UNITIL ENERGY SYSTEMS, INC

REBUTTAL TESTIMONY OF

GEORGE R. GANTZ

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DE 09-137

JANUARY 28, 2009

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I. INTRODUCTION

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

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

Q. What is the purpose of your rebuttal testimony?

A. The Company is filing rebuttal testimony to respond to the Testimony of Staff Witness George McCluskey dated December 23, 2010. My testimony will address policy, ratemaking and modeling issues. The specifics as the three project proposals, Crutchfield, Stratham and Exeter, will be addressed in the Rebuttal Testimony of Thomas Palma.

In providing this rebuttal testimony I would first like to acknowledge that as this is the first filing under RSA 374-G, I believe the Staff and the Company share the objective of making sure that the foundation in terms of policy, ratemaking and application of the statutory guidelines in this proceeding is clear and comprehensive and that it will provide a clearly articulated framework for what we hope will be a successful and expanding application of RSA 374-G. This will allow Distributed Energy Resources to develop and expand as a tool supporting achievement of the long term goals of increasing the state's efficiency, of promoting its indigenous energy sources and energy independence and of reducing its contributions to global climate change.

Q. Please summarize your testimony.

A. I will begin by addressing two overarching policy issues where the Company has concerns relative to the position of Staff. Specifically, I will discuss the implications of RSA 374-G as a framework for a utility to pursue a voluntary program on its own initiative, and why the Commission should reward such initiative with favorable ratemaking treatment. In addition, I will discuss the importance of the language in RSA 374-G which requires the Commission to balance the various statutory guidelines.

My testimony will then address the ratemaking proposals of staff and suggest that with certain modifications, a "Step Adjustment" ratemaking process could accomplish the goals of RSA 374-G in an administratively efficient manner.

Finally, I will address some of the modeling issues raised by Staff and provide the Company's recommendations for the Commission's consideration.

II. POLICY CONSIDERATIONS

Q. In his testimony, Mr. McCluskey recommends that the Commission deny the Company's request for Lost Base Revenues (LBR), and as a basis for this recommendation he notes that the Company's proposals are voluntary rather than mandatory. What is your reaction to that reasoning?

A. Frankly, I was puzzled by the recommendation and would suggest this issue be given a deeper consideration. With respect to the question of LBR itself, one of the primary considerations that Staff does not seem to have considered, is the fact that failure to provide recovery of LBR in the case of RSA 374-G investments would result in precisely the kind of disincentive for RSA 374-G investments that the legislation is trying to overcome. Given that a traditional distribution investment does NOT result in a decrease in kWh sales and corresponding distribution revenues, and an alternative DER investment generally WOULD result in a decrease in kWh sales and a corresponding decrease in distribution revenues, the failure to include LBR in the RSA 374-G ratemaking process would provide a disincentive for a utility to make DER investments. The Company believes this result in unacceptable and inconsistent with the intent of the legislation.

Moreover, the fact that DER investments are, as the staff notes, voluntary, underscores this point. Why would a Company choose to undertake a voluntary and innovative initiative that failed even to match the investment opportunity afforded by its traditional non-innovative business activity? Rather, the fact that RSA 374-G is intended to encourage such voluntary initiative means that the Commission should insure that its approach to all of the ratemaking issues under RSA 374-G, including the provision for LBR, provides a highly favorable climate for DER investment.

Indeed, while the Company has not requested consideration of an enhanced rate of return for its DER investments in this proceeding, RSA 374-G:5.IV authorizes the Commission to provide such an enhanced rate of return if it deems it appropriate.

Q. In his testimony, Mr. McCluskey offers several critiques of the Company's estimates for the costs and benefits of the proposed DER projects, and several times he makes a reference (e.g. page 22, the question beginning on Line 19) to making determination as to whether projects are cost-effective. What is your reaction to these comments?

A. As I read Mr. McCluskey's testimony, I realized that the Staff and the Company were looking at the modeling questions somewhat differently. I believe the Staff is viewing the model and its calculations as an exercise limited to consideration of the direct economic considerations of a proposed project to ratepayers, including participants and non-participants, whereas the Company had attempted to provide a quantitative analysis tool that would also factor in some of the indirect considerations contained in the RSA 374-F guidelines. Specifically, the Company developed the add-on economic impact evaluation, chose to include assumptions relative to the presently non-monetized value of carbon emission reductions, and developed a "local distribution impact" module, features which the Staff criticizes. In addition, the Company believes that while Staff has focused on the direct economic considerations, they have not adequately factored in the consideration of these other factors as required by RSA 374-G.

The Company does not object to a separation of the direct, monetized economic impacts on ratepayers from other factors, and, in fact, we think there is merit to the attempt to be more precise in the calculation of these direct impacts. However, we think it is equally important to acknowledge the significant and very large benefits over the long term that will result from DER investments in those categories where the benefits are not monetized or difficult to monetize. Indeed, some of the major benefits of DER investments in comparison to traditional utility investments relate to the transformational character of more aggressive energy efficiency and renewable resource development – and the broader "societal" objectives of energy independence, local economic development and responding to global climate change. In its "balancing" of the guidelines in RSA 374-G, the Company recommends that the Commission give appropriate weighting to these non-monetized factors – particularly in the early stages of the program development. Specifically, the balancing of these guidelines with the direct economic factors should not just be in the nature of a "tie-breaker" for projects that are borderline relative to direct ratepayer economic impact. We will refer to this issue in our rebuttal testimony on each of the projects.

III. RATEMAKING ISSUES

Q. In his testimony, Mr. McCluskey argues for the rejection of a reconciling mechanism for DER cost recovery. One of the arguments he makes is that the working capital component compensates for the time lag in the recovery of the Company's DER investments. Could you comment on this argument?

A. Yes, this statement was not correct, as Staff acknowledged in data response to UES Request 1-3. Nothing in the Commission's working capital allowance compensates the Company for the time value of money for capital or other costs prior to the point in time when those costs are included in rates. Working capital compensates for the timing related capital needs of the Company once investments and costs are included in rates, not before. The ability of the Company to begin recovering the costs associated with its DER investment activities on a contemporaneous basis is, in fact, a serious concern for the Company and was one of the key rationales behind its design of a fully reconciling DER rate recovery mechanism. Moreover, as noted above, DER investments are voluntary. Without a method for contemporaneous cost recovery, the Company would find it difficult to justify taking on these initiatives.

The Company continues to believe that a fully reconciling rate mechanism, such as the proposed DERIC, is an appropriate ratemaking method as, among other things, it would address the Company's concern for a contemporaneous investment recovery. The Company notes again, that regardless of when a rate is calculated or put in place and what estimates are included in the rate calculation, the Company would never book to actual costs any investment recovery until after the investment was in service and used and useful. Under any fully reconciling mechanism, if there is a period in which revenues are higher than they should be because of a problem with the estimates, those revenues are returned to customers with interest.

However, the Company's concern for contemporaneous recovery of its DER investments could be addressed in a Step Adjustment process in one of two ways. The first approach would be for the Company to implement the Step Adjustment in the month after the project goes into service. However, this could result in multiple step adjustments being implemented through the course of a year, creating a complex and potentially confusing result for customers. The second approach would be to provide for a single annual Step Adjustment, but to include an investment carrying charge at the Company's overall cost of capital for the period of time from placing a given DER investment in service to the implementation of the Step Adjustment.

Q. Does the Company have additional concerns relative to the Staff proposal to implement DER rates through Step Adjustments?

A. Yes. We are also concerned with how to factor in for rate recovery our start-up costs and, more significantly, the ongoing and very uncertain costs relating to the ongoing DER program development, project monitoring, evaluation and reporting, and future regulatory proceedings. Our intent with the reconciliation proposal was to treat these expenses in the same way we treat similar expenses for our energy efficiency programs – as an element of a fully reconciling cost recovery mechanism. This insures a direct match of our costs with the revenues collected – insuring neither an excess of charges to customers nor an inadequate recovery to the Company. I note that we would also agree with Staff that in a mature program/project planning and evaluation process costs should be factored into evaluations of costs and benefits, as they are in the case of the Company's energy efficiency programs.

We do not think it appropriate to recover these highly variable costs in step adjustments which are based on specific DER investments going into service. The ability to provide precise estimates and allocations to individual projects of these costs is likely to be very difficult – moreover, they are not likely to be stable over time, therefore resulting in a significant risk either that the Company would under-recover its costs or ratepayers would over-pay.

As one alternative, these costs could be recovered in a separate, and much smaller, fully reconciling charge for DER-related expenses. Or they could be incorporated into an existing reconciling cost recovery mechanism, such as the External Delivery Charge mechanism.

In this context it is important to note that all of the Company's internal costs in the DER initiative pursuant to this docket are fully incremental. For example, when we reorganized the group in July 2009, all of my prior responsibilities were shifted to others, and the appropriately allocated share of those incremental personnel costs are now recoverable in the Company's base rates. My ongoing direct personnel costs, as well as those of Mr. Palma and other personnel involved in designing and implementing DER, are being allocated directly to EE and DER program initiatives, for which base rate recovery is not anticipated. The advantage of this approach is that the internal costs for these programs do not get "baked in" to the Company's base rates – but rather are assigned to, evaluated as a part of, and recovered in conjunction with, the programs they are part of – on a fully reconciling basis.

Q. Mr. McCluskey raises a concern relative to the addition of Company overhead costs to the investment costs of the DER projects. Could you comment on this issue?

A. Yes. We appreciate and share the Staff's desire to minimize costs, but we think the Staff misunderstood what our purpose was in including a 30% factor in our estimates for project investment costs. Quite simply, we do not know, at this time, what the total costs are that will be incurred by the Company in taking any given project from the approval process through to completion. We have always intended that what gets booked to a given DER project will be based on actual accounting costs in accordance with our normal capital accounting process, not based on estimates. When we asked our accounting group for an estimate to use in our calculation, they indicated that a typical internal cost factor for locally contracted projects involving oversight but not construction supervision, would be 30%. I think it likely that our actual costs will be lower, but have no experience on which to base that conclusion.

The costs that will be tracked and booked to the project would include costs associated with: Completion of definitive Customer Participation Agreement; Inspection of facilities and installation; RFP development, issuance and contractor selection and negotiation, if any; Engineering or engineering review, if any; Costs of securing permits, licenses, easements or other approvals, if necessary; and other direct project-related activities. We continue to believe that a 30% factor is a conservatively high estimate of what these costs will be for a given project.

Q. Mr. McCluskey also objects to the Company's proposal to update the capital structure and debt costs for purposes of the return calculation, noting that "UES in seeking to shield itself from the risks of adverse changes in capital structure and debt costs." Could you comment on this issue?

A. Yes. Our proposal to update capital structure and debt costs was intended to insure that the costs included in rates over time are as accurate as possible – particularly as we expected the DERIC mechanism would be in place for a long time. This was not an effort to shield the Company against risk. In fact, we think it is as likely that updating capital structure and debt costs at any given point would result in lower rather than higher rate calculations. We continue to believe that these updates would be appropriate.

IV. MODELLING ISSUES

Q. Mr. McCluskey's testimony included a number of criticisms of the Company's economic modeling of the proposed projects. Can you respond to these?

A. Yes. There were a number of observations and critiques offered relative to the Company's cost benefit calculations. I have addressed the conceptual issue of isolating the directly monetized economic factors earlier in my rebuttal testimony. In addition, we respond to a number of the comments relative to particular project data inputs in Mr Palma's testimony. Therefore, my testimony in this section will be limited to specific modeling conventions and approaches. In sum, we agree with several of the comments, we agree in part with most, and we disagree with a few. I will begin with the disagreements.

Q. Mr. McCluskey states that he feels the discount rate utilized in the Net Present Value calculations, a value of 3.66%, "understates the consumers' time value of capital." Could you comment on that statement?

A. While there are many arguments about how to measure the "consumer discount rate" and what that rate should be, the rate calculated and provided in the Synapse study is being used for the identical purpose in the benefit cost calculations for New Hampshire's energy efficiency programs. The method on which the updated calculation is based has been in place for a number of years and has been vetted among the various parties and accepted by the Commission. We do not think it valid to abandon that Synapse discount rate in this proceeding unless it is abandoned for energy efficiency purposes as well.

Q. In his testimony and calculations, Mr. McCluskey indicates that he believes the Synapse avoided energy costs are too high, and based on a comparison with recent market rates he makes a downward adjustment of 10%. How do you respond to that recommendation?

A. We are concerned with any calculation that isolates and adjusts a single factor from a comprehensive, long term analysis such as that provided by Synapse. Individual factors may vary at any given point in time, but in doing long term comparative studies it is important to maintain as much consistency as possible, and adjusting one factor without assessing all of them risks introducing a bias. I would also note that energy prices are notoriously variable – the change noted in Mr. McCluskey's analysis could be reversed in the next few months or years. Again, I would also emphasize the importance of being consistent between evaluations of energy efficiency and DER – if energy prices are adjusted for one purpose they should be adjusted for the other as well. We do not agree with the adjustment of energy prices.

Q. What are the areas of Mr. McCluskey's testimony with which you agree?

A. We agree that there is an additional generation capacity benefit that may be available from bidding DER projects as Other Demand Resources in the ISO forward capacity market, and we did not factor this potential benefit into our analysis. I would only note that this is not a trivial process and entails significant dedication of financial and personnel resources to the application process and well as continuing reporting and monitoring requirements. We had anticipated that the net FCM revenues would be factored in as Offset Revenues in the DERIC reconciliation calculations.

We also agree that the avoided cost rates for Transmission and Distribution should reflect company-specific calculations, as they are available and are likely to be more accurate than the generic calculations in the Synapse report.

Consistent with my testimony above, we also find it acceptable to remove from the economic cost benefit calculation any indirect values that are not presently monetized. This includes the economic development benefits, the externalities of carbon reduction and the local distribution system reliability / project avoidance calculation. However, all three of these considerations have important value in the Commission's consideration and balancing of the RSA 374-G guidelines, and we think it important to calculate and assess the magnitude of these benefits to the extent possible.

Q. Mr. McCluskey's testimony identifies a number of costs, including financing costs, that he felt had been excluded from the Company's analysis. Can you comment on this argument?

A. Yes. Our analysis, which looks at the up-front capital requirement for a project relative to its lifetime benefits, is a simplified calculation. Technically, I agree with Mr. McCluskey that it would be more accurate to compute the lifetime revenue requirement associated with a project as well as the lifetime benefits, discounting both in NPV terms. This was a more elaborate modeling approach that we did not attempt in our original presentation, but we think it is appropriate for future evaluations.

I would note that the importance of the more detailed life-cycle revenue requirement calculation is largely a function of the difference between the cost of capital included in the revenue requirement and the discount rate. If they were the same, the more elaborate technique would not be necessary. But as the cost of capital in the revenue requirement is based on the Company's weighted average cost of capital, and the discounting is done at a societal discount rate, the more complex calculation is appropriate.

Q. Mr. McCluskey discusses the benefits associated with the Renewable Portfolio Standard, and indicates that the Company failed to include one of the two benefit streams that will be available from renewable DER investments. Can you respond to this claim?

A. Mr. McCluskey is correct that there are two possible RPS related benefits and the Company only factored in one. Specifically, there is a benefit to all ratepayers associated with any reduction in energy requirements resulting from the fact that this reduction will reduce the Company's RPS compliance costs. In addition, for renewable generation projects, there is also the benefit associated with Renewable Energy Credits which are generated. These may be sold in the RECs market or used to satisfy the Company's RPC compliance requirements. Mr. McCluskey claims that the Company left out the second benefit. However, I think it is actually the reverse. As noted in a data response, the Company did not factor in the value of a reduced RPS compliance obligation, and that is a relatively small benefit. We did, however, factor in the direct RECs value for renewable energy based on the renewable generation output of the projects. However, we may have modeled that factor incorrectly in the case of the Exeter project, as RECs would NOT be available for generation from the microturbine.

VII. CONCLUSION

Q. Does that complete your testimony?

A. Yes, it does.

UES Revenue Requirement Estimate - Stratham

Schedule GRG-R-1

Estimated Direct Cost		290,000					
Estimated UES Cost	15%	43,500					
Total Investment		333,500					
Customer Contribution		0					
Investment Tax Credit	30%	100,050					
Net UES Investment		233,450					
Investment Life	20						
Effective Income Tax Rate	39.61%						
Pre-Tax Rate of Return	11.45%						
After Tax Rate of Return	8.70%						
Tax Depreciation Schedule	20.00%	32.00%	19.20%	11.52%	11.52%	5.76%	0.00%
Property Tax Rate	0%						
EM&V	2%	Plant Investment					
Other O&M	per schedule						
Working Capital days	12						
Discount Rate	3.25%						

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Plant Investment	233,450	233,450	233,450	233,450	233,450	233,450	233,450	233,450	233,450	233,450	233,450	233,450	233,450	233,450	233,450	233,450	233,450	233,450	233,450	233,450
Book Depreciation	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673
Depreciation Reserve EOY	11,673	23,345	35,018	46,690	58,363	70,035	81,708	93,380	105,053	116,725	128,398	140,070	151,743	163,415	175,088	186,760	198,433	210,105	221,778	233,450
Tax Depreciation	46,690	74,704	44,822	26,893	26,893	13,447	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Timing Difference	35,018	63,032	33,150	15,221	15,221	1,774	-11,673	-11,673	-11,673	-11,673	-11,673	-11,673	-11,673	-11,673	-11,673	-11,673	-11,673	-11,673	-11,673	-11,673
Deferred Taxes	13,870	24,967	13,131	6,029	6,029	703	-4,623	-4,623	-4,623	-4,623	-4,623	-4,623	-4,623	-4,623	-4,623	-4,623	-4,623	-4,623	-4,623	-4,623
Deferred Tax Reserve EOY	13,870	38,837	51,968	57,997	64,026	64,729	60,105	55,482	50,858	46,235	41,611	36,988	32,364	27,741	23,117	18,494	13,870	9,247	4,623	0
Net Plant EOY	207,907	171,268	146,465	128,763	111,062	98,686	91,637	84,588	77,539	70,490	63,441	56,392	49,343	42,294	35,245	28,196	21,147	14,098	7,049	0
Average Net Plant	220,679	189,587	158,866	137,614	119,912	104,874	95,162	88,113	81,064	74,015	66,966	59,917	52,868	45,819	38,770	31,721	24,672	17,623	10,574	3,525
Working Capital Addition	7,255	6,233	5,223	4,524	3,942	3,448	3,129	2,897	2,665	2,433	2,202	1,970	1,738	1,506	1,275	1,043	811	579	348	116
Net Rate Base	227,934	195,820	164,089	142,138	123,855	108,322	98,290	91,010	83,729	76,448	69,167	61,887	54,606	47,325	40,044	32,763	25,483	18,202	10,921	3,640
Pre-Tax Return (incl Inc Tax)	26,098	22,421	18,788	16,275	14,181	12,403	11,254	10,421	9,587	8,753	7,920	7,086	6,252	5,419	4,585	3,751	2,918	2,084	1,250	417
Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMV	4,669	4,669	4,669	4,669	4,669	4,669	4,669	4,669	4,669	4,669	4,669	4,669	4,669	4,669	4,669	4,669	4,669	4,669	4,669	4,669
Other	500	500	500	500	500	500	500	500	500	500	50,525	500	500	500	500	500	500	500	500	500
Depreciation	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673	11,673
Revenue Requirement	42,940	39,263	35,630	33,116	31,023	29,244	28,096	27,262	26,428	25,595	74,786	23,928	23,094	22,260	21,427	20,593	19,759	18,926	18,092	17,258
NPV (beginning of year)	42,259	37,424	32,892	29,609	26,864	24,527	22,822	21,448	20,138	18,888	53,453	16,564	15,484	14,455	13,476	12,544	11,657	10,814	10,012	9,250
CUMULATIVE	444,578																			

Summary of Direct Economic Factors
Stratham Solar PV Project

Schedule GRG-R-2

	Total	Participant	Non-Participants
NPV Total Costs	**$444,578**	**$0**	**$444,578**
NPV Direct Benefits			
Capacity			
Generation			
Summer	$14,643	$0	$14,643
Winter	$0	$0	$0
Transmission	$22,974	$0	$22,974
Distribution	$40,611	$0	$40,611
DRIPE	$6,779	$0	$6,779
Total Capacity	$85,007	$0	$85,007
Energy			
Winter			
Peak	$13,471	$11,685	$1,786
Off Peak	$17,577	$15,247	$2,330
Summer			
Peak	$6,977	$6,052	$925
Off Peak	$8,231	$7,140	$1,091
Total Energy	$46,256	$40,124	$6,132
Other			
Energy DRIPE	$15,515	$0	$15,515
REC Credit	$77,898	$0	$77,898
Total Other	$93,413	$0	$93,413
Total Direct Benefits	**$224,676**	**$40,124**	**$184,552**
B/C Ratio	**0.51**	**N/A**	**0.42**

ADDITIONAL BENEFITS CALCULATED

	Total	Participant	Non-Participants
Economic Development	$421,040	$0	$421,040
CO2 Reduction	$20,083	$0	$20,083
Localized Distribution	$3,307	$0	$3,307
Total Benefits	$669,106	$40,124	$628,982
B/C ratio w/ Total Benefits	**1.51**	**N/A**	**1.41**

Stratham Solar PV Project Proposal
Review of RSA 374-G Guidelines

RSA 374-G Guidelines	**Assessment**
(a) Whether the expected value of the economic benefits of the investment to the utility's ratepayers over the life of the investment outweigh the economic costs to the utility's ratepayers.	Total estimated direct economic costs and benefits produce an expected value for the benefit cost ratio of the project of 0.51. Excluding participants, the ratio is 0.42. Including non-direct economic benefits in the calculation increases the calculated benefit cost ratios to 1.51 and 1.42, respectively, for all customers and for non-participants only.
(b) The efficient and cost-effective realization of the purposes of the renewable portfolio standards of RSA 362-F and the restructuring policy principles of RSA 374-F:3.	The project will produce Class II RECs with an estimated value of $77,898. These will be allocated to the Company’s Default Service customers. An additional benefit in reducing RPS compliance costs for all customers has not been calculated. The project supports the restructuring policy principles by: demonstrating an option for customers to increase control over their energy bills; encouraging a renewable technology with benefits to the environment; and fostering innovation in methods of assuring and improving distribution reliability; reducing distribution line losses.
(c) The costs and benefits to any participating customer or customers	The customer will be provided an economic benefit in the form of a lease payment that will help offset energy costs. There is also a significant benefit in the form of local education in the community about Solar PV and other renewable energy options.
(d) The costs and benefits to the company's default service customers.	The RECs secured by the project will be used by the Company for RPS compliance, thereby reducing the cost to the Company of securing equivalent Class II RECs.
(e) The energy security benefits of the investment to the state of New Hampshire.	The project demonstrates a new and exciting technology in a public building that directly reduces imports of electric energy and the fossil fuels used to produce it. The application will provide direct benefits in the form of energy and capacity price suppression (DRIPE) and significant economic benefits from the displacement of imports.

(f) The environmental benefits of the investment to the state of New Hampshire.	The project will displace central station electric production which results in environmental emissions, including CO2. A value has been estimated for the carbon reduction at $20,083.
(g) The economic development benefits and liabilities of the investment to the state of New Hampshire.	The project will result in economic development benefits in two ways – by displacing the importation of energy from outside the state (and consequently also displacing purchases of fuels imported into the region) - and by helping to foster the nascent renewable energy industry in the state. A value has been estimated for economic development benefits at $421,040. In addition, the project is estimated to result in a new increase in three full time job equivalents and wages and salaries of $100,399 annually. This project will be undertaken at a particularly sensitive time for the New Hampshire economy and for the renewable energy industry, and will in a small way provide a stimulative benefit for both.
(h) The effect on the reliability, safety, and efficiency of electric service.	The project is a component of the Company's plans to develop and implement new and advanced techniques for managing and improving its distribution system safely and reliably. The project will result in a direct offset to distribution system line losses. The Company anticipates local distribution system benefits will result from this or similar projects by avoiding or postponing the need for distribution system investments.
(i) The effect on competition within the region's electricity markets and the state's energy services market."	The project will be subject to competitive bidding, encouraging the advancement of the state's energy services markets. The project also demonstrates one important customer choice in support of renewable energy – a choice which competes with purchases from the region's electricity market.