STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

<u>In the matter of</u>
Unitil Energy Systems
Petition for Approval of
Investment In and Rate Recovery of
Distributed Energy Resources   Docket No. DE 09-137

DISTRIBUTED ENERGY RESOURCES

DIRECT TESTIMONY OF
George R. McCluskey

Analyst, Electric Division

December 23, 2009

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is George McCluskey, and my business address is the New Hampshire Public Utilities Commission ("Commission"), 21 South Fruit Street, Suite 10, Concord, NH 03301.

Q. WHAT IS YOUR POSITION WITH THE COMMISSION?

A. I am an Analyst within the Electric Division.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. A **summary of my qualifications and work experience** is provided in Staff Exhibit-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Unitil Energy Systems ("UES" or "the Company") is the first utility in New Hampshire to seek Commission approval to invest in distributed energy resource

(DER) projects pursuant to RSA 374-G, enacted in 2008. Under this legislation, New Hampshire electric utilities are encouraged under state regulatory oversight to invest in DERs that include electric generation equipment; 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. DER investments must be part of a strategy for minimizing the transmission and distribution costs of electric utilities.

With this background, the purpose of this testimony is to present an analysis of, and make recommendations for, three DER projects proposed by UES. Because these projects are expected to be the first of many, my testimony also analyzes the regulatory review and approval process proposed by UES, as well as the corresponding cost recovery methodology reflected in the proposed tariff. My goal is to offer a regulatory framework for the review of current and future DER projects submitted by UES and, potentially, by the state's other electric utilities. This testimony is presented on behalf of the Staff of the Electric Division.

Q. HOW IS STAFF'S TESTIMONY ORGANIZED?

A. This introduction is followed by a review of the requirements of RSA 374-G. After that, a brief description of the Company's filing is provided along with a summary of the proposed projects. This section also includes the details of the proposed regulatory review process and cost recovery mechanism. The fourth and final section includes Staff's analysis of the filing.

II. APPLICABLE LEGAL STANDARDS

Q. WHAT STANDARDS HAVE YOU USED TO ASSESS WHETHER THE DER PROJECTS PROPOSED BY UES SHOULD BE APPROVED AND THE ASSOCIATED COSTS RECOVERED?

A. The starting point for any discussion of the reasonableness of DER investments must be the enabling legislation itself. Specifically, RSA 374-G:5, I states that a utility may seek cost recovery for its DER investments by making an appropriate rate filing that includes, at a minimum, the following:

(a) A detailed description and economic evaluation of the proposed investments.
(b) A discussion of the costs, benefits, and risks of the proposal with specific reference to certain public interest factors identified in the legislation, 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.

Q. WHAT ARE THE PUBLIC INTEREST FACTORS REFERENCED ABOVE?

A. RSA 374-G:5, II states that "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 includes but is not necessarily 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."

Missing from the legislation is a detailed prescription for determining the public interest based on these nine criteria. A primary Staff goal in this proceeding is to fill that gap.

Q. DOES THE COMPANY'S FILING INCLUDE THE CUSTOMER AGREEMENTS THAT SPECIFY THE RESPONSIBILITES AND OBLIGATIONS OF THE PARTICIPATING CUSTOMERS AND THE UTILITY?

A. No, a memorandum of understanding (MOU) for each project is provided instead. Unfortunately, the MOUs omit many important details and generally raise more questions than they answer. We recommend that the Company be required to include in future filings a conditional customer agreement for each project that specifies the key responsibilities and obligations. Without this information, there is a significant risk that the proposals will not be fully understood and that the Commission will be inappropriately advised.

Q. IF THE FUNDAMENTAL PURPOSE OF THE STATUTE IS TO ENCOURAGE UTILITY INVESTMENTS THAT MINIMIZE TRANSMISSION AND DISTRIBUTION COSTS, DOES IT FOLLOW THAT DER PROJECTS MUST BE LOCATED ON THE UTILITY SIDE OF THE METER?

A. No, the legislation is clear that eligible DER projects can be located on either side of the customer meter. Location, however, does have important consequences for the allocation of cost savings among utility customers and therefore plays an important role in the determination of cost-effectiveness. This issue will be addressed later in this testimony.

Q. ARE THERE OTHER LEGISLATIVE PROVISIONS THAT SHOULD BE CONSIDERED WHEN REVIEWING A REQUEST FOR INVESTMENT APPROVAL?

A. Yes. RSA 374-G: 3 effectively limits the amount of electricity that can be produced by utility-owned generation equipment to the sum of distribution system losses and company own use; or 4% of UES' kWh purchases. In addition, the capacity of a single electric generator, whether installed on the customer side or utility side of the meter, cannot exceed 5 MW. Further, electric generation owned by or receiving investments from a utility is limited to a cumulative maximum capacity equal to 6% of the utility's system peak load. According to UES, this restriction caps its total DER generation at 18 MW.

In the case of customer-owned or on-site generation, electricity generated with non-renewable fuel must be used to displace the customer's own use. That is, there is no provision in the legislation for such electricity to leak to the utility side of the meter and displace electricity purchased for the benefit of other customers. This restriction does not, however, apply to electricity generated by customer owned or on-site generation utilizing a renewable fuel. The legislation allows such projects to occasionally generate in excess of the customer's needs; the excess may be credited to the customer's account in a subsequent period. Additions of non-renewable generation are also subject to limitations when a utility's cumulative DER generation reaches 3% of its peak distribution load.

Q. WHAT DOES THE LEGISLATION SAY ABOUT HOW AUTHORIZED INVESTMENTS SHOULD BE RECOVERED?

A. RSA 374-G: 5, III states that authorized and prudently incurred investments must be recovered in a utility's base distribution rates. Costs eligible for recovery include 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, RSA 374-G: 5, V provides for utility rate filings to be approved, disapproved, or approved with conditions within 90 days.

Q. COULD YOU PROVIDE AN EXAMPLE OF OFFSETTING REVENUE?

A. Yes. Investments in renewable generators (such as solar photovoltaic arrays) or demand response programs may enable the utility to claim and sell renewable energy certificates (RECs) associated with the renewable generation or receive payments from ISO-New England for the value of load reduction in Forward Capacity Market.

III. COMPANY FILING

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE COMPANY'S FILING.

A. On August 5, 2009, UES filed with the Commission a Petition for Approval of Distributed Energy Resources Investment Proposal and Proposed Tariff. In support of its Petition, UES submitted the direct testimony and exhibits of George Gantz, Howard Axelrod, Cindy Carroll and Justin Eisfeller. One of the proposed projects is a pilot program to test the responsiveness of residential air conditioning customers to time-of-use (TOU) rates. The other three projects are:

(a) A solar hot water system for a low-income multifamily property owned by the Concord Housing Authority. The system will convert solar energy into thermal energy to heat water for domestic use.

(b) A solar photovoltaic (PV) array for the Stratham Fire Station. The system will convert solar energy into electric energy and displace electricity purchased from UES.

(c) A solar PV array and microturbine combination for the School Administrative Unit (SAU) 16 of Exeter. The solar array will produce electricity and the microturbine both electricity and thermal energy.

On October 6, 2009, Staff filed a letter with the Commission indicating that the parties and Staff had agreed to place the TOU pilot program on a faster track than the other projects with the goal of meeting the proposed program start date of June 1, 2010. The change is also consistent with the fact that UES is no longer seeking approval of the pilot under RSA 374-G.

On December 16, 2009, UES, Staff and the OCA reached a settlement resolving all issues related to the TOU pilot program. Accordingly, Staff's testimony addresses the three non-TOU projects only.[1] Each of these projects is an example of on-site generation that inter-connects with UES' distribution system via the customer's electrical installation.

Q. DID UES REVISE ITS ECONOMIC EVALUATION OF THE NON-TOU PROJECTS?

A. Yes, on November 20, 2009 UES informally filed with the parties a revised analysis that reflected updated avoided costs and changes in the allocation of project benefits to participating and non-participating customers. The other parts of the August 5 filing were unchanged.

Q. THE AUGUST 5 FILING INCLUDED A PROPOSED TWO-STAGE FRAMEWORK FOR THE REVIEW OF DER PROJECTS. PLEASE BRIEFLY DESCRIBE THAT FRAMEWORK.

A. In stage one, UES would file with the Commission, prior to making actual investments, a detailed description of each proposed DER project along with information needed to satisfy the public interest test included in RSA 374-G. The Commission would then decide whether each project as presented satisfies the public interest test. If the Commission finds that a particular project is in the public interest, UES would be authorized to proceed to stage two, which involves filing a request to recover the DER investments once incurred. As we understand the Company's proposal, a public interest finding would not guarantee cost

[1] Because the TOU project is addressed in the direct testimony of Justin Eisfeller, this testimony responds to the direct testimony of George Gantz, Howard Axelrod and Cindy Carroll.

recovery but simply authorize UES to proceed to stage two without putting the Company at risk that the investment would fail to meet the public interest test.[2] .

Q. WHAT DOES UES NEED TO DO IN STAGE TWO TO RECOVER ITS COSTS?

A. Based on its own petition, UES would need to verify that each project had met its designed objectives within a reasonable time frame and within the anticipated budget range. In addition, UES would need to support its cost recovery request by providing the details of its revenue requirement calculations.

Q. PLEASE DESCRIBE UES' COST RECOVERY PROPOSAL.

A. UES has proposed an annual filing for the recovery of costs associated with approved DER investments. The so-called DER Investment Charge (DERIC) would be based on a revenue requirement calculation that comprises depreciation and amortization, return on rate base, taxes, deferred taxes, working capital, O&M, including monitoring and verification, mobilization expenses, reporting expenses and lost revenues. Despite the fact that authorized DER investments must be recovered through the utility's distribution rates as a component of rate base, UES has proposed that the DERIC be fully reconcilable. Specifically, UES proposes to track on a monthly basis the difference between DER revenue requirements and DER revenues and adjust the distribution surcharge (i.e., DERIC) annually for any over/under recovery plus associated interest. In addition, UES proposes that the DERIC be billed to all customers taking delivery service.

[2] See Gantz testimony at 7, lines 29-31.

Q. IS THERE ANYTHING UNUSUAL ABOUT THE COMPANY'S PROPOSED COST RECOVERY MECHANISM?

A. Leaving aside the proposal to fully reconcile the DERIC, which is addressed at length later, UES is proposing to base the return on rate base calculation not on the approved overall cost of capital from the last base rate proceeding but on a rate of return that is re-calculated annually. Specifically, UES proposes to develop this return using the capital structure and debt costs from its NHPUC Form 1-Supplemental Quarterly Financial and Sales Information for the previous year.

Q. PLEASE DESCRIBE IN GREATER DETAIL THE CRUTCHFIELD PLACE PROJECT.

A. The proposal is to install a solar domestic hot water (DHW) system in a 105 unit low-income multifamily property owned by the Concord Housing Association. The system will include storage tanks and Apricus solar collectors. UES claims that the Apricus solar DHW system will provide all of the hot water needs of the building from April through November each year and sixty percent from December through March at an estimated installed cost of $101,920 including UES overhead.[3] Offsetting this cost is an expected total benefit of $843,505.[4] These data indicate a solid benefit/cost ratio of 8.28 for the total system. The existing hot water system, which consists of a 120 kW heating element contained within a 1,500 gallon water storage tank and a 170 kBTU gas heater, will be retained to supplement and backup the solar DHW system. Since UES

[3] See Carroll Schedule CLC-2, Revised.
[4] Ibid.

supplies the existing system with electricity purchased under its default service tariff, the goal of the project is to lower the customer's electricity bill while creating cost saving for the Company's other customers.

Q. WHY DO OTHER CUSTOMERS FIGURE INTO THE ANALYSIS?

A. Other customers must be considered because UES proposes to finance 100% of the installed cost of the project. UES will then seek to recover its contribution to the project from other customers.[5]

Q. ARE THERE OTHER KEY FACTS ABOUT THIS PROJECT?

A. Yes, the customer will be responsible for the O&M expense on the project.[6] Absent this requirement, UES' contribution to the project would be open-ended and potentially much greater than the installed cost. This requirement also applies to the Stratham and SAU 16 projects.

Q. PLEASE DESCRIBE THE STRATHAM PROJECT.

A. Although the RFP for the project is in the process of being reissued, the current proposal is to install 202 BP Solar SX 3195 panels and a SMA Sunnyboy 7000 inverter on the roof of the new Stratham Fire House. This 39 kW installation is expected to produce electricity year round and meet most of the Fire House load at an estimated capital cost of $399,321 including UES overhead.[7] Offsetting this cost is an expected total benefit valued at $725,671.[8] These data point to a benefit/cost ratio of only 1.82 for this project.

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[5] Actually, since the customer will continue to purchase electricity from UES to meet the portion of its water heating load not supplied by the solar facility, the customer will pay a small part of the project cost.
[6] This precludes UES from including O&M expense in its revenue requirement, other than for UES' monitoring and verification expenses.
[7] See Carroll Schedule CLC-4, Revised.
[8] Ibid.

Since UES currently supplies the Fire House with electricity purchased under its default service tariff, the goal of the project is to lower the customer's electricity bill while creating cost savings for the Company's other customers.

Q. HOW WILL THE PROJECT BE FINANCED?

A. As with the Crutchfield project, the Company proposes to finance 100% of the installed cost.

Q. IS THE CUSTOMER RESPONSIBLE FOR O&M?

A. Yes.

Q. WILL THE COMPANY PROVIDE BACK-UP IN THE EVENT THE SOLAR PV IS ON A PLANNED OR UNPLANNED OUTAGE?

A. Yes.

Q. PLEASE DESCRIBE THE SAU 16 PROJECT.

A. This project is easily the most complex of those proposed in that it involves two utilities, a middleman, two locations, three fuels, and two on-site generators. The on-site generators are an 80 kW solar PV array mounted on the roof of the Exeter High School building and a Capstone microturbine at the school's administrative offices located elsewhere in Exeter. The solar array will meet a portion of the electricity needs of the High School while the microturbine (i.e., a compact combined heat and power facility) will meet a portion of the electricity and space heating needs of the administrative offices. The combined project, which is already well into the installation phase, was designed, developed and financed by the New Hampshire Seacoast Energy Partnership (NHSEP), LLC under an agreement with SAU 16 that provides for the former to share in the electricity and oil bill savings that result from the project.[9]

Under the operating scenario described in the Company's filing, the solar PV array will generate electricity year round during daylight hours. The microturbine is scheduled to operate only during the winter months to meet the space heating needs of the administrative offices, which are currently met by an old inefficient oil-fired boiler. The electricity produced during those winter months is considered a by-product that will be used to displace purchases from UES under its default service tariff. Further, the microturbine will be fueled with natural gas supplied by UES' affiliate Northern Utilities.[10]

The total installed cost of the project is estimated at $920,000 inclusive of utility overhead.[11] The installed cost of the project falls to $685,000 if the cost of the microturbine is excluded.[12] Offsetting this cost is an expected total electric benefit of $1,929,692.[13] From a total customer standpoint, these data indicate a benefit/cost ratio of 2.10 using the higher cost and 2.82 using the lower cost.

Q. HOW WILL THE PROJECT BE FINANCED?

A. NHSEP will finance the project through three sources: a $650,000 bank loan, a $260,000 grant from UES and internal funds. The grant amount assumes $60,000 of UES overhead.

Q. WILL THE CUSTOMER BE RESPONSIBLE FOR O&M?

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[9] NHSEP is also responsible for operating the project.
[10] This new gas load will add to Northern's peak demand.
[11] See Carroll Schedule CLC-6, Revised
[12] This is appropriate because the microturbine's primary purpose is to supply the space heating load of the administrative offices.
[13] See footnote 11.

A. Yes.

Q. WILL THE COMPANY PROVIDE BACK-UP?

A. Yes.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE COMPANY'S ECONOMIC EVALUTION OF DER PROJECTS.

A. The Company has developed an economic screening model to evaluate the proposed DER projects. This model, which was adapted from a model used by UES to evaluate the economics of energy efficiency programs, employs the Total Resource Cost (TRC) test as the primary determinant of cost-effectiveness. The TRC test compares the present value of future electric system savings associated with a proposed project to the present value of the total expenditures by the utility and participating customers necessary to implement the project. Unlike the participant and non-participant tests, which evaluate cost-effectiveness from the perspective of participating and non-participating customers respectively, the TRC test is blind to who benefits and who pays. Since this test evaluates cost-effectiveness from the perspective of all utility customers, it is sometimes referred to as the total system test. For the purpose of modeling, UES assumed that each project has a useful life of 13 years.

Q. YOU SAID THAT THE DER MODEL IS AN ADAPTATION OF THE ENERGY EFFICIENCY MODEL. PLEASE DESCRIBE THE MODIFICATIONS.

A. The energy efficiency model, which calculates the system costs avoided by energy efficiency expenditures, was modified in three ways. The first modification calculates wholesale market energy and capacity savings not reflected in the energy efficiency model. These are referred to as Energy DRIPE and Capacity DRIPE respectively.[14] The second modification calculates the local economic benefits that the Company claims result from investments in the DER projects. The third modification reflects the Company's contention that some DER projects lead to greater distribution system savings than the distribution savings reflected in the energy efficiency model.

Q. FOR COMPLETENESS, PLEASE BRIEFLY IDENTIFY THE SYSTEM AVOIDED COSTS CALCULATED IN THE ENERGY EFFICIENCY MODEL AND NOW INCLUDED IN THE DER MODEL.

A. The DER model calculates the avoided cost of energy, generation capacity, and transmission and distribution capacity associated with each DER project. The avoided energy cost calculation, for example, takes into account the fact that certain DERs produce disproportionately more electricity at times when its value is greatest.[15] In addition, the avoided transmission and distribution cost incorporates not only infrastructure cost savings but lower losses that result when less electricity flows over those lines.

The sum of these avoided energy and capacity costs for a particular program is then compared to the total cost to the Company and participants to implement and operate the program. Programs that have greater savings than costs are deemed cost-effective and eligible for Commission approval.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S MODELING?

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[14] DRIPE is the acronym for Demand Reduction Induced Price Effect.

[15] Solar PV production, for example, peaks in the middle of the day and during the summer peak months, when demand and prices are high, and is zero during the night hours.

A. The results[16], as reported in the revised filing, are summarized in the table below:

TABLE I
Benefit/Cost Ratios

	Crutchfield Solar DHW	**Stratham** Solar PV	**SAU 16** Solar/Microturbine
Total Benefits ($)	$843,505	$725,671	$1,929,692
Total Costs ($)	$101,920	$399,326	$920,000
Benefit/Cost Ratio	8.28	1.82	2.10

Q. IS THE COMPANY'S ECONOMIC MODELING LIMITED TO PERFORMING THE TRC TEST?

A. No. In order to meet the requirements of RSA 374-G the Company must also determine the cost-effectiveness of each program from the perspective of customers participating in the program (i.e., participants) and from the perspective of all other customers (i.e., non-participants). This required the Company to determine how much of the expected benefits flow to participants through bill reductions and how much is left over for non-participants.

Q. BEFORE YOU BEGIN YOUR ANALYSIS OF THE COMPANY'S FILING, PLEASE SUMMARIZE STAFF'S RECOMMENDATIONS.

A. Staff recommends:

1. All future DER filings include for each proposed project a customer agreement that specifies the key responsibilities and obligations of all parties to the agreement.

[16] Note that Revised Schedule CLC-6 incorrectly reports the total cost of the SAU 16 project.

2. Approval of the proposed two-stage framework subject to the Company seeking re-approval of projects that have not been started within a reasonable time period after the date of the Commission order finding them to be in the public interest.
3. Rejection of the proposal to reconcile the DER surcharge.
4. The DER distribution surcharge be established after-the-fact based on known and measurable costs, consistent with the step-adjustment approach approved in gas, water and electric rate proceedings.
5. Rejection of the proposal to re-calculate the rate of return annually.
6. The return on investment be calculated using the Company's authorized overall cost of capital.
7. Rejection of the proposal to recover lost base revenues.
8. Future filings contain a description of how rax credits will be handled in revenue requirements calculations.
9. UES' overhead on DER projects not exceed 3%.
10. Numerous changes to the calculation of both avoided costs and avoided benefits in the TRC Test.
11. Conditional approval of the Crutchfield project, subject to the customer agreeing to pay half of the actual installed cost.
12. Rejection of the Stratham project.
13. Conditional approval of the SAU 16 project, subject to NHSEP agreeing to operate the microturbine as a peaking unit during the summer months.

IV. STAFF ANALYSIS

1. Two-Stage Framework

Q. AS NOTED ABOVE, UES PROPOSED A TWO-STAGE FRAMEWORK FOR THE REVIEW OF DER FILINGS. DOES STAFF SUPPORT THIS PROPOSAL?

A. Yes, with certain conditions. As we understand the Company's proposal, UES would make an annual filing with the Commission for authority to proceed with projects found to be in the public interest. UES, however, would be prohibited from seeking cost recovery for projects not yet used and useful and would have no right to recover costs found to be imprudent. For projects that have not been started one year after the date of the Commission order finding them to be in the public interest, Staff recommends that UES be required to re-file for authority to proceed along with an updated economic evaluation.

2. <u>Cost Recovery</u>

Q. DOES STAFF SUPPORT UES' COST RECOVERY PROPOSAL?

A. Not completely. Staff is opposed to the proposal to reconcile DER costs and revenues. Under traditional rate base ratemaking as practiced in New Hampshire, electric utilities may, as part of a permanent base rate proceeding or as part of an authorized step increase in connection with such a proceeding or as part of a specially authorized program, seek a change in distribution rates to recover the costs of distribution projects once those projects are complete and in service. Pursuant to RSA 378:28, the costs of projects that are incomplete and not in service can not be included in rates. UES' cost recovery proposal is inconsistent with this statute because it allows recovery of the costs of projects not yet in service, but expected to be so at some point during the forthcoming rate year, to be recovered in advance. In support of its proposal, UES notes that any over/under recovery of actual costs caused by this advanced recovery would be returned to/collected from customers with interest through the proposed reconciliation process. That argument notwithstanding, UES' proposal will result not only in the elimination of regulatory lag for DER investments but also the premature recovery of certain costs, if only temporarily.

Q. DOES TRADITIONAL RATEMAKING COMPENSATE UTILITIES FOR THE COSTS OF REGULATORY LAG?

A. Yes, the cost to finance the time lag between when a cost is incurred and when it is recovered in rates is covered by the working capital allowance included in utility rate base.

Q. IS THERE A REASONABLE ALTERNATIVE TO UES' PROPOSAL?

A. Yes. Staff recommends that the reconciliation proposal be rejected on the grounds that it is contrary to traditional rate base ratemaking. Instead, Staff recommends that the DER distribution surcharge be established after-the-fact based on known and measurable costs for a recent historic period. This is consistent with the step-adjustments approved by the Commission to recover bare steel-cast iron replacement costs in natural gas, reliability enhancement costs in the electric sector and investments to meet the requirements of the Clean Water Act in water.

Q. WHAT IS STAFF'S VIEW OF UES' PROPOSAL TO RE-CALCULATE THE RETURN ON INVESTMENT ANNUALLY?

A. Staff's primary concern is that UES in seeking to shield itself from the risks of adverse changes in capital structure and debt costs (relative to the capital structure and debt costs reflected in the Company's approved overall cost of capital) without making a corresponding adjustment to the return on equity. In addition, we believe the proposal unnecessarily burdens the review process, which runs counter to the requirement in RSA 374-G for an expedited cost recovery process.

Q. WHAT DOES STAFF RECOMMEND?

A. Staff recommends that the Commission reject UES' proposal and instead direct the Company to calculate its return on investment using the authorized overall cost of capital.

Q. ARE THERE OTHER CONCERNS WITH UES' COST RECOVERY PROPOSAL?

A. Yes, Staff is opposed to the proposed recovery of lost base revenue. We base this opposition on the fact that DER projects are voluntary rather than mandatory and that the Company is rewarded for its investment through the return on rate base. In addition, we note that UES' natural gas affiliate will receive significant additional base revenues through supplying gas to the SAU 16 microturbine. Finally on this issue, it is important to note that in regard to solar PV systems the lost base revenue issue arises only because the Company elected to participate in projects that placed those systems behind the meter. Had the Company proposed projects that located the systems in front of the meter, there would be no lost base revenue issue.

On another matter, we note that the filing does not state explicitly how available federal tax credits will be handled in revenue requirement calculations. We recommend that this omission be corrected in future filings.

3. <u>Economic Evaluation</u>

A. <u>Overview</u>

Q. DOES STAFF HAVE ANY CONCERNS WITH THE PROPOSED ECONOMIC EVALUATION OF DER PROJECTS?

A. We have many concerns, some of which relate to costs and some to benefits. Our concerns relating to the calculation of total system costs will be presented first followed by a much more lengthy critique of the calculation of total system benefits. We then address the allocation of total costs and total benefits among participants and non-participants. Before addressing these concerns, however, we believe the reader's understanding of the issues can be greatly improved by first focusing on the cost per kWh produced for each project using only the cost and production data contained in the Company's filing. Using these unit costs as a yardstick, our critique of the costs and benefits hopefully will be more instructive.

Q. PLEASE CONTINUE.

A. The three projects comprise four systems utilizing three different technologies. The systems are: a solar-based facility for producing hot water; two solar photovoltaic arrays for producing electricity; and one microturbine for producing both electricity and thermal energy. Based on the cost and production data included in the filing, the average cost per lifetime kWh produced for each project[17] is as follows:

[17] Note that the SAU 16 installed cost in Table II is less than in Table I. This is to recognize that the microturbine's primary purpose is to replace the existing inefficient space heating system and that the electricity produced is as a by-product. Consequently, the installed cost of the microturbine is excluded.

TABLE II

Project Unit Costs

	Crutchfield Solar DHW	Stratham Solar PV	SAU 16 Solar/Micro
Installed Cost ($)	$101,920	$399,321	$685,000
Lifetime kWh	2,468,752	672,854	5,894,200
Average Cost (cents/kWh)	4.13	59.35	11.62

Compared to the current default service price of 9 cents per kWh, these unit costs indicate that solar PV and the solar/microturbine combination are not competitive alternatives to electricity purchased from UES. This is despite that fact that the installed costs in the table understate the real costs to implement these systems because certain capital and operating costs have been excluded.[18] Even with those costs excluded, the table indicates that the production cost for a solar PV system is about 6.6 times the current cost of default service. Thus, solar PV systems are unlikely to be a viable alternative to utility supplied power absent significant external financial support. The table also indicates that electricity from the solar PV/microturbine combination costs 1.29 times the cost of default service.

Q. PLEASE EXPLAIN HOW THE STRATHAM AND SAU 16 PROJECTS CAN BE JUDGED TO BE COST-EFFECTIVE BASED ON TABLE I BUT UNCOMPETITIVE COMPARED TO THE COST OF UTILITY SUPPLIED POWER?

A. In the previous answer we indicated that solar PV systems are unlikely to be viable "absent significant external financial support." The fact is, external

[18] See Section IV.3.B for details.

financial support is available for solar PV systems from both federal and state governments. This support takes the form of tax credits, production incentives and grants and is designed to improve the relative economics of solar PV projects. For example, the classification of solar PV as a Class II facility in New Hampshire's RPS is an example of an explicit state production incentive designed to address the current uncompetitiveness of the technology. That said, a gap in excess of 50 cents/kWh, as in the Stratham project, will be difficult to close.

Q. WHAT IS THE REASON FOR THIS SKEPTICISM?

A. While developers of solar PV facilities could potentially receive a Class II production incentive from New Hampshire Renewable Portfolio Standard (RPS) valued at 16 cents/kWh, the reality is that Class II incentives or RECs are currently trading at about one-third of the maximum level. In addition, the federal tax credit generally offsets a small portion of the investment cost. Consequently, there must be other reasons to explain the Stratham and SAU 16 benefit/cost ratios presented in Table I.

Q. WHAT OTHER POSSIBLE EXPLANATIONS ARE THERE?

A. One possible explanation is the use in the TRC test of avoided energy and generation capacity costs that far exceed the energy and capacity costs reflected in the current default service rate. These differences could, of course, reflect real or imaginary differences of opinion on the future level of wholesale power market energy and capacity prices. Another possible explanation is the inclusion in the TRC test of benefits not reflected in default service prices such as the costs saved in avoiding transmission and distribution investments and the economic development spurred by DER expenditures in the local economy. We will have more to say on these issues in Section C below. But first we address an issue that has the potential to widen rather than narrow the gap between the unit cost of DERs and the cost of default service.

B. <u>Project Costs</u>

Q. PLEASE DISCUSS STAFF'S CONCERNS REGARDING THE COSTS INCLUDED IN THE TRC TEST.

A. Staff has two primary concerns. One relates to the costs associated with designing, developing and operating the DERs that have been excluded from the installed cost estimates. The exclusion of these incremental costs from the TRC test will result in an overstatement of the benefit/cost ratio for each project and potentially the approval of projects that are not in the public interest. The other concern relates to the level of the overheads claimed by UES.

(**i) Incremental Costs**

Q. WHICH COSTS DOES STAFF THINK HAVE BEEN EXCLUDED?

A. Return on rate base, income taxes, working capital, O&M expense, A&G expense, monitoring and verification expense, mobilization expense, reporting expense, and insurance expense have all been excluded.

Q. WHAT IS THE BASIS FOR THIS CLAIM?

A. The basis is twofold. First, UES used the installed cost of each project inclusive of utility overhead in its TRC test, a cost that excludes all of the costs just listed. Second, UES has stated in testimony and confirmed in discovery that it intends to seek recovery through its proposed cost recovery mechanism of all of these costs except O&M other than UES' monitoring and verification costs. O&M is the responsibility of the customer.

Q. WOULD INCORPORATING THESE COSTS HAVE A MATERIAL IMPACT ON PROJECT COST?

A. Yes. While each individual component is small in comparison to the installed cost, the aggregate amount is significant in both nominal and present value terms.

Q. WHAT IS THE SOURCE OF THE INCREMENTAL COSTS?

A. The present value estimates for Crutchfield, Stratham and SAU 16 are presented in Staff Exhibits 2, 3 and 4 respectively. The debt and equity components reflect the capital costs approved by the Commission for UES in its most recent base rate case. UES' share of the installed cost is depreciated over 13 years for ratemaking purposes and over five years for tax purposes. O&M is based on data contained in the Company's original or revised filing. The monitoring and verification estimate is based on the method used in the CORE energy efficiency programs.

Q. YOU SAID THAT THE O&M COSTS IN YOUR CALCULATION WERE BASED ON DATA PROVIDED BY THE COMPANY. DOES THE O&M COST FOR THE SAU 16 PROJECT INCLUDE FUEL FOR THE MICROTURBINE?

A. No, fuel expense was not included in this cost estimate.

Q. IS THIS APPROPRIATE?

A. Yes. Since the primary purpose of the microturbine is to replace the existing inefficient system for heating the administrative offices and the electricity produced is simply a by-product, it would be improper to include fuel expense in the TRC test.

Q. ARE THERE OTHER INCREMENTAL COSTS THAT SHOULD BE INCLUDED?

A. Yes, there are two others. The first is the interest on the portion of the bank loan that NHSEP obtained to finance the solar PV array. The second relates to the assumed useful life of 13 years, which seems short by the standards of other analyses of solar PV systems.[19] Nonetheless, UES states that solar PV panels typically carry a 20 year warranty and inverters a 10 year warranty. Solar DHW systems typically carry a 5 year warranty on pumps and heat exchanges and 10 years for solar collectors. Our concern is that after a warranty ends any post-warranty maintenance expense will add to the capital cost of the project. Estimates of these costs should be included in TRC test.

Q. IN ORDER TO CALCULATE PRESENT VALUE ESTIMATES OF THE PROJECT, STAFF UTILIZED THE 3.66% DISCOUNT RATE EMPLOYED BY THE COMPANY IN ITS ECONOMIC EVALUATION. DOES STAFF BELIEVE THAT 3.66% RATE IS APPROPRIATE?

A. No, we do not. UES justified its use of the 3.66% discount rate on the grounds that the rate was used in the Synapse 2009 report[20] and is a surrogate for a consumer's time value of capital. Staff disagrees, believing that the 3.66% discount rate significantly understates the consumers' time value of capital. A

[19] See, for example, The Market Value and Cost of Solar Photovoltaic Electricity Production, Severin Borenstein, January 2008, page 20.

[20] Avoided Energy Supply Costs in New England: 2009 Report, Synapse Energy Economics Inc., August 29, 2009.

more appropriate discount rate, in our opinion, would be UES' overall cost of capital or the interest rate paid by NHSEP on its bank loan. That notwithstanding, it is essential that the same rate be used to discount costs and benefits. Since many of the benefits in UES' evaluation derive from Synapse 2009 and it would be time consuming to recreate the analysis, we elected to conduct our analysis using the 3.66% rate. We recommend that a more appropriate rate be used in future DER filings.

(ii) Installed Cost Estimates

Q. DOES STAFF HAVE ANY CONCERNS WITH THE INSTALLED COST ESTIMATES PRESENTED BY UES?

A. Yes, we do. Despite agreeing to pay 100% of the capital cost of the Crutchfield project, UES did not require the customer to issue a formal request for proposals. Instead, the proposed contractor was selected on the advice of a third party. In addition, UES has been unable to provide documentation to support its claim that an RFP was issued to hire a contractor for the Stratham project.

Q. IS THERE EVIDENCE THAT THE INSTALLED CAPITAL COSTS COULD HAVE BEEN REDUCED THROUGH COMPETITIVE BIDDING?

A. Yes, there is. Excluding UES overhead, the installed cost of the Stratham solar PV array is $7,798/kW. This is almost identical to the $7,813/kW for the SAU 16 solar PV array based on an estimated output of 80 kW. Both, however, compare unfavorably to the $6,778/kW cost for PSNH's solar PV array which was the result of a competitive bidding process. Thus, the 15% difference indicates that lower costs could have been achieved through the use of competitive bidding. For this reason, we recommend that UES and/or the developers it partners with utilize competitive bidding to acquire the necessary equipment and materials.

(iii) Federal Tax Credits

Q. IS THERE AN ISSUE REGARDING THE AVAILABILITY OF FEDERAL TAX CREDITS?

A. Yes. In its original filing, UES stated that federal tax credits would be available for the SAU 16 projects but not the Crutchfield and Stratham projects. The Company has since revised that position and now believes that tax credits could be available for all three projects.

In the case of Crutchfield and Stratham, UES states that it intends to evaluate the tradeoff between securing federal tax credits through taking ownership of the equipment and the impact such ownership may have on the Company. Access to tax credits would lower a project's cost and improve its economics. That said, because of the uncertainty over ownership, our analysis assumes that tax credits will not be available to Crutchfield and Stratham.

As regards SAU 16, UES notes that the project is being structured such that the federal tax benefits will be available to the developer and used to offset development or operating costs. In our modeling, we assume that the tax benefits are used by NHSEP to offset O&M expense on the solar PV facility.

Q. DOES THE COMPANY'S ECONOMIC EVALUATION REFLECT THE IMPACT OF FEDERAL TAX CREDITS ON PROJECT COSTS?

A. No, UES contends that the calculations should reflect the full investment cost. We strongly disagree with this view. Accordingly, Staff recommends that this omission be rectified in future DER filings.

(iv) Overheads

Q. PLEASE ADDRESS THE LEVEL OF OVERHEADS REQUESTED BY UES IN THIS FILING.

A. Notwithstanding the Company's intention to contract out the design, development and installation of projects to experienced independent contractors, UES has proposed to add 30% to its investment in each project (totaling over $176,000[21]) "to account for estimated overhead and administrative costs that it expects to incur in the process of working with the customer on the completion of the design and installation of the project." Staff considers this overhead to be excessive particularly given that UES has no specialized expertise in the design, installation and operation of DER projects.

Q. DOES STAFF HAVE ANY SUPPORT FOR ITS VIEW THAT 30% IS EXCESSIVE?

A. Yes. In 2009, PSNH installed a 51 kW solar PV system at its headquarters in Manchester for a total cost of $356,000. Of this total, only $11,580 or 3.3% is to cover PSNH's expenses for AFUDC, overhead and labor.

Q. WHAT DOES STAFF RECOMMEND ON THIS ISSUE?

A. We recommend that UES' overhead on DER projects not exceed 3%.

Q. WHAT EFFECT DOES THE INCLUSION OF INCREMENTAL COSTS HAVE ON THE UNIT COSTS REPORTED IN TABLE II?

[21] This overhead is more than the total equity return that UES would earn on its DER investments.

A. As shown in Table III below, the addition of incremental costs inclusive of a 3% overhead makes the solar PV and solar/microturbine combination even less competitive relative to electricity purchased from UES. These data indicate that the production cost for the solar PV system is now about 6.8 times the current cost of default service whereas electricity from the solar/microturbine combination is about 1.8 times more costly.

TABLE III

Project Unit Costs
(Incl. Incremental Costs and 3% Overhd)

	Crutchfield Solar DHW	**Stratham** Solar PV	**SAU 16** Solar/Micro
Installed Cost ($)	$106,262	$409,560	$946,530
Lifetime kWh	2,468,752	672,854	5,894,200
Average Cost (cents/kWh)	4.30	60.87	16.06

(v) Capacity Factor

Q. COULD THE UNIT COSTS IN TABLE III HAVE BEEN EVEN HIGHER?

A. Yes, they could. The unit cost for a particular project is inversely proportional to the amount of electricity expected to be produced by it. Since the amount of electricity produced is a function of the project's capacity factor, the unit cost is also inversely proportional to the expected capacity. Thus, if a lower capacity factor had been assumed for, say, the Stratham solar PV array, then the amount of electricity produced would have been lower and the estimated unit cost would have been higher all other things being equal.

Q. ARE THE CLAIMED CAPACITY FACTORS SUPPORTABLE?

A. We don't believe so. The Company used capacity factors of 15.0% and 21.03% for the Stratham and SAU 16 solar PV arrays respectively. According to a report issued by Standard & Poors[22] citing the National Renewable Energy Laboratory, a typical capacity factor for solar PV facilities located in the Northeast US is 13.5%. The claimed capacity factors, however, are more representative of the expected performance for arrays located in the desert Southwest from West Texas to California, which is 19%. Thus, absent a demonstration that each project will utilize superior technology and/or experience superior solar conditions compared to the Northeastern projects in NREL database, these data indicate that the claimed capacity factors are too high by between 1.5% and 6.5%.

Q. DID THE COMPANY MAKE SUCH A DEMONSTRATION?

A. No.

C. <u>Project Benefits</u>

Q. WHICH BENEFITS ARE INCLUDED IN THE COMPANY'S ECONOMIC EVALUATION?

A. In addition to the standard benefits such as avoided energy, generation capacity and T&D capacity costs, UES claimed benefits related to local economic impacts, enhanced distribution system savings, and the fact that certain DERs qualify for RECs under the state's RPS. We address each of these benefits in turn starting with the avoided costs of generation capacity.

(i) Generation Capacity

[22] Tracking the Economics of Wholesale and Retail Solar Photovoltaic Generation, Oct 27, 2009, S&P Research.

Q. DOES STAFF HAVE ANY CONCERNS WITH UES' ESTIMATE OF THE AVOIDED COST OF GENERATION CAPACITY?

A. With three exceptions, we believe the Company's calculation is appropriate. That calculation is based on a forecast of capacity prices in the Forward Capacity Market (FCM) that begins with transition prices for the period 2010-2011 followed by an auction-based price for 2012. In 2013, the capacity price is about half the 2012 level. Thereafter, prices climb steadily for the remaining years of the project life. Based on discussions with experts in the field, Staff finds this forecast to be credible.

Q. WHAT ARE THE THREE EXCEPTIONS?

A. One is that the Company's calculation assumes incorrectly that the DERs will always be operating during the peak hour. We believe this assumption is incorrect because no DER is one hundred percent reliable. In the case of the Crutchfield project, this view is supported by the fact that the customer will retain for back-up purposes the existing electric-based DHW system. In the case of the other two projects, back-up will be provided by the UES system.

The second exception is that under the microturbine operating scenario described in the Company's filing the microturbine would not be operating during the summer peak period. The third is that the Company uses an incorrect demand reduction for the microturbine.

Q. WHAT DO THESE EXCEPTIONS MEAN FOR CALCULATING AVOIDED COST?

A. The second exception means that unless the operating scenario is changed to require the microturbine to be running on potential peak demand days, the Company would be unable to reduce its peak load and hence could not claim the avoided generation capacity benefit for SAU 16.

The second exception means that if the microturbine does run during the summer peak demand hours, the benefit will be greater than indicted. In its evaluation of the SAU 16 project, the Company assumed a peak demand reduction of only 25 kW for the microturbine instead of the full 62.5 kW capacity of that facility.

The first exception means that the avoided generation capacity cost is overstated for all three projects. Pending information on peak period reliability for DERs, Staff's analysis assumed 100% reliability. The same opinions also apply to the calculation of transmission and distribution capacity benefits.

Q. ASSUMING ALL THREE PROJECTS OPERATE DURING THE SUMMER PEAK PERIOD, IS THERE AN ADDITIONAL FCM-RELATED BENEFIT THAT THE COMPANY CAN CLAIM FOR EACH PROJECT?

A. Yes. The first benefit is the reduction in the amount of capacity needed to meet the Company's reliability obligations due to the reduction in system peak demand attributable to DERs. The second relates to the fact that under the FCM rules the owner of a DER can bid the associated load reduction into the FCM as an "On-Peak Demand Resource" and receive in return capacity payments.[23] This additional value is not reflected in the Company's TRC analysis.

[23] Because the FCM rules require a 100 kW minimum size for participation, UES would need to aggregate the DERs into a package greater than 100 kW in order to qualify for these payments. This assumes of course that the customer participation agreement provides the rights to the load reduction to UES.
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(ii) Energy

Q. DOES STAFF SUPPORT THE COMPANY'S AVOIDED ENERGY COST ESTIMATES?

A. The avoided cost of energy is based on a reference case forecast of ISO-NE wholesale market energy prices (2010-2040) split into peak and off-peak periods for the summer and winter seasons. The source of this forecast is Synapse 2009. As stated in the report, the primary driver of market energy prices is the price of natural gas. Synpase's 2009 forecast of Henry Hub natural-gas prices starts at $6.89/MMBtu in 2010 rising to $8.09/MMBtu in 2024 and appears to be based on an EIA forecast developed in early 2009. Based on current[24] NYMEX natural gas futures prices, however, the $6.89/MMBtu price for 2010 is not realistic and the Synapse forecast is likely to produce avoided energy costs that are too high by about 17%. The same futures prices also indicate that the expected prices for 2011 and 2012 are below Synpase's estimate for 2010. To account for today's lower expectations for natural gas prices, we have conservatively discounted the Company's avoided energy costs by 10% across the board.

(iii) Transmission Capacity

Q. DOES STAFF HAVE ANY CONCERNS WITH HOW THE TRANSMISSION SYSTEM AVOIDED COSTS WERE CALCULATED?

A. We have three concerns. For each project, the transmission avoided cost was calculated as the product of the transmission capacity cost in $/kW, the demand reduction in kW during the summer period, the transmission coincidence factor and the transmission loss factor. A transmission capacity cost of $12.38 per kW

[24] For December 14, 2009.

of demand reduction was used, which supposedly represents the average for New Hampshire electric utilities. This cost, however, is lower than the $8 per kW of monthly coincident demand that UES pays for outside transmission services.[25]

We recommend that the transmission avoided cost be based on the Company's actual average transmission cost of $8/kW-month plus the assumption that the demand reduction is uniform throughout the year.

As noted above, the Company also omitted to include a peak reliability factor in the calculation of the transmission avoided cost reflecting the fact that DERs are not one hundred percent reliable.

The Company also overstated the avoided transmission cost for Crutchfield by using the incorrect demand reduction for that project. The demand reduction for the project should have been 58 kW instead of 120 kW. The Company explained that 120 kW is the rating of the existing system rather than the new system and that it corrected this error in its revised filing. However, the Company omitted to correct the formula in the spreadsheet that calculates the avoided cost.

(iv) Distribution Capacity

Q. DOES STAFF HAVE ANY CONCERNS WITH THE CALCULATION OF DISTRIBUTION SYSTEM AVOIDED COSTS?

A. Yes, our concerns relate to the distribution capacity cost used to calculate distribution benefit and the size of the load reduction for the Crutchfield project.

Q. WHAT IS STAFF'S CONCERN WITH THE DISTRIBUTION CAPACITY COST?

[25] UES has no transmission of its own.

A. The Company's distribution capacity cost of $38.02/kW was taken from Synapse 2009 and supposedly represents the blended cost for New Hampshire electric utilities. It is inappropriate, however, to use a proxy cost when the actual cost is known. The actual cost is the marginal distribution capacity cost approved by the Commission for UES in its most recent base rate case. For small C&I customers taking service at the secondary level[26] this cost is $81.1/kW (2007 $). Staff's estimate of the distribution benefit for each project is based on this marginal distribution capacity cost adjusted to 2010 dollars. The estimates also reflect the use of a peak period reliability factor for each project and the correct demand reduction for the Crutchfield project.

(v) Capacity DRIPE

Q. WHAT IS CAPACITY DRIPE?

A. According to Synapse 2009, the Capacity DRIPE is the reduction in prices in the wholesale capacity market, relative to those forecast for the FCM, resulting from the reduction in need for capacity due to efficiency and/or demand response programs. Synapse 2009 goes on to contrast Capacity DRIPE, which is a measure of the value of load reduction in terms of the reduction in wholesale capacity prices seen by all retail customers in a given period, with avoided capacity costs, which is a measure the value of load reduction in terms of the reductions in the quantity of energy used by retail customers in a given period. Synapse 2009 estimated the levelized value of Capacity DRIPE over the 15 years beginning 2010 to be $1.51/kW-yr. .

[26] This includes all three customers in this proceeding.

Q. DOES STAFF SUPPORT THE INCLUSION OF CAPACITY DRIPE IN THE ECONOMIC EVALUATION OF DERs?

A. Staff has had insufficient time to review the Capacity DRIPE proposal and therefore declines to take a position on the issue at this time. For the purposes of modeling, however, we have used the claimed benefit..

(vi) Localized Distribution Capacity

Q. DOES STAFF HAVE ANY CONCERNS WITH THE INCLUSION OF A LOCALIZED DISTRIBUTION CAPACITY BENEFIT IN THE ECONOMIC ANALYSIS?

A. Yes. Staff is opposed to its inclusion on the grounds that the Company failed to demonstrate: (i) that the local loads in the areas in which the proposed projects would be located are projected to exceed wires capacity in the short or long term; and (ii) that the distribution capacity costs avoided or deferred by the projects are not already captured by the Company's marginal distribution capacity cost.[27] The marginal distribution capacity cost represents the distribution capacity cost avoided by a kW reduction in demand. Further, because the need for distribution system upgrades is extremely variable and lumpy, Staff believes that the relatively small projects proposed in this proceeding are unlikely to affect any meaningful distribution capital project under consideration by UES engineers.

Q. DOES THE COMPANY'S CLAIM THAT THE PROJECTS PRODUCE LOCALIZED DISTRIBUTION CAPACITY BENEFITS STAND UP TO SCRUTINY?

[27] The marginal cost of distribution is addressed in Section IV, 3C(iv) above.

A. No. If the benefits were truly local, the per kW distribution avoided cost would vary with the location of the project. The avoided costs developed by the Company, however, do not vary by project. This raises serious questions about the credibility of the analytical method particular given the fact that the UES system actually comprises two separate systems and that one of the proposed projects is connected to one system and the other two projects to the other system.

(vii) Energy Dripe

Q. DOES STAFF SUPPORT THE INCLUSION OF ENERGY DRIPE IN THE BENEFIT/COST ANALYSIS OF DERs?

A. Staff has had insufficient time to review the Energy DRIPE proposal and therefore declines to take a position on the issue at this time. For the purposes of modeling, however, we have used the claimed benefit discounted by 10% to reflect Staff's belief that the Company's avoided energy costs have been overstated..

(viii) CO2

Q. WHAT VALUE DID THE COMPANY PLACE ON LOWER CO2 EMISSIONS?

A. Without explanation, the Company adopted the value presented in Synapse 2009 or a constant societal cost of $80 per ton of CO2 emissions, This value compares with current prices of $2 to $3 per ton established in the Regional Greenhouse Gas Initiative (RGGI) auctions. Since the cost placed on CO2 emissions by RGGI is passed to consumers through wholesale market energy prices (i.e., it has been internalized), the market portion of the $80 per ton cost is embedded in the avoided energy costs calculated by the Company. The CO2 costs actually embedded in avoided energy costs, however, are significantly higher than current RGGI prices.[28] The embedded costs range from $3.91/ton in 2010 to $36.79/ton in 2022, all in 2009 prices, reflecting the continuation of RGGI through 2012 and a new federal regulatory framework in subsequent years. In other words, the Company's avoided energy costs already reflect lower more aggressive caps on CO2 emissions than does RGGI.

Q. HOW IS THE NON-MARKET PORTION REFLECTED IN THE COMPANY'S ECONOMIC EVALUATION?

A. The non-market portion of the $80 per ton is reflected in a proposed CO2 externality, which varies from $76.09 per ton in 2010 to $43.21 in 2022. Staff estimates the levelized value of this externality for New Hampshire utilities to be about 2.8 cents/kWh.

Q. EVEN IF THE COMPANY HAD SHOWN THAT $80/TON IS A REASONABLE ESTIMATE OF THE SOCIETAL COST OF CO2 EMISSIONS, WHICH IT DID NOT, DOES STAFF BELIEVE THAT IT WOULD BE APPROPRIATE TO INCLUDE THE FULL VALUE IN UTILITY RESOURCE DECISIONMAKING?

A. No, we do not. As noted, the cost of CO2 allowances internalized in the avoided energy costs are significantly above the price levels resulting from the RGGI auctions. In fact, from 2012 to 2015 the internalized allowance prices exceed the maximum allowable prices in RSA 125-O:19, et seq. Thus, an argument could be made that the avoided energy costs already include a sizeable CO2 externality.

[28] Actual allowance prices have been lower than originally estimated by the designers of RGGI. .

That argument notwithstanding, the proposal to include a large externality in the selection process for DERs is equivalent to arguing that the state's current policy on CO_2 emissions and the likely more stringent federal framework are flawed and should be ignored, at least as far as resource decision making is concerned. The issue, in our opinion, is not whether future CO_2 emissions will cause environmental damage in excess of the socially optimal level but whether it is appropriate for economic regulators to be making decisions that are calculated to reduce power plant emissions, particularly when the level of those emissions are currently regulated by state law and could soon be regulated by new federal law. Staff believes that it is not appropriate to do so. Electric utility customers are already supporting the costs of important social programs. To add to that cost the cost to subsidize resources that already receive financial support from federal and state governments is neither fair nor sustainable.

Staff is also concerned that the proposal to add an externality may not stop at CO_2. Because SO_2 and NO_x are also subject to market-based emissions regulations, it is conceivable that the Company could argue that the market-based allowance prices do not capture the full societal cost of those emissions and, as a result, additional externalities could be included in the selection process.

If the Commission disagrees and decides that it is appropriate to include in the DER model a second CO_2 externality, Staff recommends that the sum of the internalized and external costs not exceed at any time the CO_2 allowance price used in the non-New England state with the most stringent CO_2 emissions policy. In other words, because of the rate implications of approving uneconomic resources, we recommend that the Commission defer to any legislative policy formulation in this area..

Q. TO AVOID ANY CONFUSION, DOES STAFF SUPPORT THE CO2 COSTS EMBEDDED IN THE COMPANY'S AVOIDED ENERGY COSTS?

A. Yes, we do.

(ix) REC Credits

Q. DOES STAFF HAVE ANY COMMENTS ON THE CALCULATION OF THE REC BENEFITS IN THE COMPANY'S ANALYSIS?

A. Yes. UES assumed that because each project acts as an on-site generator, utility supplied energy would be reduced as would the number of RECs that must be purchased on the customer's behalf. The Company is mistaken, however, in assuming that a reduction in utility supplied energy caused, for example, by a solar PV array will reduce only the number of Class II RECs to be purchased. On the contrary, any load reduction, regardless of its cause, will reduce the number of RECs to be purchased for all classes. Thus, the appropriate value to use in the avoided cost analysis is the weighted average REC price. For 2010, this price is $29.31 per REC.

Q. IS THERE AN ADDITIONAL RPS-RELATED BENEFIT THAT THE COMPANY CAN CLAIM?

A. Yes. In addition to reducing the number of RECs that must be purchased, the RPS allows an owner of an eligible renewable facility to receive a payment based on the size and type of the facility. For example, the owner of a solar PV facility that produces annually 100 MWh of energy can claim each year 100 Class II

RECs. Thus, the Company's benefit/cost analysis should include a second REC benefit equal to the product of the REC market value for the facility in question and the number of RECs claimed. This additional benefit is missing from the Company's analysis of all three projects.

Q. DOES THIS SECOND BENEFIT APPLY TO ALL DERs?

A. No, only to eligible facilities pursuant to RSA 362-F. Because the SAU 16 microturbine is not an eligible facility, the Company is not able to claim this additional benefit for that technology. It is, however, able to claim it for the solar DHW system and the solar PV systems.

Q. IF THE MICROTURBINE IS NOT AN ELIGIBLE FACILITY, DID THE COMPANY CORRECTLY CALCULATE THE ORIGINAL REC BENEFIT FOR THE SAU 16 PROJECT?

A. As noted above, any load reduction, whether caused by an eligible or ineligible on-site generator, will reduce the number of RECs that a utility must purchase to meet its RPS obligations. Thus, UES correctly claimed a REC benefit for its microturbine facility.

Q. HAVE YOU RE-CALCULATED THE REC BENEFITS FOR THE THREE PROJECTS?

A. Yes, the estimated values are shown at Staff Exhibits-5, 6 and 7.

(x) Local Economic Benefit

Q. YOU NOTED ABOVE THAT THE COMPANY HAD MODIFIED THE TOTAL RESOURCE COST TEST TO INCLUDE THE ECONOMIC

BENEFITS OF EXPENDITURES DIRECTED AT LOCAL BUSINESSES. DOES STAFF SUPPORT THIS MODIFICATION?

A. No, Staff is opposed to the inclusion of this externality in the TRC test. Although the public interest standard in RSA 374-G does require consideration of the economic development benefits of DER investments to the state, there is no explicit requirement that the TRC test be altered to include the alleged local economic benefits.

Q. WHAT IS THE BASIS OF THAT OPINION?

A. The first criterion listed in RSA 374-G details the basic economic analysis that must be undertaken to determine the public interest. Specifically, it asks:

> 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.

The focus of this inquiry is not the condition of the state or the local economic community in general. Rather, it is the condition of utility ratepayers. Therefore, only costs and benefits that directly affect utility ratepayers can be included in the analysis. Since the economic development benefits of DER investments do not flow directly to customers through the ratemaking process, they should not be included in the TRC test.

Q. IN THE EVENT THE COMMISSION CONCLUDES OTHERWISE, SHOULD THE COMPANY'S ESTIMATED BENEFITS BE ADOPTED?

A. No, for several reasons. First, the Company has not demonstrated that the DER investments will actually be spent in the local community. The solar collectors and heat exchangers associated with the Crutchfield project, for example, which account for the majority of that investment, will be manufactured in China for Apricus, an Australian company. Similarly, the solar panels for the SAU 16 project were manufactured in Arizona by Kyocera, a Japanese company, and the inverter in Massachusetts. The Capstone microturbine was manufactured in California. Accordingly, a significant portion of the investments for these projects will likely leave the state if not the county. In addition, we note that the installers, KW Management and Ayer Electric, are based in Nashua and Dover respectively and therefore do not even qualify as a local businesses, as they are outside UES' service territory.

As for the Stratham project, the vendor is currently unknown. For this reason, the Company does not currently know the type of solar array that will be purchased, the name and location of the equipment supplier, and where the equipment will be manufactured. Without this information, it is simply not possible for the Company to estimate local economic benefits of the project.

The third reason is that the installation process for each project is unlikely to be longer than two months, which means that any local economic benefit that does result from these projects will be short lived.

Q. DO THE LOCAL ECONOMIC BENEFITS CLAIMED BY THE COMPANY REPRESENT A SMALL OR LARGE PORTION OF THE OVERALL BENEFITS FOR EACH PROJECT?

A. While each project is alleged to produce economic benefits that account for a relatively large portion of the total, the data do not point to a clear relationship between dollars invested and economic development. For example, the Crutchfield project is expected to produce $144,000 in benefits from an outlay of only $78,400, a return of $1.8 for every $1 spent. In contrast, the SAU 16 investment of $860,000 is expected to produce only $371,639 in benefits, a return of $0.43 for every $1 spent. This degree of variability does not instill confidence in the underlying methodology.

Q. HOW SHOULD THE COMMISION TREAT THIS BENEFIT?

A. Given the high level of uncertainty over local economic effects and the fact that the benefit does not directly impact ratepayers, we recommend that it be considered qualitatively rather than quantitatively.

Q. WHAT OVERALL CONCLUSIONS DID STAFF REACH REGARDING THE COMPANY'S ECONOMIC EVALUATION?

A. The detailed results of our analysis are presented in Staff Exhibit-8 and a summary in Table IV below. It shows that installing the solar DHW system has the potential to be economic while the economics of the solar/microturbine combination are more marginal. Installing the solar PV system, however, is clearly not economic at this time. The difference is so large that even including the full $80/ton CO 2 externality fails to close the gap between costs and benefits. Further, the comment that the solar DHW system has the "potential" to be economic is intended to remind the reader that the results presented in Staff Exhibit-9 do not take into account which customers pay the costs and which customers receive the benefits. The results of that analysis, which we refer to as the non-participant test, are discussed in the next section. Based on the strength of that analysis, we make our recommendations on whether the proposed projects should be approved or disapproved.

TABLE IV
Total Resource Cost Test

	Crutchfield Solar DHW	Stratham Solar PV	SAU 16 Solar/Microturbine
Total Benefits ($)	$455,661	$248,337	$1,136,563
Total Costs ($)	$106,262	$409,560	$946,530
Benefit/Cost Ratio	4.29	0.61	1.20

D. Allocation of Project Costs and Benefits

Q. STAFF HAS CONCLUDED THAT TWO OF THE PROPOSED PROJECTS ARE EITHER COST-EFFECTIVE OR MARGINALLY COST-EFFECTIVE BASED ON THE TRC TEST. ARE THOSE PROJECTS ALSO COST-EFFECTIVE WHEN VIEWED FROM THE PERSPECTIVE OF PARTICIPANTS AND NON-PARTICIPANTS?

A. Because most of the benefits from the proposed projects accrue directly to the participants, the two “economic” projects, Crutchfield and SAU 16, are also cost-effective from the standpoint of participants. As shown in Table V, both projects continue to be economic when viewed from the standpoint of non-participants but the net benefit are substantially smaller..

Q. STAFF’S CONCLUSION THAT THE CRUTCHFIELD AND SAU 16 PROJECTS WILL PROVIDE LOWER NET BENEFITS TO NON-PARTICIPANTS IS BASED ON THE CLAIM THAT MOST OF THE

BENEFITS ACCRUE TO PARTICIPANTS. PLEASE SUBSTANTIATE THAT CLAIM.

A. The reason has to do with the fact that UES buys power for its default service customers in the wholesale market under so-called requirements contracts at prices that reflect the supplier's expectation of market prices during the contract term. A special feature of the requirements contracts entered into by UES is that every kWh purchased in a particular month is billed at the same fixed price. That is, power is purchased under a uniform rate schedule rather than on a block basis. Therefore, if a customer of UES installed a DER in order to reduce the amount of electricity it purchases from the utility, the power supply cost avoided by UES for every kWh saved by the customer would equal the fixed price in the requirements contract. However, the reduction in the customer's bill for every kWh saved would at least equal the fixed price in the requirements contract because the contract price is fully reflected in the default service rate.[29] Consequently, none of the power supply costs avoided by UES would be retained for the benefit of other customers (i.e., non-participants). All of those savings accrue directly to the customer (i.e., participant).

Since the requirements contract price covers the cost to the supplier to procure on behalf of UES generation capacity in the FCM and energy in the wholesale energy markets, the savings that accrue to the customer include the generation capacity and energy benefits described above in C (i) and C (ii) respectively. In addition, because the customer also avoids the charges for transmission and

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[29] The per kWh bill reduction will actually be greater because the customer also avoids the kWh related charges for transmission and distribution services.

distribution, the accrued savings include the transmission capacity and distribution capacity benefits described in C (iii) and C (iv) respectively. However, because capacity DRIPE and energy DRIPE benefit all purchasers of capacity and energy, the benefits described in C (v) and C (vi) accrue to all customers.

Regarding the REC benefit discussed in C (ix), the portion that relates to the reduction in sales by UES accrues to the participant because the cost to acquire RECs is recovered through the default service rate. The portion that relates to the RPS production incentive, however, is shared among all customers.

Q. TURNING TO PROJECT COSTS, DO THEY AUTOMATICALLY FLOW TO PARTICIPANTS?

A. No, the allocation of project costs among participants and non-participants is controlled by UES through the customer contribution.

Q. HOW DOES UES PROPOSE TO SET THE LEVEL OF THE CUSTOMER CONTRIBUTION?

A. The Company states that there are several ways to make this determination. One is to look at the level of the benefits that accrue to a participant and if that level is large seek to reduce the utility investment in order to balance the net benefits between the participant and non-participants. Another is to factor in "the customer's ability/motivation to implement the project given an up-front financial threshold," which we take to mean the customer's ability to pay. Ultimately, the Company's goal is "to achieve a reasonable allocation of costs and benefits."

Q. WHAT CUSTOMER CONTRIBUTIONS HAS UES PROPOSED?

A. The Company has proposed that Crutchfield and Stratham pay all of the O&M expense and none of the capital cost. On a present value basis and assuming a 3% overhead, we estimate that this means non-participants would pay 96% of the Crutchfield cost or $102,000 and 98% of the Stratham cost or $400,000. SAU 16, however, would pay all of the O&M expense and 77% of the capital cost. Again, on a present value basis and assuming a 3% overhead, we estimate that this means non-participants would pay 22% of the SAU 16 cost or $263,000.

Q. ARE THE PROPOSED CUSTOMER CONTRIBUTIONS CONSISTENT WITH THE ABOVE GUIDELINES?

A. Any agreement that allows the customer to accrue most of the benefits but pay virtually none of the costs does not, in our estimation, "achieve a reasonable allocation of costs and benefits." In Tables V and VI we show that the allocations to Crutchfield and Stratham do not meet this standard. In fact, the allocation of costs and benefits to the latter is such that an uneconomic solar PV system is turned into beneficial venture for Stratham by having all other customers shoulder almost all of the costs.

TABLE V
Non-Participant Test

	Crutchfield Solar DHW	**Stratham** Solar PV	**SAU 16** Solar/Microturbine
Total Benefits ($)	$154,176	$75,687	$272,517
Total Costs ($)	$102,061	$399,878	$262,647
Benefit/Cost Ratio	1.51	0.19	1.04

Because the Stratham project is simply uneconomic, we see no way to improve the situation by adjusting the customer's contribution. That is not the case with the Crutchfield project. If the customer's contribution is increased to half the installed cost, the non-participant benefit/cost ratio would increase to a defensible 3.0. While the participant ratio would be reduced to 5.46, we consider this to be a good outcome for the customer. See Staff Exhibits 9 & 10. As regards SAU 16, we believe the costs and benefits are reasonably matched for both participants and non-participants and therefore do not recommend a change in the customer contribution.

TABLE VI
Participant Test

	Crutchfield Solar DHW	**Stratham** Solar PV	**SAU 16** Solar/Microturbine
Total Benefits ($)	$301,485	$172,649	$864,047
Total Costs ($)	$4,201	$9,682	$683,883
Benefit/Cost Ratio	71.76	17.83	1.26

Q. WHAT DOES STAFF RECOMMEND REGARDING THE PROPOSED PROJECTS?

A. For the reasons set forth above, Staff recommends:

1. Conditional approval of the Crutchfield project, subject to the customer agreeing to pay half of the actual installed cost.
2. Rejection of the Stratham project.

3. Conditional approval of the SAU 16 project, subject to NHSEP agreeing to operate the microturbine as a peaking unit during the summer months.

Q. FINALLY, WHAT IS STAFF'S OPINION ON WHETHER THE COMPANY ADDRESSED ALL OF THE PUBLIC INTEREST FACTORS REFERENCED IN RSA 374-G: 5?

A. Staff believes that the Company addressed either directly or indirectly all but three of the public interest factors referenced in the statute. The factors regarding energy security benefits, reliability, safety and efficiency, and competition were addressed in a cursory, conclusory way.[30] The factor regarding competition is an example. In response to discovery, the Company stated that "basic economic wisdom would support a finding that if we can add to the list of alternative solutions to traditional utility investments, then, by definition, we are enhancing the level of competition." Our concern is that the Company has not addressed the potential anti-competitive issues associated with customer-owned generation projects that depend on potentially questionable subsidies to see them through the screening process and large utility contributions to overcome the problem of financing the project. We recommend that the Company address in more detail the three issues mentioned above in its next DER filing.

[30] See filing at page 27.

GEORGE R. McCLUSKEY

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
Analyst

George McCluskey is a ratemaking specialist with over 20 years experience in utility economics. Since rejoining the New Hampshire Public Utilities Commission ("NHPUC") in 2005, he has worked on default service and standby rate issues in the electric sector and cost allocation issues in the gas sector. While at La Capra Associates, a Boston-based consulting firm specializing in electric industry restructuring, wholesale and retail power procurement, market price and risk analysis, and power systems models and planning methods, he provided strategic advice to numerous clients on a variety of issues. Prior to joining La Capra Associates, Mr. McCluskey directed the electric utility restructuring division of the NHPUC and before that was manager of least cost planning in the economics division, directing and supervising the review and implementation of electric and gas utility least cost plans and demand-side management programs. He has testified as an expert witness in numerous electric and gas cases before state and federal regulatory agencies.

ACCOMPLISHMENTS

Recent project experience includes:

Staff of the New Hampshire Public Utilities Commission – Expert testimony before NHPUC regarding default service design and pricing issues in cases involving Unitil Energy Systems.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before Maine Public Utilities Commission regarding interstate allocation of natural gas capacity costs in case involving Northern Utilities.

Staff of the Arkansas Public Service Commission – Analysis and case support regarding Entergy Arkansas Inc.'s application to transfer ownership and control of its transmission assets to a Transco. Also analyzed Entergy Arkansas Inc.'s stranded generation cost claims.

Massachusetts Technology Collaborative – Evaluated proposals by renewable resource developers to sell Renewable Energy Credits to MTC in reponse to 2003 RFP.

Pennsylvania Office of the Consumer Advocate – Analysis and case support regarding horizontal and vertical market power related issues in the PECO/Unicom merger proceeding. Also advised on cost-of-service, cost allocation and rate design issues in FERC base rate case for interstate natural gas pipeline company.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before the NHPUC regarding stranded cost issues in Restructuring Settlement Agreement submitted by Public Service Company of New Hampshire and various settling parties. Testimony presented an analysis of PSNH's stranded costs and made recommendations regarding the recoverability of such costs.

Town of Waterford, CT – Advisory and expert witness services in litigation to determine property tax assessment for nuclear power plant.

Washington Electric Cooperative, VT – Prepared report on external obsolescence in rural distribution systems in property tax case.

New Hampshire Public Utilities Commission - Expert testimony on behalf of the NHPUC before the Federal Energy Regulatory Commission regarding the Order 888 calculation of wholesale stranded costs for utilities receiving partial requirements power supply service.

Ohio Consumer Council - Expert testimony regarding the transition cost recovery requests submitted by the American Electric Power Co., including a critique of the discounted cash flow and revenues lost approaches to generation asset valuation.

EXPERIENCE

New Hampshire Public Utilities Commission (2005 to Present)
Analyst, Electric Division

La Capra Associates (1999 to 2005)
Senior Consultant

New Hampshire Public Utilities Commission (1987 – 1999)
Director, Electric Utilities Restructuring Division
Manager, Least Cost Planning

Analyst, Economics Department

Electricity Council, London, England (1977-1984)
Pricing Specialist, Commercial Department
Information Officer, Secretary's Office

EDUCATION:

Ph.D. candidate in Theoretical Plasma Physics, University of Sussex Space Physics Laboratory.
Withdrew in 1977 to accept position with the Electricity Council.

B.S., University of Sussex, England, 1975.
Theoretical Physics

Crutchfield Place
Solar Hot Water System

Assumptions

UES Investment	$80,752
Book Life	13
Capacity (kW)	58.00
Capacity Factor (%)	37.40%
Annual Production (kWh)	190,000
Property Tax Rrate (%)	0.00%
Inflation Rate (%)	1.98%
O&M Expense ($)	Variable
Fuel Expense	0.00
Monitoring & Verification (%)	2.00%
Working Capital (days)	12
Tax Rate (%)	39.61%
Discount Rate (%)	3.66%

Revenue Requirements Analysis

Year	Rate Base (BoY)	Rate Base (EoY)	Rate Base (Avg)	Return on Debt	Return on Preferred	Return on Equity	Tax Depreciation	Book Depreciation	Deferred Tax	Taxable Income	Inc Tax Payable
1	$80,752	$70,604	$75,678	$3,191	$8	$2,943	$16,150	$6,212	$3,937	($5,052)	($2,001)
2	$70,604	$56,617	$63,610	$2,559	$7	$2,360	$25,841	$6,212	$7,775	($15,710)	($6,223)
3	$56,617	$46,724	$51,671	$2,112	$6	$1,947	$15,504	$6,212	$3,681	($6,059)	($2,400)
4	$46,724	$39,288	$43,006	$1,776	$5	$1,637	$9,303	$6,212	$1,224	($372)	($147)
5	$39,288	$31,852	$35,570	$1,440	$4	$1,328	$9,303	$6,212	$1,224	($886)	($351)
6	$31,852	$26,259	$29,056	$1,187	$3	$1,094	$4,651	$6,212	($618)	$3,378	$1,338
7	$26,259	$22,507	$24,383	$1,017	$3	$938	$0	$6,212	($2,460)	$7,769	$3,077
8	$22,507	$18,756	$20,632	$848	$2	$782	$0	$6,212	($2,460)	$7,510	$2,975
9	$18,756	$15,005	$16,881	$678	$2	$625	$0	$6,212	($2,460)	$7,250	$2,872
10	$15,005	$11,254	$13,129	$509	$1	$469	$0	$6,212	($2,460)	$6,991	$2,769
11	$11,254	$7,502	$9,378	$339	$1	$313	$0	$6,212	($2,460)	$6,731	$2,666
12	$7,502	$3,751	$5,627	$170	$0	$156	$0	$6,212	($2,460)	$6,471	$2,563
13	$3,751	$0	$1,876	$0	$0	$0	$0	$6,212	($2,460)	$6,212	$2,460
				$15,825	$42	$14,592	$80,752	$80,752	$0		$9,599

Crutchfield Place
Solar Hot Water System

Property Tax	O&M	Monitoring & Verification	Working Capital	Annual Rev Req	PV Factor	PV Rev Req	PV O&M	Utility Contribution ($)	Utility Contribution (%)	Year
$0	$0	$1,514	$285	$12,151	0.964692	$11,722.32	$0			1
$0	$0	$1,272	$239	$6,426	0.930631	$5,980.25	$0			2
$0	$260	$1,033	$195	$9,365	0.897773	$8,407.31	$233			3
$0	$0	$860	$162	$10,504	0.866074	$9,097.66	$0			4
$0	$1,298	$711	$134	$10,775	0.835495	$9,002.37	$1,084			5
$0	$276	$581	$109	$10,800	0.805996	$8,705.01	$222			6
$0	$0	$488	$92	$11,827	0.777538	$9,195.73	$0			7
$0	$0	$413	$78	$11,308	0.750085	$8,482.26	$0			8
$0	$292	$338	$64	$11,083	0.723601	$8,019.32	$212			9
$0	$3,221	$263	$49	$13,493	0.698052	$9,418.67	$2,248			10
$0	$0	$188	$35	$9,753	0.673406	$6,567.99	$0			11
$0	$310	$113	$21	$9,545	0.649629	$6,200.86	$201			12
$0	$0	$38	$7	$8,717	0.626692	$5,462.70	$0			13
$0	$5,657	$7,810	$1,470	$135,747		$106,262	$4,202	$102,061	96.05%	

Stratham
Solar PV Facility

Assumptions

UES Investment	$316,389
Book Life	13
Capacity (kW)	39.39
Capacity Factor (%)	15.00%
Annual Production (kWh)	51,758
Lifetime Production (kWh)	672,854
Property Tax Rrate (%)	0.00%
Inflation Rate (%)	1.98%
O&M Expense ($/Yr)	850.00
Monitoring & Verification (%)	2.00%
Working Capital (days)	12
Tax Rate (%)	39.61%
Discount Rate (%)	3.66%

Revenue Requirements Analysis

Year	Rate Base (BoY)	Rate Base (EoY)	Rate Base (Avg)	Return on Debt	Return on Preferred	Return on Equity	Tax Depreciation	Book Depreciation	Deferred Tax	Taxable Income	Inc Tax Payable
1	$316,389	$276,627	$296,508	$12,504	$33	$11,529	$63,278	$24,338	$15,424	($19,794)	($7,840)
2	$276,627	$221,827	$249,227	$10,027	$27	$9,245	$101,245	$24,338	$30,463	($61,554)	($24,381)
3	$221,827	$183,068	$202,447	$8,275	$22	$7,630	$60,747	$24,338	$14,422	($23,738)	($9,403)
4	$183,068	$153,933	$168,500	$6,958	$18	$6,416	$36,448	$24,338	$4,797	($1,456)	($577)
5	$153,933	$124,799	$139,366	$5,641	$15	$5,201	$36,448	$24,338	$4,797	($3,473)	($1,376)
6	$124,799	$102,882	$113,840	$4,650	$12	$4,288	$18,224	$24,338	($2,422)	$13,234	$5,242
7	$102,882	$88,185	$95,534	$3,986	$11	$3,675	$0	$24,338	($9,640)	$30,441	$12,058
8	$88,185	$73,487	$80,836	$3,322	$9	$3,063	$0	$24,338	($9,640)	$29,424	$11,655
9	$73,487	$58,790	$66,139	$2,657	$7	$2,450	$0	$24,338	($9,640)	$28,407	$11,252
10	$58,790	$44,092	$51,441	$1,993	$5	$1,838	$0	$24,338	($9,640)	$27,389	$10,849
11	$44,092	$29,395	$36,744	$1,329	$4	$1,225	$0	$24,338	($9,640)	$26,372	$10,446
12	$29,395	$14,697	$22,046	$664	$2	$613	$0	$24,338	($9,640)	$25,355	$10,043
13	$14,697	$0	$7,349	$0	$0	$0	$0	$24,338	($9,640)	$24,338	$9,640
				$62,004	$165	$57,173	$316,389	$316,389	$0		$37,608

Stratham
Solar PV Facility

Property Tax	O&M	Monitoring & Verification	Working Capital	Annual Rev Req	PV Factor	PV Rev Req	PV O&M	Utility Contribution ($)	Utility Contribution (%)
$0	$850	$5,930	$1,116	$48,459	0.964692	$46,748.46	$820		
$0	$867	$4,985	$938	$26,044	0.930631	$24,237.53	$807		
$0	$884	$4,049	$762	$36,556	0.897773	$32,819.24	$794		
$0	$901	$3,370	$634	$42,058	0.866074	$36,425.71	$781		
$0	$919	$2,787	$525	$38,051	0.835495	$31,791.04	$768		
$0	$938	$2,277	$429	$42,173	0.805996	$33,991.42	$756		
$0	$956	$1,911	$360	$47,294	0.777538	$36,772.62	$743		
$0	$975	$1,617	$304	$45,282	0.750085	$33,965.14	$731		
$0	$994	$1,323	$249	$43,270	0.723601	$31,310.35	$720		
$0	$1,014	$1,029	$194	$41,259	0.698052	$28,800.95	$708		
$0	$1,034	$735	$138	$39,248	0.673406	$26,429.98	$696		
$0	$1,055	$441	$83	$37,238	0.649629	$24,190.80	$685		
$0	$1,075	$147	$28	$35,228	0.626692	$22,077.04	$674		
$0	$12,463	$30,600	$5,759	$522,161		$409,560	$9,682	$399,878	97.64%

SAU-16
Solar PV Array

Assumptions

Bank Loan	$500,000
Bank Loan Term	10
Interest Rate	7%
UES Investment	$128,750
Book Life	13
Capacity (kW)	80.00
Capacity Factor (%)	21.03%
Annual Production (kWh)	147,400
Property Tax Rrate (%)	0.00%
Inflation Rate (%)	1.98%
O&M Expense Factor ($/kW-Yr)	$10,400
Monitoring & Verification (%)	2.00%
Working Capital (days)	12
Tax Rate (%)	39.61%
Discount Rate (%)	3.66%

Revenue Requirements Analysis

Year	Rate Base (BoY)	Rate Base (EoY)	Rate Base (Avg)	Return on Debt	Return on Preferred	Return on Equity	Tax Depreciation	Book Depreciation	Deferred Tax	Taxable Income
1	$128,750	$112,569	$120,660	$5,088	$14	$4,692	$25,750	$9,904	$6,277	($8,055)
2	$112,569	$90,269	$101,419	$4,080	$11	$3,762	$41,200	$9,904	$12,396	($25,048)
3	$90,269	$74,497	$82,383	$3,367	$9	$3,105	$24,720	$9,904	$5,869	($9,660)
4	$74,497	$62,641	$68,569	$2,831	$8	$2,611	$14,832	$9,904	$1,952	($593)
5	$62,641	$50,785	$56,713	$2,295	$6	$2,117	$14,832	$9,904	$1,952	($1,413)
6	$50,785	$41,867	$46,326	$1,892	$5	$1,745	$7,416	$9,904	($985)	$5,386
7	$41,867	$35,886	$38,876	$1,622	$4	$1,496	$0	$9,904	($3,923)	$12,388
8	$35,886	$29,905	$32,895	$1,352	$4	$1,246	$0	$9,904	($3,923)	$11,974
9	$29,905	$23,924	$26,914	$1,081	$3	$997	$0	$9,904	($3,923)	$11,560
10	$23,924	$17,943	$20,933	$811	$2	$748	$0	$9,904	($3,923)	$11,146
11	$17,943	$11,962	$14,952	$541	$1	$499	$0	$9,904	($3,923)	$10,732
12	$11,962	$5,981	$8,971	$270	$1	$249	$0	$9,904	($3,923)	$10,318
13	$5,981	$0	$2,990	$0	$0	$0	$0	$9,904	($3,923)	$9,904
				$25,232	$67	$23,266	$128,750	$128,750	$0	

SAU-16
Solar PV Array

Inc Tax Payable	Property Tax	O&M	Monitoring & Verification	Working Capital	Annual Rev Req	Bank Loan Balance (BOY)	Bank Loan Balance (EOY)	Bank Loan Balance (AVG)	Bank Loan Repayment
($3,191)	$0	$10,400	$2,413	$454	$29,774	$500,000	$450,000	$475,000	$50,000
($9,922)	$0	$10,606	$2,028	$382	$20,851	$450,000	$400,000	$425,000	$50,000
($3,826)	$0	$10,816	$1,648	$310	$25,332	$400,000	$350,000	$375,000	$50,000
($235)	$0	$11,030	$1,371	$258	$27,778	$350,000	$300,000	$325,000	$50,000
($560)	$0	$11,248	$1,134	$213	$26,358	$300,000	$250,000	$275,000	$50,000
$2,133	$0	$11,471	$927	$174	$28,251	$250,000	$200,000	$225,000	$50,000
$4,907	$0	$11,698	$778	$146	$30,555	$200,000	$150,000	$175,000	$50,000
$4,743	$0	$11,930	$658	$124	$29,960	$150,000	$100,000	$125,000	$50,000
$4,579	$0	$12,166	$538	$101	$29,370	$100,000	$50,000	$75,000	$50,000
$4,415	$0	$12,407	$419	$79	$28,784	$50,000	$0	$25,000	$50,000
$4,251	$0	$12,653	$299	$56	$28,203	$0	$0	$0	$0
$4,087	$0	$12,903	$179	$34	$27,627	$0	$0	$0	$0
$3,923	$0	$13,159	$60	$11	$27,057	$0	$0	$0	$0
$15,304	$0	$152,488	$12,452	$2,344	$359,902				$500,000

SAU-16
Solar PV Array

Interest on Avg Balance	Total Cost of Loan	Total Cost	PV Factor	PV of Total Cost	PV Rev Req-O&M	Utility Contribution ($)	Utility Contribution (%)	Year
$33,250	$83,250	$113,024	0.964692	$109,033	$18,690			1
$29,750	$79,750	$100,601	0.930631	$93,623	$9,535			2
$26,250	$76,250	$101,582	0.897773	$91,198	$13,032			3
$22,750	$72,750	$100,528	0.866074	$87,065	$14,505			4
$19,250	$69,250	$95,608	0.835495	$79,880	$12,624			5
$15,750	$65,750	$94,001	0.805996	$75,765	$13,525			6
$12,250	$62,250	$92,805	0.777538	$72,159	$14,662			7
$8,750	$58,750	$88,710	0.750085	$66,540	$13,524			8
$5,250	$55,250	$84,620	0.723601	$61,231	$12,448			9
$1,750	$51,750	$80,534	0.698052	$56,217	$11,432			10
$0	$0	$28,203	0.673406	$18,992	$10,472			11
$0	$0	$27,627	0.649629	$17,948	$9,565			12
$0	$0	$27,057	0.626692	$16,956	$8,710			13
$175,000	$675,000	$1,034,902		$846,607	$162,724	$162,724	19.22%	

SAU 16
Microturbine

Assumptions

Bank Loan	$150,000
Bank Loan Term	5
Interest Rate	6.58%
UES Investment	$77,250
Book Life	13
Capacity (kW)	62.50
Capacity Factor (%)	55.89%
Annual Production (kWh)	306,000
Property Tax Rrate (%)	0.00%
Inflation Rate (%)	1.98%
O&M Expense	$8,400
Fuel Consumption (therms)	0.00
Monitoring & Verification (%)	2.00%
Working Capital (days)	12
Tax Rate (%)	39.61%
Discount Rate (%)	3.66%

Revenue Requirements Analysis

Year	Rate Base (BoY)	Rate Base (EoY)	Rate Base (Avg)	Return on Debt	Return on Preferred	Return on Equity	Tax Depreciation	Book Depreciation	Deferred Tax	Taxable Income
1	$77,250	$67,542	$72,396	$3,053	$8	$2,815	$15,450	$5,942	$3,766	($4,833)
2	$67,542	$54,162	$60,852	$2,448	$6	$2,257	$24,720	$5,942	$7,438	($15,029)
3	$54,162	$44,698	$49,430	$2,020	$5	$1,863	$14,832	$5,942	$3,521	($5,796)
4	$44,698	$37,584	$41,141	$1,699	$5	$1,566	$8,899	$5,942	$1,171	($356)
5	$37,584	$30,471	$34,028	$1,377	$4	$1,270	$8,899	$5,942	$1,171	($848)
6	$30,471	$25,120	$27,795	$1,135	$3	$1,047	$4,450	$5,942	($591)	$3,231
7	$25,120	$21,531	$23,326	$973	$3	$897	$0	$5,942	($2,354)	$7,433
8	$21,531	$17,943	$19,737	$811	$2	$748	$0	$5,942	($2,354)	$7,184
9	$17,943	$14,354	$16,149	$649	$2	$598	$0	$5,942	($2,354)	$6,936
10	$14,354	$10,766	$12,560	$487	$1	$449	$0	$5,942	($2,354)	$6,687
11	$10,766	$7,177	$8,971	$324	$1	$299	$0	$5,942	($2,354)	$6,439
12	$7,177	$3,589	$5,383	$162	$0	$150	$0	$5,942	($2,354)	$6,191
13	$3,589	$0	$1,794	$0	$0	$0	$0	$5,942	($2,354)	$5,942
				$15,139	$40	$13,959	$77,250	$77,250	$0	

SAU 16
Microturbine

Inc Tax Payable	Property Tax	O&M	Monitoring & Verification	Working Capital	Annual Rev Req	Bank Loan Balance (BOY)	Bank Loan Balance (EOY)	Bank Loan Balance (AVG)
($1,914)	$0	$8,400	$1,448	$273	$20,024	$150,000	$120,000	$135,000
($5,953)	$0	$8,566	$1,217	$229	$14,714	$120,000	$90,000	$105,000
($2,296)	$0	$8,736	$989	$186	$17,446	$90,000	$60,000	$75,000
($141)	$0	$8,909	$823	$155	$18,958	$60,000	$30,000	$45,000
($336)	$0	$9,085	$681	$128	$18,151	$30,000	$0	$15,000
$1,280	$0	$9,265	$556	$105	$19,333	$0		
$2,944	$0	$9,449	$467	$88	$20,762			
$2,846	$0	$9,636	$395	$74	$20,454			
$2,747	$0	$9,827	$323	$61	$20,149			
$2,649	$0	$10,021	$251	$47	$19,847			
$2,551	$0	$10,219	$179	$34	$19,550			
$2,452	$0	$10,422	$108	$20	$19,256			
$2,354	$0	$10,628	$36	$7	$18,967			
$9,182	$0	$123,163	$7,471	$1,406	$247,612			

SAU 16
Microturbine

Bank Loan Repayment	Interest on Avg Balance	Total Cost of Loan	Total Cost	PV Factor	PV Total Cost	PV Rev Req-O&M	Utility Contribution ($)	Utility Contribution (%)
$30,000	$8,883	$38,883	$58,907	0.964692	$56,827.50	$11,214		
$30,000	$6,909	$36,909	$51,623	0.930631	$48,041.65	$5,721		
$30,000	$4,935	$34,935	$52,381	0.897773	$47,025.99	$7,819		
$30,000	$2,961	$32,961	$51,919	0.866074	$44,965.57	$8,703		
$30,000	$987	$30,987	$49,138	0.835495	$41,054.81	$7,575		
			$19,333	0.805996	$15,582.59	$8,115		
			$20,762	0.777538	$16,143.61	$8,797		
			$20,454	0.750085	$15,342.01	$8,114		
			$20,149	0.723601	$14,579.57	$7,469		
			$19,847	0.698052	$13,854.48	$6,859		
			$19,550	0.673406	$13,165.01	$6,283		
			$19,256	0.649629	$12,509.51	$5,739		
			$18,967	0.626692	$11,886.40	$5,226		
$150,000	$24,675	$174,675	$422,287		$350,979	$97,635	$97,635	27.82%

STAFF EXHIBIT-5

Crutchfield Place
REC Calculation

1st Benefit

		ACP	Adj Factor 0.812587	Demand Reduction	REC Cost	Discounted Cost (Discount Rate 0.0366)
1	2009	na	na	na	na	na
2	2010	$36.07	$29.31	189.90	$5,566	$ 5,370
3	2011	$37.51	$30.48	189.90	$5,788	$ 5,387
4	2012	$39.00	$31.69	189.90	$6,019	$ 5,404
5	2013	$40.56	$32.96	189.90	$6,259	$ 5,421
6	2014	$42.18	$34.27	189.90	$6,509	$ 5,438
7	2015	$43.86	$35.64	189.90	$6,768	$ 5,455
8	2016	$45.61	$37.06	189.90	$7,038	$ 5,473
9	2017	$47.43	$38.54	189.90	$7,319	$ 5,490
10	2018	$49.32	$40.08	189.90	$7,611	$ 5,507
11	2019	$51.29	$41.68	189.90	$7,915	$ 5,525
12	2020	$53.34	$43.34	189.90	$8,230	$ 5,542
13	2021	$55.46	$45.07	189.90	$8,559	$ 5,560
14	2022	$57.67	$46.87	189.90	$8,900	$ 5,578
					NPV	$ 71,148

2nd Benefit

Annual Esc. 1.039888 189.90 Discount Rate 0.0366

		ACP	Adj Factor 0.5027624	Demand Reduction	REC Cost	Discounted Cost
1	2009	$60.92	na	189.90	na	na
2	2010	$63.35	$31.85	189.90	$6,048	$ 5,835
3	2011	$65.88	$33.12	189.90	$6,290	$ 5,853
4	2012	$68.50	$34.44	189.90	$6,541	$ 5,872
5	2013	$71.24	$35.82	189.90	$6,801	$ 5,891
6	2014	$74.08	$37.24	189.90	$7,073	$ 5,909
7	2015	$77.03	$38.73	189.90	$7,355	$ 5,928
8	2016	$80.11	$40.27	189.90	$7,648	$ 5,947
9	2017	$83.30	$41.88	189.90	$7,953	$ 5,966
10	2018	$86.62	$43.55	189.90	$8,271	$ 5,985
11	2019	$90.08	$45.29	189.90	$8,601	$ 6,004
12	2020	$93.67	$47.10	189.90	$8,944	$ 6,023
13	2021	$97.41	$48.97	189.90	$9,300	$ 6,042
14	2022	$101.29	$50.93	189.90	$9,671	$ 6,061
					NPV	$ 77,314

STAFF EXHIBIT-6

Stratham
REC Calculation

1st Benefit

		ACP	Adj Factor	Demand	REC	Discounted
						Discount Rate
						0.0366
			0.8125866	Reduction	Cost	Cost
1	2009	na	na	na	na	na
2	2010	$36.07	$29.31	64.70	$1,896	$ 1,829
3	2011	$37.51	$30.48	64.70	$1,972	$ 1,835
4	2012	$39.00	$31.69	64.70	$2,051	$ 1,841
5	2013	$40.56	$32.96	64.70	$2,132	$ 1,847
6	2014	$42.18	$34.27	64.70	$2,217	$ 1,853
7	2015	$43.86	$35.64	64.70	$2,306	$ 1,858
8	2016	$45.61	$37.06	64.70	$2,398	$ 1,864
9	2017	$47.43	$38.54	64.70	$2,493	$ 1,870
10	2018	$49.32	$40.08	64.70	$2,593	$ 1,876
11	2019	$51.29	$41.67	64.70	$2,696	$ 1,882
12	2020	$53.33	$43.34	64.70	$2,804	$ 1,888
13	2021	$55.46	$45.06	64.70	$2,916	$ 1,894
14	2022	$57.67	$46.86	64.70	$3,032	$ 1,900
					NPV	$ 24,238

2nd Benefit

		ACP	Adj Factor	Demand	REC	Discounted
		Annual Esc.				Discount Rate
		1.03988		64.698		0.0366
			0.27049772	Reduction	Cost	Cost
1	2009	$159.98	na	64.70	na	na
2	2010	$166.36	$45.00	64.70	$2,911	$ 2,809
3	2011	$172.99	$46.79	64.70	$3,028	$ 2,818
4	2012	$179.89	$48.66	64.70	$3,148	$ 2,826
5	2013	$187.07	$50.60	64.70	$3,274	$ 2,835
6	2014	$194.53	$52.62	64.70	$3,404	$ 2,844
7	2015	$202.29	$54.72	64.70	$3,540	$ 2,853
8	2016	$210.35	$56.90	64.70	$3,681	$ 2,862
9	2017	$218.74	$59.17	64.70	$3,828	$ 2,871
10	2018	$227.47	$61.53	64.70	$3,981	$ 2,881
11	2019	$236.54	$63.98	64.70	$4,140	$ 2,890
12	2020	$245.97	$66.53	64.70	$4,305	$ 2,899
13	2021	$255.78	$69.19	64.70	$4,476	$ 2,908
14	2022	$265.98	$71.95	64.70	$4,655	$ 2,917
					NPV	$ 37,213

STAFF EXHIBIT-7

SAU 16
REC Calculation

1st Benefit
Solar PV

Discount Rate 0.0366

		ACP	Adj Factor 0.812587	Demand Reduction	REC Cost	Discounted Cost
1	2009	na	na	na	na	na
2	2010	$36.07	$29.31	142.99	$4,191	$ 4,043
3	2011	$37.51	$30.48	142.99	$4,358	$ 4,056
4	2012	$39.00	$31.69	142.99	$4,532	$ 4,069
5	2013	$40.56	$32.96	142.99	$4,713	$ 4,081
6	2014	$42.18	$34.27	142.99	$4,901	$ 4,094
7	2015	$43.86	$35.64	142.99	$5,096	$ 4,107
8	2016	$45.61	$37.06	142.99	$5,299	$ 4,120
9	2017	$47.43	$38.54	142.99	$5,511	$ 4,133
10	2018	$49.32	$40.08	142.99	$5,730	$ 4,146
11	2019	$51.29	$41.67	142.99	$5,959	$ 4,160
12	2020	$53.33	$43.34	142.99	$6,196	$ 4,173
13	2021	$55.46	$45.06	142.99	$6,444	$ 4,186
14	2022	$57.67	$46.86	142.99	$6,701	$ 4,199
					NPV	$ 53,568

2nd Benefit
Solar PV

Annual Esc. 1.03988 | 142.987 | Discount Rate 0.0366

		ACP	Adj Factor 0.2704977	Demand Reduction	REC Cost	Discounted Cost
1	2009	$159.98	na	142.99	na	na
2	2010	$166.36	$45.00	142.99	$6,434	$ 6,207
3	2011	$172.99	$46.79	142.99	$6,691	$ 6,227
4	2012	$179.89	$48.66	142.99	$6,958	$ 6,247
5	2013	$187.07	$50.60	142.99	$7,235	$ 6,266
6	2014	$194.53	$52.62	142.99	$7,524	$ 6,286
7	2015	$202.29	$54.72	142.99	$7,824	$ 6,306
8	2016	$210.35	$56.90	142.99	$8,136	$ 6,326
9	2017	$218.74	$59.17	142.99	$8,460	$ 6,346
10	2018	$227.47	$61.53	142.99	$8,798	$ 6,366
11	2019	$236.54	$63.98	142.99	$9,149	$ 6,386
12	2020	$245.97	$66.53	142.99	$9,514	$ 6,406
13	2021	$255.78	$69.19	142.99	$9,893	$ 6,427
14	2022	$265.98	$71.95	142.99	$10,287	$ 6,447
					NPV	$ 82,244

SAU 16
REC Calculation

1st Benefit
Microturbine

Annual Esc. 0.8125866 | 306 | Discount Rate 0.0366

		ACP	Adj Factor	Demand Reduction	REC Cost	Discounted Cost
1	2009	na	na	na	na	na
2	2010	$36.07	$29.31	306.00	$8,969	$ 8,652
3	2011	$36.09	$29.32	306.00	$8,973	$ 8,351
4	2012	$36.11	$29.34	306.00	$8,978	$ 8,060
5	2013	$36.12	$29.35	306.00	$8,982	$ 7,779
6	2014	$36.14	$29.37	306.00	$8,987	$ 7,508
7	2015	$36.16	$29.38	306.00	$8,991	$ 7,247
8	2016	$36.18	$29.40	306.00	$8,996	$ 6,994
9	2017	$36.20	$29.41	306.00	$9,000	$ 6,751
10	2018	$36.21	$29.43	306.00	$9,005	$ 6,516
11	2019	$36.23	$29.44	306.00	$9,009	$ 6,289
12	2020	$36.25	$29.46	306.00	$9,013	$ 6,070
13	2021	$36.27	$29.47	306.00	$9,018	$ 5,858
14	2022	$36.29	$29.48	306.00	$9,022	$ 5,654
					NPV	$ 91,730

STAFF EXHIBIT-8

Total Resource Cost Test

	Crutchfield Solar DHW	Stratham Solar PV	SAU 16 Solar/Micro
Capacity			
Generation	$20,242	$28,846	$104,329
Transmission	$28,913	$41,203	$149,019
Distribution	$28,760	$40,985	$148,233
DRIPE	$9,762	$6,677	$24,150
Localized Distribution	$0	$0	$0
Total Capacity	$87,677	$117,711	$425,732
Energy			
Winter			
Peak	$85,128	$15,081	$197,935
Off Peak	$28,184	$19,684	$134,329
Summer			
Peak	$37,050	$7,814	$27,896
Off Peak	$12,181	$9,222	$9,171
Total Energy	$162,542	$51,800	$369,332
Other			
Energy DRIPE	$56,979	$17,374	$113,958
CO_2	$0	$0	$0
REC Value	$148,463	$61,452	$227,542
Total Other	$205,442	$78,825	$341,500
Local Economic Dev	$0	$0	$0
Total Benefits	$455,661	$248,337	$1,136,563
Total Costs	$106,262	$409,560	$946,530
Benefit/Cost Ratio	4.29	0.61	1.20

STAFF EXHIBIT-9

Non-Particpant Test

	Crutchfield Solar DHW	Stratham Solar PV	SAU 16 Solar/Micro
Capacity			
Generation	$10,121	$14,423	$52,165
Transmission	$0	$0	$0
Distribution	$0	$0	$0
DRIPE	$9,762	$6,677	$24,150
Localized Distribution	$0	$0	$0
Total Capacity	$19,883	$21,100	$76,315
Energy			
Winter			
Peak	$0	$0	$0
Off Peak	$0	$0	$0
Summer			
Peak	$0	$0	$0
Off Peak	$0	$0	$0
Total Energy	$0	$0	$0
Other			
Energy DRIPE	$56,979	$17,374	$113,958
CO2	$0	$0	$0
REC Value	$77,314	$37,213	$82,244
Total Other	$134,293	$54,587	$196,202
Local Economic Dev	$0	$0	$0
Total Benefits	$154,176	$75,687	$272,517
Total Costs	$51,030	$399,878	$262,647
Benefit/Cost Ratio	3.02	0.19	1.04

STAFF EXHIBIT-10

Participant Test

	Crutchfield Solar DHW	Stratham Solar PV	SAU 16 Solar/Micro
Capacity			
Generation	$10,121	$14,423	$52,165
Transmission	$28,913	$41,203	$149,019
Distribution	$28,760	$40,985	$148,233
DRIPE	$0	$0	$0
Localized Distribution	$0	$0	$0
Total Capacity	$67,794	$96,611	$349,417
Energy			
Winter			
Peak	$85,128	$15,081	$197,935
Off Peak	$28,184	$19,684	$134,329
Summer			
Peak	$37,050	$7,814	$27,896
Off Peak	$12,181	$9,222	$9,171
Total Energy	$162,542	$51,800	$369,332
Other			
Energy DRIPE	$0	$0	$0
CO2	$0	$0	$0
REC Value	$71,148	$24,238	$145,298
Total Other	$71,148	$24,238	$145,298
Local Economic Dev	$0	$0	$0
Total Benefits	$301,485	$172,649	$864,047
Total Costs	$55,232	$9,682	$683,883
Benefit/Cost Ratio	5.46	17.83	1.26