**THE STATE OF NEW HAMPSHIRE**
**PUBLIC UTILITIES COMMISSION**

**DE 09-137**

**UNITIL ENERGY SYSTEMS, INC.**

**Petition For Approval Of Investment In And Rate Recovery Of Distributed Energy Resources**

**Order Approving in Part and Denying in Part**

**O R D E R N O. 25,111**

**June 11, 2010**

**APPEARANCES**: Gary M. Epler, Esq., on behalf of Unitil Energy Systems, Inc.; Clayton Mitchell, Esq., on behalf of Revolution Energy d/b/a N.H. Seacoast Energy Partnership; Russell Aney on behalf of U.S. Energy Savers, LLC; Eric Steltzer on behalf of the N.H. Office of Energy and Planning, the Office of Consumer Advocate by Meredith A. Hatfield, Esq., on behalf of residential ratepayers; and Suzanne G. Amidon, Esq., on behalf of Staff.

## I. PROCEDURAL BACKGROUND

On August 5, 2009, Unitil Energy Systems, Inc. (UES or Company) filed a proposal to invest in distributed energy resources (DERs) as authorized under RSA 374-G. With its petition, UES filed the supporting testimony and schedules of George R. Gantz, Senior Vice President of Distributed Energy Resources for Unitil Service Corp. (USC); Howard J. Axelrod, President of Energy Strategies, Inc., a consultant for UES; Cindy L. Carroll, Director of Customer Field Services for USC; and Justin C. Eisfeller, Director of Energy Measurement and Control at USC. USC is the service company for the Unitil affiliates, including UES.

UES' filing comprises a two-stage regulatory review process, a cost recovery methodology and a screening model for evaluating the cost effectiveness of proposed DER projects. In addition, the filing requested approval of specific DER projects: a solar water heating system at Crutchfield Place in Concord (Crutchfield Place); a solar photovoltaic (PV) facility at the Stratham Fire House (Stratham); a solar PV and micro-turbine combination for the Exeter School Administrative Unit (Exeter); and a time-of-use (TOU) pilot program to be conducted in New Hampshire and Massachusetts.

On August 19, 2009, the Office of Consumer Advocate (OCA) filed a letter stating it would be participating in this docket on behalf of residential ratepayers pursuant to RSA 363:28. The Commission issued Order No. 25,010 (September 4, 2009) suspending the proposed tariff and scheduling a prehearing conference on September 18, 2009, followed by a technical session on September 22, 2009.

Revolution Energy LLC d/b/a N.H. Seacoast Energy Partnership (Revolution Energy) filed a petition for intervention on September 15, 2009, which the Commission granted at the pre-hearing conference. The New Hampshire Office of Energy and Planning (OEP) filed a petition to intervene on September 23, 2009, which the Commission granted in a secretarial letter dated October 13, 2009.

On September 24, 2009, Commission Staff filed a report of the technical session held on September 22, 2009, and recommended a procedural schedule that accelerated the review of the TOU pilot project. The Commission approved the separate scheduling for the TOU project. On February 26, 2010, the Commission issued Order No. 25,079 approving a settlement agreement for the TOU pilot program.[1]

[1] For the full procedural history of the TOU pilot program, see Order No. 25,079 (February 26, 2010). Order No. 25,079 also addressed Public Service Company of New Hampshire's late filed motion for intervention filed on November 24, 2009.

Regarding the remaining three projects, Crutchfield Place, Stratham and Exeter, Staff proposed a procedural schedule on October 19, 2009, which the Commission approved in a secretarial letter dated October 22, 2009. On December 3, 2009, the Commission issued Order No. 25,049, which further suspended UES' proposed tariff to allow for the full investigation of the filing. Discovery, including nine sets of data requests and several technical sessions, ensued over the next three months.

On December 18, 2009, UES filed an electronic copy of the Synapse Energy Economics Inc.'s, Avoided Energy Supply Costs in New England: 2009 Report (AESC), and revised versions of the following documents based on Mr. Axelrod's changes to assumptions contained in the original model used by UES to develop costs and benefits associated with DER projects: CLC-2, Summary Screening Report (Crutchfield Place); CLC-3, Summary Screening Report (Stratham); CLC-6, Summary Screening Report (Exeter); and an Excel work book for each project depicting the calculation of costs and benefits.

Staff filed the testimony of George R. McCluskey on December 23, 2009. UES filed the rebuttal testimony of George Gantz and Thomas Palma, Manager of Distributed Energy Resources, Planning and Design for USC, on January 29, 2010. The testimony included a restructured Stratham project with a revised economic evaluation. The Company filed a second revision to the economic evaluation on February 11, 2010.

Public comment was received February 24, 2010 from Caroline and Buck Robinson and on March 2, 2010 from Matthew O'Keefe regarding the merits of the proposed Stratham solar PV installation. On February 25, 2010, Staff filed its economic evaluation of the restructured Stratham project presented by UES in its January 29 and February 11 filings.

On March 2, 2010, the day of the hearing, the Commission received public comment from Caroline Robinson and David Canada regarding the Stratham project. Also on March 2, 2010, the Commission received a late-filed motion for intervention by U.S. Energy Savers, LLC (USES). The Commission granted the motion at the hearing. On March 12, 2010, the Commission received written closing statements from Staff, OEP, and the OCA. USES filed its closing statement on March 15, 2010, and UES on March 16, 2010.

In response to a record request made at hearing, Staff filed an updated economic evaluation of the Stratham and Exeter projects together with associated spreadsheets on March 9, 2010. UES filed its updated economic evaluation of the Stratham and Exeter projects on March 16, 2010.

## II. POSITIONS OF THE PARTIES

### A. Unitil Energy Systems, Inc.

#### 1. Original Filing

UES petitioned the Commission for approval of a two-stage regulatory review process for DER investments. In stage one, the Commission would determine whether UES' proposed DER projects are in the public interest using the statutory criteria of RSA 374-G. Stage two would include a filing by the Company for the recovery of DER costs and expenses related to DER projects authorized in stage one. Under UES' cost recovery proposal, the DER costs and expenses would be recovered through a fully reconciling distribution charge, which it referred to as the DER Investment Charge (DERIC). The charge, the calculation of which was set forth in Schedule DERIC to the Company's proposed Tariff, would be established annually based on a forecast of recoverable costs. The charge would also include a full reconciliation with interest of any over- or under-recoveries occurring in the prior year. As proposed by UES, recoverable costs consist of the annual revenue requirement associated with proposed investments including the return of and on the investment plus related income taxes. The annual revenue requirement would also include: working capital, operation and maintenance (O&M) costs, mobilization expenses, monitoring, verification and reporting costs and lost revenues. According to UES' proposal, each year an estimate of the revenue requirement relating to investments the Company planned to make in the coming year would be filed. UES proposed that the DERIC be billed to all customers taking delivery service.

To calculate the return on investment, UES proposed to use the capital structure and debt costs for the previous year, as reported in NHPUC Form F-1- Supplemental Quarterly Financial and Sales Information. The return on equity would be the rate approved by the Commission in UES' most recent base rate case. In addition to the above referenced recoverable costs, UES proposed to recover costs billed by its consultant related to the initial development and start-up of DER projects as well as costs for "ongoing program management and reporting." According to the Company, these costs are incremental, directly attributable to DER projects and of an ongoing nature, and, therefore, appropriate for inclusion in the rate recovery mechanism.

Regarding the economic evaluation of potential DER projects, the Company testified that it developed a screening model that employs the Total Resource Cost (TRC) test as the primary determinant of cost-effectiveness. Unlike the participant and non-participant tests, which the Company also conducts, the TRC test evaluates overall cost-effectiveness from the perspective of all utility customers. The participant and non-participant tests, in contrast, evaluate cost-effectiveness from the perspective of participating and non-participating customers respectively.

The Company said most of the inputs for its screening model stem from a study conducted by Synapse[2] for New England utilities on the benefits of energy efficiency programs. Nonetheless, UES included several benefits in its screening model that New Hampshire's utilities chose to exclude when evaluating CORE energy efficiency programs.[3] These include the above-market value of reductions in carbon dioxide (CO2) emissions, the energy-related demand reduction induced price effect (Energy DRIPE)[4], the capacity-related demand reduction induced price effect (Capacity DRIPE), estimated economic development benefits of DER investments, and distribution system savings attributable to the strategic location of DER investments.

To determine economic development benefits, the Company used the federal Bureau of Economic Analysis' Regional Input/Output Modeling System (RIMS II) for Rockingham and Merrimack Counties, the counties where the proposed DER projects are to be located. RIMS II is used to predict the flow of money from a particular project, along with who receives the money and how it will be spent in the community.

In its original filing, UES excluded the impact of federal tax credits on the Crutchfield Place and Stratham projects because such credits are not available to municipally-owned projects. UES also excluded the impact of federal tax credits on the cost of the Exeter project even though that project is eligible for such credits.

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[2] Synapse Energy Economics, Inc. conducted the study "Avoided Energy Supply Costs in New England: 2007 Final Report" for the New England Avoided-Energy Supply Component Study Group. The study was updated in 2010 with the publication of the 2009 report.
[3] Order No. 25,062 *CORE Energy Efficiency Programs for 2010* (January 5, 2010).
[4] DRIPE values represent reductions in prices for energy or capacity attributable to demand reductions resulting from efficiency or demand response programs.

UES described the three DER projects and their economic evaluation as follows. The solar water heating system proposed for Crutchfield Place, a low-income multifamily property owned by the Concord Housing Authority, would replace an electric heating element contained within a 1500-gallon water storage tank. The new system would include storage tanks and Apricus solar collectors. UES claimed that the Apricus solar water heating system would provide all of the building's hot water needs from April through November each year and sixty percent from December through March. The existing gas heater would be retained to supplement and back up the solar water heating system. UES calculated that the project would have a benefit/cost ratio of 5.95 based on the TRC test and 2.14 based on the non-participant test. UES considered the non-participant test to be important because it had proposed to finance 100% of the installed cost of the project and collect the associated costs from all customers. The participating customer, the Concord Housing Authority, would be responsible for only O&M expenses.

The proposed Stratham project would consist of 202 solar PV panels installed on the roof of the Stratham Fire House. According to UES, this 39 kW installation would produce electricity year round and meet most of the Fire House load. UES calculated that the project would have a benefit/cost ratio of 1.28 based on the TRC test and 0.87 based on the non-participant test. Although the solar PV system would be located on the customer-side of the meter and be owned by the Town of Stratham, 100% of the installed cost would be financed by UES and collected from all customers. As with the Crutchfield Place project, Stratham would be responsible for O&M expenses only.

The third DER project involves the Exeter SAU 16. The proposed Exeter project would include the installation of a 100 kW solar PV system on the roof of the Exeter High School and a 65 kW Capstone micro-turbine at the school's administrative offices located elsewhere in Exeter. The solar PV would meet a portion of the electricity needs of the High School while the micro-turbine would meet a portion of the electricity and space heating needs of the administrative offices. The combined project was designed, and would be developed and financed by Revolution Energy under an agreement with Exeter that provides for the former to share in the electricity and oil bill savings that result from the project. Revolution Energy would also own the project and be responsible for maintaining it. Any federal tax credits due to the project would be the property of Revolution Energy.

Under the operating scenario described in UES' original filing, the solar PV system would generate electricity year round during daylight hours. The micro-turbine, however, would 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 by the micro-turbine during the winter months is considered a by-product that would be used to displace purchases from UES under its default service tariff. Finally, the micro-turbine would be fueled with natural gas supplied by UES' affiliate, Northern Utilities.

At the hearing, UES testified that the micro-turbine was designed to be in compliance with RSA 374-G requirements. UES said that New Hampshire had adopted the California Resource Board's 2007 emissions standards, commonly referred to as CARB 2007, and that the micro-turbine is CARB 2007 compliant. Tr. 3/2/2010 at 54. UES calculated the benefit/cost ratio for the combined project at 1.52 on a TRC test basis and 2.46 on a non-participant test basis.[5] Revolution Energy proposed to finance the project through three sources: a $650,000 bank loan, a $260,000 grant from UES and internal funds.

### 2. Revised Filing

As a result of discovery and discussions at technical sessions, UES modified its screening model with a revised filing submitted December 21, 2009. The modifications included: updating avoided costs to reflect the results of Synapse's 2009 study; expanding the computation of renewable energy credit (REC) benefits from a single year to the life of an investment; setting the REC value in any year at 75% of the forecast value of the Alternative Compliance Payment (ACP) in that year; revising the economic development analysis to better account for the displacement of utility investment; revising the allocation of energy and demand related DER benefits between the participant and non-participants; and revising the allocation of avoided energy and capacity costs between seasonal and on-peak/off-peak periods. As a result of these changes, the TRC based benefit/cost ratios for the three projects were revised as follows:

**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 |

### 3. Rebuttal Testimony

With respect to the step adjustment cost recovery mechanism recommended by Staff, Mr. Gantz stated in his rebuttal testimony that he believed a fully reconciling rate mechanism is a

[5] The non-participant benefit/cost ratio is higher because the developer absorbs a majority of the costs.

more appropriate ratemaking tool. Nevertheless, he said that the Company's concern for contemporaneous recovery of its DER investments could be addressed by combining a step adjustment with an investment carrying charge that is designed to compensate the Company for the cost of financing the investment during the time period between placing the investment in service and recovering the associated costs through rates.

Mr. Gantz agreed with Staff that a more accurate estimate of project economics would be achieved if lifetime benefits were compared to lifetime revenue requirements rather than the up-front capital cost included in the original filing. The revenue requirements analysis would also reflect the receipt of federal tax credits where appropriate. Mr. Gantz opposed, however, Staff's recommendation to use the overall cost of capital from the Company's most recent base rate case to calculate the return on investment. He argued that data used in the ratemaking process should be updated where possible to improve accuracy including updating UES' capital structure and debt costs.

Mr. Gantz stated that the Company had incorporated into its analysis the additional generation capacity and RPS related benefits recommended by Staff in its direct testimony. In addition, he agreed that UES-specific estimates of avoided transmission and distribution (T&D) costs were more accurate than the generic estimates used by Synapse in its study. Mr. Gantz disputed, however, Staff's claim that the Synapse avoided energy costs are too high and that the discount rate used by Synapse to calculate present value benefits, a rate of 3.25%, is too low. Regarding overhead costs, although UES had replaced the 30% rate included in its original filing with a rate of 1.5% it nonetheless stated that actual costs may be much higher.

In his rebuttal testimony, Mr. Palma stated that the Company was withdrawing the Crutchfield Place project, having heard from Concord Housing Authority personnel that hot water for the building was produced using both the natural gas and electric heaters. Because neither heater was separately metered, he said that it was not possible for UES to determine the extent to which the electric heater was utilized. Accordingly, UES could not estimate the amount of electricity that would be displaced by the solar water heating system and hence the benefits to its customers.

Mr. Palma also proposed to restructure the Stratham project in an effort to improve its economics, particularly with respect to non-participating customers. Although the solar PV system would continue to be located on the roof of the Stratham Fire House, it would no longer be interconnected to the Fire House electrical system. Instead, the output of the solar facility would be fed directly to UES' distribution system. This would allow the Company to retain for the benefit of its customers the RECs produced by the installation as well as the avoided energy and capacity costs. In addition, because the Company owns the restructured project, UES can claim federal tax credits. As a result, however, responsibility for operating and maintaining the system would revert to UES. To compensate the Fire House for the use of its roof space, the Company agreed to make rental payments to the Town that would increase over the assumed 20-year life of the project. Finally, in order to reduce the overall cost of the project, UES proposed to issue a request for proposals for the purchase and installation of equipment.

With respect to the Exeter project, Mr. Palma accepted Staff's recommendation to expand the period of operation for the micro-turbine to include the summer peak period.

**4. Hearing**

The Company explained that the first stage of the proposed two-stage regulatory review process would comprise a filing that includes project descriptions, testimony supporting each project, detailed cost support for each project, detailed analysis of the benefits of each project including an assessment of the participant and non-participant impacts. Tr. 3/2/2010 at 28-29. UES stated that any necessary customer agreements would also be part of this filing. *Id.* 28. With this information, UES believed the Commission could make a determination as to whether each project is in the public interest.

The Company agreed with Staff's recommendation that Commission approval of the two-stage regulatory review process should be conditioned on UES seeking re-approval of any project not started within one year after the date of the order finding it to be in the public interest. The Company also agreed that, with the exception of a few unique situations, a customer contract is an important component of a filing requesting approval of a specific DER investment. *Id* at 150.

According to UES' proposal, the second stage would occur about a year after the first filing and would consist of the rate filing for the DER projects that had been approved the prior year. The Company said that the purpose of stage two would be to verify the prudence of the spending that had been done on the previously-approved DER projects, and would necessarily contain detailed cost support that demonstrated that the project, as implemented, fell within a reasonable range of the estimated costs. *Id.* at 29. UES explained that it had proposed a fully reconciling DERIC mechanism to calculate the costs to be included in the distribution base rates and charged to UES' customers. *Id*. at 30. Using the DERIC cost recovery mechanism, the

Company would calculate a rate factor for each DER project to be included in distribution rates at the time such DER project is complete. As a fully reconciling mechanism, UES explained that the DERIC cost recovery mechanism would allow it to recover all costs incurred by the Company in implementing a previously-approved DER project. *Id*.

The Company testified that any acceptable step adjustment recovery mechanism for DER investments would need to reflect the different kinds of O&M expenses that UES would incur for its DER projects. According to UES, the O&M expenses – such as program planning and management, technical and technology assessment activities, working and contracting with customers and vendors, requests for proposal (RFPs), vendor selection and contracting, project costs and revenue requirements analysis, analysis of benefits and modeling, evaluation and reporting of projects through time, regulatory filings and reports, and legal and administrative costs associated with DER activities – could fluctuate over time and a mechanism needs to be in place to incorporate those types of activities into a step adjustment. *Id*. at 32.

UES said that one of the benefits of a reconciling mechanism is that the mechanism is updated for all key data inputs such as updated interest charges, updated capital structure and updated debt costs. While the Company said that it would be appropriate to have its return on equity based on the last cost of equity determined in a base rate case, a step adjustment should include the updated debt and capital structure components. *Id.* at 33. UES testified that, with the changes noted above, a step adjustment as proposed by Staff would be a reasonable alternative to the fully reconciling rate mechanism proposed by the Company. *Id*. at 34. UES agreed that the updated cost of capital should also be used in the economic evaluation of projects. *Id*. at 150.

The final point made by UES regarding cost recovery relates to lost base revenues resulting from DER investments. The Company testified that because DER projects reduce kWh sales and distribution revenues, any failure to recover lost base revenue would amount to a disincentive for utilities to make DER investments.

At the hearing, the Company further revised its economic analysis of the Stratham project. UES said that it adjusted its analysis over the duration of the docket in response to comments made at technical sessions and in an attempt to refine the data. The analysis summarized in Exhibit 5 reflects revenue requirements and benefits expressed in present value dollars calculated over the assumed 20-year life for the project. *Id*. at 36-37. The Company's revised analysis produced a benefit/cost ratio of 0.79, excluding indirect benefits. Including 100% of indirect benefits raised the benefit/cost ratio to 1.68. The benefit/cost ratio falls to 1.24 if 50% of the indirect benefits are included and 1.02 if 25% of indirect benefits are included.

When asked to compare its analysis of project costs with that of Staff, the Company said that both Staff and UES were using roughly the same revenue requirements analysis. The differences were minor and related to the inputs such as the inflation rate, the real discount rate, the O&M factor and monitoring and verification costs. UES said that monitoring and verification costs accounted for most of the difference between Staff's and UES' estimate of revenue requirements. *Id*. at 40-41.

With respect to differences between Staff's and UES' analysis of benefits, other than indirect benefits, the Company said that the differences relate to the calculation of avoided energy costs and the valuation of RECs. Staff's analysis excludes indirect benefits completely. *Id*. at 42.

**5. Closing Statement**

In its closing statement, UES argued that the inclusion of indirect benefits in the Commission's evaluation of the public interest is appropriate and encouraged by RSA 374-G. It also opined that DER projects will continue to face cost pressures that will hinder rapid market acceptance without the additional support proposed by UES. According to UES, RSA 374-G contemplates that, until DER projects can stand on their own, electric utilities in New Hampshire should consider investing ratepayer dollars in DER applications that help stimulate this market while also producing such additional benefits as environmental protection and economic development. Accordingly, UES requested that the Commission take into account some portion of the estimated economic development benefit in its review of the Stratham project. UES Closing Statement at 2.

**B. U.S. Energy Savers, LLC**

USES stated that UES did not propose or provide a sufficient approach to evaluating the potential impact that DER projects would have on the competitive energy service market. USES Closing Statement at 2. In that regard, USES suggests that UES not be allowed to design, develop and implement DER projects with their own staff. Instead, USES recommended that UES act as an alternative financing vehicle for projects proposed or bid upon by the competitive services market. *Id*. at 3.

USES also said that the Company failed to identify investments in its distribution system that would minimize rates for customers. USES opined that a reasonable strategy would focus on the parts of the grid facing capacity constraints and target investments in those areas. Once the capacity-constrained areas have been identified, USES contends that the Company must next demonstrate that the proposed DER projects represent a more cost-effective approach to addressing the constraint than a traditional investment in T&D. USES suggested that such an analysis is necessary to determine whether the DER projects proposed in this proceeding are reasonable. *Id*.

USES disagreed with the discount rates used by UES in its benefit/cost analysis, saying that they are ridiculously low, even lower than the rates available to the U. S. Treasury. Because these projects are being proposed as alternatives to traditional T&D investments, USES believes that a rate equal to the Company's weighted average cost of capital (WACC) or higher should be used to discount costs and benefits.

Finally, USES said that the Commission should not subsidize a project that would otherwise produce a reasonable TRC benefit/cost ratio by evaluating it as part of a portfolio of projects. USES said that each proposed project must be evaluated on its own merits and that each project must demonstrate its ability to contribute to a strategy of minimizing T&D costs for ratepayers. *Id*. at 4.

**C. Office of Energy and Planning**

OEP encouraged the Commission to find the Exeter project to be in the public interest but took no position on the Stratham project. Noting that this docket will set precedent, OEP encouraged the Commission to consider the factors included in the proposed benefit/cost analysis. According to OEP, the benefit/cost analysis used in the review of these projects and the public policies that are driving the development of renewable projects appear at odds. OEP agreed that it is important not to give blanket approval of all projects, but suggested that the review process should make it more viable and less restrictive for utilities to propose small renewable energy projects. OEP observed that values such as the public's desire for renewable energy, improvement to public health and public education of renewable energy are often difficult to quantify, but are no less important than environmental improvements or the costs of installation.

**D. Office of Consumer Advocate**

The OCA expressed its support for the two-stage process for filing and review of proposed DER investments, where the first stage is a review of proposed projects to determine whether they are in the public interest and the second stage is a request for cost recovery. The OCA emphasized that the second stage should begin only after the utility has incurred the costs associated with the DER projects and the projects are used and useful in providing service to utility customers. OCA Closing Statement at 2. In addition, the OCA said that the second stage should involve a review of actual costs and a determination of whether those costs were prudently incurred. OCA asserted that only after the conclusion of the second stage should the utility be allowed to recover its DER investments through rates. *Id*. at 3.

With respect to cost recovery, the OCA recommended a process similar to that approved by the Commission in DW 09-098 relating to a Water Infrastructure and Conservation Adjustment (WICA) for Aquarion Water Company of NH. *See* Order No. 25,019 (September 25, 2009). In that case, Aquarion filed its proposed projects, which were reviewed by the parties and approved by the Commission. In the next step adjustment, Aquarion will file for authorization for recovery of costs associated with projects in service by November 1, 2010, with an effective date for a surcharge of January 1, 2011. *Id*.

The OCA expressed concern about the use of a reconciling mechanism as proposed by UES. The OCA said that such a mechanism would be based, in part, on estimates of expenses and capital costs, potentially creating a situation where the utility is collecting through rates costs that have not yet been expended or costs for capital investments that are not yet used and useful, or found to be prudent, as required by RSA 378:28 and RSA 378:30-a. The OCA said the recovery cost mechanism for DER investments should be based on known and measurable costs, and should only include the costs of capital investments that are used and useful in providing service to a utility's customers. *Id*. at 4.

The OCA took no position on the Stratham project but supported approval of the Exeter project and recovery of the associated costs through its recommended mechanism. Further, the OCA opined that UES should provide details about its planned use of DER in the future as part of its next Least Cost Integrated Resource Plan filed pursuant to RSA 378:38. *Id*. Finally, the OCA said it supported UES' proposal to include some portion of the indirect benefits in the economic analysis of the projects. *Id*. at 5.

**E. Commission Staff**

**1. Direct Testimony**

In written testimony filed December 23, 2009, Staff presented a detailed analysis of UES' proposed regulatory review process, cost recovery mechanism and methodology for evaluating the economics of DER projects. Staff also included recommendations regarding Commission approval of the proposed projects.

**(i) Regulatory Review Process**

Staff argued that the original filing omitted important details about the proposed projects and generally raised more questions than it answered. To rectify this situation, Staff recommended that UES be required in future filings to include a conditional customer agreement for each project that details key responsibilities and obligations for all parties. In addition, Staff recommended that the Company's proposed two-stage review process be approved subject to the Company re-submitting projects not started within one year after the date of the Commission order finding them to be in the public interest.

**(ii) Cost Recovery**

Staff noted that RSA 374-G:5, III requires prudently incurred costs for authorized DER projects to be recovered through a utility's base distribution rates, and that such eligible costs include depreciation, a return on investment, taxes and other operating and maintenance expenses directly associated with the investment, net of any offsetting revenues resulting from the investment. According to Staff, offsetting revenues include, among other things, federal tax credits, RECs associated with renewable generation, and payments from the Independent System Operator-New England (ISO-NE) for the value of load reduction in the Forward Capacity Market (FCM).

Staff opposed the reconciling DERIC cost recovery mechanism because its implementation would allow costs to be collected before a project is in service, which is contrary to RSA 378:28.[6] Staff recommended instead a step adjustment mechanism, noting that the Commission had approved such a mechanism to recover bare steel-cast iron replacement costs in the natural gas sector, reliability enhancement costs in the electric sector and investments to meet Clean Water Act requirements in the water sector. Staff noted that a step adjustment also

[6] RSA 378:28 states in that that the Commission "shall not include in permanent rates any return on any plant, equipment, or capital improvement which has not first been found by the commission to be prudent, used and useful."

provides for reasonably fast recovery of investments costs and, therefore, is consistent with the legislative goal of encouraging utilities to investment in DERs.

Regarding UES' request to collect a carrying charge on DER investments during the time period between when a project is placed in service and when the project costs begin to be recovered through rates, Staff recommended that the request be denied because it is contrary to Commission precedent and would eliminate regulatory lag completely. Tr. (3/3/2010) at 34. Staff testified that eliminating regulatory lag would reduce the Company's incentives to control its costs.

Staff addressed UES' proposal to recover lost base revenues as part of its cost recovery mechanism. Staff advised against adopting this proposal arguing that lost base revenue could be avoided by appropriately selecting and locating DER projects.

Regarding the calculation of project costs, Staff opposed the proposal to update UES' capital structure and debt costs when calculating return on investment. Instead, Staff recommended that the Company use the authorized overall cost of capital from the last base rate case for that purpose.

**(iii) Economic Evaluation**

In support of its cost analysis, Staff argued that the appropriate measure is the project's lifetime revenue requirement expressed on a present value basis. In addition to the installed cost of the project, lifetime revenue requirement includes estimates of the following cost components: return on rate base, income taxes, working capital, O&M expense, administrative and general expense, monitoring and verification expense, mobilization expense, and reporting expense.

Staff noted that the installed costs for the Stratham and Exeter solar PV installations were about 15% higher than the equivalent cost on a per kW basis for Public Service Company of New Hampshire's (PSNH) solar PV installation.[7] Because the PSNH cost was the result of a competitive bidding process, Staff recommended that UES, and/or the developers it partners with, utilize competitive bidding to acquire the necessary equipment and materials. While UES said it would use a competitive bidding process for the labor and materials associated with the Stratham project, Staff recommended that the Commission require UES to utilize competitive bidding to acquire equipment and materials for all DER projects.

In its original filing, UES proposed to add 30% to its investment in each project to cover estimated overhead and administrative costs. Staff responded that 30% is excessive based on a comparison of the costs claimed by PSNH for its solar PV system. In addition, Staff noted that UES has no specialized expertise in the design, installation and operation of DER projects and, moreover, planned to contract out design and installation to experienced independent contractors. For these reasons, Staff recommended that UES' overhead not exceed 3%.

Regarding UES' calculation of the benefits of the Stratham and Exeter solar PV projects, Staff contended that the capacity factors used by the Company (15.0%[8] and 21.03% respectively) are too high, with the result that benefits are overstated. Staff based its position on a Standard & Poor's study that shows the average capacity factor for solar PV systems in the northeast is 13.5%. At hearing, Staff argued that its position is further supported by the Fat Spaniel website, which contains data for New England solar PV systems that point to an average capacity factor of just over 13%. *Id*. at 47-50.

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[7] PSNH installed a solar array on its Manchester, New Hampshire corporate offices known as Energy Park.

[8] UES subsequently revised its estimate of the Stratham capacity factor to 14.8%.

Staff also pointed out that the Company understated the benefits by excluding from its analysis of the projects a generation capacity related benefit. This benefit relates to the fact that under ISO-NE's FCM rules the owner of a DER project can bid the associated load reduction into the FCM as an "On-Peak Demand Resource" and in return receive capacity payments.

Regarding avoided energy costs, Staff recommended that the Company's avoided energy cost forecast be adjusted downward by 10% because the underlying natural gas prices, the primary driver of electricity prices, were thought to be too high. At hearing, Staff reversed its position stating that further examination of the Synapse 2009 report left it uncertain as to which natural gas price forecast was used to develop the avoided energy costs. Consequently, Staff agreed to the use of the Synapse 2009 avoided energy costs unadjusted. *Id*. at 35-36.

With respect to the Company's calculation of transmission avoided costs, Staff stated that the unit cost used by the Company was lower than the monthly charge paid by UES for outside transmission services. Accordingly, Staff contended that transmission avoided costs are understated and recommended increasing the unit cost to the Company's actual average transmission cost or $8/kW-month.

As for distribution avoided costs, Staff recommended that the Company use the marginal distribution capacity cost approved by the Commission in UES' most recent base rate proceeding. For small C&I customers taking service at the secondary level, this cost is $81.1/kW in 2007 dollars.[9]

Staff opposed the Company's claim for localized distribution capacity savings on the grounds that it failed to demonstrate: 1) that the local loads in the areas in which the proposed

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[9] Both Stratham and Exeter take service at secondary voltage levels.

projects are to be located will exceed distribution capacity in the short or long term; and 2) that the distribution capacity costs avoided or deferred by the projects are not already captured in the Commission approved marginal distribution capacity cost.

Staff also opposed the inclusion of indirect benefits in the economic evaluation of DER projects. With respect to economic development, Staff argued that extensive testimony showed that solar PV systems are unlikely to contribute meaningfully to growth in the state's economy. Underlying the Company's RIMS II economic benefit calculations is the assumption that DER investments would be spent in the local community. This, according to Staff, is unlikely to be the case for solar PV systems for the simple reason that the panels and inverters are not manufactured in New Hampshire, a claim that was not contested by the Company. Staff concluded that solar PV systems installed in New Hampshire must be manufactured outside the state and possibly outside the country. According to Staff, this fact significantly undercuts the claim of economic development since approximately two-thirds of the investment cost for solar PV systems goes to the purchase of equipment and materials. While the remaining one-third relates to the cost of installation, Staff pointed out that there is no guarantee that a contractor selected to install the system in New Hampshire will be based in New Hampshire and that it is entirely possible that the winning bidder could be a Massachusetts-based contractor that has business ties with manufacturers in Arizona or China, two locations with extensive solar PV manufacturing capability. If this scenario plays out, none of the investment would be spent in New Hampshire and none of the resulting economic development would accrue to the benefit of New Hampshire citizens.

Staff also argued that even if UES selected a New Hampshire installer, the project is unlikely to result in a net increase in economic development because the installation of DER projects displaces investment in UES' T&D systems. Because such T&D investments would normally be accompanied by dollars spent in the local economy, Staff argued that their displacement would eliminate that spending, resulting in economic contraction that offsets the economic stimulus associated with investment in the solar PV system. Staff testified that the Company did not consider this effect or the impact on economic development of installing uneconomic DER projects. According to Staff, DER projects such as solar PV systems that have higher total costs than total benefits will cause rates to increase for all customers and that higher rates adversely affect economic development.

Staff noted that the second largest indirect benefit is the proposed $CO_2$ externality. Testimony disclosed that the avoided energy benefits calculated by the Company and Staff include $CO_2$ allowance costs that range from $3.91/ton in 2010 to $36.79/ton in 2022. These costs, which are referred to as the market portion of Synapse's $80/ton estimate of the social cost of $CO_2$ emissions, reflect the assumption that the Regional Greenhouse Gas Initiative (RGGI) will continue through 2012 and be followed by a new federal regulatory framework that extends through the remaining life of the proposed DER project. Staff opposed the inclusion of the non-market portion in the TRC test because no evidence was offered to support the $80/ton cost estimate and that inclusion of this and other indirect benefits would lead to higher rates for all customers.

Finally, Staff compared the REC value it used to the REC value used by UES and identified several important differences. The first was that the Company set the REC value in

2009 at 75% of the corresponding ACP, which resulted in a price substantially above the 2009 market price. *Id*. at 52. Staff in contrast used the 2009 REC market value for N.H. Class II (solar) projects. *Id*. at 53. Both Staff and UES assumed that the 2009 price would increase over time at the same rate resulting in substantially higher REC prices under the Company's analysis. Staff noted, however, that the Synapse study indicated that the supply of RECs will exceed the demand for RECs over time, resulting in a decline in REC prices rather than an increase. *Id*. at 55.

**(iv) Proposed Projects**

Based on benefit/cost ratios in its analysis of 4.29 and 1.20 for Crutchfield Place and Exeter respectively, Staff recommended conditional approval of the projects. The Crutchfield Place condition was that the customer absorb half of the installed cost. The Exeter condition was that the micro-turbine be operated as a peaking unit during the summer months.

In contrast, Staff recommended that the Stratham solar PV project be rejected based on a benefit/cost ratio of only 0.65 in its analysis. Exhibit 9. Staff attributed this result to a technology with a unit cost close to 61 cents per lifetime kWh generated, about 6.8 times the current cost of default service power, and too few benefits to offset the excess costs.

**2. Hearing**

Despite UES' withdrawal of the Crutchfield Place project, Staff testified that solar water heating systems have very favorable economics and should be considered by UES for inclusion in future DER filings. *Id.* at 118.

Staff said that UES appropriately restructured the Stratham project to place the facility in front of the meter which produced more benefits for non-participants. *Id.* at 42. Staff made corrections to a prior version of its analysis (Exhibit 9) and included the Synapse 2009 avoided energy costs used by the Company. *Id*. at 46. Among the corrections, Staff reduced the generation capacity and REC benefits by half to be consistent with the “in-front-of-the-meter” nature of the restructured project. The net result is a benefit/cost ratio of 0.56. Exhibit 12.

Staff amended its position on the calculation of return on investment and adopted the approach proposed by the Company. *Id.* at 34. In addition, Staff reversed its position on the development of avoided energy costs in the economic evaluation. Instead of adjusting the Synapse-based avoided energy cost forecast to reflect more recent natural gas prices, Staff used the unadjusted Synapse forecast. *Id.* at 35-36.

With respect to the present valuing of costs and benefits, Staff claimed that the Company had used a rate of 3.25% to discount revenue requirements and 1.66% to discount benefits in its revised evaluation of the Stratham project. *Id*. at 36. This, according to Staff, is inappropriate because it could bias the outcome of an evaluation. To eliminate bias, Staff said that the same rate should be applied evenly to costs and benefits. *Id*. at 38. Regarding the appropriate rate for discounting costs and benefits, Staff argued that because the intent of DER investments is to displace traditional T&D investments the appropriate rate is the rate used by the Company in analyses of T&D investments, *i.e.*, the Commission-approved after tax cost of capital. *Id.* at 40.

In response to the Company’s assertion that Staff’s economic evaluation does not satisfy all of the statutory criteria, Staff stated that consistent with the legislation its analyses examined the costs and benefits to participants, non-participants and the general body of ratepayers. *Id*. at 55-56.

Staff also stated that all of its economic evaluations satisfied the legislative requirement to consider environmental benefits of DER projects. This was done by including in the TRC test the costs avoided by reducing emissions of $CO_2$, $SO_2$ and NOx emissions. The latter two benefits are reflected in avoided energy costs. *Id*. at 56. Staff also claimed that its analyses incorporate the reliability benefits of DERs by including in the TRC test specific benefits that assume the DER would be available at peak times.

Regarding the effect of DER investments on competition, Staff's first recommendation was to exclude indirect benefits from the TRC test. This would force developers to focus on projects that are capable of competing based solely on direct benefits. Staff also recommended that UES' contribution to the cost of a DER be significantly below the 100% level offered to two of the three participants in this proceeding. *Id*. at 63. According to Staff, the adoption of these recommendations would significantly mitigate the anti-competitive concerns that competitive providers may have regarding the legislation.

**3. Closing Statement**

Staff recommended that the Commission make a finding that the Stratham project is not in the public interest because it is not an economic alternative to traditional investments in T&D. Closing Statement at 1. According to Staff, all of the economic evaluations conducted in this proceeding show that the costs of purchasing, installing and operating the project over its useful life greatly exceed the expected direct benefits. Consequently, Staff cautioned that approval of a project based on questionable indirect benefits would send the wrong message According to Staff, it is inadvisable to approve DER projects such as solar PV systems that have higher total costs than total benefits because rates for all customers would increase.

## III. COMMISSION ANALYSIS

UES' filing is the first made pursuant to RSA 374-G. By the close of the hearing, the parties and Staff reached agreement on a recommended regulatory review process and partial agreement on issues relating to cost recovery and economic evaluation. The key differences remaining are as follows:

(i) Whether the cost recovery mechanism should be based on a forecast of eligible costs and reconciled annually as proposed by UES or on the costs of completed projects collected annually through a step adjustment as proposed by Staff and the OCA.

(ii) Whether, in the event a step-adjustment approach is adopted, a carrying charge should be applied to DER investments during the time period between placing those investments in service and recovering the associated costs through rates.

(iii) Whether the discount rates used by UES (3.25% for costs or 1.66% for benefits) in cost effectiveness tests is more appropriate than the rate advocated by Staff and USES (after tax cost of capital).

(iv) Whether the capacity factor for the Stratham solar PV facility should be 14.8% as advocated by UES or 13.5% as advocated by Staff.

(v) Whether some or all of the indirect benefits calculated by UES should be reflected in the economic evaluation of DER projects.

(vi) Whether the REC benefit included in cost-effectiveness tests should be based on the assumption that REC prices will rise significantly in the future, as argued by UES, or rise more modestly as argued by Staff.

(vii) Whether the restructured Stratham project is in the public interest.

Applying the public interest criteria set forth in RSA 374-G:5, II, we resolve below the issues on which UES and Staff were in dispute and comment on key issues where agreement was reached. We address the adequacy of UES' filing, the two-stage regulatory review process, the costs and expenses eligible for rate recovery and the means of that recovery, the costs and benefits included in cost effectiveness tests for DER projects, including whether indirect benefits should be part of that evaluation, and the methodologies used to calculate costs and benefits.

**A. Adequacy of Filing**

We find that UES' filing partially complied with the requirements of RSA 374-G:5, I (a) and (b) in that it provided a description and economic evaluation of each project, and an analysis of the costs and benefits of each DER project, with one exception. Despite clear statutory language that rate impacts be submitted as part of a DER application, UES failed to do so. The Company produced the information after a request was made in the course of the hearing but that late filing resulted in further delay in consideration of the proposal and did not afford parties and the Staff the opportunity to engage in normal discovery on the details of the submission.[10] Future DER filings must provide estimated rate impacts "to the participating customers, to the company's default service customers, and to the utility's distribution customers" for all proposed projects or packages of proposed projects in a filing, as required by RSA 374-G:5, I (b).

In addition, the record shows that the costs associated with the initial and restructured Stratham projects were uncertain because UES had yet to receive cost estimates or bids for the purchase and installation of the proposed solar PV system. Because this made evaluation of the

[10] Decision on the proposals was further delayed by agreement of the parties and Staff to deal first with the Time of Use pilot program and then take up the Stratham, Exeter and Crutchfield Place projects.

project more difficult, petitioners in the future should obtain the necessary information for proposed projects by issuing an RFP, where feasible and appropriate, and conditioning the award to the winning bidder on the Commission's approval of the project. The definition of distributed energy resources in RSA 374-G:2, I (b) includes a full range of possible non-wires alternatives that might help address T&D reliability and capacity issues, including distributed generation, storage, energy efficiency, demand response and certain smart grid technologies. In general, the policy of the State of New Hampshire is to promote "competitive markets for wholesale and retail electricity services." RSA 374-F:1. The procurement of many, though perhaps not all, distributed energy resources can be done in manner that harnesses the power of competitive markets. In the future, petitioners should carefully consider when to use market mechanisms in the evaluation and procurement of distributed energy resources, by RFP or otherwise, and when direct involvement of utilities in the design, development and implementation of projects might be more appropriate and cost effective. Accordingly, we do not adopt USES' recommendation that the approach used by UES to select DERs must, in every case, be beneficial, or at least neutral, to the competitive energy services market. Certainly "the effect on competition within the region's electricity markets and the state's energy services market" is a factor to be considered, but the final determination must be whether the company has demonstrated that the proposed investments in distributed energy resources on balance, are in the public interest. RSA 374-G:5, II (i).

UES provided a description of equipment and installation specifications for the DER projects consistent with RSA 374-G:5, I (c). We find that it made efforts to involve local businesses in this initial filing by partnering with Revolution Energy for the Exeter project, consistent with RSA 374-G:5, I (d). Further, the record shows that UES provided documentation that the Exeter project complies with applicable emission limitations consistent with RSA 374-G:5, I (e). At the same time, we find that the memoranda of understanding (MOUs) filed by UES for the proposed DER projects do not meet the requirements of RSA 374-G:5, I (f) that specifies inclusion of "a copy of any customer contracts or agreements to be executed as part of the program." Future DER filings should include, at a minimum, a model customer agreement for each project that details key responsibilities and obligations for all parties. These agreements will assist in the allocation of costs and benefits between participant and non-participant customers, which is a factor in the economic evaluation of DER projects. *See* RSA 374-G:5, II (c) and (d).

In its filing, UES failed to describe, except in the most general of terms, how the proposed DER projects would be "part of a strategy for minimizing transmission and distribution costs" as suggested by RSA 374-G:2, I (b). The OCA in its closing statement recommended that the Commission require UES to address in its next least cost resource plan the role played by DERs in meeting T&D needs. We agree with the OCA's recommendation and direct UES to include in its next LCRP its strategy for minimizing T&D costs and, if relevant, the role played by DER investments in that strategy along with details of the T&D circuits or substations likely to benefit from the distributed energy resource investments. A basic strategy for minimizing T&D costs might identify distribution and local network service transmission facilities (circuits and substations) ranked by need for reliability or capacity upgrades. This ranking could be followed by an examination of those facilities where improvements may be needed in the foreseeable future, but are not so urgent as to require immediate investments in T&D

infrastructure. For these less urgent but foreseeable T&D capacity needs, UES should evaluate non-wires alternatives (DERs) that may contribute to T&D reliability or capacity solutions by deferring or avoiding potentially more costly investments in T&D infrastructure. DER investments might produce additional value for ratepayers and the state, such as a reduction in the cost of emissions offsets or economic development benefits, which should be identified.

**B. Two-Stage Process**

UES proposed a two-stage regulatory review process for DER investments: the first would entail Commission approval of proposed projects; and the second would entail approval of cost recovery for authorized projects. We note that RSA 374-G does not preclude such a two-stage process and we find that it is reasonable to use such a process in reviewing DER investments. In this Order we set forth a reasonable framework for calculating the costs and benefits of DER investments which, if used by applicants, will minimize the issues in dispute and enable the Commission to issue a timely response. Therefore, we find it in the public interest to approve the proposed two-stage process, subject to Staff's recommendation that UES seek re-approval of any project not in service one year after the date of the order finding the project to be in the public interest.

**C. Economic Evaluation**

As noted above, Staff and the parties narrowed their differences through the course of the proceeding on the costs and benefits to be included in economic evaluations of DER projects. For example, with the exception of O&M expense and the discount rate, Staff and the parties were in agreement on how to calculate the revenue requirements associated with DER investments, including how to handle deferred taxes and investment tax credits. While progress was also made in the calculation of benefits, major differences on issues such as indirect benefits and RECs remained. We find the points of agreement reasonable and approve them.[11]

With respect to the unresolved issues, we rule as follows. In calculating the present value of costs and benefits, we agree with Staff that the same rate must be used to discount both costs and benefits. The use of one rate for costs and another for benefits must be rejected because it would bias the evaluation either for or against DERs. As to the actual discount rate to use in these evaluations, we look to the statute itself, which defines DERs for the purposes of RSA 374-G in the context of a strategy for minimizing T&D costs. The determination of whether specific DER investments would lower T&D costs over the long term typically requires an economic comparison of the alternatives. To calculate T&D reinforcement costs, utilities generally use the authorized after tax cost of capital as a discount rate to calculate the present value of a long term cost stream. For consistency, we find that it is appropriate to use the after tax cost of capital in the first instance when calculating the present value of DER costs and benefits. There may be times when it appropriate to use other discount rates as part of a secondary analysis for sensitivity or because the proposed project is primarily to be expensed and is funded from working capital with a significantly different cost of capital, in which case the petitioner should provide justification for such alternative discount rate analyses. An example may be geographically targeted energy efficiency investments, where the discount rate in the most recent Synapse AESC study may be used.

Information provided after the hearing on the estimated impact on rates of the Stratham and Exeter projects[12] shows a total revenue requirement of $340,467 for 2010, which includes

[11] The details of the parties' agreement on the method for deriving revenue requirements and benefits are shown in the calculations contained in exhibits to this order.

$135,640 for “ongoing program management and reporting.” We understand the latter amount to be the internal labor costs that UES expects to incur in 2010 related to its DER activities. Our primary concern is that very little of this expense found its way into UES’ evaluation of the proposed projects despite the Company’s claim that the “costs associated with [ongoing program management and reporting] are incremental for the company, directly attributable to the DER projects and of an ongoing nature …”[13] Accepting that the 2010 labor cost estimate may be high due to the start-up nature of the current proceeding, we find that the Company’s failure to include a reasonable percentage of this expense in its evaluations creates uncertainty over the true cost-effectiveness of the proposed projects. For this reason, future DER filings should set forth detailed estimates of the cost of l personnel or consultants for on-going program management as part of a proposal’s economic evaluation. In the alternative, to the extent that evaluation of DER options are incorporated into regular system planning as part of an integrated strategy for minimizing T&D costs, such cost might reasonably be included in the regular distribution rate base. In addition, regarding the rate for overheads, absent cost data from completed projects that indicate otherwise or other reasonable justification, future DER evaluations should employ the 1.5% rate that was used here for the revised benefit/cost analysis for Stratham.

Staff recommended that a capacity factor of 13.5% be used in the economic evaluation of the Stratham project, while the Company said that a more accurate capacity factor is 14.8%. Recognizing limitations with both estimates, we used the Company’s estimate in modeling the

[12] Exhibit 10, Attachment 4.
[13] Exhibit 3, page 13.

Stratham project. Future solar PV projects should base the capacity factor estimate on operating data for similarly situated projects.

Staff and the Company differed significantly on the future value of Class II RECs. Because of this difference, we undertook a sensitivity analysis of REC prices. We used as the upper bound UES' estimate of Class II prices. For the lower bound we started with the Class II market price for 2010, recognizing that such market data was limited, and escalated that at an annual rate of 3.99%, which is the percentage increase in Class II ACP prices from 2008 to 2009. The mid-point between these two price forecasts was used to calculate the REC value used in our modeling of the Stratham project. This modeling is attached to this Order for illustrative purposes. In future DER filings, REC price estimates should be guided by reasonable extrapolations of historic market price trends, absent better evidence.

Regarding the treatment of indirect benefits in the evaluation of DER projects, we find that it is appropriate to include such benefits as a secondary analysis after first considering direct and readily quantifiable benefits in a primary analysis. In situations where projects, or a package of related proposed projects, may be marginally uneconomic based on direct benefits alone, we will allow reasonable estimates of indirect benefits to be considered and, if appropriate, to support a public interest finding.

With respect to the Company's claim that strategically located DER investments can produce distribution cost savings that exceed those reflected in the Commission approved generic distribution capacity cost for UES, we agree with Staff that the Company failed to show that the loads in the areas in which the proposed projects would be located approach or exceed distribution capacity in the short or long term. We also agree that the Company failed to show that the distribution costs avoided or deferred by the projects exceed the Commission approved marginal distribution capacity cost.

The Company failed to make a convincing case that its proposed solar PV projects are likely to contribute significant economic development benefits to the state. Underlying the Company's economic benefit case is the assumption that DER investments would be spent in the local community, as might be the case with standard residential or commercial construction, resulting in a greater employment and economic multiplier effect than alternative uses of investment funds. While the Company's use of the regional input/output model, RIMS II, is reasonable, it made a simplifying assumption that investment in PV is equivalent to generic construction expenditures in New Hampshire, and that this investment might be in lieu of a comparable expenditure on "utilities" that is less labor intensive and thus has a smaller local economic multiplier and benefit. First, it is unclear that installation of a PV system is typical of the "construction" category in the model. Most of the costs for the proposed solar PV systems are for capital intensive equipment, mainly PV panels and inverters that are unlikely to be manufactured in New Hampshire. Second, it is not clear that the alternative use of the funds is for "utilities" as that category is defined in RIMS II. If the funds were used to construct a distribution system upgrade for example, there might be a comparable or greater economic benefit to the state. Likewise, if a rate increase for the DER investment was avoided altogether, the funds would be retained by consumers and invested in other ways that may have greater or lesser economic benefit. The record does not clearly establish the economic benefit of the proposed PV investments versus alternative uses of the funds.

The other major indirect benefit used in the Company's analysis was the incremental externality cost of $CO_2$ emissions from the mix of electric generation on the margin in New

England. This environmental externality or societal cost estimate is based on the amount of estimated long-run marginal abatement costs of $CO_2$ emissions developed in the 2009 AESC report of $80/ton that are in excess of projected internalized market costs of $CO_2$. While Staff argued that no evidence was offered to support this cost estimate, we note that the AESC report as a whole was entered into evidence and includes an extensive discussion and explanation of its estimates, with sources, on pages 6-74 through 6-89. In the absence of evidence to the contrary, we find that use of AESC's environmental externality costs estimates are a reasonable indicator of indirect environmental benefits for renewable or load-reducing distributed energy resources.

Having reviewed the Stratham project consistent with the foregoing analysis, we find that the costs significantly outweigh the benefits and, therefore, the project is not in the public interest. Our analysis of the project is attached to this Order for illustrative purposes. The direct benefit/cost ratio is only 0.52, which is extremely low. Even allowing 100% of the $CO_2$ externality benefits as well as 25% of the indirect economic benefits the Company asserts, which, as we have stated, are not well substantiated, the costs still exceed all of the benefits. Accordingly, the Company's request for approval of the Stratham project is denied. We do, however, find the Exeter project to be in the public interest regardless of which of the proposed capacity factors is used in the analysis. Accordingly, we approve the Company's request. We also commend UES for working with a local business to make cost-effective generation available to the Exeter school district. Finally, we note that the solar water heating system initially proposed for Crutchfield Place, appeared on its face to be cost effective and is the type of project that merits further development.

**D. Cost Recovery Mechanism**

Having decided the merits of the two remaining projects, we now turn to the issue of cost recovery. We have examined UES' reconciliation proposal and find that it is not consistent with existing statute. The reconciling mechanism as proposed by UES would allow the Company to recover the costs of DER projects before those projects are used and useful, which is contrary to RSA 378:28 and RSA 378:30-a. Further, allowing the Company to reconcile estimated and actual investment costs might reduce its incentive to control its costs. On the other hand, we find Staff's proposed step adjustment mechanism to be appropriate because it provides for relatively quick recovery of actual costs and expenses. Accordingly, UES is authorized to petition the Commission on an annual basis for a step adjustment to its base distribution rates to collect the actual costs associated with authorized DER projects. Such costs will be subject to review for prudence and reasonableness.

Further, we will deny UES' request to assess a carrying charge on DER investments during the time period after those investments have been placed in service and before the associated costs are collected through rates. We agree with Staff that approval of the request for such carrying charges would be contrary to Commission precedent and create a different treatment than conventional T&D capital investments.

We will grant UES' request to use the updated capital structure and debt costs to calculate its return on investment. The return on equity component of the capital cost will be based on the equity rate authorized in UES' last base rate case.

UES requested recovery of certain costs labeled "Ongoing Program Management and Reporting Costs," which are estimated at $135,640 for 2010. Exhibit 10, Attachment 4. Given the absence of documentation describing the composition of these costs and the failure to include them in its economic evaluations, we cannot approve the Company's request at this time.

UES requested that lost base revenues associated with the Exeter project be included in the costs it is allowed to recover through distribution rates until such time as a new base rate case is filed.[14] We find that request to be reasonable and therefore approve it. UES is directed to provide detailed data supporting the amount it proposes to recover as lost base revenue when it files to recover the costs of the Exeter project.

**Based upon the foregoing, it is hereby**

**ORDERED**, that the two-step regulatory review process for distributed energy resource investments made pursuant to RSA 374-G as modified herein is hereby APPROVED; and it is

**FURTHER ORDERED**, that the step adjustment mechanism proposed by Staff for the recovery of distributed energy resource investments is hereby APPROVED with the modification that Unitil Energy Systems, Inc. is authorized to recover lost base revenue demonstrated to be related to the Exeter project; and it is

**FURTHER ORDERED**, that any future investments for distributed energy resource investment shall be part of a utility strategy to minimize transmission and distribution costs and shall be part of the utility's least cost integrated resource plan filed pursuant to RSA 378: 38; and it is

**FURTHER ORDERED**, that the economic evaluation of proposed distributed energy resource investments shall be conducted consistent with this Order and shall use the Company's after-tax cost of capital in calculating the present value of cost and benefits; and it is

[14] The UES base rate filing now pending in Docket DE 10-055 should not address these costs as the approved DER investments are not slated to be put into service until later this year at the earliest.

**FURTHER ORDERED**, that the distributed energy resource investment in the Stratham Project in not in the public interest and is hereby DENIED; and it is

**FURTHER ORDERED,** that the distributed energy resource investment in the Exeter SAU 16 project is in the public interest and is hereby APPROVED.

By order of the Public Utilities Commission of New Hampshire this eleventh day of June, 2010.

| | | |
|---|---|---|
| Thomas B. Getz<br>Chairman | Clifton C. Below<br>Commissioner | Amy L. Ignatius<br>Commissioner |

Attested by:

Debra A. Howland
Executive Director

Unitil Energy Systems, Inc.
Petition For Approval of Investment In And Rate Recovery Of Distributed Energy Resources
Order Approving in Part and Denying in Part

**Stratham**
**Solar PV Facility**
**Base Case Revenue Requirement Analysis**

Assumptions

| | |
|---|---|
| UES Investment | $275,282 |
| Depreciable Basis | $233,989 |
| Book Life | 20 |
| Initial Lease Payment ($/Yr) | $4,600 |
| Before Tax Rate of Return (%) | 11.18% |
| After Tax Rate of Return (%) | 8.37% |
| Inflation Rate (%) | 1.56% |
| DS Inflation Rate (%) | 2.92% |
| Initial O&M Expense ($/Yr) | $500 |
| Monitoring & Verification (%) | 2.00% |
| Working Capital (days) | 12 |
| Tax Rate (%) | 39.61% |
| Real Discount Rate (%) | 6.71% |
| Federal Tax Credit | 30.00% |
| Depreciable Basis Adj | 50.00% |

20 Year Analysis

| Year | Rate Base (BoY) | Rate Base (EoY) | Rate Base (Avg) | Return on Rate Base | Tax Depreciation | Book Depreciation Unadj | Tax Adj. Book Depreciation | Deferred Tax | Amort of Tax Credit | Amort Gross Up | Grossed Up Amort | Lease Payments | O&M | Monitoring & Verification | Working Capital | Annual Rev Req | PV Factor | PV Rev Req |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | $275,282 | $247,615 | $261,448 | $29,230 | $46,798 | $13,764 | $11,699 | $13,902 | $4,129 | $2,708 | $6,838 | $4,600 | $500 | $5,229 | $961 | $47,446 | 0.937160 | $44,464.84 |
| 2 | $247,615 | $208,827 | $228,221 | $25,515 | $74,877 | $13,764 | $11,699 | $25,024 | $4,129 | $2,708 | $6,838 | $4,734 | $508 | $5,311 | $839 | $43,833 | 0.878268 | $38,497.22 |
| 3 | $208,827 | $181,902 | $195,364 | $21,842 | $44,926 | $13,764 | $11,699 | $13,161 | $4,129 | $2,708 | $6,838 | $4,873 | $516 | $5,393 | $718 | $40,268 | 0.823078 | $33,143.65 |
| 4 | $181,902 | $162,094 | $171,998 | $19,229 | $26,956 | $13,764 | $11,699 | $6,043 | $4,129 | $2,708 | $6,838 | $5,015 | $524 | $5,478 | $632 | $37,804 | 0.771355 | $29,160.46 |
| 5 | $162,094 | $142,287 | $152,191 | $17,015 | $26,956 | $13,764 | $11,699 | $6,043 | $4,129 | $2,708 | $6,838 | $5,161 | $532 | $5,563 | $559 | $35,757 | 0.722883 | $25,848.14 |
| 6 | $142,287 | $127,819 | $135,053 | $15,099 | $13,478 | $13,764 | $11,699 | $704 | $4,129 | $2,708 | $6,838 | $5,312 | $540 | $5,650 | $496 | $34,024 | 0.677457 | $23,049.67 |
| 7 | $127,819 | $118,689 | $123,254 | $13,780 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $5,467 | $549 | $5,738 | $453 | $32,913 | 0.634885 | $20,895.96 |
| 8 | $118,689 | $109,559 | $114,124 | $12,759 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $5,627 | $557 | $5,827 | $419 | $32,116 | 0.594989 | $19,108.90 |
| 9 | $109,559 | $100,429 | $104,994 | $11,738 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $5,791 | $566 | $5,918 | $386 | $31,326 | 0.557600 | $17,467.37 |
| 10 | $100,429 | $91,299 | $95,864 | $10,718 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $5,960 | $575 | $6,011 | $352 | $30,542 | 0.522560 | $15,960.02 |
| 11 | $91,299 | $82,169 | $86,734 | $9,697 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $6,134 | $41,876 | $6,104 | $319 | $71,057 | 0.489722 | $34,798.06 |
| 12 | $82,169 | $73,039 | $77,604 | $8,676 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $6,313 | $593 | $6,200 | $285 | $28,994 | 0.458948 | $13,306.57 |
| 13 | $73,039 | $63,909 | $68,474 | $7,655 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $6,498 | $602 | $6,296 | $252 | $28,230 | 0.430108 | $12,141.79 |
| 14 | $63,909 | $54,780 | $59,345 | $6,635 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $6,687 | $611 | $6,395 | $218 | $27,473 | 0.403079 | $11,073.69 |
| 15 | $54,780 | $45,650 | $50,215 | $5,614 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $6,883 | $621 | $6,494 | $185 | $26,723 | 0.377750 | $10,094.61 |
| 16 | $45,650 | $36,520 | $41,085 | $4,593 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $7,084 | $631 | $6,596 | $151 | $25,981 | 0.354012 | $9,197.47 |
| 17 | $36,520 | $27,390 | $31,955 | $3,573 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $7,290 | $641 | $6,699 | $117 | $25,246 | 0.331766 | $8,375.75 |
| 18 | $27,390 | $18,260 | $22,825 | $2,552 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $7,503 | $651 | $6,803 | $84 | $24,519 | 0.310917 | $7,623.40 |
| 19 | $18,260 | $9,130 | $13,695 | $1,531 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $7,722 | $661 | $6,909 | $50 | $23,800 | 0.291379 | $6,934.87 |
| 20 | $9,130 | $0 | $4,565 | $510 | $0 | $13,764 | $11,699 | ($4,634) | $4,129 | $2,708 | $6,838 | $7,948 | $671 | $7,017 | $17 | $23,089 | 0.273069 | $6,305.01 |
| | | | | $227,961 | $233,989 | $275,282 | $233,989 | $0 | $82,585 | $54,167 | $136,752 | $122,603 | $52,923 | $121,630 | $7,495 | $671,141 | | $387,447 |

Unitil Energy Systems, Inc.
Petition For Approval of Investment In
And Rate Recovery Of Distributed Energy Resources
Order Approving in Part and Denying in Part



**Stratham**
**Solar PV Facility**
**Base Case TRC Test**

| | | | | |
|---|---|---|---|---|
| Assumptions | | | | |
| Capacity (kW) | 40.00 | | | |
| Capacity Factor (%) | 14.80% | | | |
| Annual Production (kWh) | 51,859 | | | |
| Lifetime Production (kWh) | 1,037,184 | | | |
| Real Discount Rate (%) | 6.71% | | | |
| | | **Benefits/ Costs** | | |
| Direct Benefits | | | | |
| Capacity | | | | |
| Generation | | $17,537 | | |
| Transmission | | $43,303 | | |
| Distribution | | $36,582 | | |
| DRIPE | | $5,357 | | |
| Localized Distribution | | $0 | | |
| Total Capacity | | $102,779 | | |
| Energy | | | | |
| Winter | | | | |
| Peak | | $13,231 | | |
| Off Peak | | $17,150 | | |
| Summer | | | | |
| Peak | | $6,902 | | |
| Off Peak | | $8,191 | | |
| Total Energy | | $45,474 | | |
| Other | | | | |
| Energy DRIPE | | $12,028 | | |
| CO2 | | $0 | | |
| REC Value | | $41,862 | | |
| Total Other | | $53,891 | | |
| Local Economic Dev | | $0 | | |
| Total Benefits | | $202,144 | | $202,144 |
| Total Costs | | $387,447 | | |
| Benefit/Cost Ratio | | 0.52 | | |
| Indirect Benefits | | | | |
| Economic Development | | $426,282 | 25% | $106,571 |
| CO2 Externality | | $18,397 | 100% | $18,397 |
| Localized Distribution | | $0 | | |
| Total Benefits including 25% of claimed economic benefits + 100% of CO2 Ext. | | | | $327,112 |
| Benefit/Cost Ratio with indirect benefits as described above | | | | 0.84 |