBUTED ENERGY RESOURCES INVESTMENT CHARGE**

1. (Over)/under Recovery - Beginning Balance January 1, 2010	to be filed
2. Estimated Total Costs (January 2010 - December 2010)	to be filed
3. Estimated Interest (January 2010 - December 2010)	to be filed
4. Costs to be Recovered (L.1 + L.2 + L.3)	to be filed
5. Estimated Calendar Month Deliveries in kWh (January 2010 - December 2010)	to be filed
6. Distributed Energy Resources Investment Charge ($/kWh) (L.4/L.5)	to be filed

Authorized by NHPUC Order No. in Case No. , dated

UNITIL ENERGY SYSTEMS, INC
DER ESTIMATED BUDGET

LINE NO.	(1) DESCRIPTION	(3) AMOUNT	
	CAPITAL INVESTMENT:		
1	Crutchfield: Solar Domestic Hot Water (DHW) system	$ 101,920	
2	Stratham Municipal: Solar Photo Voltaic (PV)	$ 399,321	
3	SAU 16: Solar Photo Voltaic (PV) and Micro-Turbine CHP	$ 260,000	
	Total Investment	$ 761,241	
	OTHER OPERATING EXPENSE:		
4	Time-of-Use Pilot Program	$ 312,136	External Costs
5	DER Start-up Consulting Services	$ 120,000	External Costs
6	Ongoing Program Management and Reporting	$ 145,210	Internal Costs
	Total Expense	$ 577,346	

UNITIL ENERGY SYSTEMS, INC

DIRECT TESTIMONY OF

HOWARD J. AXELROD

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DE 09-___

AUGUST 5, 2009

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I. INTRODUCTION

Q. Please state your name, title and business address.

A. My name is Howard J. Axelrod. I am President of Energy Strategies, Inc. and my business address is 5 Danbury Court, Albany, New York

Q. Please summarize your qualifications and affiliation to Unitil.

A. I have been a management consultant for the last 25 years and the owner and chief executive officer of Energy Strategies, Inc., since 1995. Energy Strategies, Inc. specializes in energy planning and analysis. Our clients have included a number of electric utilities, regulatory agencies and large industrial customers throughout the United States and within New England in particular. (See www.energystrategiesin.com) Energy Strategies, Inc. was retained by Unitil to assist in the development of this DER program including model development and the rate application framework.

Prior to my consulting career, I served for nearly fourteen years in a number of senior level positions with the New York State Public Service Commission (PSC), the Consumer Protection Board (CPB) and the Energy Research and Development Authority (NYSERDA). I was also appointed by Governor Cuomo as the Chief Economist on the Shoreham Commission. At the PSC I served as a special assistant to Chairman Alfred Kahn where I oversaw the development of productivity measures and research and development programs funded by electric and gas utilities in New York. At the CPB, I was Director of Utility Intervention, the Nation's largest residential advocacy organization at that time. Finally, at NYSERDA I managed a number of innovative research and development projects including the development of one of the first comprehensive DSM screening models.

Over the last 25 years I have personally performed a number of studies and analyses relating to power systems requirements, alternative generation and renewable resources and emerging technologies including vehicle to grid (V2G) applications, smart meters and superconducting applications for transmission and distribution systems. For the later, I served as Executive Director of CCAS, the Coalition for Commercial Advancement of Superconductors.

I am a graduate of Rensselaer Polytechnic Institute where I earned my Doctor of Philosophy degree in Managerial Economics, from the State University of New York (Albany) with an MBA in Marketing and from Northeastern University with MSEE and BSEE degrees in Power Systems Planning. I also completed General Electric's 3-year training program as an Application Engineer. I am a Senior Member of the Institute of Electrical and Electronic Engineers and a Professional Engineer (retired.)

Q. What is the purpose of this testimony?

A. In response to the recently enacted DER legislation, Unitil Energy Systems, Inc. ("UES"), asked me to assist in the development of a set of analytical screening tools to be used to evaluate:

- DER Cost/benefit
- Environmental impact
- Particpating and non-participating customer costs and benefits
- Economic Development Impact

In my opinion, these tools provide the appropriate information necessary for the company and ultimately the Commission to determine whether a DER project meets the test for being in the "public interest." The models can also used to assess the level of company contribution to any DER project that would be owned by the customer. In this testimony I will describe the models and methods used by UES to evaluate those DER projects it seeks to pursue.

Q. What factors need to be considered in determining whether a DER project meets the test for public interest?

A. RSA 374-G:5, paragraph II, identifies a number of factors that the Company should address in establishing whether a project is in the public interest. In summary those factors should consider:

- The "economic benefits of the investments to the utility's ratepayers over the life of the investment outweigh the economic costs to the utility ratepayers."
- The relative economic cost/benefit to participating customer as well as default service customers
- The environmental benefits
- The economic development benefits

The models that I will discuss in this testimony were designed to provide exactly the information called for in this section of the DER statute.

Q. Are there any other requirements that UES must provide in supporting its finding that the proposed 2009 DER program is in the public interest?

A. Paragraph II also requires the Company to assess energy security benefits, effects on reliability, safety and efficiency and effect on competition. It is our contention that each of the DER projects, by their very design will, at a minimum, have a neutral effect on each of these objectives, but should have a positive intrinsic benefit although the degree of impact will be difficult to quantify.

Q. What is the basis for your finding that there will be an intrinsic benefit?

A. The DER projects that UES is considering are designed to improve system reliability by reducing distribution congestion, improve system stability and mitigate equipment degradation due to overload conditions. If we can design a DER project to defer the need for conventional distribution investments by reducing load conditions that tax the distribution network, UES's system reliability will be improved while concurrently reducing distribution network investments. Furthermore, the very fact that these projects offer a wider range of innovative and diversified solutions to traditional distribution network enhancements, by definition, enhances the competitive market.

II. DEVELOPMENT OF THE SCREENING MODEL

Q. What are the criteria for Utility DER Investments?

A. RSA 374-G contemplates utility investment in DER technologies, including utility-owned DER, to offset distribution system losses (3 – 5 percent of energy sales) or internal company use, as well as customer-owned DER equipment. While the legislation identifies a range of economic and environmental criteria, and also seeks impacts on affected customers as well as default customers and overall system impacts, it does not stipulate that all of the criteria have to have some minimum positive benefit. In fact, under a number of plausible circumstances, the benefits attributed to one class of criteria (e.g. cost/benefit ratio) can be inversely linked to the attributes of another. For example, the cost benefit ratio of a particular DER initiative might be negatively affected by an environmental objective. Similarly, if one of the goals is to enhance local economic development, cost/benefit might be sacrificed for higher cost in-state procurement. Bottom line, the criteria for determining if a DER project should be consistent with a standard prudency test where net benefits exceed net costs, considering both tangible (internal) and implied (external) factors.

Q. Does the NHPUC apply similar standards for other utility programs?

A. Yes, it does. Specifically, in the area of Energy Efficiency programs funded by the System Benefits Charges, the Commission approves programs based on a demonstration of positive benefit-costs based on total societal costs and benefits. UES documents that it meets the Commission's standards for cost-effectiveness testing by relying on the UES Screening Model. This model, which calculates avoided system costs for energy efficiency expenditures, is used to evaluate the Company's energy management and conservation "investments." This provides the same types of analysis and information needed to assess DER investments.

Q. Will UES use exactly the same model as previously used before this Commission?

A. The UES Screening model as applied to the proposed DER projects did require some enhancements in order to meet all of the DER assessment requirements, specifically including:

- Adding an environmental impact analysis – This component can be developed using the environmental impact analysis developed for the Massachusetts utilities and included in cost-benefit of energy efficiency programs in that state.
- Adding a module for economic impact - The United State Bureau of Economic Analysis Regional Input/Output Modeling System (RIMS) has been acquired for the Rockingham and Merrimack Counties that UES serves in New Hampshire. RIMS provides economic multipliers for 60 industry categories for the following economic measures:
    - Employment
    - Income
    - Value-Added
    - Regional Output

For every dollar invested in New Hampshire, the RIMS multipliers can determine impacts on wages, numbers of new employees and overall economic development.

Q. Will the UES Screening Model be the only analytical tool used to evaluate DER investments?

A. The UES Screening Model computes system-wide impacts based on avoided costs. However, some DER projects could have a very localized and specific benefit that produces even greater benefits. For example, a distribution substation might be approaching maximum load conditions necessitating the addition of a new bus bar or transformer bank at a very substantial cost. A strategically located DER investment could defer or even eliminate the need for such a traditional utility investment. In order to capture the potential benefits of localized DER technologies the following analysis has been performed:

- An assessment of distribution system limitations including potential upgrades for the following conditions:
- Low voltage conditions and frequency modulation
- Substation and transformer overload
- Excessive line losses
- An estimation of system upgrade costs and project schedule
- An estimation of minimum corrective response via DER investments to affect deferment or avoidance.

Based on this analysis we have been able to identify potential avoided costs for certain classes of DER investments that would be in addition to the system-wide benefits derived by the UES model.

Q. Please summarize the quantitative models used by UES to evaluate the DER projects.

A. In order to fully evaluate each of the proposed DER projects we incorporated the features of three separate models. Our primary analytical tool is the 2009 UES Screening tool. This screening tool was developed for energy conservation and load management evaluations and has been accepted by the Commissions in New Hampshire and Massachusetts.

The Company has projected the expected benefits and costs associated with its four proposed 2009 DER projects consistent with the requirements delineated in RSA 374G:5. Where appropriate, the Company has included values for non-electric and non-resource benefits related to expected program installations in its assessment of cost-effectiveness. Factors included in the calculation of the benefit/cost ratios are the same as those used in the Company's 2008 Energy Efficiency Plan. Two additional factors were also identified – the values for the benefits for CO_2 reductions and energy-related demand reduction induced price effect (DRIPE).

Q. Further explain how the 2009 UES Model addresses the cost/benefit tests required in Paragraph II of RSA 374G:5.

A. The Total Resource Cost Benefit Test (TRC) is the benefit / cost test used in examining the overall economics of the DER programs. It compares the present value of future electric system and other customer savings to the total of the expenditures and customer costs necessary to implement the programs. The benefit of a measure is the net present value of the avoided costs (i.e.; value of the savings) associated with the net savings of a measure over the life of that measure. The net savings include impact factors and realization rates that result from evaluation studies. The measure life is based on either the technical life of the measure or study results.

Q. Please explain how avoided costs were derived.

A. The avoided costs used to determine program cost effectiveness in the 2008 Energy Efficiency Plan were developed in the "Avoided Energy Supply Costs in New England: 2007 Final Report" prepared by Synapse Energy Economics, Inc. for the New England Avoided-Energy-Supply-Component Study Group in August 2007 ("AESC Study"). In addition to the biennial updating of avoided generation capacity and energy values, the report developed recommendations for the inclusion of the demand reduction induced price effect (DRIPE) as an additional capacity benefit, which were adopted by the Massachusetts utilities and used in the b/c analysis in this plan.

Avoided electric energy and capacity values incorporate a reserve margin, pool transmission losses incurred from the generator to the point of delivery to the distribution companies, and a retail adder as recommended by the AESC Study consultant. The current ISO-NE reserve margin is incorporated, since energy efficiency avoids the back-up reserves for that generation as well as the generation itself. The avoided costs do not include non-pool transmission losses or distribution losses. They also do not include company specific avoided transmission and distribution capacity values.

Q. Then how are company specific avoided transmission and distribution values quantified?

A. As noted, avoided Transmission and Distribution ("Avoided T&D") capacity values used in the analysis are utility specific. The Company's avoided T&D values were developed from the Long-Run Marginal Cost of Service and Loss studies from Docket D.T.E. 02-25, the Company's petition for a General Increase in Electric Rates, filed in May 2002. The 2008 avoided T&D values are $17.13/kWYr for transmission and $155.56/kWYr for distribution capacity. These values are assumed to be constant in 2008 $ throughout the TRC analysis period.

Demand and energy losses account for local transmission and distribution losses from the point of delivery to the distribution companies' system to the ultimate customer's facility. Since they are a function of the individual utility's system, losses are also calculated on a utility-specific basis.

Q. How does the model compute the net value of the DER project under review?

A. The dollar value of the program's benefits is calculated by multiplying the expected savings by the appropriate avoided value component. The avoided value component for each benefit (fuel, non-fuel or non-resource) is the cumulative net present value (2009$'s) of lifetime avoided costs for each year of the planning horizon from the base year. For example, the avoided value component in Year 10 for any given benefit is the sum of the net present value of the annual avoided costs for the resource for Year 1, Year 2, Year 3, etc. through Year 10, in 2009 dollars. This value is applied to the annual savings for a measure with a 10 year life to generate the lifetime avoided benefit for that measure. Since all of the future year values are in constant 2009 dollars, lifetime benefits thus calculated are discounted back to 2009 using a real discount rate equal to [(1 + Nominal Discount Rate) / (1 + Inflation)] -1.

Q. When calculating the DER benefits for the Participating customer, aren't the actual benefits simply the sum of the reduced electricity bills over the life of the DER project?

A. Technically, that is correct. However, from a practical matter, the calculation of offset electricity costs based on actual customer rates will be predicated on a number of forward looking assumptions including rate schedule, monthly usage (hourly usage for time-of-use customers), peak demands and generation cost adjustments. As a result, the analysis of each DER project would require a very detailed and customer-specific assessment of cost savings resulting from the proposed DER project. Considering the relative size and scale of each project, the time commitment and cost to perform such a study for each individual project does not outweigh the potential impact on forecast accuracy when using avoided costs as a surrogate.

Q. Is it your belief that the use of avoided costs as a surrogate for average prices is a conservative assumption?

A. Yes, I do. First, over the long run average prices should approach avoided costs. So, a long term DER project will likely result in very similar results whether using average prices or avoided costs. Second, and pragmatically, a large percentage of retail electricity prices are generation based (between 40% – 60%), which is priced at near term clearing prices. This means that for either approach we would use the same or similar assumptions to calculate generation based benefits. In conclusion, we believe that the use of the UES avoided cost model provides a reasonable assessment of DER project benefits without undo bias in either direction.

Q. You also mentioned that this model computes the demand reduction induced price effect or DRIPE. Please explain how the DRIPE is computed and why it is an essential component of the DER cost/benefit analysis?

A. The AESC Study also quantified a price reduction benefit associated with energy efficiency. This benefit is referred to as the Demand Reduction Induced Price Effect (DRIPE). DRIPE is the reduction of wholesale energy and capacity market prices that results from reductions in demand as a result of conservation efforts. The AESC study recommended that these reductions be included in benefit-cost screening. Briefly, capacity DRIPE was estimated using projections of the theoretical effect DSM would have on what the cost of new generation would be. Energy DRIPE was estimated by analyzing the interactions of small changes in load in each zone on the clearing prices in that zone and on neighboring zones. These estimates are very small when expressed in terms of impacts on the market prices of energy and capacity, i.e., reductions of a fraction of a percent. These impacts are projected to dissipate over four to five years as the market reacts to the new, lower level of energy and capacity required. However, DRIPE impacts are significant when expressed in absolute dollar terms, since very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts. Thus, consideration of DRIPE impacts can increase the cost effectiveness of DSM programs on the order of 15% to 20%, because the estimated absolute dollar benefits of DRIPE are being attributed to a relatively small quantity of reductions in energy and/or capacity.

Q. Are there any other economic factors that the 2009 UES model derives?

A. Yes, there are. The 2009 UES model also computes the estimated environmental benefits associated with the avoidance of electric generation. The 2009 UES model estimates the amount of carbon dioxide that is avoided should the design of a DER project result in energy savings either through improved efficiencies or a shift in demand from peak periods when greenhouse gases are at a maximum to off-peak period when a greater portion of generation is nuclear and hydroelectric.

III. LOCALIZED SYSTEM BENEFIT MODEL

Q. As discussed above, the 2009 UES model does calculate utility specific benefits for avoided T&D investments. Does this assessment accurately quantify DER projects that can reduce or defer the need for a specific distribution investment?

A. While the UES model does compute avoided T&D investments, they are generic representations of the average system impact. DER provides the added benefit of deferring system infrastructure improvements on a localized level. In order to derive this very specific effect, a model has been developed to be used as a method to quantify the benefit DER projects have on a local level.

Q. Explain how this model was developed.

A. The approach we took was to conduct an engineering review of the specific benefits of DER projects located in different parts of the system. In an attempt to make the benefit analysis on the local system more efficient, three categories were developed: 1) System Level Benefit, 2) Substation Level Benefit, and 3) Circuit Level Benefit.

Q. Please describe what the system level benefit is.

A. A DER project that provides System Level Benefit can be connected anywhere on the system. Any load offset from the system will have an effect of deferring system level projects such as new system supply points or added capacity at existing supply points.

Q. And what is the substation level benefit?

A. A DER project that provides Substation Level Benefit is generally connected close to, if not directly, at the substation. Any load offset from the substation will have an effect of deferring substation level projects such as new substation power transformers or upgrading other substation equipment. DER projects that provide Substation Level Benefit also provide a System Level Benefit.

Q. Finally, please explain what the circuit level benefit is?

A. A DER project that provides circuit level benefit is physically connected on the circuit level or even at a customer location. The amount of load offset through DER would have an effect of deferring circuit level improvements (reconductoring, voltage conversions, load transfers, etc.) for a given period of time. Projects that provide circuit level benefit would also provide a System Level Benefit and a Substation Level Benefit.

Q. How do you then calculate total system benefits?

A. The model used to complete the benefit analysis is a combination of: 1) the most recent three year capital budget forecast of known capital improvement projects; and 2) system level, substation level, and circuit level peak demand load forecasts. The model is designed to develop the benefit of deferring 1 kVA of demand for by one year. The benefit is calculated by dividing the average annual cost of a project in a certain category by the average peak demand growth each project is trying to address. That amount is then multiplied by the weighted average cost of capital to develop the savings produced by deferring a project within a specific category by one year.

To use this model, you can add up the applicable system level, substation level, and circuit level benefits and multiply that amount by the expected kVA of the DER at the time of the system peak demand. The result is the cost that the Company has deferred through the installation of the DER.

IV. ECONOMIC DEVELOPMENT BENEFITS

Q. RSA 374G:5 also requires an assessment of economic development benefits. Please explain how economic impacts are assessed?

A. Generally, it is our belief that most of the DER projects that we are considering will have a direct and immediate impact on the local economy. Recall that a DER project will be one that addresses a need at the local distribution level. For DER projects that improve the customer's operational efficiency, the most immediate benefit is the reduction of electric consumption. Assuming, hypothetically, the cost benefit analysis results in a break even between DER installation and operation expenses as compared to avoided production costs, the local economy benefits as a greater percentage of those same dollars are spent locally. The greater the benefit cost ratio, the greater the impact on the local economy.

Q. So the economic development benefit will, at maximum, be equal to the investment and operational costs of the DER project, assuming all components are manufactured locally?

A. That is not correct. The actual local investment and operational costs only measure direct impacts on the local economy. For example, $100,000 spent on a DER project as opposed to $100,000 spent on electricity generated in another state, would have a direct impact of $100,000 infused into the local economy. However, this direct affect also has a number of secondary impacts often referred to as the multiplier effect.

Q. Please explain what the multiplier effect is.

A. Using the above example, $100,000 infused into the local economy may take the form of wages & salaries, materials and goods and machinery and equipment. As salaries and wages increase, workers tend to spend locally on such things as groceries, new cloths and even new houses. As materials and goods are purchased, local distributors and manufacturers expand their facilities and add new employees. Once again, this expansion is met with growth in demand and supply. For each dollar spent locally, depending of course on the nature of the expenditure, the multiplier effect is the number of times that initial dollar is spent in the local economy. We can measure those impacts in terms of new employees, salaries and wages and net economic growth.

Q. How is the economic multiplier derived?

A. For each business category, for example restaurants versus hospitals, the local impact can be derived. The more labor intensive the business function, the greater the employment multiplier. As an example, a typical multiplier for general economic output is about 2, namely for every dollar invested in a community, roughly two dollars are actually spent.

Q. Please explain how UES has derived these economic development multipliers?

A. There are a number of economic services who provide such analysis. UES has acquired from the federal Bureau of Economic Analysis (BEA), its Regional Input-Output Modeling System or RIMS II for the two counties that UES serves in New Hampshire, namely, Rockingham and Marrimack. A copy of the RIMS summary report is attached as Schedule HJA-1. It is my opinion that the RIMS II economic multipliers are the most widely used and impartial assessments of economic impact available to governmental agencies and businesses. The RIMS II output tables provides economic multipliers for employment, wages and salaries and output that specifically measures changes in these two counties.

Q. Can you briefly explain how the RIMS II process works and what are its key advantages over other economic models?

A. In response to this question, I have extracted from the BEA website the following information.

In summary, "RIMS II is based on an accounting framework called an I-O table. For each industry, an I-O table shows the distribution of the inputs purchased and the outputs sold. A typical I-O table in RIMS II is derived mainly from two data sources: BEA's national I-O table, which shows the input and output structure of nearly 500 U.S. industries, and BEA's regional economic accounts, which are used to adjust the national I-O table in order to reflect a region's industrial structure and trading patterns.[1]

Using RIMS II for impact analyses has several advantages.[2] RIMS II multipliers can be estimated for any region composed of one or more counties and for any industry or group of industries in the national I-O table. The cost of estimating regional multipliers is relatively low because of the accessibility of the main data sources for RIMS II. According to empirical tests, the estimates based on RIMS II are similar in magnitude to the estimates based on relatively expensive surveys." [3]

Q. Please explain how the RIMS multipliers are used.

A. The BEA states that to "effectively use the multipliers for impact analysis, users must provide geographically and industrially detailed information on the initial changes in output, earnings, or employment that are associated with the project or program under study. The multipliers can then be used to estimate the total impact of the project or program on regional output, earnings, or employment."

As a first step in our process, for each DER project we assumed that the types of investments that will be locally made fall into one of two categories: either utilities or construction. For each dollar investment, we can then determine what the multiplier is for the region, in general, or among some sixty end-user groups.

It is interesting to note that the Final-Demand Output multiplier, which is a broad measure of regional economic development impact, is 1.85 for the construction trades versus 1.23 for utility investments. This further suggests the positive economic development impact of shifting utility investments for local construction. While not all

[1] See U.S. Department of Commerce, Bureau of Economic Analysis, *Benchmark Input-Output Accounts of the United States, 1987*(Washington, DC: U.S. Government Printing Office, 1994); and U.S. Department of Commerce, Bureau of Economic Analysis, *Local Area Personal Income, 1969–92* (Washington, DC: U.S. Government Printing Office, 1994).
[2] 4. For a discussion of the limitations of using I-O models in impact analysis, see Daniel M. Otto and Thomas G. Johnson, *Microcomputer-Based Input-Output Modeling* (Boulder, CO: Westview Press, 1993), 28–46.
[3] See *Regional Input-Output Modeling System (RIMS II)*, 39–57 ; and Sharon M. Brucker, Steven E. Hastings, and William R. Latham III, "The Variation of Estimated Impacts from Five Regional Input-Output Models," *International Regional Science Review* 13 (1990): 119–39.

DER investments will be considered construction, this is a strong indicator that any DER investments should have a positive economic development impact.

Q. Who else uses the RIMS multipliers to assess economic impact?

A. The BEA claims that "RIMS II is widely used in both the public and private sector. In the public sector, for example, the Department of Defense uses RIMS II to estimate the regional impacts of military base closings, and state departments of transportation use RIMS II to estimate the regional impacts of airport construction and expansion. In the private sector, analysts, consultants, and economic development practitioners use RIMS II to estimate the regional impacts of a variety of projects, such as the development of theme parks and shopping malls."

Q. Do the BEA RIMS II multipliers provide an accurate forecast of economic benefits resulting from a DER investment?

A. The RIMS multipliers provide a reasonable assessment of economic impact. Because the multipliers are based on historical relationships, any forward looking projection is limited to the understanding that the past may not represent the future. However, the RIMs multipliers do represent a reasonable approximation or ballpark estimate that provides at good estimate of how dollars invested in a community impact employment and the economy in general. We can also tell from the RIMs multipliers the relative advantage of one type of investment over another. For example, the utility employment multiplier is 2.13 versus the construction trades at 11.62. This means that for every $1 million invested in the community, if it were done by a utility it would generate 2.13 jobs as compared to 11.62 jobs if the same amount of money was spent at a general construction site.

V. SUMMARY SCREENING REPORT

Q. Have you prepared a summary report which identifies the costs and benefits for each DER project and how those costs are allocated between the project participant, default customers and all other customers?

A. Yes, I have. Schedule HJA-2 is a sample summary report that was developed for each DER project. This report presents the costs and benefits as derived from the three analytical models we used to assess each DER project. The three models included the UES marginal cost spreadsheet, the locational specific distribution analysis and the RIMSII economic impact assessment.

The Summary Report identifies the project name, project cost as well as Until's expected contribution. Other non-monetary or intangible benefits such as load reduction, energy saved and jobs created are also provided. The primary economic benefits include both capacity and energy related decremental costs resulting from the reduction in peak loads and electric energy saved. Other benefits such as DRIPE (Demand Reduction-Induced Price Effect), CO_2 Credit and Renewable Energy Certificates (RECs) are listed.

Q. How did you allocate the derived DER benefits among UES's customers including default customers as well as the DER project participant?

A. For the proposed DER projects we assumed that the energy and capacity saved by the application of the DER project would be derived by the participating customer via reduced energy and capacity expenses. All other distribution customers would reap the benefit of DRIPE savings, CO_2 credits and the benefits of increases in economic output, wages and salaries and additional jobs induced by the local investment in DER projects. Default Service customers would also see the benefits of any RECs credits retained by the Company, under the assumption that those credits would be used by the Company towards fulfillment of its RPS compliance obligations.

Finally, the Benefit/Cost (B/C) ratio is derived for the total project, participant and all other customers. A B/C ratio of greater than one means that benefits exceed costs. A B/C ratio of less than one does not necessarily mean that a project should not be supported. Other less tangible benefits might offer either economic or environmental advantages that may not be easily translated into a monetary value.

VI. CONCLUSION

Q. Does that complete your testimony?

A. Yes, it does.

RIMS II Multipliers (2006/2006)

Table 2.5 Total Multipliers for Output, Earnings, Employment, and Value Added by Industry Aggregation
New Hampshire

INDUSTRY	Multiplier					
	Final Demand				Direct Effect	
	Output/1/ (dollars)	Earnings/2/ (dollars)	Employment/3/ (jobs)	Value-added/4/ (dollars)	Earnings/5/ (dollars)	Employment/6/ (jobs)
1. Crop and animal production	1.4992	0.2614	18.7793	0.6533	1.5437	1.1990
2. Forestry, fishing, and related activities	1.6461	0.3432	11.9843	0.8060	1.5984	1.6239
3. Oil and gas extraction	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4. Mining, except oil and gas	1.4950	0.2754	5.7675	0.8887	1.5282	1.7736
5. Support activities for mining	1.8755	0.4441	10.2824	1.0345	1.7572	2.1368
6. Utilities*	1.2345	0.1333	2.1336	0.7381	1.5481	2.6009
7. Construction	1.8523	0.4282	11.6215	0.9784	1.6449	1.6900
8. Wood product manufacturing	1.8664	0.2974	8.2395	0.7936	2.2022	2.1416
9. Nonmetallic mineral product manufacturing	1.7301	0.2947	6.4332	0.8465	1.9006	2.2001
10. Primary metal manufacturing	1.5931	0.2349	5.1948	0.5986	1.9101	2.1293
11. Fabricated metal product manufacturing	1.6303	0.2745	6.2623	0.7731	1.7933	1.9531
12. Machinery manufacturing	1.7511	0.3110	6.3031	0.8079	1.8630	2.2750
13. Computer and electronic product manufacturing	1.8436	0.2920	5.4320	0.8305	2.2838	3.4656
14. Electrical equipment and appliance manufacturing	1.7282	0.2573	5.3623	0.7778	2.1178	2.5267
15. Motor vehicle, body, trailer, and parts manufacturing	1.6664	0.2455	5.1693	0.5621	2.0756	2.5448
16. Other transportation equipment manufacturing	1.3871	0.2155	3.8710	0.6776	1.5577	2.0790
17. Furniture and related product manufacturing	1.7746	0.3309	9.1364	0.8013	1.8116	1.7430
18. Miscellaneous manufacturing	1.7633	0.3512	7.1845	0.8808	1.7160	2.0567
19. Food, beverage, and tobacco product manufacturing	1.8095	0.2465	7.0789	0.6707	2.6533	3.6504
20. Textile and textile product mills	1.6615	0.2269	5.2152	0.6307	2.1250	2.2771
21. Apparel, leather, and allied product manufacturing	1.5642	0.2134	6.9030	0.8293	1.9528	1.6570
22. Paper manufacturing	1.5981	0.2552	5.3221	0.6574	1.8456	2.2035
23. Printing and related support activities	1.7133	0.3654	9.2072	0.8724	1.6223	1.6627
24. Petroleum and coal products manufacturing	1.5309	0.1596	3.0735	0.4619	2.8340	4.9699
25. Chemical manufacturing	1.7045	0.2429	4.6945	0.7173	2.2310	3.0268
26. Plastics and rubber products manufacturing	1.6825	0.2489	5.5931	0.7059	2.0037	2.2113
27. Wholesale trade	1.6178	0.3352	6.7948	1.0240	1.5767	2.0026
28. Retail trade	1.6687	0.3475	12.4131	1.0251	1.5735	1.3954
29. Air transportation	1.5179	0.2292	5.7437	0.6520	1.9169	2.4286
30. Rail transportation	1.5665	0.2645	5.0500	0.9049	1.7240	2.4726
31. Water transportation	1.7186	0.2090	5.9081	0.6918	3.5341	2.9261
32. Truck transportation	1.7414	0.3329	8.6801	0.8959	1.8068	1.8725
33. Transit and ground passenger transportation*	1.7399	0.4510	20.8259	0.9240	1.5096	1.2665
34. Pipeline transportation	1.5613	0.2410	4.2828	0.6663	2.0175	4.0398
35. Other transportation and support activities*	1.4895	0.3642	8.5748	1.0619	1.3677	1.5124
36. Warehousing and storage	1.6315	0.4696	13.3678	1.1406	1.3331	1.3632
37. Publishing including software	1.7510	0.3273	6.9389	0.9722	1.8708	2.5652
38. Motion picture and sound recording industries	1.5659	0.2720	12.2666	0.7867	1.6694	1.3547
39. Broadcasting and telecommunications	1.8426	0.2130	4.6477	0.9012	2.6233	3.6648
40. Information and data processing services	1.6740	0.2944	7.4652	0.8290	1.8449	2.1394
41. Federal Reserve banks, credit intermediation and related services	1.4265	0.2294	5.3911	1.0211	1.6153	1.8247
42. Securities, commodity contracts, investments	1.7882	0.4735	8.8753	0.9860	1.5191	1.9625

(Continued)

Region Definition: Merrimack, NH; Rockingham, NH

*Includes Government enterprises.
1. Each entry in column 1 represents the total dollar change in output that occurs in all industries for each additional dollar of output delivered to final demand by the industry corresponding to the entry.
2. Each entry in column 2 represents the total dollar change in earnings of households employed by all industries for each additional dollar of output delivered to final demand by the industry corresponding to the entry.
3. Each entry in column 3 represents the total change in number of jobs that occurs in all industries for each additional 1 million dollars of output delivered to final demand by the industry corresponding to the entry. Because the employment multipliers are based on 2006 data, the output delivered to final demand should be in 2006 dollars.
4. Each entry in column 4 represents the total dollar change in value added that occurs in all industries for each additional dollar of output delivered to final demand by the industry corresponding to the entry.
5. Each entry in column 5 represents the total dollar change in earnings of households employed by all industries for each additional dollar of earnings paid directly to households employed by the industry corresponding to the entry.
6. Each entry in column 6 represents the total change in number of jobs in all industries for each additional job in the industry corresponding to the entry.
NOTE.–Multipliers are based on the 2006 Annual Input-Output Table for the Nation and 2006 regional data. Appendix C identifies the industries corresponding to the entries.
SOURCE.–Regional Input-Output Modeling System (RIMS II), Regional Product Division, Bureau of Economic Analysis

RIMS II Multipliers (2006/2006)

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	Output/1/ (dollars)	Earnings/2/ (dollars)	Employment/3/ (jobs)	Value-added/4/ (dollars)	Earnings/5/ (dollars)	Employment/6/ (jobs)
43. Insurance carriers and related activities	2.0575	0.3534	6.8718	0.9965	2.1553	2.6893
44. Funds, trusts, and other financial vehicles	1.7487	0.3190	9.3564	0.6600	2.1970	1.7034
45. Real estate	1.4127	0.1212	4.5590	0.9396	2.7875	1.9345
46. Rental and leasing services and lessors of intangible assets	2.0073	0.3002	8.7230	0.9824	2.7767	2.6818
47. Professional, scientific, and technical services	1.7762	0.4678	10.4853	1.0842	1.5125	1.7992
48. Management of companies and enterprises	1.6745	0.3305	5.5618	0.9996	1.6316	2.6890
49. Administrative and support services	1.7474	0.4306	15.5683	1.0619	1.5403	1.4170
50. Waste management and remediation services	1.7661	0.3319	7.7966	0.9105	1.8258	2.1619
51. Educational services	1.8132	0.4987	17.1852	1.0689	1.4391	1.3694
52. Ambulatory health care services	1.7534	0.5037	11.2058	1.1122	1.4200	1.6438
53. Hospitals and nursing and residential care facilities	1.8606	0.4877	13.1142	1.0496	1.5066	1.5945
54. Social assistance	1.7396	0.4369	23.1636	1.0350	1.4657	1.2135
55. Performing arts, museums, and related activities	1.7031	0.5061	26.2689	1.1020	1.4266	1.2603
56. Amusements, gambling, and recreation	1.6978	0.3817	19.4657	1.0434	1.5147	1.2402
57. Accommodation	1.6012	0.2675	10.2459	0.9658	1.7549	1.4709
58. Food services and drinking places	1.6633	0.3093	15.9131	0.8674	1.6102	1.2788
59. Other services*	1.7626	0.3852	13.9918	0.9305	1.6218	1.4378
60. Households	1.1037	0.2177	6.8272	0.6487	0.0000	0.0000

Region Definition: Merrimack, NH; Rockingham, NH

*Includes Government enterprises.
1. Each entry in column 1 represents the total dollar change in output that occurs in all industries for each additional dollar of output delivered to final demand by the industry corresponding to the entry.
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SOURCE.–Regional Input-Output Modeling System (RIMS II), Regional Product Division, Bureau of Economic Analysis.

Summary Report
Sample DER Project

Unitil Investment	$130,000
Total Project Cost	$130,000
Other Intangible Benefits	
Load Reduction	
Summer	**39**
Winter	**39**
Lifetime	**512**
MWh Saved	
Annual	**103**
Lifetime	**1,343**
Economic Development	
Jobs Created	**1**
Wages & Salaries	**$48,506**

Allocation of Economic Benefits

Capacity	Total	Participant	All Customers	Default
Generation				
Summer	$51,109	$51,109		
Winter	$0	$0		
Transmission	$5,024	$5,024		
Distribution	$15,499	$15,499		
DRIPE	$10,346		$10,346	
Localized Distribution	$3,256		$3,256	
Total Capacity	**$85,235**	**$71,632**	**$13,603**	**$0**
Energy				
Winter				
Peak	$33,310	$33,310		
Off peak	$28,403	$28,403		
Summer				
Peak	$16,783	$16,783		
Off peak	$13,775	$13,775		
Total Energy	**$92,272**	**$92,272**	**$0**	**$0**
Other				
Energy				
Dripe	$13,074		$13,074	
Non-Electric				
CO2 Reduction	$34,559		$34,559	
REC Credit	$10,335		$10,335	$10,335
Total Other	**$57,968**	**$0**	**$57,968**	**$10,335**
Economic Development				
Total Output	**$89,605**		**$89,605**	
Total Benefits	**$325,079**	**$163,904**	**$161,176**	**$10,335**
B/C Ratio	**2.50**	**N/A**	**1.24**	

UNITIL ENERGY SYSTEMS, INC

DIRECT TESTIMONY OF

CINDY L. CARROLL

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DE 09-___

AUGUST 5, 2009

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LIST OF SCHEDULES

I. INTRODUCTION

Q. Please state your name and business affiliation.

A. My name is Cindy Carroll and I am the Director of Customer Field Services, formerly Business Services, with Unitil Service Corp., and I am testifying on behalf of Unitil Energy Systems, Inc. ("UES" or the "Company"). As Director of Business Services I have been responsible for energy efficiency program design, evaluation, administration, reporting and implementation as well as key customer account management and business and economic development. With the recent organizational changes, the responsibility for energy efficiency and DER program planning and management fall into the new DER group reporting to Mr. Gantz, and my responsibilities will focus on customer field services including the field delivery of energy efficiency and DER initiatives. My business address is 325 West Road, in Portsmouth, NH.

Q. Please summarize your qualifications and current position with the company.

A. I joined Unitil Service Corp. in 1997. I also have 20 years of professional experience in the utility industry primarily in business development. My primary responsibilities have included the development, implementation and advancement of the Company's business expansion and economic development programs, energy efficiency programs and critical customer management.

I received an MBA from Southern New Hampshire University in 1998 and my Bachelor of Arts degree in Communications from the University of New Hampshire in 1985. Since joining Unitil Service Corp. as Business Development Executive in 1997, I have held several progressively challenging management positions in the areas of sales, marketing, business and economic development. Prior to joining Unitil Service Corp., I was a Regional Sales Executive with Bay State Gas Company where I generated revenue from the sale of natural gas and other energy related products and services, and developed positive, long-term business relationships with large commercial and industrial customers and trade allies.

I have been active in various industry associations, committees and events. I am also a member of the Board of Directors of Big Brothers Big Sisters of the Greater Seacoast, the Maine State Chamber of Commerce and Maine & Company Inc. and a past member of the Board and Chair of the Exeter Area Chamber of Commerce.

Q. What is the purpose of your testimony?

A. In my testimony I will describe three DER projects that UES plans to complete during 2009 and early 2010. I will also demonstrate that based upon our cost/benefit analysis, including an assessment of environmental and economic impacts, each of the projects meet the public interest test as defined in RSA 374:G. For each project I will provide the following information:

- A description of the project
- An estimate of the installation costs
- A determination of system impact: both general or specific
- An assessment of cost/benefit, and economic and environmental impact.
- A projection of expenses and capital charges.

Q. Please identify the three DER projects being offered in this testimony.

A. This filing will present three DER projects to be completed in 2009:

- Solar Domestic Hot Water: Crutchfield Place – Concord Housing Authority
- Solar PV Electric Project - Stratham Municipal
- Solar PV and Micro Combined Heat and Power (CHP) – Exeter SAU 16

Q. At what stage of development is each project and is UES prepared to immediately begin installation upon Commission approval?

A. During 2008 and 2009, UES staff assessed a wide variety of possible DER projects, both company owned and company supported. We have met with equipment manufacturers, vendors, developers and UES customers who have indicated an interest in partnering with UES in such a program.

Based on this assessment, three DER projects were identified as technologically feasible, and economically viable, with a high probability of being completed quickly. While actual start-up will depend on a number of factors including permitting, final design and delivery of equipment, we are confident that construction, testing and start-up can be accomplished in 2009 and early 2010 assuming, of course, that they are approved by the New Hampshire Public Utilities Commission ("Commission"). It should be further noted that at this juncture UES is only seeking the Commission's endorsement that as proposed, each of the DER projects meet the public interest test as outlined in Chapter 374G:5. If the Commission also approves our proposed bifurcated DER rate process, UES will file for cost recovery during the fourth quarter of this year.

Q. How will the Company move forward with these customers in terms of procuring equipment and services necessary to complete the projects?

A. Once approval from the Commission has been received, the Company expects to work in collaboration with the customers and our consultants on the identification and selection of equipment and vendors. In this effort, the Company recognizes its obligation to promote the development of local economic activity including support for local vendors and contractors and will insure that those interests are incorporated in the procurement process.

II. Solar Domestic Hot Water System (Crutchfield Place)

Q. Please provide a summary description of the proposed solar domestic hot water system.

A. Schedule CLC-1 is a copy of the signed Memorandum of Understanding (MOU) between UES and the Concord Housing Authority. The MOU provides detailed information as to the scope and purpose of the Crutchfield Place DER project. In summary, this project is a Solar Domestic Hot Water (DHW) system to replace the existing electric DHW system at Crutchfield Place, a 105 unit low income multifamily property in downtown Concord owned and managed by the Concord Housing Authority. The existing system is a 120KW, 333Amp, 208V 3 phase electric heating element contained within a 1500 gallon water storage tank. The system is supplemented by a 170KBtu gas Ray Pac heater. We propose to replace this system with a solar water heating system including storage tanks and solar collectors.

Q. Why is UES proposing to install this solar hot water heating system and what are the primary benefits associated with this DER project?

A. This project offers a number of benefits to both UES and its customers. First and foremost, this solar hot water heating system is highly cost effective for both Crutchfield Place as well as all other UES customers. Schedule CLC-2 is a summary report of the economic and environmental benefits that we expect from this solar domestic hot water heating system. The summary provides the output for the Screening model developed by Mr. Axelrod, with the input data for the project as identified in Schedule CLC-1.

Q. How does this project generate such savings?

A. The existing hot water system is heated with a 120KW electric element contained within a 2,400 gallon pressurized water storage tank. The existing system is also equipped with an 85% efficient natural gas boiler for emergency backup. Demand for domestic hot water at Crutchfield is approximately 2,536 US Gal per day for its elderly permanent residents. The system draws approximately 18,260 kWh per month at an average cost of $0.168 per kWh or $3,067.68 monthly.

The proposed Apricus Solar DWH system provides one hundred percent of building DHW needs from April through November and sixty percent from December through March. Based on these operating characteristics, nearly 190,000 kWh are saved each year, which would have cost approximately $32,000. On a non-inflation adjusted basis, it would take about 2.4 years to save enough electricity to pay back the initial cost for this project.

Q. What are the estimated project costs?

A. Schedule CLC-1 provides a breakdown of projected capital costs. Note that added to the initial direct costs of $78,400 for the system, we have added a factor of thirty percent to account for estimated overhead and administrative costs that UES expects to incur in the process of working with the customer on the completion of the design and installation of the project. UES will account for the direct costs and overheads in accordance with its normal plant accounting procedures and document all charges in its construction work order process. The total estimated investment for this project is $101,920.

Q. Please summarize the benefits that this project will have for both the Concord Housing Authority and all other customers including default customers?

A. Overall, this initial investment of approximately $102,000 will produce over $387,000 in direct benefits for the participating customer, Crutchfield Place, over $218 thousand for all other UES customers and nearly $19 thousand for UES' default customers. From a benefit/cost (B/C ratio) perspective, this DER project has an overall B/C ratio of 5.95 and 2.14 for all other UES customers.

Q. What other benefits are derived from this DER project?

A. We have also evaluated the environmental and economic development impacts as well. The annual energy savings of approximately 190,000 kWh reduces the amounts of air emissions derived from electric production in New England. Assuming this displaced electricity was produced by an efficient combined cycle gas turbine, carbon emissions would be reduced by about 760 tons (CO_2) each year. This is based upon an emissions rate of .4 tons per MWh. To put this in some perspective, the 760 tons saved is equivalent to the emissions from 100 automobiles.

Because this system utilized renewable solar energy, it should also qualify for Renewable Energy Cerificates or RECs. Although the value of each REC in New England varies, at an assumed value of $100 per MWH, this DER project could generate approximately $19,000 in REC-based benefits.

Q. What is the estimated economic value of this environmental benefit?

A. CO_2 emissions are currently being traded within the RGGI (Regional Greenhouse Gas Initiative) conference of which New Hampshire is a member. Under the RGGI process, the participating states will stabilize power sector CO_2 emissions at the capped level through 2014. The cap will then be reduced by 2.5 percent in each of the four years 2015 through 2018, for a total reduction of 10 percent. In September 2008, RGGI held its first CO2 auction and all of the 12,565,387 allowances offered for sale on September 25, 2008 were sold at a clearing price of $ 3.07 per allowance. The 760 tons saved by this DER project would have an added environmental benefit of approximately $2,333 assuming the RGGI auction rate. However, there have been a number of international (KYOTO Accord) and federal legislative initiatives to create either a Carbon Tax or a CO_2 Cap and Trade program that many estimate will cause CO_2 allowances to rise to \$20 - \$40 per ton. At \$20 per ton, this DER project could save and additional \$15,000 a year.

Q. Are there any additional economic development benefits derived from the installation of this DER project?

A. Yes, there are. Since the investment in this DER project substitutes local construction for central station generation, imported fuels and utility transmission and distribution investment, there are direct economic development benefits. Dr. Axelrod obtained from the RIMS II tables the Final-Demand multipliers for regional Output, a measure of overall economic development and growth in employment. The Final Demand multipliers can be used to estimate economic impacts associated with known changes in the local economy, for example, a capital injection such as a new stadium or military base. In our case, we are using the initial capital cost of the DER project, which is estimated at \$78,000. The Final Demand multiplier for Output is 1.8523, which means the \$78,000 investment will translate into approximately \$144,479 of local economic development. The Final-Demand multiplier for Employment is 11.6215. This means there are 11.6215 jobs per million dollars of investment. The \$78,000 investment therefore translates into roughly one new full time job (\$78,000/1,000,000 times 11.6215 = .906 FTE jobs)

III. Solar PV Electric Project - Stratham Municipal

Q. Please describe your second DER project, the Stratham Municipal Solar project.

A. Schedule CLC-3 is the signed MOU between UES and Stratham and provides a detailed description of this DER project. The proposal is to install 202 panels of BP Solar SX 3195, 195 watt or equivalent on the new Stratham Fire House, which has been prepared for the array. The PV array will be on a ballasted racking system, with no penetration of roof membrane. The installation will also include a SMA Sunnyboy 7000 inverter or equivalent, Sunny WebBox central data acquisition and diagnosis unit. Not only will this solar project produce over 100,000 kwh of electricity per year, it will reduce UES' peak demand by nearly 40 kilowatts.

Q. What is the total cost for this DER project?

A. Schedule CLC-3 provides a breakdown of project direct costs, which totals $307,174. With overheads included we estimate a total cost of $399,321.

Q. Please summarize the economic and environmental benefits that will be derived from this solar electric DER project.

A. Schedule CLC-4 is a summary report, similar to Schedule CLC-2, which provides a breakdown of economic and environmental benefits that we expect from this DER project. In summary, the Stratham Municipal photo-voltaic system will generate approximately $510,000 in total benefits, with $163,000 in savings for the Stratham municipality and $347,000 in benefits for all other UES customers. The overall B/C ratio is positive (1.28), however the B/C ratio for UES's other customers is .87. Given the educational and public benefits of this project and the fact that our estimates for lifetime benefits are conservative, we feel funding this project is, on balance, in the public interest. In fact, we hope that this DER project will serve as a model for other municipalities in New Hampshire and that future economy and technological advancements will validate the true economic benefit of PV systems such as being proposed for Stratham.

IV. Solar PV and Micro Combined Heat and Power (CHP) – Exeter SAU 16

Q. Please describe your third DER project, the Stratham Municipal Solar project.

A. Schedule CLC-5 is the signed MOU between UES and School Administrative Unit (SAU) 16 of Exeter and provides a detailed description of this DER project. In summary, SAU 16 is seeking to carry out an innovative project designed to provide more efficient, environmentally friendly energy to the school system. Through the incorporation of the microturbine and solar PV array, the school aims to reduce overall energy costs through the generation of onsite electricity, lower heating fuel related expenses through the installation of a more efficient heating system, divert the related energy savings to critical curriculum based programs, and demonstrate the possibilities available to SAU districts (and others) across the State regarding alternative forms of energy. This project is truly unique to New Hampshire, and should establish the high water mark for school districts throughout the State to strive for. In light of current economic conditions, and state and municipal budget environment in particular, providing that every dollar possible go toward educational programs benefits our society as a whole.

The SAU 16 project will employ two forms of alternative, distributed energy generation. The first form is through the installation of a 100 kilowatt (kW) photo voltaic (PV) solar array mounted on the roof of the new SAU 16 high school building. The second form will be the installation of one Capstone microturbine combined heat and power unit at the administrative offices located at 30 Linden Street, Exeter, NH.

Q. What is the total cost for this DER project?

A. Schedule CLC-5 also provides a breakdown of direct project costs of $860,000, of which UES has committed $200,000. Including overhead costs, we estimate total charges to the Company will amount to $260,000.

Q. Please summarize the economic and environmental benefits that will be derived from this solar electric DER project.

A. Schedule CLC-6 is a summary report, similar to Schedule CLC-2, that provides a breakdown of economic and environmental benefits that we expect from this DER project. In summary, this DER projects produces over $1.3 million in avoided costs for a net B/C ratio of 1.52. Because UES' investment is only $260,000, the B/C ratio is 2.46 based on net savings in avoided costs of $639,000. Default customers also reap a $45,000 benefit as well.

The environmental benefits from this DER project are also significant. As the largest photovoltaic array in New Hampshire, annual avoided electric production will be 453 megawatt-hours. This translates into an annual reduction of 579 tons of CO_2, the equivalent to removing 117 cars or light trucks from New Hampshire's roads. Finally, UES' $260,000 investment in this DER project should generate two additional full time jobs in New Hampshire.

Q. Why does UES plan to invest 100 percent of the projects costs for the Crutchfield and Stratham DER projects, but only 23 percent for SAU 16?

A. We believe that all three DER projects are important to New Hampshire, not only for the economic and environmental benefits as discussed above, but also as an important educational mechanism to stimulate the further development of renewable resources and alternative solutions to energy distribution investments. For Crutchfield and Stratham, neither entity had the alternative financial resources to move forward. UES believes that the economic, environmental and business development benefits clearly support UES's total investment in these DER projects. For SAU 16, the school district already had significant funding commitments and UES's portion allowed for the project to move forward at an expedited pace.

V. CONCLUSION

Q. Does that complete your testimony?

A. Yes, it does.

MEMORANDUM of UNDERSTANDING
BETWEEN
Concord Housing Authority (CHA)
and Unitil Energy Systems, Inc. ("Unitil")

Regarding a Distributed Energy Resource (DER) Investment Proposal
(DRAFT 7-6-09)

WHEREAS: CHA intends to install a DER project as described in Attachment A, and

WHEREAS: Unitil proposes to make an investment in this DER project pursuant to the authority under RSA 374:G,

THEREFORE: Unitil and CHA (the "Parties") hereby enter into this Memorandum of Understanding setting forth their intentions and expectations relative to the DER project proposal.

The Parties agree as follows:

1.0 Unitil and CHA confirm their mutual interest in working together toward the successful development and completion of the DER project described in Attachment A.

2.0 Unitil will, subject to the approval of the New Hampshire Public Utilities Commission, fund the project at an expected direct cost of $78,400 up to a maximum of $__<+10%>___. Remittance will be made directly to the vendor or vendors responsible for providing and/or installing the equipment being purchased, after a final inspection by Unitil's representative.

3.0 Unitil will facilitate the interconnection of generators with Unitil's electric system in accordance with Unitil's Interconnection Requirements for Customer Owned Generation.

4.0 Unitil will provide metering equipment to separately measure the customer's load and the output of the generators. Generating facilities qualifying for net energy metering will be handled in accordance with the provisions of Chapter PUC 900 but data on generator output will be independently tracked. CHA will provide Unitil with reasonable access to the meters for purposes of meter reading, testing and maintenance.

* 5.0 CHA will make a reasonable and timely effort to seek and secure any additional funding that may be required to completely fund the project.

6.0 CHA will take appropriate security precautions to protect the equipment and to perform routine maintenance to ensure that it remains in good operating condition. CHA will also provide Unitil with reasonable access to the equipment and installation for purposes of inspection and monitoring.

* CHA will explore the availability of ARRA funding to support the project. JB

7.0 CHA agrees to defend and indemnify Unitil from any liability associated with the project and to maintain a general liability insurance policy of no less than $1,000,000 naming *Unitil Corporation and its subsidiaries* as additional insureds.

8.0 The Parties agree to execute a definitive Customer DER Participation Agreement once the project has been approved by the PUC and in advance of the investment being made by Unitil.

This MOU shall become effective upon the latter date of signature of the Parties and shall terminate upon execution of a Customer DER Participation Agreement or after one year. The MOU may be amended or otherwise terminated only by the mutual written agreement between CHA and Unitil.

Acknowledged and agreed this 14 day of July, 2009:

By:

John Hoyt Jr.
(Name)
(Title) Executive Director
Concord Housing Authority

By:

Unitil Energy Systems, Inc. ("Unitil")

(Name)
(Title) Director, Business & Economic Development

Distributed Energy Resources (DER) Project Proposal

Project Title: Crutchfield Place – Concord Housing Authority

Description of Technology:

This project proposal is for the installation of a medium sized solar hot water pre heating system. The system would consist of (16) Apricus AP30 evacuated tubes roof rack mounted in four rows of four tilted at 50 degrees.

Solar water heating systems include storage tanks and solar collectors. The solar collectors used in this application are Evacuated-tube solar collectors (ETSC). The system has parallel rows of transparent glass tubes. Each tube contains a glass outer tube and metal absorber tube attached to a fin. The fin's coating absorbs solar energy but inhibits radiative heat loss. The system will also require one or more well-insulated storage tanks. Solar storage tanks have an additional outlet and inlet connected to and from the collector.

Description and Scope of Project:

Crutchfield Place is a 105 unit low income multifamily property in downtown Concord owned and managed by the Concord Housing Authority. The existing system is a 120KW, 333Amp, 208V 3 phase electric heating element contained within a 1500 gallon water storage tank. The system is supplemented by a 170KBtu gas ray pac 85% efficient Natural Gas boiler for emergency backup. Demand for DHW at Crutchfield is approximately 2,536 US Gal per day for elderly residents. The system draws approximately 18,260 kWh per month at an average cost of $0.168 per kWH or $3,067.68 monthly. The proposed Apricus Solar DWH system will provide 100% of the facilities DHW needs April through November and 60% December through March, the system would be capable of heating 500 gallons of water approximately 80 degrees per average day.

Breakdown of Estimated Project Costs:

Project costs below include the equipment acquisition and equipment installation costs, the breakdown is as follows:

MEMORANDUM of UNDERSTANDING
Attachment A

Equipment	**Cost**
Apricus Collectors	$24,400.00
Racking	$9,900.00
Roofing	$7,200.00
Pipe and insulation	$16,200.00
Coring and patching	$2,900.00
Storage or heat exchanger	$13,800.00
Misc	$4,000.00
Total	**$78,400.00**

Any additional work will be billed at a rate of $65.00 per man per hour and actual cost plus 35% on all materials.

Summary of Project Benefits :

- Peak Demand Reduction: 120 KW maximum
- Installed Cost per Reduction in Peak Demand: $653.33 per KW
- Reduction in Customer Consumption 189,904 kWh/yr max, 120KW demand max
- Future O&M Estimated Cost: $ TBD per (month, quarter, annual)
- Demand Response dispatchable? No
- Renewable Energy Credits: Yes
- Tax Incentives: no

Summary Report

Crutchfield

Unitil Investment	$	101,920
Total Project Cost	$	101,920

Other Intangible Benefits	
Load Reduction	
Summer	**120**
Winter	**90**
Lifetime	
MWh Saved	
Annual	**190**
Lifetime	**2,469**
Economic Development	
Jobs Created	**1**
Wages & Salaries	**$38,029**

Allocation of Economic Benefits

Capacity	Total	Participant	All Customers	Default
Generation				
Summer	$155,702	$155,702		
Winter	$0	$0		
Transmission	$15,305	$15,305		
Distribution	$47,218	$47,218		
DRIPE	$31,520		$31,520	
Localized Distribution	$9,920		$9,920	
Total Capacity	**$259,664**	**$218,224**	**$41,440**	**$0**
Energy				
Winter				
Peak	$61,210	$61,210		
Off peak	$52,193	$52,193		
Summer				
Peak	$30,840	$30,840		
Off peak	$25,313	$25,313		
Total Energy	**$169,556**	**$169,556**	**$0**	**$0**
Other				
Energy				
Dripe	$24,024		$24,024	
Non-Electric				
CO_2 Reduction	$63,505		$63,505	
REC Credit	$18,990		$18,990	$18,990
Total Other	**$106,520**	**$0**	**$106,520**	**$18,990**
Economic Development				
Total Output	**$70,250**		**$70,250**	
Total Benefits	**$605,990**	**$387,780**	**$218,210**	**$18,990**
B/C Ratio	**5.95**	**N/A**	**2.14**	

MEMORANDUM of UNDERSTANDING
BETWEEN
The Town of Stratham, New Hampshire
and Unitil Energy Systems, Inc. ("Unitil")

Regarding a Distributed Energy Resource (DER) Investment Proposal
(DRAFT 7-6-09)

WHEREAS: The Town of Stratham, New Hampshire intends to install a DER project as described in Attachment A, and

WHEREAS: Unitil proposes to make an investment in this DER project pursuant to the authority under RSA 374:G,

THEREFORE: Unitil and The Town of Stratham, New Hampshire (the "Parties") hereby enter into this Memorandum of Understanding setting forth their intentions and expectations relative to the DER project proposal.

The Parties agree as follows:

1.0 Unitil and The Town of Stratham, New Hampshire confirm their mutual interest in working together toward the successful development and completion of the DER project described in Attachment A.

2.0 Unitil will, subject to the approval of the New Hampshire Public Utilities Commission, fund the project at an expected direct cost of $ 300,000.00. Remittance will be made directly to the vendor or vendors responsible for providing and/or installing the equipment being purchased, after a final inspection by Unitil's representative.

3.0 Unitil will facilitate the interconnection of generators with Unitil's electric system in accordance with Unitil's Interconnection Requirements for Customer Owned Generation.

4.0 Unitil will provide metering equipment to separately measure the customer's load and the output of the generators. Generating facilities qualifying for net energy metering will be handled in accordance with the provisions of Chapter PUC 900 but data on generator output will be independently tracked. The Town of Stratham, New Hampshire will provide Unitil with reasonable access to the meters for purposes of meter reading, testing and maintenance.

5.0 The Town of Stratham, New Hampshire will make a reasonable and timely effort to seek and secure additional funding to offset Unitil's investment that may be required to completely fund the project. Examples of sources for additional funding may include; RGGI grants, rebates available through the Renewable Portfolio Standard – Alternative Compliance Payment administered by the NH Public Utility Commission or by town Warrant Article.

6.0 The Town of Stratham, New Hampshire will take appropriate security precautions to protect the equipment and to perform routine maintenance to ensure that it remains in good operating condition. The Town of Stratham, New Hampshire will also provide Unitil with reasonable access to the equipment and installation for purposes of inspection and monitoring.

7.0 The Town of Stratham, New Hampshire agrees to defend and indemnify Unitil from any liability associated with the project and to maintain a general liability insurance policy of no less than $1,000,000 naming *Unitil Corporation and its subsidiaries* as additional insureds.

8.0 The Parties agree to execute a definitive Customer DER Participation Agreement once the project has been approved by the PUC and in advance of the investment being made by Unitil.

This MOU shall become effective upon the latter date of signature of the Parties and shall terminate upon execution of a Customer DER Participation Agreement or after one year. The MOU may be amended or otherwise terminated only by the mutual written agreement between The Town of Stratham, New Hampshire and Unitil.

Acknowledged and agreed this 13th day of July, 2009:

By:

David Canada

David Canada
(Name) Chair,
(Title) Board of Selectmen

By:

Unitil Energy Systems, Inc. ("Unitil")

(Name)
(Title) Director, Business + Economic Development.

Unitil
Unitil Energy Systems, Inc.

July 14, 2009

Project Title:
STRATHAM MUNICIPAL SOLAR PROJECT
Appendix A

Project Sponsor:
TOWN OF STRATHAM
Contact: Caroline Robinson, 772-6646

Description of Technology:
+/- 202 PV solar panels + 1 inverter, to be bid by contractor following new RFP.
(Information below is from a January 2008 bid.)

The system design and components will meet all national, state, and local utility regulations for utility interconnected photovoltaic systems.

Description and Scope of Project: Grid connected photovoltaic power system

1. Installation of +/- 202 panels of BP Solar SX 3195-195 watt (or equivalent) on the new Stratham Fire House. The PV array will be mounted on a ballasted racking system, with no penetration of roof membrane;
2. Installation of one SMA Sunnyboy 7000 inverter (or equivalent), one Sunny WebBox central data acquisition and diagnosis unit;
3. Installation of all equipment and conduit, cables, fittings, connectors to NEC 690 standard;
4. Sign-off with Unitil and the local permit authority.

Breakdown of Estimated Project Costs:
Initial low bid as of January 2008: $307,174
New 2009 bids to be solicited through RFP.

Justification and Project Benefit (include major assumptions):

- Peak Demand Reduction: 39.390 kW
- Installed Cost per Reduction in Peak Demand: $7798 per kW
- Reduction in Customer Consumption: 64,698 kWh per year
- Generation: 64,698 kWh per year
- Future O&M Estimated Cost: To be estimated by contractor
- Ownership: 100% Town of Stratham
- Demand Response dispatchable? No
- Renewable Energy Credits: estimated at 64.7

- Tax Incentives: Zero at this time, as it will be funded by a gift from Unitil to the Town of Stratham, as per MOU.

  The Town of Stratham will also pursue funds from the State of NH's Renewable Energy Fund.

- Societal Benefits:

  1. The project will reduce our municipal footprint by at least 48 tons of CO_2 per year, the equivalent of taking at least 9.8 cars off the road.
  2. It will provide the Town of Stratham with an alternative source of renewable energy.
  3. It will zero out the expected yearly electrical costs associated with the Stratham Fire Station.
  4. It will provide a benefit to all Stratham residents through a reduction of taxes for municipal energy costs.
  5. In the case of a major regional or town-wide power loss, the solar system will continue to provide the firehouse with electricity. This will greatly benefit the emergency response capability of the staff and volunteers.
  6. It will serve as a model for other municipalities in NH.
  7. As of August 2009, it will become the fourth largest solar array in the state.
  8. It will generate positive publicity for municipal solar power, for Unitil, for the Town of Stratham and for the State of New Hampshire.

Concerns or Challenges:

1. Verifying the structural stability of the building.
2. Meeting the need for electrical engineering and design to fully integrate the solar system with the existing electrical systems and back-up systems of the firehouse. This is a potential set-up cost to the town.
3. Working out the details and negotiating the parameters of the pilot study with Unitil and the staff and volunteers of the Stratham Fire Department.

Relevant reference material: RETScreen analyses (available on request).

Summary Report
Stratham Municpal

Unitil Investment	$399,321
Total Project Cost	$399,321
Other Intangible Benefits	
Load Reduction	
Summer	**39**
Winter	**39**
Lifetime	**512**
MWh Saved	
Annual	**103**
Lifetime	**1,343**
Economic Development	
Jobs Created	**4**
Wages & Salaries	**$148,997**

Allocation of Economic Benefits

Capacity	Total	Participant	All Customers	Default
Generation				
Summer	$51,109	$51,109		
Winter	$0	$0		
Transmission	$5,024	$5,024		
Distribution	$15,499	$15,499		
DRIPE	$10,346		$10,346	
Localized Distribution	$3,256		$3,256	
Total Capacity	**$85,235**	**$71,632**	**$13,603**	**$0**
Energy				
Winter				
Peak	$33,310	$33,310		
Off peak	$28,403	$28,403		
Summer				
Peak	$16,783	$16,783		
Off peak	$13,775	$13,775		
Total Energy	**$92,272**	**$92,272**	**$0**	**$0**
Other				
Energy				
Dripe	$13,074		$13,074	
Non-Electric				
CO2 Reduction	$34,559		$34,559	
REC Credit	$10,335		$10,335	$10,335
Total Other	**$57,968**	**$0**	**$57,968**	**$10,335**
Economic Development				
Total Output	**$275,240**		**$275,240**	
Total Benefits	**$510,714**	**$163,904**	**$346,810**	**$10,335**
B/C Ratio	**1.28**	**N/A**	**0.87**	

MEMORANDUM of UNDERSTANDING
BETWEEN
NHSEP and Unitil Energy Systems, Inc. ("Unitil")

Regarding a Distributed Energy Resource (DER) Investment Proposal

WHEREAS: **New Hampshire Seacoast Energy Partnership LLC "NHSEP"** intends to install a DER project through and on behalf of Exeter Region Cooperative School District as described in Attachment A, and

WHEREAS: Unitil proposes to make an investment in this DER project pursuant to the authority under RSA 374:G,

THEREFORE: Unitil and **NHSEP** (the "Parties") hereby enter into this Memorandum of Understanding setting forth their intentions and expectations relative to the DER project proposal.

The Parties agree as follows:

1.0 Unitil and **NHSEP** confirm their mutual interest in working together toward the successful development and completion of the DER project described in Attachment A.

2.0 Unitil will, subject to the approval of the New Hampshire Public Utilities Commission, fund the project at an expected direct cost of $ 200,000.00 <+10%>. Remittance will be made directly to the vendor or vendors responsible for providing and/or installing the equipment being purchased, after a final inspection by Unitil's representative.

3.0 Unitil will facilitate the interconnection of generators with Unitil's electric system in accordance with Unitil's Interconnection Requirements for Customer Owned Generation.

4.0 Unitil will provide metering equipment to separately measure the customer's load and the output of the generators. Generating facilities qualifying for net energy metering will be handled in accordance with the provisions of Chapter PUC 900 but data on generator output will be independently tracked. **NHSEP** will provide Unitil with reasonable access to the meters for purposes of meter reading, testing and maintenance.

5.0 **NHSEP** will make a reasonable and timely effort to seek and secure any additional funding that may be required to completely fund the project.

6.0 **NHSEP** will take appropriate security precautions to protect the equipment and to perform routine maintenance to ensure that it remains in good operating condition. **NHSEP** will also provide Unitil with reasonable access to the equipment and installation for purposes of inspection and monitoring.

7.0 **NHSEP** agrees to defend and indemnify Unitil from any liability associated with the project and to maintain a general liability insurance policy of no less than $1,000,000 naming *Unitil Corporation and its subsidiaries* as additional insureds.

8.0 The Parties agree to execute a definitive Customer DER Participation Agreement once the project has been approved by the PUC and in advance of the investment being made by Unitil.

This MOU shall become effective upon the latter date of signature of the Parties and shall terminate upon execution of a Customer DER Participation Agreement or after one year. The MOU may be amended or otherwise terminated only by the mutual written agreement between **NHSEP** and Unitil.

Acknowledged and agreed this 16 day of July, 2009:

By:	By:
NHSEP	Unitil Energy Systems, Inc. ("Unitil")
Clay Mitchell Member - NHSEP	(Name) (Title) Director, Business & Economic Development

MEMORANDUM of UNDERSTANDING
Attachment A

Distributed Energy Resources (DER) Project Proposal

Project Title: School Administrative Unit (SAU) 16

Description of Technology:

The SAU 16 project will employ two forms of alternative, distributed energy generation. The first form is through the installation of a 100 kilowatt (kW) photo voltaic (PV) solar array mounted on the roof of the new SAU 16 high school building. The second form will be the installation of one Capstone microturbine combined heat and power unit at the administrative offices located at 30 Linden Street, Exeter, NH.

Description and Scope of Project:

SAU 16 is seeking to carry out an innovative project designed to provide more efficient, environmentally friendly energy to the school system. Through the incorporation of the microturbine and solar PV array, the school aims to reduce overall energy costs through the generation of onsite electricity, lower heating fuel related expenses through the installation of a more efficient heating system, divert the related energy savings to critical curriculum based programs, and demonstrate the possibilities available to SAU districts (and others) across the State regarding alternative forms of energy. This project is truly unique to New Hampshire and shall establish the high water mark for school districts throughout the State to strive for. Schools are created to educate our children and providing every dollar possible to go toward educational programs benefits our society as a whole.

The project scope will include the following actions:

- Removal of the existing oil fired boilers
- Installation of one (1) natural gas Capstone C65 CARB Microturbine Unit
- Installation of a 100 kW solar PV array (roughly 450 panels)
- Ten (10) year service contract for the equipment between SAU 16 and the vendor

Breakdown of Estimated Project Costs:

Project costs will fall into one of three main categories: project development and oversight; equipment acquisition; and equipment installation. Following The three main cost parameters, the breakdown is as follows:

Project Development and Oversight –

Solar PV Array:	$ 100,000.00
Design of system configuration	
Engineering & Interconnectivity	
Permitting	
Microturbines:	$ 50,000.00
Design of system configuration	
Engineering & system Interconnectivity	
Permitting	
Total:	**$ 150,000.00**

Equipment Acquisition –

One (2) Capstone C65 CARB Microturbine Unit:	$ 135,000.00
100 kw Solar PV Array and Inverters:	$ 450,000.00
Total:	**$ 585,000.00**

Equipment Installation –

Capstone Microturbine Installation:	$ 50,000.00
100 kw Solar PV Array Installation:	$ 75,000.00
Total:	**$ 125,000.00**

Total Project Cost:	**$ 860,000.00**
Project Request: (23% Project Cost)	**$ 200,000.00**

MEMORANDUM of UNDERSTANDING
Attachment A

Summary of Project Benefits :

- Peak Demand Reduction:
  - Solar PV Array – 80 kW (variable)
  - Microturbines – 62.5 kW

- Reduction in Customer Consumption:
  - Solar PV Array – 147,400 kWH per year, 80 kW Demand
  - Microturbine – 306,000 kWH per year, 62.5 kW Demand

- Generation:
  - Solar PV Array – 147,400 kWH per year
  - Microturbine – 306,000 kWH per year

- Future O&M Estimated Cost:
  - Solar PV Array – $12,000.00 per year
  - Microturbine – $7,500.00 per year

- Demand Response Dispatchable? Yes

- Renewable Energy Credits: Yes

- Tax Incentives:
  - 30% Federal Tax Credit Solar Array
  - 10% Federal Tax Credit Microturbine

- Social Benefits:
  - Reduced operating costs for the school district
  - Significant example of community/utility partnership opportunity.
  - Annual reduction of 579 tons of CO^2, equivalent to removing 117 cars or light trucks from the road.
  - Largest solar array in New Hampshire.
  - Project can be reproduced on many similar facilities in the Unitil service area with the same partners and the same benefit ratio.

- Key Assumptions:
  - Figures presented in this worksheet are based on rough, conservative financial estimates

Schedule 6

Summary Report

SAU 16

Unitil Investment	$260,000
Total Project Cost	$860,000
Other Intangible Benefits	
Load Reduction	
Summer	**143**
Winter	**143**
Lifetime	**1,853**
MWh Saved	
Annual	**453**
Lifetime	**5,889**
Economic Development	
Jobs Created	**2**
Wages & Salaries	**$81,461**

Allocation of Economic Benefits

	Total	Participant	All Customers	Default
Capacity				
Generation				
Summer	$184,896	$184,896		
Winter	$0	$0		
Transmission	$18,174	$18,174		
Distribution	$56,071	$56,071		
DRIPE	$37,430		$37,430	
Localized Distribution	$11,780		$11,780	
Total Capacity	**$308,351**	**$259,141**	**$49,210**	**$0**
Energy				
Winter				
Peak	$146,012	$146,012		
Off peak	$124,502	$124,502		
Summer				
Peak	$73,565	$73,565		
Off peak	$60,382	$60,382		
Total Energy	**$404,461**	**$404,461**	**$0**	**$0**
Other				
Energy				
Dripe	$57,308		$57,308	
Non-Electric				
CO2 Reduction	$151,486		$151,486	
REC Credit	$45,300		$45,300	$45,300
Total Other	**$254,094**	**$0**	**$254,094**	**$45,300**
Economic Development				
Total Output	**$336,476**		**$336,476**	
Total Benefits	**$1,303,383**	**$663,602**	**$639,781**	**$45,300**
B/C Ratio	**1.52**	**1.11**	**2.46**	

UNITIL ENERGY SYSTEMS, INC

DIRECT TESTIMONY OF

JUSTIN C. EISFELLER

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DE 09-___

AUGUST 5, 2009

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LIST OF SCHEDULES

I. INTRODUCTION

Q. Please state your name and business affiliation.

A. My name is Justin C. Eisfeller and I am the Director of Energy Measurement and Control at Unitil Service Corp., and I am testifying on behalf of Unitil Energy Systems, Inc. ("UES" or the "Company"). As Director of Energy Measurement and Control (EM&C) I am responsible for daily operations of the metering, substation, and gas and electric dispatching areas. These responsibilities have involved shaping the company's direction in areas of advanced metering applications and regulatory actions due to EPACT and distributed generation. My business address is 325 West Road, in Portsmouth, NH.

Q. Please summarize your qualifications and current position with the company.

A. I joined Unitil in 2003 as Manager of Distribution Engineering with responsibility for distribution system design and support. In 2004, I assumed the responsibilities of Director of Engineering with responsibilities for distribution engineering, planning, transmission and substation engineering, system protection and control, computer aided design, and geographic information systems. In 2008 I assumed responsibilities for my current position. The functions of the Director, EM&C include responsibility for the installation, operation, and maintenance of equipment necessary to provide for metering, dispatching and substation systems; as well as equipment and systems necessary for the implementation of new energy technology, the digitization and automation of the electric system, equipment communications, system performance data gathering, demand response, and the enabling of other displacement energy technologies. Metering functions include installation, maintenance, and testing of all gas and electric meters; monthly procurement of energy usage data; development of metering system standards to optimize efficiency and performance; and the procurement, maintenance, enhancement of automated meter reading systems (AMI systems). System Dispatch includes radio operation; outage reporting; system monitoring & control (SCADA systems); and ISO reporting of regional operating procedures. Gas functions include load forecasting, daily nominations, tracking of gas inventories, daily estimates and telemetering of daily readings for gas suppliers. System operations functions includes substation equipment installation and maintenance; system switching, emergency restoration efforts; and management of a predominantly union workforce.

Prior to joining Unitil, I was employed for 6 years at Heidelberg Web Systems, as Director, Product Performance Group, with primary responsibility for overseeing engineering support for service operations and product upgrades. Prior to this experience, I worked for Public Service Company of New Hampshire ("PSNH") for 10 years where I held various positions of increasing responsibility within their engineering departments.

Q. **What is the purpose of your testimony?**

A. In this testimony I will describe Smart Grid Time of Use DER Project - Pilot Phase, which UES plans to complete during 2010. I will also demonstrate that based upon our cost/benefit analysis including an assessment of environmental and economic impacts, this project meets the public interest test as defined in RSA 374-F.

II. TIME OF USE/ SMART GRID PILOT

Q. **Please provide a summary description of the proposed Time of Use/Smart Grid pilot project.**

A. I have attached Schedule JE-1 which provides a detailed description of this pilot project as originally filed with the Massachusetts Department of Public Utilities in April 2009. In summary, the Time-of-Use/Demand Response (TOU/DR) Pilot Program is designed to investigate the costs and benefits associated with three distinct demand reduction programs. Two of these programs will investigate TOU rates incorporating low, medium and high-cost time based rates with a critical peak price (CPP) that can be initiated during periods of extreme electricity demand. The third program is a non-TOU program that entails a utility-controlled thermostat that requires no intervention from the customer. Each of these programs is described briefly below. The pilot will be conducted jointly in Unitil's Massachusetts and New Hampshire service territories in order to achieve maximum efficiency at the lowest cost to the ratepayers of either state.

- Simple TOU Program – Enrolled customers will receive basic educational materials, with no technology enhancement. CPP notification will be handled via email or a phone call. The simple rate will not include a time-of-use rate structure. Comparisons in demand reduction and implementation costs between the three programs shall be made.

- Enhanced Technology Program – Enrolled customers will receive the same educational materials, but will also receive an in-home wireless control system with a suite of energy management tools, a utility integration portal, and flexible control devices (smart thermostats and outlets). This package will allow for both utility and customer-automated load control and demand response. The *Enhanced Technology Program* will not include direct demand control from UES through the customer's thermostat.
- Smart Thermostat Program – This is not a TOU rate program. Instead, enrolled customers will receive a utility controllable thermostat that offers digital programming features and customer feedback. The utility will have the ability to either cycle the customer's heating and cooling load, or change the temperature on the thermostat during periods of extreme electricity demand. This change in thermostat setting will not be accompanied with specific customer notification, but customers will be able to override the changed setting.

Phase I of this pilot entails establishing sample sizes for each of the above three programs (and a "control" group), developing educational materials, and coming up with a marketing and recruiting approach that minimizes non-response bias. Guidance will also be provided as to the best methods for implementing the pilot in a way that will allow the project objectives to be met. A primary project objective is to obtain information that can be used to inform price elasticity models. Phase I will ultimately deliver an approach for fully implementing the pilot in Phase II.

The information contained in Schedule JCE-1 will be updated once the pilot program has been approved in MA and NH. In particular, additional analyses and rate design work will be required to complete the design of the TOU rates, and the TOU Tariff and Rate Schedules will need to be finalized and approved by the commissions.

Q. **Please explain why UES considers this a DER project?**

A. The primary objective for this project is to provide consumers with more accurate pricing information so that they may better allocate their limited resources as they make their purchasing decisions. Additionally, this pilot will demonstrate technologies and processes that can save consumers real dollars by shifting demand from peak to off-peak periods. Consumer savings are derived from both lower priced generation and the avoidance of transmission and distribution investments driven by rising peak demands. We believe that this project will have a direct impact on our ability to achieve system reliability and security by deferring the need to add new T&D infrastructure through load management via time of use applications.

Q. What is the estimated cost for this DER pilot project?

A. A detailed cost breakdown for this project is included in Schedule JCE-1 Appendix A. As noted above, this pilot is being implemented by Unitil in both its New Hampshire and Massachusetts electric distribution service areas. Overall pilot costs are split evenly between the companies. The actual customer equipment installations will be greater in New Hampshire, however, corresponding to the larger number of customers, so those costs are allocated on the number of participating customers, resulting in a slightly higher cost allocation to New Hampshire. In addition, these cost estimates exclude internal personnel and overhead costs, as we wanted to insure that no costs included for recovery in the pilot program were also, arguably, being recovered in the Company's base rates in either state.

The total cost for the pilot project, consistent with those assumptions, is estimated at $526,560, with the share for New Hampshire estimated at $312,136. This excludes internal personnel costs or overheads.

Q. How did you derive the economic and environmental benefits associated with this pilot project?

A. Schedule JCE-2 is a summary report of the economic and environmental impact assessment performed for this project. Load and energy impacts were estimated by GDS Associates, the company assisting UES in the development of this pilot project, based on utility experience derived from other TOU programs.

We analyzed the economic and environmental benefits using the same model introduced by Dr. Axelrod. Overall, the project has a Benefit/Cost (B/C) ratio of 1.80. In other words, there are $561,000 in total savings for UES' New Hampshire customers derived from the $312,000 initial cost. While the participating customers will reap over $268,000 in benefits, all customers benefit from $292,000 in benefits. The B/C ratio for all non-participating customers is .94. We believe this is an excellent result for a pilot program.

Q. Are there other tangible benefits that can be derived from this pilot project?

A. Annual energy savings amounts to 56 megawatt hours per year. Associated with this reduction is also a reduction in air quality emissions. More significantly, as loads are shifted from on-peak to off-peak periods, more efficient and less polluting generation is called upon. Over the life of this project, some $16,000 dollars will be avoided in CO_2 charges. We also estimate that the economic development benefits will result in 3 new jobs and $116,000 in added wages and salaries within the region. Based on the economic multiplier effect that Dr. Axelrod discussed in his testimony, UES' $312,000 investment in the TOU Pilot project will produce nearly $300,000 in regional economic output.

Q. **Why do you believe the Commission should approve a project with a B/C ratio that is less than one?**

A. We believe that our estimates for lifetime benefits are very conservative, and that future benefits, especially those associated with environmental costs, will likely result in a B/C ratio of greater than one for UES' non-participating customers. For example, avoided CO_2 emissions are priced at the current RGGI auction rates. A national cap and trade program, if instituted, could result in avoided CO_2 emission fees between 5 and 10 time greater. Note that we estimate that this project will produce some $16,000 in lifetime CO_2 benefits based on RGGI prices (between $3 - $4/ton). Some economists project CO_2 prices in the $20 - $30 range, which would increase this benefit alone to more than $120,000.

We also believe the demand impact will increase as customers and technologies catch up to concept of time of use pricing. For example, a part of this pilot is an enhanced technology study where remotely transmitted pricing signals can automatically trigger demand responses without the customer's intervention.

Furthermore, this pilot project incurs a number of expenses designed to test systems and evaluate customer responses. For example, UES is purchasing additional metering just to quantify direct and immediate reactions to price signals and technology applications. Under a full scale program, such expenses will be minimal as compared to total project costs, as UES' current AMI system is fully capable of implementing TOU rates without additional expense.

III. CONCLUSION

Q. **Does that complete your testimony?**

A. Yes, it does.

Schedule
JCE-2

Summary Report
TOU

Unitil Investment	$312,136
Total Project Cost	$312,136
Other Intangible Benefits	
Load Reduction	
Summer	155
Winter	155
Lifetime	1,550
MWh Saved	
Annual	56
Lifetime	558
Economic Development	
Jobs Created	3
Wages & Salaries	$116,466

Allocation of Economic Benefits

Capacity	Total	Participant	All Customers	Default
Generation				
Summer	$153,817	$153,817		
Winter	$0	$0		
Transmission	$18,112	$18,112		
Distribution	$55,880	$55,880		
DRIPE	$40,713		$40,713	
Localized Distribution	$12,814	$12,814		
Total Capacity	**$281,336**	**$227,809**	**$53,527**	**$0**
Energy				
Winter				
Peak	$11,619	$11,619		
Off peak	$8,543	$8,543		
Summer				
Peak	$11,925	$11,925		
Off peak	$8,245	$8,245		
Total Energy	**$40,331**	**$40,331**	**$0**	**$0**
Other				
Energy				
Dripe	$7,599	$7,599		
Non-Electric				
CO2 Reduction	$16,211	$16,211		
REC Credit	$0	$0	$0	
Total Other	**$23,810**	**$0**	**$23,810**	**$0**
Economic Development				
Total Output	$215,146	$215,146		
Total Benefits	$560,623	$268,140	$292,483	$0
B/C Ratio	1.80	n/a	0.94	

Unitil
Unitil Service Corp.

March 31, 2009

BY OVERNIGHT MAIL and ELECTRONIC FILING

Mary L. Cottrell, Secretary
Massachusetts Department of Public Utilities
One South Station, 2nd Floor
Boston, MA 02110

RE: Fitchburg Gas and Electric Light Company, d/b/a Unitil
Smart Grid Pilot Program Development Plan
Docket: DPU 09-31

Dear Secretary Cottrell:

Pursuant to Section 85 of the Green Communities Act, Chapter 169 of the Acts of 2008, and on behalf of Fitchburg Gas and Electric Light Company, d/b/a Unitil ("Unitil" or the "Company"), enclosed please find the Company's Smart Grid Pilot Program for filing in the above-referenced docket. Hard copies of this filing are being provided by overnight-delivery.

If you should have any questions, please do not hesitate to contact me directly. Thank you for your consideration in this matter.

Sincerely,

Gary Epler
Attorney for Fitchburg Gas and
Electric Light Company

Enclosure

cc: Jed Nosal, Assistant Attorney General (3 copies)
Robert Sydney, Senior Counsel DOER

Gary Epler
Chief Regulatory Counsel

6 Liberty Lane West
Hampton, NH 03842-1720

Phone: 603-773-6440
Fax: 603-773-6640
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Unitil

Fitchburg Gas and Electric Light Company
d/b/a Unitil

Smart Grid Pilot Program

April 1, 2009

Docket No. DPU 09-31

Filed with the Massachusetts
Department of Public Utilities
April 1, 2009

Table of Contents

I. Introduction

Section 85 of the Green Communities Act requires electric utilities to develop and file with the Department plans for two specific pilot programs:

> 1) a proposed plan to establish a smart grid pilot program utilizing advanced technology to provide real time measurement and communication of energy consumption, automated load management, remote system status and operation of distribution system equipment; and
>
> 2) a proposal to implement a pilot program that requires time of use or hourly pricing for commodity service for a minimum of 0.25 per cent of the company's customers.

Fitchburg Gas and Electric Light Company's d/b/a Unitil ("Unitil" or "Company") Automated Metering Infrastructure (AMI), with its advanced metering and two-way communication capabilities, already meets much of the functionality specified for the smart grid pilot. The combination of two-way communication capability and reprogrammable endpoints, permits the Company to implement time-of-use (TOU) and critical peak period (CPP) rate designs without the need for costly meter change-outs.

Although Unitil plans a multi-year effort to expand the use of its AMI system, it expects to take a measured approach to investigating smart grid technologies and program development. As discussed herein, the Company has designed its pilot programs to incorporate the advanced features of its AMI system in such a manner as to satisfy both of the pilot requirements under the Green Communities Act. In Section II.A. of this filing, Unitil addresses the first provision above for a smart grid pilot program. This section also discusses the Company's plans for expanding the use of its AMI system in the near future.

In Section II.B., Unitil addresses the second provision concerning a time of use pilot program. It should be noted that the time of use pilot has been designed as a joint pilot of both Unitil and its NH affiliate, Unitil Energy Systems, Inc. ("UES"), to include customers of both utilities. The proposed joint pilot was designed to ensure statistical validity of the program results while providing for lower costs by reducing the required number of customer participants for each company and for the sharing of common costs between companies. If, however, UES is unable to obtain regulatory approval in New Hampshire on the same terms and in the same time frame as is obtained by Unitil from the Department, Unitil will nonetheless proceed with its portion of the pilot as approved. In that circumstance, however, Unitil will seek to recover the portion of costs which would no longer be shared by its New Hampshire affiliate.

II. Program Description

A. AMI as a Smart Grid Platform

A.1 Advanced Metering Infrastructure System

Unitil's AMI system is a platform for intelligent grid projects, since it provides for two way communications with the meter and other field devices, is capable of gathering system performance data at every meter, and can be easily integrated with other systems.

The AMI system utilizes ultra-low bandwidth, power line carrier signals and parallel frequency communications for simultaneous communication with all meters. Data is transmitted to a server with router capability located at substations. The data is then transmitted by telecommunication lines to Unitil's centralized server room in Hampton, New Hampshire, where it is made available across the Company's information network to all of the operating centers for billing, status monitoring, or analysis. The Company views the AMI system as offering a strategic platform for additional technological, management, and evaluative capabilities, including:

(1) better estimating load shapes and peak load conditions of specific circuits;
(2) on-demand meter reads;
(3) remote "virtual" access (e.g., for disconnections and reconnections);
(4) electric system monitoring, including load, voltage, reliability, power quality, outage detection, and management;
(5) remote configuration of demand meters and TOU meters; and
(6) distribution automation.

Most importantly, AMI can serve as the platform for demand-response and TOU programs that will encourage resource conservation and offer other benefits relating to energy delivery and customer empowerment via informed energy usage choices.

The Company anticipates the next phase of the AMI project (beyond automated meter reading), expected to take place over the next three to five years, will involve integrating the AMI system with other Company systems and expanding the AMI system capability through additional investments. This future evolution of the AMI system is part of the Company's larger strategy to develop and implement elements of what has become known in the industry as the "Smart Grid." The Company is proposing two smart grid pilot projects outlined herein that leverage the AMI system's capabilities and is pursuing additional planned smart grid projects as part of its normal course of business.

A.2 Unitil Vision of Smart Grid

A.2.1 Conceptual Framework

Grid modernization has emerged as an important element of national energy policy in recent years in conjunction with new priorities aimed at improving the cost, efficiency, reliability, independence, and environmental friendliness of the nation's energy supply. Many names have been given to this vision of a modern grid, though the term "Smart Grid" has become most synonymous with a modern 21st century grid that incorporates state of the art technologies to achieve important functional capabilities. While there is no standard definition of a Smart Grid, it is most often described in terms of robust two-way communications, advanced sensors, and distributed computing/control to enable intelligent decisions in order to run the grid more efficiently, reliably and at lower cost. The Smart Grid is also described in terms of its ability to seamlessly integrate energy efficiency, demand response and other distributed-resources and to enable the interaction of loads and resources in real time.

Unitil's AMI system is but one element of a larger vision to achieve the functionality of the modern Smart Grid. The Company envisions a future in which resources are increasingly distributed, with much greater penetration of distributed generation, energy storage, and demand response technologies. A "smart" utility network will have the ability to reduce customer power consumption during peak hours through utility intervention (load control) and/or customer empowerment (demand response), enable grid connection of distributed generation and energy storage devices, and provide grid energy storage and supplemental service for extensive distributed generation load balancing (net metering). These changes will have profound implications for the design of the distribution system.

In order to effectively and efficiently pursue a Smart Grid strategy, it is first necessary to have a clear vision of what the strategy is intended to achieve. A Smart Grid is defined not by specific technologies and features, but by its ability to deliver desired capabilities. In this regard, Unitil has defined its vision of the Smart Grid around the work of the National Energy Technology Laboratory ("NETL") Modern Grid Strategy.[1] The NETL Modern Grid Strategy seeks to revolutionize the electric system by integrating 21st century technology to achieve seamless generation, delivery and end use that benefits the nation. This strategy is then further defined in terms of six key goals, and seven key characteristics that benefit consumers, business, utilities and national security.

A.2.2 Goals and Characteristics of the Modern Grid

The NETL Modern Grid Strategy identifies six key goals of grid modernization in order to achieve the power system required for the future:[2]

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[1] The National Energy Technology Laboratory (NETL), part of DOE's national laboratory system, is owned and operated by the U.S. Department of Energy (DOE). NETL supports DOE's mission to advance the national, economic, and energy security of the United States.

[2] National Energy Technology Laboratory, The Modern Grid Strategy. http://www.netl.doe.gov/moderngrid/

(1) The grid must be more reliable
A reliable grid will provide power dependably, when and where its users need it and of the quality they value.

(2) The grid must be more secure
A secure grid will withstand physical and cyber attacks without suffering massive blackouts or exorbitant recovery costs. It will also be less vulnerable to natural disasters and will recover faster.

(3) The grid must be more efficient
An economic grid will operate under the basic laws of supply and demand, resulting in fair prices and adequate supplies.

(4) The grid must be more economic
An efficient grid will take advantage of investments that lead to cost control, reduced transmission and distribution electrical losses, more efficient power production and improved asset utilization.

(5) The grid must be more environmentally friendly
An environmentally friendly grid will reduce environmental impacts through initiatives in generation, transmission, distribution, storage and consumption.

(6) The grid must be safer
A safe grid will not cause any harm to the public or to grid workers and will be sensitive to users who depend on it as a medical necessity.

The NETL Modern Grid Strategy further defines seven key characteristics of the modern grid. These characteristics represent the NETL's vision, and the desired functionality, for the modern grid.

(1) Self-healing
The modern grid will perform continuous self-assessments to detect, analyze, respond to, and as needed, restore grid components or network sections.

(2) Motivates and includes the consumer
Consumer choices and increased interaction with the grid bring tangible benefits to both the grid and the environment, while reducing the cost of delivered electricity.

(3) Resists attack
The grid deters or withstands physical or cyber attack and improves public safety.

(4) Provides power quality for 21st century needs
Digital grade power quality avoids productivity losses of downtime, especially in digital device environments.

(5) Accommodates all generation and storage options
Diverse resources with "plug-and-play" connections multiply the options for electrical generation and storage including new opportunities for more efficient, cleaner power production.

(6) Enables markets
The grid's open-access market reveals waste and inefficiency and helps drive them out of the system while offering new consumer choices such as green power products. Reduced transmission congestion leads to more efficient electricity markets.

(7) Optimizes assets and operates efficiently
Desired functionality at minimum cost guides operations and fuller utilization of assets. More targeted and efficient grid maintenance programs result in fewer equipment failures.

Unitil uses these goals and characteristics as the framework for its own strategy related to AMI and Smart Grid development, and has been focusing efforts primarily in the areas of customer empowerment and demand response, accommodating generation and other Distributed Energy Resource ("DER") options, and optimizing assets and improving the efficiency of grid operations.

A.2.3 The Role of AMI in Advancing the Smart Grid

The advanced metering and two-way communication capabilities inherent in the AMI system are essential to meeting key functional capabilities and characteristics of the Smart Grid. In particular, the ability to implement time-based rates and demand response programs is essential to motivating and empowering consumers by providing accurate pricing signals as well as choices to increase customer interaction with the grid and thereby reduce consumption.

Future evolutions of the AMI system are expected to include hourly meter intervals, bringing metered consumption closer and closer to real time. Furthermore, meters currently under development will include ZigBee[3] wireless communication capability and the ability to communicate consumption information wirelessly into the home, and to interact with other devices, appliances, and gateways within the home over a Home Area Network ("HAN"). Ultimately, the line between the utility grid and the in-home network will become increasingly blurred as utility meter and equipment providers work together with white goods manufacturers, home energy management and networking solutions providers to develop smart appliances and energy management and demand response solutions incorporating utility consumption information and pricing signals.[4]

In addition to customer empowerment programs, the AMI system provides important functionality to optimize utility assets, improve operating efficiency, and enhance outage restoration, while delivering new and enhanced services to customers. These improvements are

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[3] ZigBee is the name of a specification based on the IEEE 802.15.4-2006 standard for wireless personal area networks (WPANs).
[4] The ZigBee Alliance is an association of companies working together to enable reliable, cost effective, low-power, wirelessly networked, monitoring and control products based on an open global standard.

already evident in Unitil's ability to get more timely and accurate readings. The Company has seen a reduction in billing estimates and improvement in on-cycle reads. This performance is expected to further improve with enhancements to the information systems associated with the Company's billing and work order systems. System operations data captured by the AMI system on a daily basis is also being leveraged to improve the design and operation of the system. The AMI system captures outage data, voltage data, and power quality data that are now being incorporated into the planning, design, and maintenance of the system, improving the quality of service. Since this information and customer usage data is available on a daily basis, it can also be utilized to answer customer inquiries regarding billing or outages. The Company has plans to further leverage this data by more closely integrating the AMI system with its billing, work order, planning systems and a future outage management system.

The initial plans to test the functionality, cost effectiveness and potential program development include the two pilot projects outlined below. Additionally, the Company is pursuing several planned projects as part of it normal course of business that further leverage the AMI system.

A.3 Smart Grid Projects

The Company has already completed several AMI initiatives. These projects were outlined in the Companies response to response to the Department of Public Utilities request for a report regarding its plan for the implementation of the next phase of its AMI project.[5] These projects included:

1. End of line voltage monitoring;
2. GIS and AMI system integration for meter communications diagnostics and ability to find loose power connections (potential losses);
3. GIS outage viewer;
4. Improved system modeling data, utilizing per phase and per customer load data from AMI system;
5. Improved service transformer sizing guideline, utilizing the AMI system capability of capturing every customers' daily peak demand;
6. Daily Watt/Var data at step transformers utilizing standard AMI meters; and
7. On demand customer reads and individual outage history to address customer inquiries;

Unitil's plans include a number of other smart grid projects for 2009/10 implementation, including an outage management system that integrates AMI, Interactive Voice Response (IVR), and Geographic Information Systems (GIS) systems; a pilot project to utilize AMI to monitor power quality on the distribution system; and a pilot project that uses the AMI system to control distribution capacitor banks.

[5] See DPU 07-71 at page 44 and August 28, 2008 Unitil response at page 13. Plans outlined also include projects beyond 2010.

The following schedule outlines the timeline for these projects:

Dec. 1, 2009	Outage Management – Phase I (tabular reporting)
Dec. 1, 2010	Outage Management – Phase II (full integration with AMI, SCADA, and GIS
Dec. 1, 2009	Power Quality monitoring with AMI Pilot
Dec. 1, 2009	AMI control of distribution capacitor banks Pilot

A.3.1 Outage Management System

Unitil does not currently have an Outage Management System (OMS). An OMS will provide a means to use real-time information to manage outage related events in a more effective manner and contribute to minimizing the time and costs associated with the outage restoration process. The system will have intelligence to make predictions and decisions based upon the information it obtains. The data management interface will be efficient when collecting outage information in order to provide data for crew management and real time reporting of outage statistics. The system will have two way communication and the flexibility to change when more demands are placed upon reliability management.

An OMS system can use several different data sources to make predictions about the outage size and severity. The data sources can be from customer calls (IVR), SCADA interfaces and /or the AMI system. Since the Unitil AMI system is a two way system capable of communicating outage information, it is apparent that the AMI system may play a key role in the development of an OMS. The continuous monitoring (24 hours per day, 7 days per week, 365 days per year) at every meter point provides valuable information about the status of each and every customer. The AMI system notifies the Command Center within 10 – 20 minutes of an outage. This data may be useful in assessing the situation so that crew dispatch can be completed in an efficient manner to resolve the outage and verify restoration of the area, before the crews move on to another location. This system is able to distinguish between a sustained and a momentary outage based upon predefined, hardwired settings.

An OMS will provide the following benefits:

- Increase reliability and control costs with improved visibility and response time
- Increase return on invested capital by better managing distribution assets
- Provide access to real-time, decision-driving data, thus reducing risk and uncertainty
- Minimize restoration time
- Improve operations efficiency
- Provide ability for segmented or sequential implementation
- Leverage existing systems

A.3.2 Power Quality Monitoring Pilot

Unitil chose to implement the GE kV2c meter for all three phase demand customers. This meter can be upgraded to record power quality information such as voltage and current per phase measurements, voltage sags and swells, voltage distortion, current distortion, and total harmonic distortion. The Company plans to experiment with utilizing the capability of the AMI system to read this information and provide it for analysis of power quality concerns. This pilot would be accomplished with internal Company resources. Therefore there are no incremental costs.

A.3.3 Distribution Capacitor Bank Control Pilot

Unitil is required to maintain its system power factor within the limits set by ISO-NE. This is accomplished through daily capacitor bank switching as well as seasonal switching to address heavier seasonal loading periods. Daily capacitor switching is used as a fine tuning approach to account for daily variations in load cycle while the seasonal switching is required to account for seasonal variations in load. Daily switching is completed through a combination of SCADA controlled and automated capacitor banks switched on time, voltage or power factor.

At the present time, seasonal switching is completed by line crews which are dispatched to place fixed capacitor banks in service. The AMI system is capable of providing some increased level of distribution automation that Unitil does not presently have. The AMI system, with some modifications to the capacitor banks, is capable of switching these banks similar to a SCADA system. Unitil is designing a pilot installation to test the capabilities of this approach. Based upon this pilot, Unitil will determine the cost and benefit of the installation to determine if a larger deployment would be cost effective. If this is effective, it would eliminate a line crew having to switch capacitor banks on a seasonal basis. The cost of the installation is estimated to be $2,000 to $3,000 if the capacitor is already equipped with switches and $8,000 to $10,000 if not. It is assumed that Unitil could implement this with internal resources.

B. *TOU / CPP / Demand Reduction Pilot*

This section presents the methodology for implementing a demand response pilot program throughout Unitil's service territory. The pilot program has been developed to fulfill the second requirement of Section 85 of the Green Communities Act. The program will ultimately include customers of both Unitil and its NH affiliate, UES; however this submittal focuses on Unitil's customers. The intent of this section is to outline a detailed approach for fully implementing the pilot program.

Unitil has completed a consultant selection process to assist with program development and administration as part of the first phase of the project including: scope development, sampling methodology, marketing and recruitment, and development of educational materials[6]. Unitil will require assistance with the second phase of the project which will include: contractor selection, project management, regulatory support, data analysis and reporting.

B.1 Objective

The primary focus of this pilot program is to meet and exceed the requirements of the Massachusetts Green Communities Act Section 85. Accordingly, a key objective of the pilot is to achieve reductions in peak demand and average load of at least 5 percent for all customers participating in the program. The Company's peak demand normally occurs during the summer months ranging from early June through late August. The pilot is being designed and administered in a manner that will minimize sampling bias and will provide measurable and useful results.

B.2 Pilot Details

B.2.1 Program Overview

This pilot program is designed to investigate the costs and benefits associated with three distinct demand reduction programs. Two of these programs will investigate time-of-use (TOU) rates incorporating on-peak and off-peak periods with a critical peak period (CPP) rate that can be initiated during periods of extreme electricity demand. The third program is a non-TOU program where demand response is achieved through the use of a utility-controlled thermostat. Each program is described briefly below and will be proposed in both Unitil's and UES' service territories.

- *Simple TOU Program* – Enrolled customers will be set up on a time-of-use rate structure and will receive basic educational materials only with no additional enabling technology. Notification of a CPP event will be handled via email, pager, or phone call, based on customer preference.

[6] GDS Associates of Manchester, NH was selected and has made a significant contribution to the development of this filing.

- *Enhanced Technology Program* – Enrolled customers will be set up on a time-of-use rate structure and will receive the same educational materials, but will also receive an in-home wireless control system with a suite of energy management tools, a utility integration portal, and flexible control devices (smart thermostats and outlets). This package will allow for both utility and customer-automated load control and demand response. The Enhanced Technology Program will not include direct demand control by Unitil through the customer's thermostat.

- *Smart Thermostat Program* – Enrolled customers will stay on the existing fixed rate billing structure. Unitil will provide a controllable thermostat that offers digital programming features and customer feedback. Unitil will have the ability to either cycle the customer's heating and cooling load, or change the temperature on the thermostat during critical peak periods. This change in thermostat setting will be accompanied by local notification at the thermostat unit. Customers will be able to override the changed setting.

Customers enrolled in the TOU programs will receive access to a web portal that will provide access to their energy usage (next day daily reads) as well as tools to effectively manage their energy consumption. Pilot participants could use the web portal to experiment with the impact of their daily decisions regarding use of electrical equipment. The web portal will also give participants on the TOU rates the ability to follow their usage during peak times and track the potential cost impacts.

Also anticipated to be available on the web portal will be enhanced web tools and calculators. The web tools and calculators are expected to help Unitil customers identify potential electrical demand savings on a per appliance basis. The web tools are also expected to help TOU rate customers calculate the financial impact of decisions made by reducing demand. The environmental benefits related to emission reductions will also be integrated into the web tools for customers to realize the positive impact on the environment of energy efficiency and load shifting.

In order to calculate per participant load reductions and program savings for peak load and total electric usage, interval data must be collected for program participants and the control group. This requires the installation of interval recording meters. The cost of this equipment and installation is included in the program costs discussed below. Pre and post pilot surveys will be conducted to evaluate customer attitudes and behavior patterns.

B.2.2 Project Parameters

Project Schedule

The following schedule is proposed for the implementation of the pilot program. A key milestone in the program implementation process is the DPU and NHPUC approval of the project by September, 2009. Without timely approval of the project, it will be difficult to initiate the actual pilot program in time for Unitil's 2010 summer peak period.

Aug. 1, 2009	Customer Survey completed (and associated prerequisite materials)
Sept. 1, 2009*	DPU and NHPUC Approval of Pilot Project
Oct. 1, 2009	Completion of RFP for Turnkey Project Completion
Dec. 1, 2009	Award Project Contract
Jan. 1, 2009	Demo Customer Web-Site Available
Feb. 1, 2010	228 Customers Recruited
March 1, 2010	Begin installation of equipment and education of enrolled customers
March 1, 2010	Customer Web-Site completed
May 1, 2010	Installation and training completed
May 1, 2010	Billing System tested and approved
June 1, 2010	Pilot begins
Sept. 1, 2010	Pilot ends
Nov. 1, 2010	Project Report completed

Program Costs

The summary table below presents the cost estimate for the pilot program for Unitil. A 10% contingency has been added to account for variability in equipment and labor pricing, and to account for additional administrative time that may be needed to support the program development. A complete detailed cost matrix including total pilot costs for NH and MA is provided in Appendix A. As shown, equipment and materials are directly assigned based on use (estimated to be 32%) and programming or administrative costs are allocated 50/50.

$81,500	Materials and Installation

$74,000	Project Consulting
$5,500	Participation Incentives
$10,000	Meter Interface and Feeds into the Billing System
$10,000	CIS Billing System
$0	Internal Revenue Reporting
$5,000	Customer Data Management / Internal and External Web
$0	Administration Costs
$18,500	Contingency (10%)
$204,500	**Total**

The cost summary table presented above includes estimates for consultant, contractor and material costs associated with the pilot program in Unitil's service territory. Internal resource costs necessary to support the program are not included. A description of each cost item is provided below:

- Materials and Installation: Materials include analysis meters, Zigbee meters, smart thermostats, enabling technologies, and recruiting and educational materials. Also included is the installation of equipment and training for contractors and customers.

- Project Consulting Fees: Consultant fees to manage the pilot project, provide regulatory support, coordinate contractor outreach and qualification, conduct pre and post pilot surveys, oversee the recruiting effort, manage and analyze the collected data, and prepare a final report documenting the results.

- Participation Incentives: Incentives offered to customers for enrolling in the programs and for completing the pilot period. The need for and magnitude of incentives will be assessed during the marketing surveys.

- Meter Interface and Feeds into Billing System: Includes the planning, design, modification, interface and testing of the meter and billing systems. The smart metering will be an implementation plan to test the data collection, time of use billing interface to automate the billing process and test the reliability of smart meter data collection.

- CIS Billing System: Includes the planning, design, modification, bill printing and testing of the time of use billing process and paper/electronic billing format.

- Internal Revenue Reporting: Includes the planning, design, interface, modification and testing and audit of billing to ensure that all data is tracked and accounted for. Unitil will be using internal personnel for this work.

- Customer Data Management / Internal and External Web: Includes the planning, design, and testing of the web portal for usage information and customer tools posted on the website.

➢ Administration Costs: Costs associated with maintaining customer relationships and rate management. These are additional internal program cost impacts. Unitil will be using internal personnel for this work.

B.2.3 Sampling Plan

Samples for each element of the pilot will be selected from customer peak and average usage data. Table 1 shows the distribution of total residential customers broken out by state.

Table 1: Total Unitil Massachusetts and UES New Hampshire Residential Customer Breakdown

State	Total Residential		Estimated Residential A/C	
Massachusetts	24,290	27.82%	4,637	23.47%
New Hampshire	63,000	72.17%	15,120[7]	76.53%
Total	87,290	100.00%	19,757	100.00%

The sampling plan is based on two key elements; first, the type of data being measured, and second, the desired level of precision of the estimates developed using the research data. For this project, the type of data being measured is continuous (i.e., in this case - demand savings) rather than proportional (percentage of responses to yes/no or multiple choice type questions). When measuring continuous data, determination of the sample size is based on the estimated statistical variance in the data and the desired level of precision.

The sampling plan incorporates the Green Communities Act specification which requires that the aggregate pilot program samples include a minimum of 0.25% of Unitil's customers (71).

Level of Precision and Sample Size
The sampling plan is designed to achieve precision of 90% confidence with 10% sampling error for each of the three program samples and a control group (four sample groups in all). A sample requirement of 68 customers is estimated for each of the four sample groups to achieve the necessary level of precision.[8] A sample size of 76 customers is proposed to account for expected drop-outs and still achieve the desired confidence levels. If the number of drop-outs in any one sample group exceeds 8, replacement participants should be recruited or the precision of results will be reduced.

Four customer samples will be selected, one for each of the three pilot programs and one for a control group that will be used as a basis of comparison to the pilot project samples. Each sample will contain customers from both New Hampshire and Massachusetts. The purpose of developing samples using customers from both states is to accurately represent the company's entire service area. Unless there are significant differences in energy consumption and peak

[7] Estimate based on data from GDS's 2009 NH Tech Potential Study. Final numbers to be determined from analysis of customer usage records.
[8] Sample size computation based on mean kW savings of **1 kW** with a corresponding standard deviation of **0.5 kW**. The actual sample statistics may vary, but these estimates are reasonable and based on previous GDS consultant work.

demand between Massachusetts and New Hampshire customers, there is no reason to estimate peak kW savings individually for each state. Therefore, final estimates of demand savings and the corresponding confidence bands will represent the total company system. Larger samples would have to be specified to conduct a thorough analysis of demand savings by state. The sample sizes are presented in Table 2.

Table 2: Unitil Massachusetts and UES New Hampshire TOU/DR Pilot Program Sample Sizes

Sample Group	Massachusetts		New Hampshire	
Simple TOU	24	25.0%	52	25.0%
Enhanced Technology	24	25.0%	52	25.0%
Smart Thermostat	24	25.0%	52	25.0%
Control Group	24	25.0%	52	25.0%
Total Received	96	100.0%	208	100.0%

The confidence intervals developed on the final estimated demand savings will be based on the mean and standard deviation of the respective samples. The standard deviation in the measured demand savings typically decreases as the sample size increases, which tightens the confidence interval about the estimated average demand savings.

<u>Sampling Methodology</u>
The purpose of the pilot program is to assess customer behavior and estimate resulting peak kW and average kWh savings; therefore, the samples selected for each pilot program should theoretically be based on a distribution of kW and kWh savings. Because kW and kWh program savings from past or similar demand response projects are not available, average customer kWh consumption will be used as a proxy. Stratified random samples will be selected for each of the three programs as well as for the control group. A systematic sampling approach will be used to select the customers for each sample. This method is commonly used in the utility industry as it insures representation of a total population with respect to geographic location, peak demand, energy consumption, or other key elements.

<u>Population Frame</u>
The customer billing system provides the population frame from which sample customers will be selected for each of the three pilot projects and the control group. The population frame database contains three key files.

1. The "Total Population" file contains the key categorical data needed to perform the data analysis and select the customer samples, including name, address, state, telephone number, and the most recent 12 months of kWh consumption for all residential customers.

2. The "Qualified Population" file contains the 12 months of kWh consumption for residential customers. The source of the data for this file is the Total Population file. The consumption for each customer has been analyzed to identify customers with a pattern of year round consumption. From the year round population, any customer with

average summer kWh consumption less than 400 kWh will be eliminated as it's highly probable that consumption of 400 kWh or less is not reflective of air conditioning load.

3. Two individual "A/C Customer" files will be created:

    1. "A/C Customer – NH"
    2. "A/C Customer – MA"

    These files will contain all residential customers in the respective states with usage characteristics that reflect air conditioning systems. The files for NH customers may be further categorized by service territory if statistically significant differences between the territories are identified from the customer data.[9]

    The source data for these files will be the Qualified Customers file. The consumption patterns for each customer will be analyzed to identify those customers using air conditioning (A/C). A customer will be identified as an A/C customer if their average consumption during the months of June, July and August (peak months) exceeds the average consumption during April and October (shoulder months) by 30% or more. Those customers identified to be A/C users will remain in these files, while all others will be eliminated. Average annual energy consumption for the population of all residential A/C customers will be computed using this data.

<u>Sample Design for Formal Pilot Implementation</u>
As a means of minimizing the required sample sizes for each pilot program, stratified samples will be developed. Stratification will be based on average kWh consumption during the summer months. The purpose of stratifying for this study is to produce gains in precision of program savings by dividing the population of program participants into subpopulations, or strata, of smaller homogeneous groups. The variation in peak and energy savings estimates within each stratum will be less than the variation for the entire sample of program participants, allowing savings estimates to be developed at the desired level of precision with a small sample in each stratum. This process provides a means for minimizing the total sample requirement, thereby reducing project costs. Delenius and Hodges techniques will be used to determine the strata boundaries, and Neyman allocation techniques will be used to allocate the sample among the strata.[10]

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[9] Development of the NH Customer files is beyond the scope of this submittal but will generally follow the methodology presented for the MA customers.
[10] William G. Cochran. Sampling Techniques, (John Wiley & Sons, New York, 3rd edition, 1977), pages 98-130.

The kWh strata of A/C customers and the required sample sizes are presented in table 3 below.

Table 3: A/C Customer kWh Strata

kWh Strata	Population	% of Population	Sample Size
401-600	1,129	24.3%	9
601-900	1,461	31.5%	18
901-1,200	990	21.4%	12
1,201-1,700	741	16.0%	14
1,701+	316	6.8%	23
	4,637	100%	76

Sample Selection

Four customer samples will be selected, one each for the three pilot programs and one for a control group. Each sample will include 76 customers. The breakdown of customers for each sample with respect to state is presented in Table 2 above and the breakdown of A/C customers by kWh strata is presented in Table 3 above. The sample customers will be recruited first from within the two "A/C Customer" files created in the population frame database, and then from within individual kWh strata. The files will be sorted in ascending order on annual average kWh consumption. Attempts will be made to recruit every n^{th} customer, where n equals the population of each strata divided by the desired sample size for each strata. This systematic sampling approach will ensure that the average kWh consumption for each sample is equal to the overall population. A sample population frame of 1,000 potentially eligible customers in Massachusetts and 1,500 potentially eligible customers in New Hampshire will be developed for ultimate recruitment.

Qualified customers who express interest in the programs will be recruited into one of the three programs until the quotas established in Table 2 are filled. The approach for marketing and participant recruitment is discussed later in this report. It is anticipated that the Massachusetts quota will be filled first and then the New Hampshire quota will be filled.

Control Group

The control group will be used as the baseline against which demand response actions of the pilot participants will be measured. The control group will be comprised of Unitil's existing residential load survey customers. The existing load survey customers are already provided with interval meters and have historical peak and usage data to serve as a reference. Additional control group samples will be recruited from within the "Qualified Population" file as necessary to fulfill the sample quotas.

The control group will include the same kWh strata distribution as represented in Table 3 above. The past twelve months usage data was reviewed for all load survey customers, and the average annual kWh was used to assign each customer into one of the kWh strata's. The ratio of peak month (June, July & August) average usage was compared to the shoulder month (April & October) average usage for each customer to assess whether the load survey customers meet the criteria for air conditioning users. Only load survey customers with a ratio of peak to shoulder month average usage of 130% or greater were included as "qualified" control group participants.

The number of qualified control group participants from the load survey customers is shown in the table below:

Table 4: Control Group Analysis of Load Survey Customers

kWh Strata	Required Sample Size	Desired Control Group Size		"Qualified" Load Survey Customers		Additional Recruitment Needed	
		MA	NH	MA	NH	MA	NH
401-600	9	3	6	7	8	0	0
601-900	18	6	12	7	16	0	0
901-1,200	12	4	8	14	12	0	0
1,201-1,700	14	4	10	5	11	0	0
1,701+	23	7	16	5	12	2	4
Total	76	24	52	38	59	2	4

The table above indicates that six (6) additional control group participants will need to be recruited from the Qualified Population file. To the greatest extent possible, control group participants will be selected to ensure a uniform distribution of average kWh usage within each stratum to minimize variation.

B.2.4 Marketing and Recruitment

Overview

The approach for marketing the pilot program to customers and for effectively recruiting participants is important to the success of the pilot. The marketing and recruitment process will include an initial mailer with a brochure describing the pilot program and inviting customers to participate. The tri-fold brochure will describe the program and provide methods for the customer to register such as a tear and return post card, on-line, or call in. A recruiting script will be administered to customers who register to determine whether they qualify for the program (i.e. A/C Customer) and to assess other pertinent demographic and behavioral information. If the required sample sizes are not achieved through the randomly selected sample of customers who self-register, a third party firm will be utilized to call the remaining customers who received the marketing materials but who did not register.

Background Research

After extensive research into other demand reduction programs, it was decided to name the pilot program. According to Peak Rewards™ (BGE Pilot Program Fact Sheet[11]) 72% of all respondents, which was 386 surveys out of 1,000 participants, ranked cost savings as the most important reason for choosing to participate with only 20% to conserve energy and improve the environment. Therefore, it was recommended to brand the pilot program Energy Savings Management (ESM).

[11] 2007 Pilot Fact Sheet, Peak Rewards, a BGE Smart Energy Savers Program, Demand Response Infrastructure (DRI) pilot program for Peak Rewards

Additional market research was conducted to determine whether incentives are necessary to recruit customers into the program. For every white paper and statistical research in favor of offering a financial incentive, there are others against it. Additionally, if incentives are offered, there are no resources to determine what is the correct amount? For this pilot, some forms of incentives are contemplated. The incentives will be in the form of initial sign up incentives, incentives for completing the program, or as rebates offered to customers who incur significantly higher than average utility bills due to an incomplete understanding of the rate structure. The need for, and ultimate amount of incentives offered will be determined based on results of the marketing study. Customer interest in each of the three programs will be assessed first on its own merits, and then if a participation incentive was offered. If customer interest is sufficient with no additional incentives, none will be offered.

Marketing Study

A limited marketing study will be conducted prior to the recruitment effort for formal pilot implementation participants, to help inform final pilot design and implementation protocols. This study will consist mainly of secondary data collection and review and a small primary data collection (phone survey) effort with input and assistance provided by RKM Research and Communications (of Portsmouth, NH). A total of 75 phone surveys will be targeted to a random selection of Massachusetts customers who have been identified as potential A/C users. The phone surveys will gather information on whether the customers do in fact have A/C and will gauge general interest in the programs. The surveys will also be used to assess the need for monetary incentives to encourage program participation. The TOU rate structure will be discussed with the customers and reactions will be gauged. The results of the marketing survey will help determine whether the rate structures should be modified to encourage participation. Topics and sample questions that will be addressed during the survey are included in Appendix B, Attachment 1.

Initial Mailer

The first phase of the marketing and recruitment effort will be to send out a direct mailer to the randomly selected sample groups in the MA and NH service territories. The mailer will be sent out separately from the bills; bill stuffers will not be used. The mailer will include a 4-color tri-fold brochure that will describe the program and highlight benefits to the customer, the utility, and the environment. To keep with the integrity of the Unitil brand the ESM logo will be very simple – there will not be a graphic element to keep in line with Unitil's brand standards. The brochures will identify three options for interested customers to register for the program; by visiting a link off the Unitil website, by phone, or by tearing off and returning a perforated portion of the brochure. Each sign-up option will include key marketing questions that will help to better qualify customers for the program. A sample brochure for the Simple TOU program is included in Appendix B, Attachment 2.

Incentives may be offered for initial registration or for completing the pilot program. The need for financial incentives and the monetary value of such incentives will be determined based on results of the initial marketing telephone surveys.

Recruitment Script

A recruitment script will be used to qualify interested customers for the programs and to assess relevant demographic and household information. Gathering household information such as the size and age of the property, the number of people living in the residence, properties of space conditioning and water heating systems can help normalize pilot results. The primary qualifying characteristic for participation is the presence of an air conditioning system. Customer specific information will be collected so that conclusions on demand response actions and customer satisfaction may be drawn between different demographic categories.

The recruitment phase will also be used to determine the primary motivations customers have for participating in the program. Assessing customer motivations at this stage will assist the marketing effort for a full rollout of the program if it is successful. Customers will be asked whether they have taken any significant actions to improve energy efficiency in their homes in the past two years. This information will be useful in determining whether results are potentially skewed by early adopter bias, and whether or not much of the "low hanging fruit" efficiency measures have already been incorporated. A list of topics to be addressed during the recruitment phase is included in Appendix B, Attachment 1.

Pilot program participants will be first recruited from within the group of randomly selected customers who responded to the initial mailer either on-line, on the phone, or via the registration card. If the program quotas are not filled from within this group, customers who did not respond to the initial mailer will be directly targeted for recruitment via telephone.

B.2.5 Educational Materials

Once the target number of customers has been enrolled into each of the three programs, they will be sent educational materials relevant to the program in which they are enrolled. The materials will include a letter from Unitil describing the pilot program, briefly outlining the benefits to both the customer and to Unitil. A sample letter that will be sent to customers being recruited for the Simple TOU program is included in Appendix C, Attachment 1 for reference. The education materials will be presented in a special folder that will contain handouts illustrating examples of how customers can manage electricity usage to benefit from the programs. An outline of the educational materials for the Simple TOU program is included in Appendix C, Attachment 2 for reference.

A focus of the educational materials for the Simple TOU and the Enhanced Technology Program participants is to develop the concept of a time-of-use rate schedule so that the customers understand they are paying a premium price for on-peak electricity but are getting a heavily discounted price for off-peak usage. The educational materials will expand on this concept by identifying the best ways to minimize on-peak electric usage. Specific examples of load shifting will be provided, along with simple calculations showing the cost savings associated with off-peak usage. Coupling a thorough understanding of the time-of-use rate schedule with the tools and knowledge to effectively manage electricity usage is intended to incent customers to wisely manage their consumption.

Educational materials for all the programs will include material on incorporating general energy efficiency practices in homes to reduce overall consumption. Examples of energy efficiency practices include turning off lights when rooms are not occupied, replacing incandescent bulbs with compact fluorescents, turning down the set point of electric water heaters and so on. The educational materials are based in large part on information presented by the U.S. Department of

Energy (DOE) and include references to the DOE and *ENERGY STAR*® websites for more detailed information on energy efficiency practices and products.

An important aspect of the educational materials is to identify the benefit of demand response to the utility. The educational materials highlight the enhanced cost and increased greenhouse gas emissions associated with peak generation. Demand response is a means to increased reliability of the distribution system and to potentially lower costs for all customers by limiting the cost paid by the utility for peak generators.

The educational materials will also develop the concept of critical peak periods. The frequency and typical duration of critical peak periods are discussed in Section B.3. The educational materials will focus on a higher level view of the benefits and savings opportunities of Demand Reduction and the impact of CPP on end users and utility wide costs and emissions. The educational materials will explain time of use rates at a higher level and will then focus on the impacts of participating in demand reduction. The educational materials will also outline the impacts of not participating and the potential cost impacts.

Customers in the enhanced technology and smart thermostat programs will be provided with information specific to the equipment they are provided with. Participants of both the enhanced technology and smart thermostat programs will receive thermostats that visually indicate whether it is a period of on-peak, off-peak, or critical peak so that the customers can respond accordingly. The visual indicators will be summarized in the educational materials and will be covered by contractors at the time of equipment installation. Participants in the enhanced technology program will be provided with literature on the Tendril package when the equipment is installed.

B.2.6 Customer Management

Specific procedures will be developed to handle customer interactions pertaining to the pilot programs. Program participant accounts will be specifically identified as being part of a time of use pilot program and all relevant billing and usage information will be available. Customer service representatives will be prepared to deal with anticipated issues such as higher than normal bills, problems with the enabling technology provided, customers moving out of area, and customers wishing to un-enroll in the program. Customer service representatives that will interact with pilot participants may undergo a brief training session to review the details of the program and important differences between the three programs.

For high-bill complaints, customer service representatives will be capable of retrieving billing records and evaluating the usage during each time of use period with the customer. The service representative will attempt to determine why the bills are higher than normal, likely due to excessive on-peak usage, and discuss means and methods for shifting load to off-peak hours to save money. The customer service representative may review the online educational materials with the customer.

If customers are unhappy with the program and wish to be un-enrolled, there will be a procedure for returning the customer to a flat rate. The procedure first involves identifying the reason why the customer is unhappy with the program and attempting to work through the problem with the customer. If the customer insists on dropping out of the program, they will be returned to a flat rate and a post-pilot survey will be administered. The survey will be used to assess the customer's experience throughout the program and to concretely identify the reason why they are dropping out. Customers will be asked to comment on ways to improve the program in the future.

B.2.7 Measurement and Verification

The successful measurement and verification of load reduction and energy usage savings achieved is a key objective of the pilot. To quantitatively measure the per participant load reduction during on-peak and critical peak periods, interval recorder electric meters will be installed for each customer participating in the pilot and the control group customers. The interval meters will collect peak and usage data in fifteen (15) minute intervals.

Unitil plans to incorporate AMI endpoint technology at each interval meter for billing purposes. AMI meters are currently installed throughout Unitil's Massachusetts and UES' New Hampshire service territories and it is desirable to test the billing capabilities of the AMI system with a time of use rate structure. The AMI endpoints are capable of reporting up to four separate registers for kWh usage in a single day. For the pilot, two AMI registers will be used; 1pm to 6pm and 6pm to 1pm the following day. These registers will be capable of reporting usage during on-peak, off-peak, and critical peak periods for pilot program participants. The daily reporting capability of AMI will be utilized to capture usage during a CPP event.

Demand reduction during CPP events will be assessed by comparing interval load data during a CPP event to the same time period on a non-CPP day with similar weather conditions as well as immediate load changes observed. The outdoor air temperature, RH, solar heat gain coefficient and wind will be taken into consideration for the Non CPP and CPP afternoons. Demand response of the pilot participants will also be measured against the control group during the CPP period. The length of demand response actions during CPP periods will also be assessed to determine whether there are significant changes as length of the CPP event increases.

The impact of the time-of-use rates and enabling technologies will be calculated by comparing interval data from the pilot program participants to the interval data from the control group, and also with similar periods from the previous year (2009). Objectives of the pilot include quantitatively measuring the following:

- Overall usage (kWh reduction)
- Demand response (kW reduction) during on-peak periods
- Demand response (kW reduction) during critical-peak periods
- Electric usage (kWh reduction) during on-peak periods
- Electric usage (kWh reduction) during critical-peak periods
- Price elasticity (customer response to different price points)

In addition to the quantitative measurement of interval data as discussed above, participant surveys will be conducted at the onset and at the completion of the pilot project. The surveys will be used to assess customer reaction to the programs, customer behavior, and feedback for improving the program for full program roll out. Anticipated survey topics are presented in Appendix B, Attachment 1.

Program Evaluation
The success of the pilot program will be judged based on performance in the following key categories:

1) **Customer Experience**: A successful pilot program will result in an overall positive customer experience. Customer satisfaction will be assessed using the post-pilot surveys.

2) **Low Dropout Rate**: Some customer complaints are expected as would be with any new program with a new form of billing. The means with which customer service representatives can mitigate customer complaints and keep participants enrolled is important to the success of the program. A goal of the program is to limit dropouts to not more than 10% of any sample population.

3) **On-time and Accurate Billing**: This pilot program will test the TOU capabilities of Unitil's existing AMI "smart" metering systems. One of the goals of the program is to ensure timely and accurate billing to all participants.

4) **Achieve Measureable Demand and Usage Savings**: The pilot program is designed to achieve demand and usage savings of at least 5%. A goal of this program is to exceed those minimum thresholds as well as collect statistically valid price elasticity information.

5) **Program Cost Effectiveness**: Administering and managing the pilot project on-schedule and on-budget is a goal of the program. The pilot program is also designed in such a way to evaluate the most cost effective method to achieve demand reduction at peak times. The pilot is expected to develop a price elastically model to show at what point participants react or don't react.

B.2.8 Implementation

The implementation involves the upgrading of all participant meters and enabling technology for the program participants. The installation phase will be initiated with a RFP that will outline a concise scope of work and will solicit competitive bids to install the meters and enabling technology equipment. It is anticipated, but not necessary, that the upgrade of meters will be conducted separately from the enabling technologies. The RFP will require the contractors to install and test the meters and technologies to ensure functionality at the onset of the pilot.

Product installation will include customer education where the contractor will review the operation of the equipment with the customer and answer any questions they may have. For the programmable thermostats, the contractors will assist in setting up a weekly schedule with input from the customer if so desired. The on-peak and-off peak period will be specifically explained to pilot participants. The Tendril packages will be installed by technicians specially trained in using the systems who will be able to guide the customer through the program and answer any questions they may have.

B.3 Pricing

This section describes the methodology the Company used in determining the summer months that the TOU/CPP Pilot Program would be in place, the hours to be used for the on-peak and critical peak periods as well as the relative pricing of default service during the period when the Pilot Program would be in place. A pricing section has been developed to provide the Department with estimates of Default Service ("DS") pricing ratios for the different rate periods. As noted earlier, the results of the marketing survey will help determine whether the rate structures should be modified to encourage participation.

B.3.1 Term of the Pilot Program and Pricing Periods

Recognizing the goal of reducing summer peak demand, the Company anticipates that the Pilot Program would be run for 3 months, June through August, since these are the months in which an annual peak is most likely to occur. The Company analyzed whether or not it was likely that a summer peak would occur outside this 3 month period. It reviewed the last three years of Unitil system load data from May 1 to September 30 of the years 2006 to 2008 to determine the likelihood that a system load in May or September exceeded 90% of the summer peak load in each year. See Appendix D, Attachment 1. This confirmed the Pilot Program term of June 1 to August 31. June 1 is also the effective date of the mid-year DS rates change.

The next step in the process was to determine the appropriate time periods to use for the on-peak rates and critical peak period rates. The Company reviewed its system load data during the summer of 2008 in order to determine appropriate hours for the on-peak period. The on-peak period would not include weekend days or holidays occurring during a weekday. During the period June 1 to August 31, the only holiday would be Independence Day. The top 75 hours of system load data were reviewed and the individual hours in which the loads occurred were counted. The majority (43 of the 75) of the highest system loads occurred in the period between hours ending 14:00 and 18:00. Therefore the Company decided the on-peak period would be from 1:00 PM to 6:00 PM on non-holiday weekdays. See Appendix D, Attachment 2. The use of a five hour window for the peak period allows customers ample load switching opportunity and it is hoped this will increase customer participation in the Pilot Program.

The Company then reviewed whether the critical peak periods, when called for, should be the same hours as the on-peak period. The Company's AMI system must be configured in advance of when the critical peak periods occur for the appropriate time periods to collect consumption data. The lead time to reprogram the meter endpoint for a critical peak period may be up to a few days. Since the Company may not know it is likely to request a critical peak period that far in advance, it was decided that the critical peak period hours would be the same as the on-peak hours, from 1:00 PM to 6:00 PM during non-holiday weekdays. When a critical peak period day is declared, the Company would program its command center to recognize the data collected during the on-peak hours of that day as critical peak period consumption. If the data was not collected from an endpoint in the evening following the critical peak event due to technical reasons, the Company would either calculate the consumption based on interval data, if available, for the customer or would forgive the critical peak pricing for that customer for that event. In other words, the missing consumption data for the period would be considered on-peak period consumption rather than critical peak period consumption if the data was not available. Thereby the customer is not penalized if the Company has not collected the critical peak period consumption data. The Company will not call a critical peak period more than 8 times during the term of the Pilot Program. This will help in the enrolling of customers since they know there will be a predefined limit to the number of called critical peak periods.

All Customers participating in the Pilot will be metered with an interval data recorder which will collect interval data in 15 minute intervals. This data will be used in the analysis of the amount of load shifted from the peak period and during a critical peak event. Unless required, the interval data will not be used for billing customers. One of the lessons to be learned from the Pilot Program will be about the functionality of the Company's AMI system in collecting time-of-use and critical peak period load data and transfer that data to the billing system. These will be necessary components of any type of full scale time-of-use program that might possibly be implemented in the future.

B.3.2 Default Service pricing ratios for each time-of-use period

The Pilot Program pricing for each time-of-use period will be based on the Fixed DS prices in effect for the period June - November of the year in which the pilot program is effective. It is currently expected that this will be 2010. The vast majority of residential customers are on the Fixed DS rate. This rate is level for the six month period that rates are in effect and does not vary from month to month like the Variable DS rate. At the conclusion of the Pilot Program, customers will return to whichever DS rate they were on prior to the start of the program, Fixed or Variable.

First, the Company reviewed the locational marginal price data for the Western Central Massachusetts Load Zone of ISO-New England for the period June 1 – August 31, 2008 in order to attempt to develop cost based prices for each time-of-use period. The average price was $96.45 per MWh during the period. In order to compute a more reflective price of that which was incurred by residential customers in Unitil's service territory, the residential class average load profile data in each hour was multiplied by the price in each hour and a load weighted average price was determined to be $0.10229 per kWh. This result appears logical, since residential customers will typically use more energy during the daytime and evening when prices are higher and will use less energy during the nighttime period when prices are lower.

In order to attempt to determine pricing for the critical peak period, the Company sorted the data by price from highest to lowest and determined the top twelve days in which the highest prices occurred, regardless of hour in which they occurred. Four of these days occurred on a weekend and were removed from the analysis since the Company will not call a critical peak period on a weekend. For the other 8 days, the Company computed the load weighted average LMP prices from 1:00 PM to 6PM. The load weighted average critical peak period price was $0.21169 per kWh, only 107% higher than the average price. This compares with the average on-peak period price of $0.13250 per kWh (only 30% higher than average) and the average off-peak period price of $0.09691 per kWh (only 5% lower than average). Because the percentage differences between the average price and the on-peak period and the critical peak period prices were so small, the Company decided that these percentage variances, if applied to the DS prices for the pilot program, would most likely not result in significant enough shifting by customers of load from the on-peak and critical peak periods to the off-peak period or overall reduction of load.

Based on this conclusion the Company then chose to evaluate different time-of-use price levels based on various ratios to an average DS price of $0.12000 per kWh. This estimate was used because the current residential fixed DS price is $0.11787 per kWh. This estimate is used to evaluate different pricing scenarios in order to develop actual pricing ratios to be used in the implementation of the Pilot Program for each time-of-use period. The Company reviewed different price ratios based on two assumptions: 1) a pricing multiplier for on-peak and CPP versus the calculated off-peak DS price and 2) a pricing multiplier for on-peak and CPP versus the Fixed DS price. See Appendix D, Attachment 3.

Page 1 shows the results of the pricing multiplier versus the calculated off-peak price. The off-peak period price has a pricing multiplier of 1 in all the scenarios since it used as the basis of the multiplier. On-peak pricing multipliers of 2 and 3 are reviewed and critical-peak pricing multipliers of 5 and 8 are reviewed. The rates are developed to be revenue neutral based on class average residential load profiles allocated to each time period in the summer of 2008. For example, at the top of page 1, the on-peak price is set at 2 times the off-peak price and the critical peak price is set at 5 times the off-peak price. The off-peak price is calculated based on these criteria so that the total revenue averages $0.12000 per kWh. In this example, the following prices result: off-peak kWh: $0.09809; on-peak kWh: $0.19618; CPP kWh: $0.49045. The resulting ratios to the Fixed DS price would be off-peak kWh: -18.3%; on-peak kWh: +63.5%; CPP kWh: +308.7%. This exercise is repeated for each scenario on page 1.

Page 2 shows similar examples, but with a slight variation. The pricing multiplier used is versus the Fixed DS price, rather than the calculated off-peak price. In the first example at the top of page 2, the on-peak price is set at $0.24000 per kWh (2 times the DS price) and the CPP price is set at $0.60000 per kWh (5 times the DS price). The off-peak kWh price is then determined for revenue neutrality and is determined to be $0.08842 per kWh. The Company reviewed the different scenarios and chose the bottom scenario on page 2 which uses a pricing multiplier of 3 for the on-peak period and 8 for CPP. This scenario produces the lowest off-peak kWh price ($0.06024 per kWh in the example) which accounts for about 85% of customer load and hours. The Company determined a low off-peak price would incent customers to not only want to participate in the Pilot Program but to also shift load from the on-peak period. In addition, the Company felt that the higher on-peak period and CPP prices would help it meet its goals of 5% energy and peak demand reduction for the participants. In the example, the on-peak price would be $0.36000 per kWh and the CPP price would be $0.96000 per kWh. These are 3 times (200%) and 8 times (700%) higher than the Fixed DS price, respectively. The ratio to be applied for the off-peak period price would be -49.8%, resulting in a rate of $0.06024 in the example. These are the ratios that will be applied to the actual DS prices in effect on June 1, 2010 when the pilot program is implemented.

If the actual DS price in June, 2010 has declined to $0.10000 per kWh for example, the on-peak price would $0.30000 per kWh and the CPP price would be $0.80000 per kWh. The off-peak price will be calculated based on the kWh in each time period to produce a revenue neutral rate, assuming no shifting, and would be $0.05020 in this example. To the extent customers shift or reduce load, it will create an opportunity for them to reduce their bills and pay a lower price per kWh for DS. For example, with the rates calculated in the paragraph above, a customer who is able to shift 100 kWh in one month from the on-peak period to the off-peak period would save almost $30 on their monthly bill (100 x ($0.36000-$0.06024)).

B.4 Sample Tariffs

A sample tariff for the Pilot Program is included in Appendix E, Attachment 1. Rates are not shown since they will be determined at a future date based on the Default Service rates determined for June 1, 2010 and the pricing multipliers developed in this filing. Since the Pilot Program is a temporary three month program, the Company proposes to show the Pilot Program DS rates in this schedule rather than its complete summary of rates, currently M.D.P.U. 174.

A sample redlined tariff for Default Service is also included. As discussed in Section III, Cost Recovery, these costs will be collected through the Default Service Costs Adder mechanism, which is included in the Default Service rate for billing purposes. Paragraph F. is added to the tariff to reflect the addition of these costs for recovery.

Both tariffs are filed for "information purposes only" at this time and are therefore unnumbered. When the Pilot Program concept has been approved and Fixed Default Service rates for June 1 of the year in which the Pilot Program will be implemented are known, the Pilot Program tariff will be re-filed. The revisions to the DS tariff will most likely be filed at the same time.

B.5 Billing Presentation

For bill presentation of the rates, the DS prices and kWh consumed as shown on customer bills will be itemized into off-peak, on-peak, and critical peak periods. Since the pilot program runs for three calendar months and customers are billed on a billing cycle basis, Customers will receive a bill with blended (pro-rated) pricing in the first month of the program and the first month after the program has ended.

III. Cost Recovery

The Company proposes that incremental costs incurred in the providing of the Pilot Programs be recovered through the Default Service ("DS") Costs Adder, included in the DS Charge, so that it may be appropriately recovered only from the Company's DS Customers. The total costs are estimated at $214,424 as shown in Appendix A, Costs Summary. These costs would be included in the Company's DS Cost Adjustment model filed on or about September 1 of each year, for recovery over the period of one year beginning in December 2010. This methodology is in Compliance with section 85 of the Green Communities Act. Although the DS rates are designed to be revenue neutral, the Company expects there will be some under/over-recovery of DS costs which the Company proposes to reconcile through DS. This reconciliation will be automatic in that the DS Pilot revenues and costs will be included in the DS reconciliation.

Due to the limited nature of the Pilot Programs, the Company is not seeking recovery of lost distribution revenue due to associated demand and energy reductions.

Based on the estimated costs above, rate impacts are estimated to be approximately $0.00084 per kWh if recovered in one year using an estimated 256,741 MWh for the recovery year. This represents an impact of $0.42, or about 0.4%, on the typical 500 kWh customer's monthly bill assuming current rates.

Unitil
Estimated Incremental Implementation and Administration Costs for Smart Grid Pilot Projects

Appendix A

		Hours and Cost	FG&E Allocation	UES Allocation	Notes:
	Power Quality Monitoring with AMI				
1	Internal Labor Resources only	$ -			
	Capacitor Control with AMI				
2	Estimated equipment costs	$ 10,000			
3	Internal Labor Resources only	$ -			
4	**Total AMI Pilot Projects**	**$ 10,000**	**$ 10,000**		FGE only
	TOU/CPP/Demand Response Pilot Project Installation and Materials Costs				
5	Cost of Analysis Meters installed	$ 500			
6	Estimated quantity installed	235			
7	Total Cost of Analysis Meters installed	$ 117,500			
8	Cost of Tendril Package installed	$ 1,000			
9	Estimated quantity installed	76			
10	Total Cost of Tendril Packages installed	$ 76,000			
11	Cost of Thermostats installed	$ 650			
12	Estimated quantity installed	76			
13	Total Cost of Thermostats installed	$ 49,400			
14	Marketing and Educational Materials	$ 12,000			
15	**Total Installation and Material Costs**	**$ 254,900**	**$ 81,568**	**$ 173,332**	32%/68%
	Project Consulting				
16	Estimated Cost for Project Plan Support	$ 60,000			
17	Estimated Cost for Regulatory Support	$ 36,000			
18	Estimated Cost for Bid and Installation Oversight	$ 9,000			
19	Estimated Cost for Customer Service training	$ 3,600			
20	Estimated Cost for Data Management and Analysis	$ 12,000			
21	Estimated Cost for Administer post-pilot surveys	$ 9,000			
22	Estimated Cost for Report and Recommendations	$ 18,000			
23	**Total Program Management Costs**	**$ 147,600**	**$ 73,800**	**$ 73,800**	50%/50%
	Participation and Incentive Costs				
24	Estimated participants	228			
25	Estimated cost per participant	75			
26	**Total Participation and Incentive Costs**	**$ 17,100**	**$ 5,472**	**$ 11,628**	32%/68%
	Meter Interface and Feeds into the Billing System (Plan, Design, Modify, Interface and Test)				
27	Cost of Labor per Hour for Contract Programmer	$ 100			
28	Estimated Range of Time Required	200			
29	**Total Meter Interface**	**$ 20,000**	**$ 10,000**	**$ 10,000**	50%/50%
	CIS Billing System (Plan, Design, Interface, Modify, Bill Print, Test)				
30	Cost of Labor per Hour for Contract Programmer	$ 200			
31	Estimated Range of Time Required	100			
32	**Total for CIS Programming**	**$ 20,000**	**$ 10,000**	**$ 10,000**	50%/50%
	Internal Revenue Reporting (Plan, Design, Interface, Modify, Test, Document)				
33	Internal Labor Resources only	$ -			
	Customer Data Management/Internal and External Web (Plan, Design, Test)				
34	Cost of Labor per Hour for Contract Programmer	$ 100			
35	Estimated Range of Time Required	100			
36	**Total for Customer Data Management**	**$ 10,000**	**$ 5,000**	**$ 5,000**	50%/50%
	Administration Costs (Customer Relationship and Rate Management)				
37	Internal Labor Resources only	$ -			
38	**Contingency (10%)**	**$ 46,960**	**$ 18,584**	**$ 28,376**	
39	**Total TOU/CPP/Demand Response Pilot Costs**	**$ 516,560**	**$ 204,424**	**$ 312,136**	
40	**Grand Total Pilot Projects**	**$ 526,560**	**$ 214,424**	**$ 312,136**	

Marketing Phone Survey Topics and Sample Questions

This section presents the topics and some sample questions that will be covered in the marketing surveys. The marketing surveys will be targeted to 75 Massachusetts customers with air conditioning systems and is intended to inform the final development of the pilot program.

Topic: Air Conditioning System

1) Do you have a central air conditioning system?
2) What is the approximate age of the system?
3) Do you have a programmable thermostat?
4) Do you use the Programmable thermostat?

Topic: Demographics

5) Age bracket – Age of the head of house hold.
6) Household income bracket – Estimated annual combined income.

Topic: Home Characteristics

7) Is the home seasonal or permanent?
8) Do you own or rent the property?
9) Do you pay your electric bill or does someone else?
10) What is the approximate square footage of the home?
11) How many floors is the home?
12) Is the basement heated and or cooled?
13) Do you have high speed internet access?

Topic: Customer Behavior

14) Do you set back at nights (winter) and during unoccupied times (summer)?
    a. Via set thermostat or manually?
    b. To what temperature in the summer?
15) Is anyone in the household home during a typical day?
16) Do you manage your electric bills online?
17) Do you have a business in the home?
18) Do you know what demand response is?

Topic: Customer Interest

Goals:

- *Assess interest in programs, willingness to change behavior to save money*
- *Gather information on price impacts, including willingness to participate at the various program levels*

- *Assess whether incentives are required to recruit customers, and the magnitude of such incentives*
- *Assess initial customer perception of programs (i.e. likes, don't likes, etc.)*
- *Assess reaction to the number and duration of CPP events*

Sample Questions

19) How interested would you be in participating in a program that allowed you to reduce your monthly electric bills?
20) Rate your interest if the savings was dependant on shifting some of your electric usage to off peak periods (6pm at night-1pm the following afternoon)
21) How willing would you be to raise the set point of your thermostat between 1-6pm on a hot summer day if the cost of electricity on that day was twice as high as the normal rate? Four times? (Craft question to assess price point response) From both the monthly bill stand point and signup/participation perspective.
22) How interested would you be in receiving a free in-home electronic energy management system with wireless control that allows you to monitor electric usage in real time?
23) How interested would you be in receiving a free (installed) programmable thermostat if the set point could be raised by the utility for up to four hours between 1-6pm on a hot summer day? 5pm?
    a. What if the utility could raise the set point on a hot summer day, but you could override the setting at the thermostat?

Briefly describe the simple, enhanced, and smart thermostat programs:

24) Would you participate in one these programs?
    a. Rank level of interest?
    b. Is level of interest affected if monetary incentives or utility rebates are offered?

Encourage open dialogue to obtain customer reaction to these programs.

Recruiting Script Topics

- Do the customers have central air conditioning?
- Do the customers have a programmable thermostat?
    - Do they set back temperature at night and during the day?
- Rate motivations for participating on a 1-5 scale:
    - Lower utility bill
    - Reducing greenhouse gas emissions
- Age and Income Bracket
- Number of people in household
- Do they plan to undertake any load shifting measures?
    - What actions?
- Have they recently undertaken any measures to become more energy efficient?
- Preferred method of communication for a critical peak event (Phone, page, email)

Post-Pilot Survey Topics

- What actions did customers take to reduce usage, or shift load to off-peak hours?
  - Did they raise thermostat set points? If so, by how much?
- Did customers respond differently to on-peak events compared to critical peak periods?
- Rate customer satisfaction on a scale of 1-10
  - What could be done to improve the customer experience?
- For the enabling technology segments:
  - Rate the technology on a scale of 1-10
  - What could be done to improve the technology / customer experience
- Would they participate in a similar program if it were offered year round through Unitil?
  - Why or why not?

SIMPLE TIPS ON HOW TO CONSERVE ENERGY

- Plug home electronics into a power strip and turn off the power strip when not in use – this reduces "phantom" loads
- Minimize any electrical use during on-peak periods (washers, dryers, dehumidifiers, etc.)
- Replace incandescent light bulbs with CFLs
- Replace outdoor lighting with CFLs, LEDs or solar powered fixtures
- If replacing water heaters or appliances use ***EnergyStar*** brands
- Air dry dishes instead of using the drying cycle
- Wash only full loads of dishes or clothes
- Take showers instead of baths
- Unplug second refrigerators or freezers if they are not necessary
- Turn off CPU and monitor when not in use
- Insulate hot water pipes

For a complete list of tips visit www.unitil.com/esmtips

For more information

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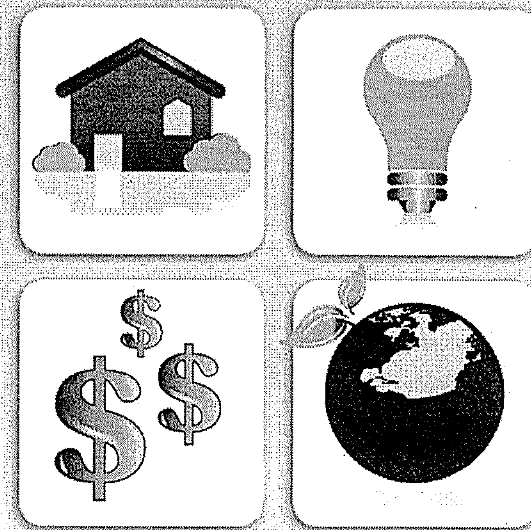
1-888-8-UNITIL • www.unitil.com



ENERGY$AVINGS MANAGEMENT

An initiative powered by:

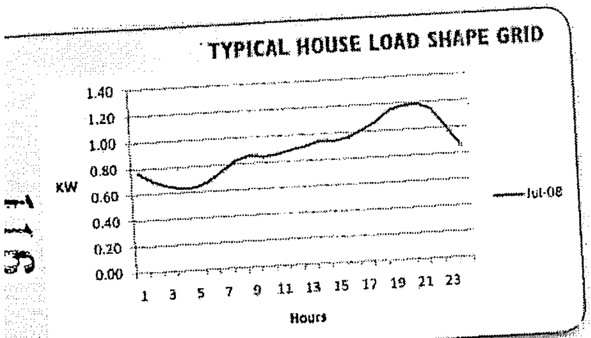
Unitil
We deliver. It's that simple.

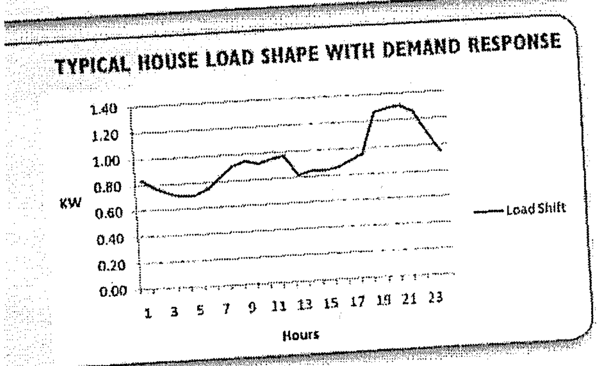
At Unitil, we are always in search of programs and products that offer consumer cost-savings and environmentally-friendly programs. *Energy Savings Management* offers you the ability to manage your energy usage and save money all while protecting the load or energy demand on the environment. You have been selected as a potential consumer that would benefit from this program and potentially reduce electrical needs from this program and therefore your electricity bill.

What is Energy Savings Management?

Energy Savings Management is a pilot program developed by Unitil to save you money on your electricity bill. If this pilot is as successful as we hope this may be added to Unitil's product offering.

You, the residential customer, have the power to reduce your energy usage during periods of peak demand. When you reduce usage during peak demand, you conserve natural resources such as coal and natural gas used to produce electricity and prevent harmful greenhouse gases from entering the atmosphere.





What is Peak Demand?

Peak demand is a period during which there is a significantly higher than average usage (demand) of electricity. These occur most frequently in the summer months when homeowners and businesses are running air conditioning. In some cases, the demand is near what the utility is capable of supplying, resulting in potential power instability. Utility companies pay a premium price to purchase power to meet peak demands and pass this cost on to consumers in the form of higher fixed rates.

What is Demand Response?

For the purpose of this pilot program, "demand response" refers to curtailing residential electric usage during times of extreme demand. Even small reductions in residential peak demand, taken cumulatively across the larger number of households, can have a profound effect of reducing costs and greenhouse gas emissions. By not having to purchase "peak" electricity at a premium price the savings could be passed on in the form of lower rates.

What's the Next Step?

Register for this pilot program by simply filling out the form or online at www.unitil.com/esmregister. You will receive a packet of education materials complete with how to instruction and tips on how to conserve energy and SAVE money while protecting the environment.

Yes, sign me up to participate in Unitil's *Energy Savings Management* program today!

ENERGY$AVINGS MANAGEMENT

Name

Name on Unitil Account if different than above

Street Address

City, State, Zip

Daytime Phone #

Evening Phone #

Cell Phone #

Email Address

Unitil Account #

Please contact me:

- ❑ By Phone
  - O *Daytime* O *Evening* O *Anytime on Cell*
- ❑ By Email
- ❑ By Mail

Signature: By signing this document you agree to participate in the pilot program for Unitil Energy Savings Management. I authorize, Unitil and their energy partner, GDS & Associates to use share my account information for the purpose of this program and not for any other purpose.

Signature

Date

Please detach panel and mail to:

Unitil
c/o GDS & Associates
1181 Elm Street
Manchester, NH 03101

Or sign up online at www.unitil.com/esmregister

Appendix C
Attachment 1

Unitil
We deliver.
It's that simple.

April 2010

Dear Unitil Customer,

At Unitil we are always looking for innovative ways to become more energy efficient and to offer consumer cost savings initiatives. In this time of earth conscience consumerism we are offering a new program to customers in your area. The Energy Management Savings pilot program is a cutting edge technology based product that will not only save you money but support the environment as well.

This pilot program includes different products and concepts that are intended to reduce electricity consumption during periods of peak demand when both the cost and demand of energy is at its highest. By reducing the electrical use in peak times when we have to pay a premium for electricity we will be able to pass that savings onto you the consumer.

I am eager to analyze the results of this program. I feel that energy efficiency, cost savings and simple but effective changes to electrical usage are the key to our energy future. All of these actions can significantly reduce the amount of greenhouse gases that are emitted to our atmosphere. Anything we can do to protect our environment for future generations is everyone's responsibility – especially ours. As an added incentive to participate in these energy savings initiatives I am pleased to offer you a $75 credit voucher toward your electricity bill upon completion of this project. I encourage you to review the enclosed educational materials and visit our website for an exciting new suite of tools designed to help you understand and manage your utility bills!

Sincerely,

Program Coordinator

APPENDIX C
Energy Savings Management (ESM) Educational Component – Simple Product

Front Cover:

- similar/same look and feel as recruitment brochure:
- Four elements....a house (residential), light bulb (energy), dollar sign (savings) and maybe something to signify "green" or earth. (I envision it like one big square with four squares within each one color)
- Energy Savings Management logo
- *An initiative powered by:*

Unitil
We deliver.
It's that simple.

Back Cover:

- Unitil Logo

For more information Unitil Corporation
6 Liberty Lane West / Hampton, NH 03842-1720 / 1-888-8-UNITIL
www.unitil.com

This was printed on recycled material.

APPENDIX C
Energy Savings Management (ESM) Educational Component – Simple Product

Inserts:

- 4 color process over 0/ size varies – stacked inserts

Insert #1: About *Simple TOU* Product

Thank you for participating in Unitil's Energy Management Savings pilot program. This pilot program is designed to investigate the costs and benefits associated with demand reduction programs. This pilot program will investigate time-of-use (TOU) rates incorporating on-peak and off-peak rates with a critical peak price (CPP) that can be initiated during periods of extreme electricity demand. You have been selected to participate in the *Simple TOU Program.* Therefore you are set up on a time-of-use rate structure and you will be notified of a CPP event via email, page, Web posting, or phone call, based on what you selected during recruitment.

The educational materials in this packet contain the tools and information you will need to reduce your energy costs. The packet includes helpful information to become more energy efficient as well as "load shifting measures" like washing clothes or dishes outside of the "peak demand" timeframe (1 pm to 6 pm) you can reduce "energy demand." By reducing usage during periods of peak demand, you conserve natural resources such as coal and natural gas used to produce electricity and prevent harmful greenhouse gases entering the atmosphere.

With the information in this packet you should have everything you need to make your home more energy efficient. This and additional information can be found on the web at www.unitil.com/DRpilot

Insert #2: *Peak Demand*

What is peak demand and what is the relevance?

- Peak demand is a period during which there is a significantly higher than average usage/demand of electricity (typically during a heat wave).
- In some cases, the demand for electricity is near what the peak generation a utility is capable of supplying, resulting in potential power instability.
- Periods of peak demand occur most frequently in the summer months when homeowners and businesses are running air conditioning systems to keep cool.
- Special electric generation stations, called "peakers", are used to generate the additional electricity needed to meet peak demand. Peakers are generally among the least efficient electric generators and emit higher than average amounts of greenhouse gases.

APPENDIX C
Energy Savings Management (ESM) Educational Component – Simple Product

- Utility companies pay a premium price to purchase power to meet peak demands and pass this cost off to consumers in the form of higher fixed rates.

<u>Insert #3</u>: *Demand Response*

What is demand response and what is the benefit?

- Need charts/graphs
- For the purpose of this pilot program, "demand response" refers to curtailing residential electric usage during times of extreme demand (1-6pm, weekdays, in summer months).
- Even small reductions in residential peak demand, taken cumulatively across the larger number of households, can have a pronounced effect on reducing costs and reducing greenhouse gas emissions.
    - Consider the following example:
        - If a typical household reduced peak demand by only 10% during the summer peak periods (1pm-6pm), and that reduction could be applied across Unitil's entire Massachusetts customer base, there would be the following benefits:
            - Unitil customer participating on demand response would save approximately $xxx,xxx by not having to purchase "peak" electricity at a premium price. This savings could be passed back to the customers in the form of lower rates.
            - From Unitil's perspective if as a whole the utility can "flatten" is demand for electricity this would provide the opportunity for reduce costs that would then be shared with customers through reduced energy component prices.
            - Avoided greenhouse gas emissions of over **95 tons of CO_2**.
            - Increased electric grid reliability, reducing the potential for power instability.

<u>Insert #4:</u> *General Energy Efficiency Sheet*

Energy Efficiency Measures

APPENDIX C
Energy Savings Management (ESM) Educational Component – Simple Product

- Lighting
    - Replace incandescent light bulbs with CFL's
    - Replace outdoor lighting with CFL's, LED's, or solar powered fixtures
    - Visit www.energystar.gov for a complete list of available energy efficient lighting
- Water heating can account for 14%–25% of the energy consumed in your home.
    - If replacing a water heater, choose an EnergyStar brand
    - Reduce set point temp on water heater to 120 deg F
    - Insulate hot water pipes
    - Install heat traps at hot water tank
    - Install times to turn off water heater during time when hot heater is not used, such as at night
    - Drain water heat recovery
    - Take short showers instead of baths
    - Install aerators on faucets, low flow showerheads to reduce hot water usage
- Appliances
    - If replacing appliances, choose EnergyStar
    - Air dry dishes instead of dishwasher drying cycle
    - Wash only full loads of dishes
    - Run clothes washer using cold water to conserve hot water
    - Dry heavier loads separately from lighter materials, routinely empty lint filter, check exhaust connection for lint. Improves energy efficiency and reduces fire hazard
    - "Don't keep your refrigerator or freezer too cold. Recommended temperatures are 37° to 40°F for the fresh food compartment of the refrigerator and 5°F for the freezer section. If you have a separate freezer for long-term storage, it should be kept at 0°F."
    - Unplug second refrigerators or freezers if they are not necessary
- Home Electronics
    - Turn off CPU and monitor when not in use
    - Plug home electronics, such as TVs and DVD players, into power strips and turn the power strips off when the equipment is not in use to eliminate "phantom" loads

APPENDIX C
Energy Savings Management (ESM) Educational Component – Simple Product

    - Other "smart" power strips are available too, where some outlets stay active for cable boxes that need to stay on to record

<u>**Insert #5**</u>: *Load Shifting Measures*

Load Shifting Measures

- Raise thermostat set point during on-peak times by 5 degrees or 10 degrees
- Wash and dry clothes during off peak hours
    - Or hang dry clothes
- Run dishwasher during off peak hours
- Avoid drying cycle of dishwashers, allow to air dry
- Minimize appliance usage during on-peak periods
    - Toaster ovens
    - Electric ovens and ranges
    - Home electronics (TV, CPU, Stereo, etc.)
        - Plug home electronics into a power strip, and turn off the power strip when not in use (reduce phantom loads)
    - Hair dryers
    - Dehumidifiers
- Use timer on pool filters and pumps to run only during off-peak periods
- Turn off spa's during on-peak periods
- Turn off waterbed heaters during on-peak periods
- If you have an electric water heater, add a timer to shut off the water heater during peak periods, and turn it back on during off-peak periods. Timers cost approximately $60 and can be installed by homeowners or licensed professionals
- If you have a well pump, minimize water usage during on-peak hours
    - Avoid car washing
    - Use flow restricting devices on faucets and showerheads
    - Minimize use of lighting, indoor and outdoor, during on-peak periods

APPENDIX C
Energy Savings Management (ESM) Educational Component – Simple Product

Insert #6: *Additional References & Resources*

For more educational resources please visit the following websites:

Visit the U.S. Department of Energy, Energy Efficiency and Renewable Energy (DOE EERE) website at http://apps1.eere.energy.gov/consumer/

DOE EERE – Energy Saving Lighting Reference
http://apps1.eere.energy.gov/consumer/your_home/lighting_daylighting/index.cfm/mytopic=11980

DOE EERE – Appliances and Home Electronic

http://apps1.eere.energy.gov/consumer/your_home/ appliances/index.cfm/mytopic=10020

DOE EERE Energy Savers (general energy efficiency information)
http://www1.eere.energy.gov/consumer/tips/

EnergyStar website, for appliance and lighting product information

http://www.energystar.gov/

Learn about renewable technologies

http://apps1.eere.energy.gov/consumer/

Fitchburg Gas and Electric Light Company
May and September Percent of Annual Peaks 2006-2008

Year	May Peak kW	May % Annual Peak	Sept Peak kW	Sept % Annual Peak	Summer Peak kW	Month of Summer Peak
2006	77,461	76.6%	74,331	73.5%	101,165	August
2007	73,621	79.2%	82,697	88.9%	93,009	June
2008	70,074	73.5%	79,255	83.1%	95,356	June

Fitchburg Gas and Electric Light Company
Top 75 system load hours - Summer 2008

Date	Hour Ending	Load kW
6/10/08	17	95,356
6/10/08	18	94,674
6/10/08	16	94,238
6/10/08	14	94,178
6/10/08	15	94,050
6/10/08	19	93,648
6/10/08	21	93,050
6/10/08	13	93,017
6/10/08	20	92,708
6/10/08	12	91,150
6/10/08	22	90,124
6/9/08	17	88,783
6/9/08	18	88,390
6/9/08	19	88,135
6/10/08	11	87,694
6/9/08	20	87,243
6/9/08	16	87,033
6/9/08	15	86,989
6/9/08	21	86,226
7/18/08	17	85,858
6/9/08	14	85,582
7/18/08	16	85,450
6/9/08	13	84,986
7/18/08	18	84,675
7/18/08	14	84,498
7/18/08	15	84,424
6/10/08	10	83,956
7/31/08	17	83,864
7/18/08	13	83,838
6/9/08	22	83,640
6/9/08	12	83,594
7/17/08	15	83,404
7/17/08	17	83,308
7/9/08	14	83,289
7/31/08	16	83,243
7/31/08	15	83,199
7/9/08	15	83,139
7/18/08	19	83,099
7/9/08	16	83,017
7/9/08	13	82,990
7/17/08	18	82,904
7/31/08	18	82,897
7/17/08	16	82,834
6/10/08	23	82,819
7/9/08	17	82,291
7/18/08	20	82,139
7/18/08	12	81,915
7/31/08	14	81,913
7/17/08	19	81,618
7/17/08	14	81,386
7/9/08	12	81,384
7/18/08	21	81,200
7/31/08	19	80,360
6/11/08	17	80,320
6/9/08	11	80,312
7/8/08	17	80,119
7/17/08	20	79,561
7/31/08	13	79,554
7/18/08	11	79,522
7/16/08	18	79,443
7/8/08	18	79,422
7/16/08	17	79,380
6/11/08	15	79,254
7/31/08	21	79,234
6/11/08	16	79,200
7/9/08	18	79,099
7/8/08	16	79,077
6/11/08	14	79,033
7/17/08	21	79,019
7/30/08	16	79,016
7/17/08	13	78,795
7/30/08	15	78,703
8/1/08	17	78,581
6/11/08	18	78,547
6/10/08	9	78,518

Hour Ending	Occurrence
1	0
2	0
3	0
4	0
5	0
6	0
7	0
8	0
9	1
10	1
11	3
12	4
13	6
14	7 *
15	8 *
16	9 *
17	10 *
18	9 *
19	5
20	4
21	5
22	2
23	1
24	0

* On-Peak Period

Fitchburg Gas and Electric Light Company
Sample Calculations of Residential Default Service Pilot Program Pricing
based on an assumed 12¢/kWh Default Service Price
Pricing Multipliers based on Off-Peak Price

	Residential Load Profile (kWh)	Percentage Load	Hours	Pricing Multiplier	Revenue at Average Price	Revenue at Pilot Program Price	Pilot Program Price	Pilot Program Price Change vs Default Service Price	Pilot Program Price Change vs Off-Peak Price
Off-Peak Period	36,461,373	84.9%	1,888	1	$4,375,365	$3,576,476	$0.09809	-18.3%	0.0%
On-Peak Period	5,465,094	12.7%	280	2	$655,811	$1,072,136	$0.19618	63.5%	100.0%
Critical Peak Period	1,032,707	2.4%	40	5	$123,925	$506,489	$0.49045	308.7%	400.0%
Total	42,959,174	100.0%	2,208		$5,155,101	$5,155,101	$0.12000		

Assumed Residential Default Service Price $0.12000 per kWh

	Residential Load Profile (kWh)	Percentage Load	Hours	Pricing Multiplier	Revenue at Average Price	Revenue at Pilot Program Price	Pilot Program Price	Pilot Program Price Change vs Default Service Price	Pilot Program Price Change vs Off-Peak Price
Off-Peak Period	36,461,373	84.9%	1,888	1	$4,375,365	$3,377,380	$0.09263	-22.8%	0.0%
On-Peak Period	5,465,094	12.7%	280	2	$655,811	$1,012,452	$0.18526	54.4%	100.0%
Critical Peak Period	1,032,707	2.4%	40	8	$123,925	$765,269	$0.74103	517.5%	700.0%
Total	42,959,174	100.0%	2,208		$5,155,101	$5,155,101	$0.12000		

Assumed Residential Default Service Price $0.12000 per kWh

	Residential Load Profile (kWh)	Percentage Load	Hours	Pricing Multiplier	Revenue at Average Price	Revenue at Pilot Program Price	Pilot Program Price	Pilot Program Price Change vs Default Service Price	Pilot Program Price Change vs Off-Peak Price
Off-Peak Period	36,461,373	84.9%	1,888	1	$4,375,365	$3,239,597	$0.08885	-26.0%	0.0%
On-Peak Period	5,465,094	12.7%	280	3	$655,811	$1,456,723	$0.26655	122.1%	200.0%
Critical Peak Period	1,032,707	2.4%	40	5	$123,925	$458,781	$0.44425	270.2%	400.0%
Total	42,959,174	100.0%	2,208		$5,155,101	$5,155,101	$0.12000		

Assumed Residential Default Service Price $0.12000 per kWh

	Residential Load Profile (kWh)	Percentage Load	Hours	Pricing Multiplier	Revenue at Average Price	Revenue at Pilot Program Price	Pilot Program Price	Pilot Program Price Change vs Default Service Price	Pilot Program Price Change vs Off-Peak Price
Off-Peak Period	36,461,373	84.9%	1,888	1	$4,375,365	$3,075,380	$0.08435	-29.7%	0.0%
On-Peak Period	5,465,094	12.7%	280	3	$655,811	$1,382,881	$0.25304	110.9%	200.0%
Critical Peak Period	1,032,707	2.4%	40	8	$123,925	$696,840	$0.67477	462.3%	700.0%
Total	42,959,174	100.0%	2,208		$5,155,101	$5,155,101	$0.12000		

Assumed Residential Default Service Price $0.12000 per kWh

Fitchburg Gas and Electric Light Company
Sample Calculation of Residential Default Service Pilot Program Pricing
based on an assumed 12¢/kWh Default Service Price
Pricing Multipliers based on Default Service Price

	Residential Load Profile (kWh)	Percentage Load	Hours	Pricing Multiplier	Revenue at Average Price	Revenue at Pilot Program Price	Pilot Program Price	Pilot Program Price Change vs Default Service Price	Pilot Program Price Change vs Off-Peak Price
Off-Peak Period	36,461,373	84.9%	1,888	n/a	$4,375,365	$3,223,854	$0.08842	-26.3%	0.0%
On-Peak Period	5,465,094	12.7%	280	2	$655,811	$1,311,623	$0.24000	100.0%	171.4%
Critical Peak Period	1,032,707	2.4%	40	5	$123,925	$619,624	$0.60000	400.0%	578.6%
Total	42,959,174	100.0%	2,208		$5,155,101	$5,155,101	$0.12000		

Assumed Residential Default Service Price $0.12000 per kWh

	Residential Load Profile (kWh)	Percentage Load	Hours	Pricing Multiplier	Revenue at Average Price	Revenue at Pilot Program Price	Pilot Program Price	Pilot Program Price Change vs Default Service Price	Pilot Program Price Change vs Off-Peak Price
Off-Peak Period	36,461,373	84.9%	1,888	n/a	$4,375,365	$2,852,079	$0.07822	-34.8%	0.0%
On-Peak Period	5,465,094	12.7%	280	2	$655,811	$1,311,623	$0.24000	100.0%	206.8%
Critical Peak Period	1,032,707	2.4%	40	8	$123,925	$991,399	$0.96000	700.0%	1127.3%
Total	42,959,174	100.0%	2,208		$5,155,101	$5,155,101	$0.12000		

Assumed Residential Default Service Price $0.12000 per kWh

	Residential Load Profile (kWh)	Percentage Load	Hours	Pricing Multiplier	Revenue at Average Price	Revenue at Pilot Program Price	Pilot Program Price	Pilot Program Price Change vs Default Service Price	Pilot Program Price Change vs Off-Peak Price
Off-Peak Period	36,461,373	84.9%	1,888	n/a	$4,375,365	$2,568,043	$0.07043	-41.3%	0.0%
On-Peak Period	5,465,094	12.7%	280	3	$655,811	$1,967,434	$0.36000	200.0%	411.1%
Critical Peak Period	1,032,707	2.4%	40	5	$123,925	$619,624	$0.60000	400.0%	751.9%
Total	42,959,174	100.0%	2,208		$5,155,101	$5,155,101	$0.12000		

Assumed Residential Default Service Price $0.12000 per kWh

Selected Scenario

	Residential Load Profile (kWh)	Percentage Load	Hours	Pricing Multiplier	Revenue at Average Price	Revenue at Pilot Program Price	Pilot Program Price	Pilot Program Price Change vs Default Service Price	Pilot Program Price Change vs Off-Peak Price
Off-Peak Period	36,461,373	84.9%	1,888	n/a	$4,375,365	$2,196,268	$0.06024	-49.8%	0.0%
On-Peak Period	5,465,094	12.7%	280	3	$655,811	$1,967,434	$0.36000	200.0%	497.7%
Critical Peak Period	1,032,707	2.4%	40	8	$123,925	$991,399	$0.96000	700.0%	1493.7%
Total	42,959,174	100.0%	2,208		$5,155,101	$5,155,101	$0.12000		

Assumed Residential Default Service Price $0.12000 per kWh

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

RESIDENTIAL DEFAULT SERVICE TOU/CPP PILOT

SCHEDULE DS-P

PURPOSE

This Schedule is for the purpose of implementing Time of Use and Critical Peak Period Default Service Rates through a Pilot Program. The Pilot Program is filed with the M.D.P.U. pursuant to Section 85 of the Green Communities Act. A specific objective of the Pilot shall be to reduce, for those customers who actively participate in the pilot, peak and average loads by a minimum of 5 per cent.

AVAILABILITY

Service is available under this Schedule for residential customers on rate Schedule RD-1 Residential Delivery Service or RD-2 Low Income Residential Delivery Service who have central or whole house air conditioning and who choose to participate in this Pilot Program and are not receiving Generation Service from a Competitive Supplier.

DEFAULT SERVICE PILOT CHARGES – MONTHLY

The Charges for Default Service under this Schedule are shown below:

Default Service Charges:
Off-Peak kWh .... $_______ per kWh
On-Peak kWh .... $_______ per kWh
Critical Peak kWh .... $_______ per kWh

These rates were developed based on the following multipliers applied to the residential Fixed DS price under Schedule DS which would otherwise be applicable to customers on this Schedule:

Off-Peak kWh .... 0.502 times the Fixed DS price
On-Peak kWh .... 3 times the Fixed DS price
Critical Peak kWh .... 8 times the Fixed DS price

For the purposes of billing under the DS-P rate, "On-Peak" is defined to be between the hours of 1:00 P.M. and 6:00 P.M. (local time) for all non-holiday weekdays, Monday through Friday. "Off-Peak" is defined to be between the hours of 6:00 P.M. and 12:00 A.M. (local time) and between the hours of 12:00 A.M. and 1:00 P.M. (local time) during non-holiday weekdays and all-day for weekends, Saturday and Sunday, and all-day for official Federal and Massachusetts holidays that occur on a weekday. "Critical Peak" is defined to be between the hours of 1:00 P.M. and 6:00 P.M. (local time) for non-holiday weekdays, Monday through

M.D.P.U. No. ___
Sheet 2

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

RESIDENTIAL DEFAULT SERVICE TOU/CPP PILOT

SCHEDULE DS-P (Continued)

Friday, on those dates which are initiated by the Company. A maximum of 8 critical peak day events will be called during the term of this Pilot.

CRITICAL PEAK DAY NOTIFICATION

Customers will be notified of when a Critical Peak Day will occur through a variety of methods which may include the internet notification, voice messages, or text messages. Notification will be given by 3:00 P.M. of the day preceding the event.

TERM OF CONTRACT

The term of contract under this Schedule shall be for the three month period June 1 to August 31, 2010. Upon completion of the program, Customers will return to the Residential Fixed or Variable Default Service Charges, whichever the Customer received prior to participation in the Pilot.

DEFAULT SERVICE TERMS AND CONDITIONS

The Company's Default Service Tariff, Schedule DS, in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this Schedule.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this Schedule.

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

DEFAULT SERVICE

SCHEDULE DS

1. General

This Tariff may be revised, amended, supplemented or supplanted in whole or in part from time to time according to the procedures provided in MDPU regulations and Massachusetts law. In case of conflict between this Tariff and any orders or regulations of the MDPU, said orders or regulations shall govern.

2. Definitions

A. "Company" shall mean Fitchburg Gas and Electric Light Company.

B. "Competitive Supplier" shall mean any entity licensed by the MDPU to sell electricity to retail Customers in Massachusetts, with the following exceptions: (1) a Distribution Company providing Default Service to its distribution Customers, and (2) a municipal light department that is acting as a Distribution Company.

C. "Customer" shall mean any person, partnership, corporation, or any other entity, whether public or private, who obtains Distribution Service at a Customer Delivery Point and who is a Customer of record of the Company.

D. "Customer Delivery Point" shall mean the Company's meter or a point designated by the Company located on the Customer's premises.

E. "Default Service" shall mean the service provided by the Distribution Company to a Customer who is not receiving Generation Service from a Competitive Supplier in accordance with the provisions set forth in this tariff.

F. "Distribution Company" shall mean an electric company organized under the laws of Massachusetts that provides Distribution Service in Massachusetts.

G. "Distribution Service" shall mean the delivery of electricity to Customers by the Distribution Company.

H. "Generation Service" shall mean the sale of electricity, including ancillary services such as the provision of reserves, to a Customer by a Competitive Supplier.

I. "MDPU" shall mean the Massachusetts Department of Public Utilities.

3. Availability

Default Service shall be available to any Customer who is not receiving Generation Service from a Competitive Supplier.

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

DEFAULT SERVICE

SCHEDULE DS (continued)

4. Rates

Fixed Pricing Option:

This pricing option is available to all customers, but is not available to GD-3 customers when their monthly rate is determined by Market Based Pricing.

Effective January 1, 2001, all residential customers on Schedules RD-1 and RD-2 and small general service customers on Schedule GD-1 receiving Default Service will automatically be placed on this fixed rate, unless the Customer elects the Variable Monthly Pricing Option.

The fixed rate will remain the same for three or six months at a time and will be based on the average monthly wholesale price over the three or six-month period that the Company pays to its Default Service provider. The rate is fixed for a period of three months for customers on Schedule GD-3, when applicable. The rate is fixed for six months for customers on Schedules RD-1, RD-2, GD-1, GD-2, GD-4, GD-5 and SD.

Customers assigned to this Fixed Pricing Option may choose the Variable Monthly Pricing Option. Customers electing the Variable Monthly Pricing Option will not have the opportunity to switch back to the Fixed Pricing Option for as long as the Customer continues to receive uninterrupted Default Service.

Monthly bills will be recalculated for Customers who are on the Fixed Pricing Option for Default Service and decide to switch to a competitive supplier before the three or six-month period is over. The electric bill for the period of the fixed three or six month rate will be recalculated using the monthly variable rate for that period. This ensures that all consumers pay the actual cost of electricity they have used. This adjustment may be a credit or a debit, and will be reflected on the first bill after the switch is effective.

Residential customers on Schedules RD-1 and RD-2 and small general service customers on Schedule GD-1 who switch to a competitive supplier and later return to Default Service will be initially placed on the Fixed Pricing Option unless the Customer elects the Variable Monthly Pricing Option.

The rates for Fixed Pricing Option Default Service shall be as provided in Schedule SR as in effect from time to time.

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

DEFAULT SERVICE

SCHEDULE DS (continued)

Variable Monthly Pricing Option:

This option is available to all customers, but is not available to GD-3 customers when their monthly rate is determined by Market Based Pricing.

Effective January 1, 2001, general service customers on Schedules GD-2, GD-3 (when applicable), GD-4, and GD-5 and outdoor lighting customers on Schedule SD receiving Default Service will automatically be placed on this variable monthly rate option, unless the Customer elects the Fixed Pricing Option.

The variable rate will change from month to month reflecting the monthly wholesale price that the Company pays to its Default Service provider.

Customers assigned to the Variable Monthly Pricing Option may choose the Fixed Pricing Option. Customers electing the Fixed Pricing Option will not have the opportunity to switch back to the Variable Monthly Pricing Option for as long as the Customer continues to receive uninterrupted Default Service.

General service customers on Schedules GD-2, GD-3 (when applicable), GD-4, and GD-5 and outdoor lighting customers on Schedule SD who decide to switch to a competitive supplier and later return to Default Service will be initially placed on the Variable Monthly Pricing Option, unless the Customer elects the Fixed Pricing Option.

The rates for Variable Monthly Pricing Option Default Service shall be as provided in Schedule SR as in effect from time to time.

The rate(s) for Default Service are established through a competitive bidding process, but in no case shall exceed the average monthly market price for electricity, as determined by the MDPU.

Large General Service GD-3 - Market Based Pricing:

Default Service prices for Customers on Schedule GD-3 may be determined monthly on an after the fact basis. If this is the case, "MARKET" shall be shown in the Variable Monthly Pricing Option shown in Schedule SR and the Fixed Pricing Option will not be applicable to GD-3 customers during that month, indicated by "N/A" in the Fixed Monthly Pricing Option shown in Schedule SR. The monthly price will be determined using the ISO-New England real time hourly locational marginal prices for the West Central Massachusetts load zone weighted by the wholesale hourly kWh volumes of the Company's Schedule GD-3 Default Service Customers and adjusted for the distribution losses shown in the Terms and Conditions for Competitive Suppliers, Appendix A. The monthly price will also include a

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retail Supplier Costs Adder for capacity, ancillary services, and other supplier costs established through a quarterly competitive bidding process, plus the estimated retail cost of Renewable Energy Certificates and the Default Service Costs Adder.

Customers will be notified of changes in Default Service rates in advance of their effective dates in accordance with guidelines set forth by the MDPU, as may be amended from time to time. Such notifications will be made in a variety of manners including a toll free number, the Company's website, bill inserts, and bill messages. Notification of rates will be made via the Company's website at www.unitil.com and a toll free number 30 days in advance of the effective date, but this information will not be available to GD-3 customers when their monthly rate is determined by Market Based Pricing. Default Customers will receive 60 day notification of upcoming rate changes via a bill message and 30 day notification of the new rates via a bill message. All Customers will receive a bill insert explaining Default Service in the billing cycle prior to the rate change.

5. Billing

Each Customer receiving Default Service shall receive one bill from the Company, reflecting unbundled charges for their electric service.

6. Initiation of Default Service

Default service may be initiated in any of the following manners:

A. A Customer who is receiving Generation Service from a Competitive Supplier notifies the Company that he wishes to terminate such service and receive Default Service. In this instance, Default Service shall be initiated within two (2) business days of such notification for residential Customers. For other Customers, Default Service shall be initiated concurrent with the Customer's next scheduled meter read date, provided that the Customer has provided such notification to the Company two (2) or more business days before the next scheduled meter read date, in accordance with the Company's Terms and Conditions for Competitive Suppliers. If the Customer provided such notification fewer than two (2) days before the Customer's next scheduled meter read date, Default Service shall be initiated concurrent with the Customer's subsequent scheduled meter read date;

B. A Competitive Supplier notifies the Company that it shall terminate Generation Service to a Customer. In this instance, Default Service shall be initiated for the Customer concurrent with the Customer's next scheduled meter read date, provided that the notice of termination of Generation Service is received by the Company two (2) or more business days before the next scheduled meter read date, in accordance with the Company's Terms and Conditions for Competitive Suppliers. If the notice of termination is received fewer than two (2) days before the Customer's next scheduled meter read date,

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Default Service shall be initiated concurrent with the Customer's subsequent scheduled meter read date;

C. A Competitive Supplier ceases to provide Generation Service to a Customer, without notification to the Company. In this instance, Default Service to the Customer shall be initiated immediately upon the cessation of Generation Service.

7. Termination of Default Service

Default Service may be terminated by a Customer concurrent with the Customer's next scheduled meter read date provided that notice of initiation of Generation Service by a Competitive Supplier is received by the Company two (2) or more business days before the next scheduled meter read date, in accordance with the Company's Terms and Conditions for Competitive Suppliers.

If the notice of initiation of Generation Service by the Competitive Supplier is received by the Company fewer than two days before the Customer's next scheduled meter read date, Default Service shall be terminated concurrent with the Customer's subsequent scheduled meter read date.

There shall be no fee for terminating Default Service.

8. Reconciliation of Default Service Costs

At the end of each calendar year, the Company shall reconcile recoveries with the cost of Default Service pursuant to the Company's Default Service Adjustment - Schedule DSA, MDTE No. 101. These costs include the costs billed to FG&E by its Default Service providers, the cost of Renewable Energy Certificates purchased for Default Service in compliance with 225 CMR 14.00 – Renewable Energy Portfolio Standard, and the FERC approved costs billed to the Company by ISO-New England for the operation of the New England Power Pool ("NEPOOL") Generation Information System ("GIS"). GIS costs are billed to the Company pursuant to the Attribute Laws, as defined in the NEPOOL cost allocation document. Renewable Energy Certificates are the title or claim for the generation attributes associated with a Renewable Generator that is compliant with the definition of a New Renewable Generation Source as found in 225 CMR 14.00 – Renewable Energy Portfolio Standard. The February 29, 2008 Base Rate Reduction balance, including any associated prior period adjustments and revenue, shall also be included.

Recoveries and costs associated with the Default Service Costs Adder shall be excluded from this reconciliation since the Default Service Costs Adder is separately reconciled as discussed below.

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9. Default Service Costs Adder

Effective June 1, 2005, the Default Service rates will include the Default Service Costs Adder. The Company shall perform an annual reconciliation of recoveries with the costs of the Default Service Costs Adder and credit or charge any imbalances, with interest, in the computation of the Default Service Costs Adder for the following twelve month period. Interest shall be calculated using the prime rate after tax (i.e. prime rate * (1 – tax rate)). The tax rate shall be the combined federal and state income tax rate. The prime rate is to be fixed on a quarterly basis and established as reported in The WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter; if more than one rate is reported, the average of the reported rates shall be used. The Company may file to change the factor at any time should significant over- or under-recoveries occur or be expected to occur.

The Default Service Costs Adder shall include the following costs associated with Default Service:

A. Cost of Working Capital, calculated as follows,

Cost of Working Capital = Working Capital Requirement * Tax Adjusted Cost of Capital,

where:

Working Capital Requirement = Supplier Costs * Number of Days Lag/365

Number of Days Lag is the number of days lag to calculate the purchased power working capital requirement as defined in the Company's most recent Lead Lag Study approved by the Department,

Tax Adjusted Cost of Capital = Cost of Debt + (Cost of Equity/(1-Effective Tax Rate))

where:

The Cost of Debt is the debt component of the rate of return as approved by the Department in the Company's most recent base rate case,

The Cost of Equity is the equity component of the rate of return as approved by the Department in the Company's most recent base rate case, and

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SCHEDULE DS (continued)

The Effective Tax Rate is the combined effective state and federal income tax rate;

B. Bad Debt Costs which shall equal the uncollected costs associated with electric supply.

C. Administrative cost of compliance with Massachusetts Renewable Energy Portfolio Standard, 225 CMR 14. Annually, these costs shall be $3,100.70.

D. Cost of the design and implementation of competitive bidding process, including evaluation of supplier bids and contract negotiations, and ongoing administration and execution of contracts with suppliers, including accounting activities necessary to track payments made to suppliers. Annually, these costs shall be $69,817.68.

E. Cost of compliance with MDPU's regulatory requirements including required communication with Default Service customers pursuant to 220 CMR 11.06. Annually, these costs shall be $57,923.17.

F. Incremental costs of the design, implementation, and analysis and reporting of the Company's Smart Grid Pilot Programs filed in compliance with section 85 of the Green Communities Act. Incremental costs shall include such items as consultant costs, contractor costs, external programmer costs and equipment costs that are directly related to these pilot programs. Costs associated with existing internal resources shall not be considered incremental.

Annually, the costs in C., D. and E. above sum to $130,841.55 and shall be fixed until the next general distribution rate case unless otherwise proposed to be adjusted by the Company, subject to approval by the MDPU. However, at such time that the migration of the Company's customers from Default Service to competitive supply increases to a significant level as compared to the level at the time these costs were developed, the costs detailed above may be adjusted to reflect the decline in Default Service customers.