New Hampshire Public Utilities Commission
Docket No. DE 09-137
Unitil Energy Systems, Inc. Petition for Investment in Distributed Energy Resources
Staff Closing Statement
March 12, 2010

INTRODUCTION AND SUMMARY

Pursuant to Commission order at the March 3, 2010 hearing in the above-captioned docket, Staff hereby submits its closing statement and recommendations regarding whether the SAU 16 and Stratham projects, proposed by Unitil Energy Systems, Inc. (UES or Company) as Distributed Energy Resources (DER) are in the public interest pursuant to RSA 374-G:5, II. Staff's position is that. while approval of the SAU 16 project would be in the public interest, approval of the Stratham project would not. More generally, Staff disagrees with the inclusion of non-direct benefits in cost-effectiveness tests of DER projects. Finally, Staff has made specific recommendations regarding the cost recovery mechanism for DER projects.

ARGUMENT

I. APPROVAL OF THE RESTRUCTURED STRATHAM PROJECT IS NOT IN THE PUBLIC INTEREST.

Despite restructuring the Stratham solar photovoltaic (PV) project in ways that reduce its overall cost, increase the benefits that flow to customers and eliminate lost revenues, the project is clearly not an economic alternative to traditional investments in transmission and distribution. The economic evaluations conducted by the Company and by Staff clearly demonstrate that the incremental costs of purchasing, installing and operating the project over its useful life are greater than the expected direct benefits. Staff's analysis shows costs exceeding benefits by almost two to one, a result that can only lead to rate increases if the project is approved. Staff's concern, however, is not so much with the rate impact that approval of this one project would inflict on customers but with the signal it would send to utilities and developers of DER projects. If the Commission gives its approval to a technology that is clearly uneconomic, utilities and developers will be encouraged to submit more projects that use the same technology and have the similar economics. In fact, those entities will be encouraged to submit uneconomic projects regardless of technology. The net result of course will be an increase in rates, the magnitude of which will depend on the number and size of uneconomic projects approved. Staff urges the Commission not to send this wrong signal.

II. THE MARCH 9 BENEFIT/COST ANALYSIS PREPARED BY UES FOR THE COMBINED SAU 16 AND STRATHAM PROJECTS PRESENTS A DISTORTED PICTURE OF PROJECT ECONOMICS.

In its March 9 filing, Staff presented an analysis (Staff Attachment 4) of the economic impact of the combined SAU 16 and restructured Stratham projects from the perspective of customers not fortunate enough to be a participant. Because there are no participants in the restructured Stratham project, Staff's combined analysis incorporates all of the costs and benefits included in Exhibit 9 in this proceeding. The SAU 16 project, however, is located on the customer side of the meter and therefore includes a participant. The participant in this case is the developer, New Hampshire Seacoast Energy Partnership, LLC. Therefore, in order to present an analysis from the perspective of non-participating customers, Staff, in its analysis, removed the costs and benefits that relate to the participant. The resulting non-participant costs and benefits are shown in Staff Attachment 3 and the combination of SAU 16 and restructured Stratham in Staff Attachment 4. In summary, Staff's combined analysis shows non-participant costs exceeding non-participant benefits by a wide margin.

In contrast, the combined analysis presented in UES Attachment 3 mixes costs and benefits that are the responsibility of the participant with costs and benefits are the responsibility of non-participants. Because participant benefits far exceed participant costs, UES Attachment 3 provides a completely distorted picture of the economics of the combined projects when viewed from the perspective of the general customer.

III. THE COMPANY IMPROPERLY CLAIMS THAT STAFF'S ANALYSIS ADDRESSED ONLY ONE OF THE NINE CRITERIA SPECIFIED IN RSA 374-G.

RSA 374-G requires the Commission to consider nine criteria when assessing whether a specific DER is in the public interest. The Company has claimed that Staff's analysis addressed only the first criterion and omitted all others. In direct testimony at the hearing, Staff explained how its economic analyses took into account almost all but one of these criteria. For example, certain environmental benefits were monetized and included in the Total Resource Cost (TRC) test certain but would not have been had the proposed projects been non-renewable. Similarly, regarding reliability benefits, Staff met this requirement by including in the TRC test specific benefits that assume the DER would be available at peak times. If the proposed DER had been determined to be less reliable than traditional supply-side resources, Staff would not have been able to include all of the above direct benefits in the TRC tests with the result that cost effectiveness would have been reduced. Staff's position on the economic development benefits is described in IV below.

IV. THE NON-DIRECT BENEFITS CLAIMED BY THE COMPANY ARE NOT SUPPORTED BY THE FACTS. IN ADDITION, THE INCLUSION OF SUCH BENEFITS IN COST-EFFECTIVENESS TESTS WILL RESULT IN RATE INCREASES FOR CUSTOMERS NOT FORTUNATE ENOUGH TO PARTICIPATE IN DER PROJECTS.

The Company argues that it is appropriate for the Commission to take into account non-direct benefits for economic development, reductions in carbon emissions above those required by existing or expected future regulations and localized distribution cost savings when assessing the public interest of DER. Staff maintains that the Commission should reject any estimate of non-direct benefits where investigation shows that no such benefits exist. With respect to economic development, the most important by dollar value according to UES, extensive testimony disclosed that solar PV projects are unlikely to contribute meaningfully to the growth in the state's economy. Underlying the Company's economic benefit calculations is the assumption that the DER investments would be spent in the local community. This 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. Solar PV systems installed in New Hampshire will be manufactured outside the state and possibly outside the country. This fact has important implications for the claim of economic development since approximately two thirds of the total cost of a solar PV system can be attributed to equipment and materials. While the remaining one third covers the cost of installation, there is no guarantee that a contractor selected to install the system in New Hampshire will be based in New Hampshire. 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 for the benefit of New Hampshire customers.

Even if UES selected a New Hampshire installer, the resulting economic impact could be smaller than calculated because the installation of solar-based DER displaces investment in UES' transmission and distribution (T&D) systems. Because such T&D investments would normally be accompanied by dollars spent in the local economy, their displacement eliminates that spending, resulting in economic contraction that offsets the economic stimulus associated with investment in solar PV systems. Unfortunately, the Company failed to consider this effect. Nor did the Company consider the impact on economic growth of installing uneconomic DER projects. DER projects such as solar PV systems that have higher total costs than total benefits will cause rates to increase for all customers. Higher rates adversely impact economic development, a fact that must be taken into account when calculating the effect of DER projects on the economy.

The second most highly valued non-direct benefit is the proposed CO2 externality. Testimony disclosed that the avoided energy benefits calculated by the Company and Staff include CO2 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 CO2 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. Leaving aside the fact that the prospects for approving a new federal framework at this time do not look good, which suggests the market portion of the CO2 cost could be overstated, Staff believes that the inclusion of the non-market portion in TRC or public interest tests is inappropriate. Not only is there no evidence in the record to support an $80/ton cost of CO emissions, the inclusion of this and other non-direct benefits in cost effectiveness tests will lead to higher rates for all customers. This is so because the use of such non-direct benefits will enable higher cost DER project to pass the Company's economic screening test whereas previously only lower cost DER project would pass. Stated differently, non-direct benefits are designed to encourage investment in DER projects that otherwise would not be installed because of their high cost. These higher costs, however, must be recovered fully through rates if the project is located on the utility side of the meter.

The third non-direct benefit is labeled localized distribution capacity and relates to the claim that interconnecting DER projects to the system at specific points can produce more distribution capacity cost savings than is possible with traditional distribution investments. The Company, however, failed to demonstrate: (i) that the local loads in the areas in which the proposed projects are to be located will exceed the wires capacity in the short or long term; and (ii) that the distribution capacity costs avoided or deferred by the proposed projects are not already captured by the Company's marginal distribution capacity cost, which UES used to calculate the standard distribution capacity benefit.

Even if UES had demonstrated that more distribution capacity costs could be avoided by strategically locating DER projects, the methodology that it used to quantify the additional benefit does not support that claim. Staff noted in its testimony that if the localized distribution capacity benefits truly are local, the per kW avoided distribution cost would vary with the location of the project. The fact that the Company's avoided costs do not vary with location raises important questions about the soundness of its analytical method.

V. THE COMPANY'S REQUEST THAT IT BE ALLOWED TO COLLECT A CARRYING CHARGE ON DER INVESTMENTS WOULD ELIMINATE UES' INCENTIVE TO CONTROL ITS COSTS AND IS CONTRARY TO COMMISSION PRECEDENT.

In response to Staff's recommended step adjustment, the Company has proposed that it be allowed to collect a carrying charge on DER investments. All of the parties agreed that the charge would eliminate the regulatory lag that the Company would incur in carrying a DER investment during the time period that spans the time the investment is placed in rate base and the time the step adjustment is implemented. Staff opposes this proposal because it would eliminate the Company's incentive to control its costs.

New investments in distribution plant usually come into base rates through a general rate case, but here, Staff has proposed to bring the costs of DER investments into rates through an annual step adjustment. While this proposal substantially reduces regulatory lag, it does not eliminate it completely. The Company would continue to experience a small amount of regulatory lag in the depreciation of the DER investment between when the investment is placed in rate base and when rates including the investment go into effect. Distribution rates, however, would be re-set based upon a rate base that included the new investment at its almost fully-capitalized amount. Although the investment's contribution to rate base would then decline over time as it continued to depreciate, rate base would not be re-calculated for ratemaking purposes until the next general rate case. Because UES earns a rate of return on its rate base, not reducing rate base as the investments depreciate means that customers systematically over-pay for these assets. This over-payment by customers offsets the regulatory lag on the DER investment. Eliminating regulatory lag completely not only disturbs this long established balance, it removes any incentive the Company would have to control its costs including DER costs.

VI. THE CLAIM THAT LOST BASED REVENUE NECESSARILY DISCOURAGES THE COMPANY FROM INVESTING IN DISTRIBURED ENERGY RESOURCES IS FLAWED.

Although RSA 374-G does not explicitly provide for the recovery of lost base revenue, the Company contends that not recognizing those costs in the cost recovery mechanism would discourage it from making DER investments. While this claim might have some merit if the goal of DER investments was to conserve energy, it has no merit under the goal contained in the legislation. That goal is to "minimize[e] transmission and distribution costs" which usually involves initiatives that focus on reducing or shifting peak loads. Moreover, the tools available to reduce or shift peak loads do not generally result in large reductions in kilowatt hours (kWhs). Given these facts, Staff contends that the case for lost revenue recovery is far less compelling when a utility elects to reduce its transmission and distribution costs through the use of projects that resemble energy efficiency programs more than demand reduction programs.

The same argument can be made with respect to the location of DER projects. That is, Staff believes the case for lost revenue recovery is less convincing when the utility elects to reduce its T&D costs through projects that are located on the customer side of the meter instead of the utility side. As the restructured Stratham solar project amply demonstrated, locating DER projects on the utility side of the meter eliminates the lost base revenue problem.

As to the specific request to recover lost revenue associated with the SAU 16 project, Staff believes that it is important to keep in mind that non-participating customers are expected to receive no net benefit despite paying a portion of the total cost. In fact, these customers will be rewarded with a small increase in rates regardless of the Commission's decision on lost revenues. In contrast, the Company will receive a full return on its investment and SAU 16 will enjoy lower energy bills for the next 20 years or so. To add insult to injury, the Company has taken the position that the incremental base revenues that its natural gas affiliate will receive in supplying gas to the SAU 16 microturbine should not be factored into the determination of lost base revenue. Further, the electrical energy generated by the microturbine (which is the source of part of the Company's request for lost base revenue) has little to do with reducing T&D costs. That electrical energy is a by-product of operating the microturbine in the winter months to meet the space heating needs of the SAU 16 administrative offices. The peak demands on the T&D system occur during the summer months.