EXHIBIT
#39
DE 16-576

UNITIL ENERGY SYSTEMS, INC.

REBUTTAL TESTIMONY OF

H. Edwin Overcast

New Hampshire Public Utilities Commission

Docket No. DE 16-576

I. Introduction

Q. Please state your name and business address.

A. H. Edwin Overcast. My business address is P. O. Box 2946, McDonough, Georgia 30253**.**

Q. Are you the same H. Edwin Overcast that filed direct and supplemental direct testimony in this case?

A. Yes.

Q. What is the purpose of this rebuttal testimony?

A. This rebuttal testimony responds to testimony filed by various witnesses related to a variety of issues that have arisen in that testimony. Specifically, I will respond to issues raised by the following witnesses: Paul Chernick for the Conservation Law Foundation (CLF), James Bride for the New Hampshire Sustainable Energy Association (NHSEA), R. Thomas Beach for The Alliance for Solar Choice (TASC), Kate Bashford Epsen for the NHSEA, Patrick Bean for the Energy Freedom Coalition of America (EFCA), Nathan Phelps for the NHSEA, Lon Huber for the Office of Consumer Advocate (OCA) and Elizabeth Doherty for the OCA. Please note that to the extent that I have not addressed the testimony of other witnesses does not imply that I agree with the points they make or their analysis. Moreover, with respect to the witnesses whose testimony I do respond to, I have not attempted to address each and every point they have raised, and this does not signify my agreement on those issues. Rather, I have attempted to respond to their major points and arguments.

Q. How is your rebuttal testimony organized?

A. In addition to this introduction, my rebuttal testimony consists of the following sections:

II. General Themes

III. CLF Witness Chernick

IV. TASC Witness Beach

V. NHSEA Witness Bride

VI. NHSEA Witness Epsen

VII. NHSEA Witness Phelps

VIII. EFCA Witness Bean

IX. OCA Witness Huber

X. OCA Witness Doherty

XI. Conclusions

Q. Please briefly summarize you rebuttal testimony.

A. My rebuttal testimony concludes that many of the recommendations and analyses of the witnesses listed above do not comply with PURPA and the FERC regulations that Congress promulgated under PURPA as they relate to QFs, state regulation of the sale for resale of the excess energy, and net metering. Net metering itself must comply with the purposes of PURPA for it to be approved.

First, I show that the use of tools developed for integrated resource planning (IRP) is not consistent with ratemaking and the calculation of avoided costs, based on the standards for IRP analysis that are inconsistent with the two fundamental concepts in PURPA and the FERC regulations: "as available" resources require a specific definition of avoided costs and must use the "but for" standard for calculating avoided costs. These are the only rate considerations, and the purchase of QF excess generation cannot exceed actual avoided costs. Further, there is no basis for approving payments above the avoided costs that will comply with the two purposes of PURPA in Section 101, namely: the optimization of the efficiency of use of facilities and resources by electric utilities; and equitable rates to electric consumers. (92 Stat. 3121; 16 U.S.C. § 2611)

Second, the failure to recognize the role of cost of service studies in determining if there is a cost shift and the magnitude of that shift in ratemaking is a fundamental flaw in the testimony of these advocates. The cost of service study is also important in establishing cost based revenue requirements for partial requirements customers who select the services and use the system differently from full requirements customers. It is consistent with both economic theory and with regulatory procedures including those endorsed by legislation and court decisions.

Third, the pervasive view that two-part TOU rates offers a solution to cost recovery for DG revenue requirements is simply not credible. That conclusion applies to both integrated utilities and even more so to delivery only utilities as a simple example will illustrate. Assume that the utility consists of three customers labeled A, B, and C. Each customer has identical demands and identical costs for delivery service as they would under rates that are cost-based. The following Table 1 provides an analysis of three rate options based on the data for each customer.

The table assumes a customer cost of $240 per year and a demand cost $50 per kW per year. The simple two part rate is a customer charge of $10 per month and a flat kWh charge of ($1470-$360)/41,000 kWhs=$0.0271. The TOU rate has the same customer charge of $10.00 per month. The on-peak charge is $0.0364 per kWh and the off-peak charge is $0.0214 per kWh. The simple three part rate consists of the same $10 per month customer charge and a demand charge of $6.17 per kW per month. The kWh charge for cost recovery is the charge that causes each customer to pay the cost of service with a $10.00 customer charge.

Table 1

Rate Design Comparisons

Customer	A	B	C	Total
Demand kW/month	5	5	5	15 kW
On-Peak kWh	8000	4000	3500	15500
Off-Peak kWh	17000	6000	2500	25500
Total Annual kWh	25000	10000	6000	41000
Load Factor	57%	23%	14%	31%
Revenue Requirement	$490	$490	$490	$1470
Simple Two Part Rate	$797.50	$391.00	$282.60	$1471
TOU Rate	$775.00	$394	$300.90	$1470
Simple Three Part Rate	$490.20	490.20	490.20	$1471
Per kWh Charge for Cost Recovery	$0.0148	$0.037	$0.0617	

Table 1 shows that neither a two-part rate nor a TOU rate tracks actual costs simply by virtue of the non-homogeneous loads of the customers. Any energy related rate, TOU or otherwise, will only recover costs from the average class load factor customer. TOU has the added complication of the average on-peak to off-peak ratio moves costs around in addition to load factor. It also calculates the different kWh charges necessary to reflect load factor in the energy charge, and those values vary by as much as 400%. It is impossible for a two part rate, TOU or otherwise, to reflect cost causation within a group of customers who are no longer homogeneous. The residential class is certainly not homogeneous when solar DG customers are included, as I have shown in my direct testimony.

The principle conclusions I reach are as follows:

- Solar DG customers must have their own rate class and be served under a three part rate.

- There is a large, persistent and growing subsidy per customer from non-DG to DG customers under current net-metering as demonstrated by the cost studies filed in direct testimony. The subsidy is most of the delivery rate, both a non-compensatory customer charge and a kWh delivery charge that recovers fixed demand related and customer costs in the use of the average energy charge. In addition, the collection of other system costs in kWh charges allows solar DG customers to bypass recovery of a number of non-avoidable, sunk costs.
- Current rates result in undue discrimination in favor of solar DG customers who have the same or greater demands as full requirements customers but purchase kWhs resulting in load factors as low as zero and up to very low annual load factors that are far below the average for full requirements customers and far below the DG customers' load factor before they installed DG. The discrimination is exacerbated by the low customer charge and the inverted kWh energy blocks, neither of which are cost based.
- Solar DG customers must be served on their own rate schedule to recover the costs they cause through demand charges and other non-bypassable charges.
- The only benefit measure that applies to ratemaking for solar DG is the avoided cost at the time excess power is delivered to the utility. Avoided cost is the maximum rate that can be paid for excess energy.
- The proper avoided cost for solar DG is the LMP value at the time of delivery. UES does not yet have the capability to use this value and will therefore base the credit on the default service rate which exceeds avoided costs, unless the value is reduced by non-avoidable costs.
- The use of an annual billing period for purposes of banking allows the DG customer to benefit from energy price arbitrage and that is a subsidy separate from the base rate subsidy. Banking must be eliminated.
- The existence of unrecovered costs from solar DG customers is proof that the rates exceed marginal cost and are thus economically inefficient, causing losses in social welfare.

- DG is not the same as energy efficiency (EE) and demand side management (DSM) as asserted by some witnesses. The impact on system kWh and kW use for distribution differs in important and material ways.

II. General Themes

Q. Is there a general theme among the witnesses whose testimony you are discussing related to cost causation and the use of cost of service studies to evaluate the costs and benefits of solar DG?

A. Yes. These witnesses ignore any use of cost of service studies to evaluate cost causation associated with solar DG customers specifically -- and other forms of DG, despite that the FERC regulations find the use of a cost of service study appropriate for determining the rates for sales to QF customers. This also directly contradicts the purpose of this proceeding as outlined in the NHPUC's Order of Notice that specifies this proceeding is to set net metering tariffs. It is impossible to set just and reasonable tariffs by completely ignoring the utility cost structure. FERC regulations state the following:

> (a) General rules. (1) Rates for sales:
>
> (i) Shall be just and reasonable and in the public interest; and
>
> (ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.
>
> (2) *Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.* (Emphasis added.)

Compliance with this regulation requires an embedded cost of service study that uses the same principles of cost causation and data for the customer's load and other cost related characteristics. The three cost studies in my direct testimony are the only evidence in this docket for UES that comply specifically with this requirement for determining just and reasonable rates. Those three studies use the same principles of cost causation for all customers. These cost studies show that solar DG customers have different load and cost causative factors than the full requirements customers in the residential class because they produce significantly lower negative rates of return. These customers were producing positive returns for the class before they installed solar DG.

I have also demonstrated in Appendix E to my direct testimony that solar DG customers are very different in cost causative factors. I show that over 60% of bills for solar DG are for zero kWh, with no zero bills when these same customers were full requirements customers. The average monthly billing load factor for these customers after installing solar DG is 7%, compared to 55% for those customers as full requirements customers. These factors alone account for the significant cost shift to other customers that will only grow larger based on the rapid growth in solar DG installations, driven by the significant and unwarranted subsidies provided under net metering.

Q. Do the FERC regulations provide guidance on the rates utilities apply to the sale to QFs?

A. Yes. The FERC regulations identify the types of service a utility provides to QF customers in § 292.305 Rates for sales. The FERC identifies these services as supplementary power; back-up power; maintenance power; and interruptible power. In the case of solar DG, the first two services are relevant. The utility provides supplemental power when solar output will not serve the full load requirements of the solar DG customers. For example, supplemental power is provided at the summer class NCP because the solar output is not sufficient to meet the customer's peak load, as shown in the base cost of service study filed with my direct testimony. The utility provides back-up power when solar does not generate at times such as the residential peaks in the months of January through March, and September through December, or seven months of the year. The maximum generation at any residential peak is only 15.3% of installed capacity and equals about 1 kW of class NCP per solar customer based on the cost study data. This is an important factor because it helps to demonstrate that solar DG has no ability to save capacity on the local delivery system because the saving is not large enough to be able to replace current facilities with smaller facilities in the future and is not large enough to allow additional customers with the same likely load to be served without adding additional capacity. Accordingly, there is no basis for avoided distribution costs even if one considers only load and not the impact of excess generation on those facilities.

Q. Have the various witnesses that you are providing rebuttal testimony to generally ignored the realities of a distribution utility that owns no generation and no transmission as it relates to the "but for" standard as used in in the PURPA definition of incremental cost to the utility?

A. Yes. There is no recognition of the relationship between the "but for" standard and the witnesses' arguments related to the alleged benefits of solar DG as it relates to the avoided costs benefits for delivery-only utilities. For example, there is no recognition that the ISO-NE transmission charges are based on embedded cost formula rates that include a true-up provision so that actual transmission costs are recovered regardless of changes in load at the time of the 12 coincident peaks. Reducing the load at a peak hour in a month does not change the total dollars of cost for transmission and does not reduce the total dollars collected to recover those costs. Under the "but for" standard there is no benefit if a cost cannot be avoided by the utility. The ISO-NE OATT is the FERC approved

Tariff applicable to the utilities, and does not provide an opportunity for the utilities to avoid costs applicable to transmission investments approved in the revenue requirements of transmission system providers. A delivery-only utility owns no transmission and hence cannot avoid any cost related to transmission.

For generation, the use of the ISO-NE marginal cost of new thermal capacity as avoided generation cost is likewise not the appropriate avoided capacity for solar DG. This conclusion is based on the PURPA requirements for rules related to minimum reliability during emergencies for both capacity and energy and the FERC ruling that avoided cost may be calculated using a like resource when state law requires that solar DG represent a specific portion of the utilities production. In that case, the avoided cost of solar DG should be based on the capacity component of a market based payment to a utility scale solar facility, assuming that the requisite legally enforceable obligation exists to permit a payment in excess of avoided costs at the time of delivery as specified in the FERC regulations.

This discussion shows that delivery-only utilities only avoided costs as noted by the FERC is the LMP at the time of excess delivery. The LMP also includes a real-time generation and transmission component, as well as losses, and therefore represents the acceptable measure of current avoided costs as required for an “as available” resource.

Q. Is there a common theme among the witnesses related to payments for solar DG that exceed actual avoided costs?

A. Yes. The witnesses, in one form or another, all promote or accept payments for solar DG in excess of the avoided cost, which is directly prohibited under the FERC regulations implementing PURPA.

Q. Does a result that compensates solar DG for more than avoided costs result in just and reasonable rates that are in the public interest?

A. No. The proposals made by a variety of witnesses recommend compensation far in excess of avoided costs, including the continuation of net metering in its present state. Each of these proposals violates the just and reasonable standards of rate making and in particular the PURPA requirement that essentially defines the just and reasonable standard as one that holds other non-participating customers harmless. PURPA specifically states that "with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, *but for* the purchase from such cogenerator or small power producer, *such utility would generate or purchase from another source*." (Emphasis added.) Thus, for delivery-only utilities such as those in New Hampshire, that value is limited to the hourly LMP from ISO-NE. This is consistent with the FERC's view of avoided costs in areas served by regional entities such as RTOs or ISOs.

Q. Are there issues related to the views of witnesses related to losses that need to be addressed?

A. Yes. There are multiple issues related to the views on losses. First, the value of marginal losses is mischaracterized. Second, avoided losses must be measured as the net effect on losses, so as to recognize the increase in losses associated with export and redelivery to the customer. Third, the loss calculation must recognize that losses as measured on the system include two components: load losses and no-load or core losses. Fourth, as a matter of the mathematics of loss calculations, the sum of marginal losses that vary with load, plus no load losses that are fixed and do not vary with load, equals the system average loss over a specific month or year. This fourth point is fundamental to understanding the true avoided cost associated with solar DG, and leads directly to the conclusion that the level of avoided losses must be less than the average losses for the system simply because of the lack of correlation of peak loads and solar DG.

Q. Please explain why avoided losses must be less than average losses based on correlation of solar DG output and load.

A. Load losses that are only a portion of total losses are highest when loads are highest. Solar DG output is zero in seven of the highest monthly load hours and is virtually zero in two other months. Even when solar DG is producing in the highest load hours the production only averages less than 38% of the solar DG kW capacity based on the 873 highest load hours. In 178 of those high load hours the solar DG output was zero. Solar DG operates in 4551 hours of the year and produces over 80% of its output in hours that are not the highest load hours. When output is produced in lower load hours and after removing no-load losses from the average losses, the remaining average loss factor for DG must be below the average of the remaining loss factor. This would be the case even before netting added losses for excess delivery to the system and adding the additional losses for the redelivery of excess generation back to solar DG customers in peak load periods. In short, loss estimates based on the testimony of the non-utility witnesses is unreliable at best. This is the reason that the TVA report on "Distributed Generation- Integrated Value" put the avoided distribution losses at below 2%.

Q. With the exception of circuits that may be overloaded or nearly so currently, why is it impossible for DG to avoid distribution costs or to result in a reduction in the size of local delivery facilities?

A. There are several related reasons for this conclusion, including lumpy capital additions, the basic mathematics of solar DG and the design of local distribution systems. First, utilities stock and install a limited number of transformer and other delivery equipment sizes to serve customers based on system characteristics and loads. This is the most efficient and economical way to design, build, operate and maintain an electric system. In particular, utilities must keep spare transformers, conductor and poles available to restore service. Stocking every size of equipment rather than a set of common sizes is both impractical and expensive. Thus, we find that a utility has a minimum size of transformer - 10 kVa for UES - and for other delivery service equipment. Utilities also use standard sizes of substation transformers. Although load changes associated with DG may be continuous in nature, those values must fit the local facilities in a way to allow a smaller transformer to replace a larger transformer or to free up adequate total capacity on existing equipment to add another customer to an existing transformer in order to avoid distribution costs.

The problem is that solar DG only produces a fraction of its output at the time of, for example, the residential peak. Since solar DG only produces a fraction of its output at the peak, the math of reducing transformer size does not work, as the following example illustrates. Suppose that 3 residential customers are served from a 25 kVa transformer. In order to install the next smallest size- a 15 kVa transformer - customers would need to reduce demand at the peak hour whenever that peak might occur by 10 kVa. Assuming a power factor of one (the actual power factor is far below one for solar DG customers because solar produces no vars) that would mean solar would need to be able to generate 10 kW at the time of the peak load or even a near peak load. For a summer afternoon peak that would require 50 kW of installed capacity to supply 10 kW of solar at a 20 percent production factor. This would also mean that in the spring and fall, the 50 kW of capacity would require a 50 kVa transformer, not a 25 kVa as installed, in order to accept the excess generation into the system. This same analysis would apply to conductor and even pole size.

A similar analysis applies to substation transformers where a 5 MVa transformer could be replaced with 3.75 MVa only if load is reduced by 1.25 MVa. To achieve that reduction requires installing 6.25 MW of capacity that continues to require a 5 MVa transformer to accept excess generation. Essentially, the math of transformer sizing is such that there is no possibility of reducing transformer capacity and no way to avoid the delivery capacity with solar DG. That conclusion also applies where the underlying load of a premise remains unchanged by solar DG and thus requires the same installed capacity to meet the sum of the customer NCPs that may occur when DG output is zero.

The net result is that only in very limited circumstances can solar DG avoid any distribution costs, and the timing of DG installations on specific circuits must be such that the capacity demand on a circuit is matched by installed solar DG in a finite time period that the utility does not control.

Q. How are cross subsidies determined within the ratemaking context?

A. Cross subsidies are determined by the use of consistent, system-wide costing principles in an embedded cost of service study or studies that demonstrate the earned return under current rate designs for customers who have different load and service characteristics. In this case those cost studies show that solar DG customers are receiving large subsidies from other customers. The subsidies have also been confirmed by showing that customers with identical cost causation pay different bills under the two-part delivery service rate by an amount that constitutes undue discrimination.

Q. Please comment on the use of cost benefit analysis to measure cross subsidy?

A. The argument that a cost benefit analysis can determine cross subsidy is not sound. Several parties recommend the use of the California Standard Practice

Manual that establishes four distinct tests for cost benefit analysis. Those tests are the following:

1. The Participant Test
2. Rate Impact Measure (RIM)
3. The Total Resource Cost Test
4. The Societal Cost Test.

These tests were developed to determine the cost effectiveness of various options in the context of an Integrated Resource Planning evaluation. It was and is used as a tool to compare non-utility solutions to utility solutions used to address future resource adequacy. The tools are decidedly not useful for determining cost shifting, and more importantly do not address the actual avoided costs that represent the benefits of DG to the utility system. As screening tools, the tests provide a variety of perspectives to determine the best, least cost options for meeting future changes in utility loads as measured by capacity and energy requirements in the context of an IRP. It should be noted that rooftop solar DG is certainly not the least cost alternative to address utility energy and capacity requirements in the future when compared to larger scale solar DG installations. Since that is the basis for comparing the cost effectiveness of alternatives to meet kW and kWh requirements in the future, these tests cannot be used to determine the avoided costs that are required under PURPA as the benefit measure for QF energy and capacity.

As proposed by various parties to this case, the calculation of the net present value (NPV) of a stream of future costs and benefits, even if properly measured (none of the proposed calculations are properly measured) does not provide a basis for determining cross subsidy. It only provides a basis for comparing the cost effectiveness of alternative resources. Those NPV values in the context of a test year do not permit a conclusion that there is no cost shift when in fact there are both temporal cross subsidies (current customers pay more and only benefit if the forecast of benefits is accurate (which it is not) and if the discount rates are proper (which they are not)) and forecast error.

The underlying assumptions used to develop these studies rely on several implicit assumptions that are false. First, the analyses assume that there is no technological change over the forecast period. Given the rate of change in technology, it is conceivable that over the life of these studies there will be multiple changes in technology that would impact many of the variables, including utility capacity options and fuel efficiency. Second, the studies assume that the relative prices of inputs do not change over time. We know based on the experiences in estimating avoided costs in the 1980s for PURPA, that both of these assumptions were proven to be false within ten years of the estimates and by amounts that stranded billions of dollars in out-of-market contracts. Finally, the future benefits ignore the growing penetration of DG and DER resources that will reduce future costs based on current technologies, as less efficient units fall out of the merit order dispatch in favor of more efficient generation operating at lower avoided costs. When a cost study shows a current subsidy that is large and persistent on a per customer basis, growth in penetration under the current net metering rules will increase the amount of subsidy annually and non-DG customers will bear an increasing share of that subsidy. I discuss these factors below in my criticism of the study filed by TASC witness Beach and have discussed a number of these issues in Appendix C, the evaluation of the Acadia Study, in my direct testimony.

Since the subsidy comes from current customers there is an impact on the correct discount rate for evaluating NPV. As I note in my Appendix C, since these costs are borne by customers in the current period, the most correct discount rate would be the consumer discount rate, which is far higher than the utility discount rate and the social discount rate, regardless of the customer class. If there are reasonable and logical adjustments to these studies it is unlikely that the benefits equal anywhere near the level of the retail rate. Further, the conclusions are not applicable to QFs such as solar and wind DG since they are intermittent resources and entitled to only the avoided costs at the time they deliver power to the system.

Q. In discussing solar DG contribution to peak demand do the witnesses generally fail to account for the effects of ambient temperature on solar DG output?

A. Yes. As a general comment, the witnesses do not recognize that solar DG capacity values are based on an ambient temperature of 25 degrees Centigrade. The actual hourly output varies with temperatures above and below the reference temperature. Specifically, for each one degree Centigrade rise in temperature, the output is reduced by 0.4 to 0.5 percent of rated capacity. If temperatures are below the reference temperature the output capacity is increased by the same percentage range per degree. In addition, solar panel output declines over its life by about 0.5 percent per year. 25 degrees centigrade is about 77 degrees Fahrenheit as a reference point for this discussion. Importantly, the temperature of solar panels at the time of system peak in the summer (typically the highest temperature day and late afternoon when the maximum temperature is reached) the actual temperature of rooftop solar may be 50 degrees Centigrade or higher, reducing the average output at that hour up to 12.5 percent. None of the witnesses make any attempt to address this impact in their estimate of the available peak solar DG avoidance and therefor their solar production estimates are overstated.

III. CLF Witness Chernick

Q. At pages 3 and 4 CLF witness Chernick states that DG flowing back to the system "has essentially the same effect on utility costs as reduction in customer loads." Is that statement correct?

A. No. This is a mistake often made by DG advocates who do not understand the fundamental difference between DG and energy efficiency or demand side management. First, DG is intermittent both behind the meter and even more so as delivered to the system. This intermittency at the customer level is a function of both load and generation variation. Energy efficiency is not intermittent nor is DSM measures. For instance, even if a consumer's only energy efficiency measure is to change to the use of a lower wattage lightbulb, that bulb will always use a lower amount of energy than the lightbulb that was replaced (all else equal).

Q. Is revenue decoupling an efficient solution for recovering the utility losses associated with solar and other forms of DG?

A. No. Quite the opposite is the case. Since current rates depart from the economically efficient rate for delivery service based on marginal costs, adding recovery of lost revenues to the energy charge increases welfare losses and is decidedly inefficient and inequitable for non-DG customers. For decoupling to be economically efficient and avoid welfare losses, these costs must be recovered in fixed charges not kWh charges.

Q. Is there any reason to use other states to compare New Hampshire's solar DG penetration?

A. No. One of the most fundamental facts about DG is that no two states are alike when it comes to valuing DG or to forecasting penetration. It is obvious that states with high energy costs and high solar insolation would always have penetration greater than other states with lower energy costs and lower insolation, all else equal. Hawaii, for example, generated almost all of its electricity with imported fuel oil prior to the expansion of solar DG. This meant that avoided energy costs were much higher than on the mainland. That plus good solar insolation, made solar DG more economic than in New Hampshire, for example.

Similarly, inverted block rates in California rewarded large solar DG customers with kWh rates that were higher than other parts of the U.S. Comparisons of penetration rates are not very useful for assessing policy since the only data that applies is the data for individual utilities in the state, and that may differ by utility.

Q. How does data from other states support a conclusion that "there is no obvious rationale for major changes in the near term" as noted by Chernick on page 7, line 7?

A. Simply, this data provides no rationale for keeping the current net metering rules in place. Other states not only have large cost shifts but a vested interest group that relied on the artificial subsidy and now want to maintain that subsidy into the future at the expense of non-DG customers. Changing the policy to comply with the statutory and rule making requirements will avoid the potential for large, long-term subsidies that are ultimately unsustainable. Further, the Commission has an obligation to cure undue rate discrimination. As Table 2 below demonstrates, the growth rate of DG resulting from artificial subsidies presents a rapidly growing problem.

Table 2 - DG Growth Rate for UES

Month (2015)	Customer Count	kW AC
1	130	749
2	136	788
3	139	812
4	147	885
5	159	988
6	166	1,095
7	177	1,175
8	186	1,232
9	197	1,317
10	213	1,425
11	241	1,623
12	285	1,928

Q. Chernick states that "photovoltaics provide more energy in on-peak than in off-peak hours, particularly in the summer, the solar generation (whether it reduces the customer's load or feeds back into the distribution system to serve other nearby customers) will tend to reduce average costs, benefiting other customers." Is that conclusion correct?

A. No. That conclusion is contrary to the evidence. The data provided in my counterfactual workpapers shows that solar DG is worth less than the residential average energy costs. That same data shows that solar DG delivered to the system is worth less than the average residential LMP and the solar DG energy used by these customers exceeds the average LMP. Table 3 below illustrates these values.

Table 3
LMP Values for Energy

Service Type	UES Average LMP per MWH
Full Requirements Residential	$47.04
Solar Production	$45.28
KWH Deliveries to Solar	$47.25
Excess KWH Deliveries to Utility	$44.08

The results in Table 2 prove that not only is witness Chernick's conclusion incorrect but that solar DG customers actually increase energy costs for full requirements residential customers in two ways. First, the energy they consume behind the meter is worth less than the average cost of energy credit and second, the energy they consume from the system costs more than the energy they deliver to the system. Since fuel cost recovery includes a true up provision, all other (non-solar DG) customers must pay higher fuel costs than they impose on the system.

Q. Chernick states at page 14 lines 7-12 that there are only "some moments" when solar DG increases losses. Please comment on that assertion.

A. The statement is not correct. Generally speaking, at the times when solar DG generates maximum power for delivery to the grid, the solar output is many more multiples of loads than two. This delivery increases voltage and also increases losses, as noted above. For the typical solar facility installed on the UES system, the average of the monthly peak deliveries is over 5.3 kW per DG customer at 12 or 1 PM but the average monthly NCP that occurs for full requirements customers is 1.65 kW and occurs uniformly at hours in the 6 to 7 PM time period. This means that there are many hours when DG deliveries exceed the customer's load. Since the class NCP occurs at a different time, we know the average load at mid-day is less than the NCP value. Table 4 below provides the peak delivery from solar DG and the average load for residential customers in those hours.

Table 4

Deliveries and Typical Loads

Peak Export Hour	(a) Solar DG Export Load per Customer (kW)	(b) Residential Load per Customer (kW)	Ratio a/b
1/14/15 12:00 PM	4.36	1.12	3.90
2/23/15 12:00 PM	5.53	0.98	5.64
3/11/15 1:00 PM	6.12	0.62	9.85
4/17/15 1:00 PM	6.08	0.65	9.39
5/14/15 12:00 PM	6.18	0.58	10.60
6/8/15 12:00 PM	5.41	0.70	7.74
7/23/15 12:00 PM	5.48	0.92	5.96
8/6/15 12:00 PM	5.19	0.89	5.84
9/14/15 12:00 PM	5.59	0.69	8.09
10/7/15 12:00 PM	5.43	0.61	8.89
11/2/15 12:00 PM	4.34	0.63	6.92
12/3/15 12:00 PM	4.28	0.72	5.95

Table 4 shows that for the midday hours in all months where output is maximized, DG deliveries exceed the customer's load by almost four times. Further, there are

1,696 hours when generation is more than twice the load. Chernick's claim is not only false, it also demonstrates that net losses are far less than average losses, given the time pattern of loads.

Q. Is Mr. Chernick correct that fixed charges provide no useful price signal, as he states at page 23, line 6?

A. Yes. However, he completely misses the relationship between a useful marginal cost price signal and the requirement for fixed charges. The seminal work of economist R. H. Coase, "The Marginal Cost Controversy,"[1] states the problems with rate setting in the context of public utilities where marginal and average costs diverge. Coase also notes that within this fundamental problem there are also two other problems that arise, as follows:

> First, some of the costs are common to numbers of consumers and any consideration of the view that total costs ought to be borne by consumers raises the question of whether there is any rational method by which these common costs can be allocated between consumers. Secondly, many of the so-called fixed costs are in fact outlays which were made in the past for factors, the return to which in the present is a quasi-rent, and a consideration of what the return to such factors ought to be (in order to discover what total costs are) raises additional problems of great intricacy.[2]

The resulting two-part rate design would consist of a marginal cost based unit charge and a fixed charge equal to the dollars per customer to raise the revenue requirements. It is this relationship of price to marginal cost that is the basis for determining if the customer charge allows the utility to send a proper price signal.

[1] Economica, New Series, Vol. 13, No. 51. (Aug., 1946), pp. 169-182
[2] Ibid. p. 170

For UES, the marginal energy price signal is the hourly LMP from ISO-NE. There is no marginal energy price signal associated with distribution demand because delivery costs do not vary with energy consumption. The marginal energy cost component of delivery costs would be zero. We also know that those costs related to customers at the margin are $38 per month per customer, based on the marginal cost study filed in the current rate case. The simple conclusion from this result is that marginal cost pricing using two part rates would require that the delivery revenue requirement be recovered in a graduated fixed monthly charge that is larger for larger customers. Those costs could be the basis for the customer charge and would reduce the energy delivery charge substantially below the current level. The result would improve total social welfare and do so without harming low income customers who receive bill discounts from 9 percent to 77 percent depending on the poverty level as a percentage of Federal Poverty Guidelines.

Q. Does Chernick have an incorrect view of utility fixed costs?

A. Yes. Chernick defines fixed costs incorrectly and fails to understand that sunk costs are fixed over the life of the asset. Further, the concept of the long run from microeconomics whereby all costs become variable, as in the competitive model, never exists for the regulated utilities. This is a common fallacy among many advocates in utility rate cases. The reason that all costs are never variable is because there are always sunk costs that have life remaining because of different vintages of plant. When Chernick states that "even though transmission and distribution costs are overwhelmingly fixed over the year, none of them are fixed over load,"[3] this is a flaw if load means kWh, and is inconsistent with his recommended rate recovery if load means demand. The inconsistency here is that, as noted by Coase (see above), customer costs ought to be borne by customers. Further, Alfred Kahn clearly defines that the parameter of the defect in

[3] Chernick Direct at p. 25 lines 1-3

cost of service is where marginal costs diverge from average costs. That divergence occurs for any utility exhibiting economies of scale. Kahn also states that the full distribution of costs "is in part along the lines that reflect true causal responsibility."[4] He goes further in that same chapter to conclude that "for those segments of demand that do not have the requisite high elasticity—prices based on fully distributed costs have much to recommend them."[5] Simply, the weight of economic theory and the practical reality that kWh do not and cannot cause delivery costs means that these fixed costs must be recovered either in the customer charge or a demand charge if the just and reasonable rate standard is to be satisfied. The recovery of fixed costs in customer and demand charges is a necessary condition for avoiding undue discrimination in a mixed monopoly and competition model.

Q. Please comment on the conclusions Chernick reaches related to demand charge price signals being inappropriate.

A. Chernick's arguments are not sound on any grounds. Importantly, recovery of demand related costs in kWh charges has been a compromise from the earliest history of electric rates. As Russel Caywood points out in his 1956 book Electric Utility Rate Economics, "Thus, compromise rates are necessary, with the result that the demand charge is sometimes included in the energy charge." (Emphasis added.)[6] As early as the 19th century, rate practitioners recognized that delivery demand costs should be recovered through demand rates. Indeed, the first electric rates were flat demand rates based on connected load demand. The early pioneers of the electric industry recognized that a three-part rate consisting of a customer

[4] The Economics of Regulation: Principles and Institutions, Alfred E. Kahn, John Wiley and Sons, Inc., New York, Sixth Printing, 1995, p. 150
[5] Id. at p. 158
[6] Electric Utility Rate Economics, Russell E. Caywood, Sixth Printing, 1972, Sponsored and Distributed by Electrical World and Russell E, Caywood, p. 27

charge, a demand charge and a kWh charge, was a superior option to any other rate form.

Q. Is Chernick correct that demand charges do not provide appropriate incentives?

A. No. Chernick creates only confusion by his claims that demand charges do not provide appropriate price signals. First, delivery demand charges are designed to reduce customer peak demands on the distribution system. There is no reason to believe that the demand charge results in higher coincident peak demands as claimed by Chernick. Local diversity is reflected in the demand charge, and does give an appropriate price signal. Chernick does not understand demand, as his claim that an electric water heater and a refrigerator that come on at the same time will create a new high demand. That is not the case. Both the water heater and the refrigerator cycle and are not likely to operate continuously for the demand interval. Further, the peak demand interval is typically not driven by just two appliances such as water heating and a refrigerator. It is also not true that customers do not respond to price signals, as evidenced by the reduced power supply costs for Butler REC in Kansas where residential customers have shifted use from the peak demand period.

IV. TASC Witness Beach

Q. TASC witness Beach states at page 3 lines 5-7 that "a DG customer effectively nets their production and consumption over a *billing period*, and pays a bill based on the net of the two." Please comment on this statement.

A. This statement is incorrect because banking is currently allowed. There is no ambiguity about the definition of a "billing period," as that term is defined in the UES Tariff and likely in each of the utilities' tariffs. In the UES TERMS AND

CONDITIONS FOR DISTRIBUTION SERVICE we find the following: "A. Billing Period Defined: The basis of all charges is the billing period, defined as the time period between two consecutive regular monthly meter readings or estimates of such monthly meter readings. The standard billing period is thirty (30) days. Bills for Distribution Service will be rendered monthly." Section 111 (d) (11) of PURPA provides the net metering standard as follows:

> Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term `net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer *during the applicable billing period*. (Emphasis added.)

It is reasonable to conclude that this definition is consistent with both the statutory construct for net metering and for the Commission to use this billing period definition and thereby eliminate the banking provision in net metering pursuant to the PURPA standard.

Q. At page 5, lines 16-17 Beach makes the statement that "New NEM tariffs that are based solely on cost of service analyses would not comply with HB 1116" because the benefits of DG are not included in cost studies. Is that statement correct?

A. No. Beach fails to understand the purpose of filing multiple cost studies that allow the Commission to review the explicit, embedded cost benefits that accrue to net metering customers. First, the energy, production and transmission benefit for net metered customers is equal to the sum of the default service rate plus the kWh portion of recovery of the external delivery charge, the stranded cost recovery charge, the storm recovery adjustment factor and the systems benefit charge. As I have shown in my direct testimony, none of these added charges are avoided costs but are nevertheless a benefit for net metering currently. Also, I have shown that the default service rate for DG customers exceeds avoided costs, and there is an explicit subsidy per kWh even in the default service. With respect to delivery service, a comparison of the revenue requirements in the base cost study to the counterfactual cost study identifies the benefit DG customers receive on an embedded cost basis. This full amount is a subsidy since there are no avoided distribution costs. The full magnitude of that subsidy is shown in a comparison of the base study to the solar class study. That subsidy results from applying system-wide costing principles to solar DG service. Table 5 below provides the customer and demand values for delivery service and provides an assessment of the implicit benefits that flow to solar DG customers under net metering.

Table 5

		UNITIL ENERGY SYSTEMS, INC.				
		COS Study Results - Revenue Requirement				
	Total	**Domestic**	**Domestic- DG**	**G2**	**G1**	**OL**
Base Study						
Energy	560,574	231,872	381	163,558	161,170	3,592
Demand	18,958,401	8,834,693	41,741	5,534,862	4,407,626	139,479
Customer	39,574,314	30,367,906	130,715	5,452,138	338,611	3,284,944
Total	59,093,289	39,434,472	172,836	11,150,559	4,907,407	3,428,015
Counterfactual Study						
Energy	559,833	231,050	1,625	162,979	160,598	3,580
Demand	18,937,309	8,815,332	62,402	5,522,586	4,397,815	139,175
Customer	39,528,585	30,332,573	130,651	5,445,919	338,200	3,281,242
Total	59,025,728	39,378,955	194,678	11,131,484	4,896,613	3,423,997
Solar Class Study						
Energy	560,574	231,872	381	163,558	161,170	3,592
Demand	18,958,401	8,802,690	111,145	5,514,318	4,391,290	138,958
Customer	39,574,314	30,367,906	130,715	5,452,138	338,611	3,284,944
Total	59,093,289	39,402,468	242,241	11,130,015	4,891,071	3,427,494

Table 5 shows a benefit to solar DG customers of over $21,000, or about $77 per customer of reduced revenue requirements. When the system-wide costing methodology is used, the benefit grows to over $69,000 or about $244 per customer. Given that these costs are not avoided at all, this is measure of the subsidy if rates were cost based. Since the rates are not cost based, the subsidy is actually much larger on a per customer basis because it is rate design that creates benefits for solar DG customers. For example, a customer that zeros out the kWh portion of the bill and pays only a portion of customer related costs, receives a subsidy of $335.41 based on rate design and the customer revenue requirement from the cost study.

Q. Have you made a forecast of the expected impact on non-participants based on the current rate of DG growth rate?

A. Yes. Table 6 below provides a forecast based on the current growth rate (2015-2016). This is a conservative estimate since the growth rate in installed PV for this set of customers is greater than the growth rate for customer count.

Table 6
Subsidy Growth[7]

Year	Forecast No. of DG Customers	Subsidy at $77 per customer	Subsidy at $244 per customer
2016	624	$48,060	$152,293
2017	1,367	$105,250	$333,521
2018	2,993	$230,498	$730,411
2019	6,556	$504,792	$1,599,599

Q. Does Beach adhere to the federally mandated "but for" avoided cost standard in suggesting the elements to be used in assessing benefits?

[7] Customer growth rate is based on the percentage change in Residential DG customers on the UES system between 2015 and 2016 for a nearly 120% growth rate; growth rate of installed PV capacity for same set of customers during same period is higher.

A. No. Beach violates this standard by including costs that are not actually avoided by UES. Under the heading of social costs, Beach includes externality costs that have not been internalized such as the cost of carbon and local economic benefits. Together these two items alone are more than six cents per kWh of the estimate of avoided costs prepared by witness Beach. Beach also double counts the cost of "criteria pollutants" by adding them as a separate item where those costs are already included in the LMP price than he escalates based on gas costs. This double counting adds another three cents to his avoided costs that cannot be avoided. The total societal costs in Beach's cost benefit analysis do not comply with the "but for" standard.

Q. Do you agree with Beach that using the same cost benefit analysis for evaluating EE, DR and DG is a reasonable proposal?

A. Yes. The use of these tools as part of an IRP process is appropriate, as I have discussed above. However, these tools are not appropriate for calculating avoided costs or payments for excess energy, and unless used properly can distort the benefits of DG, as has been done by Beach and discussed below. These costs are decidedly not the equivalent of avoided costs as that term is defined by PURPA and FERC regulations.

Q. Please comment on the statement at page 9 lines 15-16 that "each net-metered DG project is generally associated with a load at least as large as the DG project's output."

A. This is the kind of misleading statement that causes confusion and leads to incorrect conceptions of DG economics. In the context of this statement the term load has two potential meanings. First, load may be measured as kWh consumption. That is the only case where this statement is generally true. In the second context load may be measured in kW or capacity. In that context the statement is incorrect because in order for the first meaning to be correct (kWhs of production = kWhs of consumption) it is impossible for solar DG to be at least as large as kW demand for a premise. The kW of generation capacity must always be significantly larger than the kW of load for the first proposition to be true. The basic reason is obvious since the capacity factor of solar DG production is less than the load factor of the customer. For UES, the solar DG customers have an NCP class load factor before installing solar DG of 44%. The DG capacity factor we have used is 18.7%. The result is that installed DG capacity must be 2.35 times the class coincident peak load. Using the NHSEA capacity factor of 13.5% would require about three times the class coincident peak and with no diversity as with load. Table 7 below provides a comparison of the various loads that DG customers have imposed on the system as both full requirements customers and as partial requirements customers.

Table 7
Comparison of DG Customer System Loads

Month	Base case Peak Load (kW)	Counter Factual Peak Load (kW)	Solar Class (Export) Peak Load (kW)
1	788	788	1,244
2	834	834	1,575
3	728	728	1,745
4	578	579	1,733
5	637	785	1,763
6	732	737	1,541
7	667	978	1,562
8	810	933	1,479
9	948	948	1,594
10	635	635	1,548
11	703	703	1,237
12	745	745	1,219

This is why it is not possible to assume any avoided delivery costs since the solar DG excess load requirements causes the utility to have to use the same size or larger transformer and associated delivery facilities to accept the output without damaging that equipment as was required by customer load.

Q. Beach recommends a long-term, life-cycle timeframe for assessing avoided costs. Please comment on that concept.

A. As I noted above, this may be appropriate for an IRP analysis but not for calculating avoided costs. The FERC regulations are prescriptive in this regard. An "as available" resource such as solar DG or wind is only entitled to avoided cost at the time of delivery. Life-cycle cost analysis is only available under a long-term legally enforceable agreement. Even in the IRP it is imperative that this type of analysis uses the correct avoided costs and an applicable discount rate, and follows the "but for" standard set forth in PURPA and the FERC regulations.

Q. Does Beach support the conclusion that DG differs from EE and DR?

A. Yes. In contrast to witnesses Chernick and Bride who mistakenly conclude that DG is like EE and DR, Beach reaches the correct conclusion.

Q. At page 13 lines 1-4 witness Beach states that export power will serve 100% of neighboring load with renewable energy. Please comment?

A. The statement is incorrect for a number of reasons. First, the statement cannot be correct under today's mode of operation since solar DG produces no vars and the neighboring loads will require vars to operate. Vars are ultimately only available from central station generators. Second, the extent of service to neighboring loads depends on the aggregate DG output, which is a function of installed capacity, ambient temperature and other factors that impact output, the penetration of DG on a circuit and the aggregate loads of non-DG customers on the circuit at the time of excess production. For example, if there are three customers on a transformer and two of those customers have DG, the maximum power delivery will exceed load during low load periods when DG excess power is delivered. If we assume, for example, about 15 kW of deliveries, that power would serve about

20 plus customers. This would mean that power would flow into the primary system and move through about 6 transformers that serve 3 customers each. The larger the DG penetration on a circuit, the larger the likelihood that power will flow to a substation and onto the transmission system. Third, regardless of the source of power, the grid still requires voltage and frequency regulation for all customers. This is important, since overvoltage may impact neighboring customers and disconnect DG from the system. This precludes delivery to any customers.

Q. At page 14, lines 8-11, Beach states that "it is not the DG customer who is using the distribution system, it is the distribution utility and the DG customer's neighbors, because the title to the exported power transfers to the utility at the solar customer's meter. Please comment on this statement.

A. The statement is incorrect based on the concept that customers who cause cost must pay for that cost. The cost causation results from the utility providing sufficient capacity to the DG customer to permit the power to flow from the generation to load. In order to accept the expected maximum delivery of a DG facility the utility must provide adequate capacity to not only serve DG load but also to permit excess delivery. To take a simple example, suppose a commercial customer has 90 kW of load and is served from a 100 kVa transformer. If that customer operates at a 50 percent load factor (think a 24 hour McDonalds) the required solar capacity to zero out kWhs is about 240 kW. If the facility operates at 90 kW at noon on a spring or fall day there is 150 kW flowing back to the system. To accept delivery of 150 kW the transformer would need to be at least 150 kVa, if not larger. It potentially may require 200 kVa to accept delivery. It is obvious from this example that the customer with DG causes the utility to install a larger transformer to accept generation. Clearly, the utility must provide adequate capacity to accept the maximum delivery of the DG customer, and that delivery is larger than the kW load requirement of the customer, as I have shown in my direct testimony. It is the DG customer that causes the cost, not the customers receiving delivery service who only cause the cost of their own peak demand.

Q. Please explain the net savings associated with DG delivered in the neighborhood as discussed by Beach.

A. Beach does not properly assess the value of the excess DG delivered to the system. The value is the loss adjusted LMP in the hour of delivery, less the losses associated with energy measured at the DG customer's meter and ultimately delivered to the consuming customers' meters, consisting of load losses on the host service line, in the transformer, on any conductor to move to the next transformer, transformer load losses and the receiving customer's service line. In addition, there are losses associated with the elevated voltage when power flows back to the system. Thus, the net saving in that part of the transaction result in a value less than the loss adjusted LMP. Then one must consider the losses associated with the generation and delivery of that same metered kWh back to the DG customer at some later period. This is the correct definition of avoided costs, not the discounted future value of inflated avoided costs as proposed by Beach.

Q. Please explain why you say Beach uses inflated avoided costs.

A. As I note above, all of the societal costs included in Beach's avoided cost calculation do not comply with the PURPA definition of avoided costs. These costs are speculative, not subject to any reliable estimate, and from an economic perspective should not be included in valuing one product when not included in other products, since that distorts social welfare. I will not discuss those values any further. I will, however, discuss some other components of the calculated avoided cost from Appendix D. Before providing that discussion, it should be remembered that solar DG, as an intermittent resource, is only entitled to avoided costs at the time of delivery. Having said that, I will discuss the errors that result in inflated avoided costs, focusing on energy, generation capacity, transmission capacity and distribution capacity. As I have discussed other elements in my review of the Acadia study in Appendix C of my direct testimony, I will not address those issues as they relate to witness Beach's avoided cost calculation. I merely point out that the same criticisms apply as these other items are not part of avoided costs for UES.

Q. How does Beach inflate avoided energy costs?

A. The calculation of avoided energy costs is based on erroneous assumptions, ignores the impact of growing DG penetration over time, uses an incorrect discount rate, uses an incorrect avoided loss factor and fails to recognize the role of technology changes on the expected avoided costs, particularly over such a long period as 25 years. I will explain the issues individually below.

Erroneous Assumptions:

Beach assumes that the marginal heat rate from the 12 months ended in the third Quarter of 2016 remains the same over the entire future period. Implicitly, this ignores the fact that the actual level of forced outages in that period is equal to the expected level of forced outages in all of the future years. It also assumes that the scheduled maintenance in the twelve months used to develop LMP is identical to the schedule for maintenance over the next 25 years. By escalating the LMP value by the cost of gas, Beach assumes that the marginal fuel in all hours when solar DG is operating is natural gas. Table 8 below shows that in over 50% of the hours when DG is operating the marginal fuel cost is less than natural gas, based on a comparison of actual delivered gas costs and a calculated gas unit monthly average heat rate that over the year averaged 9,580 BTU/kWh.

Table 8

UNITIL ENERGY SYSTEMS, INC.		
Marginal Fuel Analsysis		
Summary		
Description	**Amount**	**Units**
Annual Solar DG Production per KW Installed Capacity	1,637	kWh
No. Of hours when marginal fuel cost less than gas	6,056	
Solar DG production when marginal fuel cost less than gas	879	kWh
% of solar DG production that displaces marginal fuel cost less than gas	53.7%	

Table 8 shows that assuming a rate of LMP based on the escalation of gas prices overstates the expected LMPs. A proper calculation would dispatch ISO-NE for each year using a probabilistic dispatch model and determining the nodal prices for the New Hampshire load node. The forecast would include the expected load growth, net of DG, DSM, EE and the resulting modification of the load shape resulting from DG. The forecast would also include the unit retirements and the capacity additions. This type of work is critical for ISO-NE because of the impact of pumped storage that serves to lower on-peak costs and raise off-peak costs. The modification of the load shape will likely change the dispatch of pumped hydro and the pondage hydro assets. In addition, the increase in renewables will also impact the marginal fuel costs. None of this is taken into account in the assumption that escalating the LMP by a gas price index does not reflect the future value of LMPs by itself.

Impact of DG Penetration

As DG penetration increases, the marginal unit, gas or otherwise, becomes more efficient, thereby reducing avoided costs. By 2025, ISO-NE forecasts an additional 2000 MWs of additional solar and 3200 MWs of wind generation on the system. At these levels of generation, the interaction of wind with pumped storage and solar will almost certainly lower the peak period marginal costs. Since these changes occur during the first ten years of the period that avoided costs are calculated over, the costs are likely to be overstated significantly since the discounting effect is smaller over time.

Discount Rates

The discount rate used to estimate the net present value of future energy costs is the utility's weighted cost of capital. In this case we are determining the costs and benefits for customers because LMP and related costs are passed through to customers. The customer discount rate is higher than the utility discount rate and varies by class of service. The business discount rate is higher than the domestic customer discount rate. In the domestic class, discount rates are higher for low income customers (some might say infinite) and decline as income increases. In any case, they are higher than a utility's weighted average cost of capital, with a typical estimate being about 20%.

Incorrect Avoided Losses

Beach uses a loss factor for UES of 6.47%. This value is the same loss factor that is used for peak generation and therefore must be the marginal loss factor that witness Beach assumes to be the peak loss factor. The loss factor, however, is not the system loss factor. It is the residential loss factor, and overstates the avoided losses for both capacity and energy because the value includes no load losses and ignores the added losses of DG. As I have explained above, the marginal loss factor for solar DG must be less than the system average loss factor. A reasonable estimate for UES would be less than 2%. If the levelized cost of energy is adjusted for only the discount rate and the lower loss factor, the NPV is reduced by over 1.2 cents per kWh. The resulting value on an NPV basis is also less than the Default Service Rate.

Technological Change

Beach has not accounted for any technological changes that would improve heat rates, increase the use of nuclear resources, create options for lower cost fuel resources and so forth. Although this kind of information is difficult to quantify, witness Beach opines that even difficult to quantify benefits should be included. For example, it might be reasonable to track the progress of full load heat rates over time and estimate some value for that factor that would further reduce avoided energy costs.

Taken together, it is difficult to say precisely how much correcting for these errors would reduce the NPV of energy costs. It is likely to be less than $0.05 per kWh. Since an intermittent resource is only allowed current avoided costs, the point means nothing except for getting the rooftop solar value correct in an IRP Plan.

Q. How does Beach inflate the NPV of avoided generation capacity costs?

A. As with the energy component, Beach has inflated a number of values used to make the calculation. These include significant differences in the avoided capacity cost, using an incorrect avoided capacity value based on an analysis inconsistent with the requirements of SECTION III, MARKET RULE 1, STANDARD MARKET DESIGN that is incorporated in the ISO-NE OATT, using incorrect losses and double counting reserve margins. Each of these points will be discussed below.

Incorrect Avoided Capacity Value

The Forward Capacity Market Value (FCM) is based on bids of thermal generation. The FERC has allowed utilities to base capacity payments on the avoided costs of like capacity to recognize that where utilities have an obligation to include renewable resources thermal resources cannot be avoided. Based on utility contracts with utility scale solar DG, the total payments have been between four and six cents. This would translate to a capacity payment of only about one or two cents per kWh if solar DG were entitled to a capacity payment beyond that included in LMP. Solar DG is not allowed to be paid more than current avoided cost at the time of delivery under the FERC regulations for intermittent resources. ISO-NE defines solar DG as an intermittent resource.

Incorrect Avoided Capacity Value

Beach has developed his own method for calculating the capacity value of solar PV. He refers to this value as the "PV Load Match%." He calculates this value based on "the median of hourly PV capacity factors during the top annual load hours in the New Hampshire zone on the ISO-NE system."[8] The use of the top 100 load hours results in the capacity value being based on hours that occur only in the summer and in hours that are as early as hour ending at 11 AM. To meet the ISO-NE test for inclusion as a resource in the FCM auction the resource must file a claimed summer Qualified Capacity and a winter Qualified Capacity as required by Market Rule 1. The rule states further in the FCM that the "The Summer Intermittent Reliability Hours shall be hours ending *1400 through 1800 each day of the summer period (June through September)* and all summer period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone." (Emphasis added.)

The first issue is that Beach does not provide an analysis consistent with the ISO-NE requirements. The determination of the summer capacity is calculated as "With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's *net output* in the Summer Intermittent Reliability Hours." (Emphasis added.) This means that Beach has overstated the value by using the total solar DG output, not the net output. This is critical because the output used behind the meter has been counted in the analysis as reduced load, so the analysis by witness Beach double counts a portion of the

[8] Beach Direct Testimony, Appendix D, page D-3, first full paragraph on the page.

output. The effect of this error is quite large, as witness Beach uses a value for Unitil that is 50.9%. The value that is consistent with summer Qualified Capacity is actually 8.24% or one-sixth of the value used by witness Beach. Using this corrected value reduces the avoided cost to $2.73 per mWh, not adjusted for losses. In any event, this is a value that is less than three tenths of a cent per kWh. There is more than this value included in the default service rate.

Using Incorrect Losses

Similar to energy, the capacity loss factor is inconsistent with the way the capacity value is calculated. The capacity value is calculated as discussed above, and includes 610 hours, not all of which are high load hours. As with energy, the loss factor should not be higher than the average loss factor less no load losses for those hours. In any case it cannot be as high as 6.47% because that is the residential loss factor not the system.

Double County Reserve Requirements

Beach adds a reserve margin to the FCM value in calculating the avoided generation costs. In doing so, witness Beach double counts reserves. This occurs because the capacity acquired by ISO-NE in the auction is already based on load plus reserves. Thus, the FCM includes a reserve component in the capacity costs. Adding a reserve component is incorrect in the market environment, but may be appropriate when using a proxy unit that just matches the load growth component. If the proxy unit meets load growth plus the reserve requirement then it is inappropriate to add a reserve requirement. This adds 14.3% to a cost that already includes the ISO-NE required reserves. Further, Beach makes this calculation based on the loss adjusted cost of capacity and yet there are no avoided losses associated with reserve capacity since reserves are only substituted for load service capacity when a load serving entity is out of service. The losses related to load are already accounted for in the avoided capacity cost component. This is just a further example of inflating avoided costs as a result of a lack of rigor in the analysis. Therefore, the 14.3% increase in avoided costs is not correct and must be removed in its entirety from the avoided cost calculation.

Q. How does Beach inflate transmission capacity costs?

A. Beach makes no attempt to calculate avoided transmission costs for UES. Instead, he uses an embedded cost rate as a proxy for avoided costs. Given that much of the increase in transmission embedded costs reflects infrastructure replacement and system hardening, those costs are not avoidable as a result of DG. Like distribution capacity costs, avoided transmission costs, if any, are unique to a location or are avoided generation laterals if any. Transmission congestion costs are already included in LMP and have been accounted for in the energy component of the avoided costs. The embedded cost value bears no relationship to avoided costs and in fact, the costs cannot even be avoided because of the formula rates underlying these costs and the true-up provision in the respective Tariffs. He also uses his load match analysis to determine the capacity contribution, and as a result, double counts the avoided transmission costs. This is because part of the output has already reduced the load as measured, and only the net portion is available to reduce the capacity requirement that is not already reflected in both the LMP portion and the default service rate. The lower default service rate provides a direct benefit to DG customers on the basis of an embedded cost. Those reduced kWh are treated the same as any other change in load in the peak hours and those avoided charges flow back to other customers in the true-up provision as another source of subsidy. In essence, the analysis provided by Beach provides no basis that these costs can be avoided at all under the "but for" standard for avoided costs.

Q. How does Beach inflate avoided distribution capacity costs?

A. Beach uses the marginal cost from the rate case marginal cost study. Unfortunately, the marginal cost of serving additional load does not and cannot equal the avoided cost of reduced load. As a result, the dollars used to estimate avoided cost based on a marginal cost study cannot be used to estimate avoided costs. It is important to understand that traditionally, the two values would be equal because marginal cost is the first derivative of a continuous cost function. In reality, however, a utility does not have a continuous cost function because additions are lumpy as in the case of the data used in the UES marginal cost study. A decrement of load must be large enough to change the investment either by avoidance or delay of the installation of delivery service equipment. As noted above, neither of these options are realistic for UES and there are no avoided distribution costs. Further, Beach states that these values were derived by regression analysis and that is not the case. In fact, his use of regression results always overstates marginal cost and cannot be correct because the underlying data is not forward looking (the only correct view of marginal cost), does not properly reflect load growth and does not properly identify the actual added capacity. This value, like transmission avoided cost, is unreliable, calculated incorrectly and ultimately is zero, with the one exception being unique to a particular location at a specific time. This value should be completely removed from the analysis.

Q. Have you corrected the analysis prepared by witness Beach?

A. No. The errors are so numerous and the results are not relevant for ratemaking or avoided costs, so there was no attempt to correct the errors. Having said that, it is reasonable to assume the value would be less than the default service charge.

V. NHSEA Witness Bride

Q. Please comment on NHSEA witness Bride's views related to consumers rent seeking.

A. I am not aware of any consumers who have filed testimony on their own behalf. The concept of rent seeking could be an individual customer and often is where customers are large enough to intervene on their own behalf. I note that the interveners in this case with a few exceptions are in fact "rent seeking." I reach this conclusion based on the same factors that Alfred Kahn recognized. Specifically, Dr. Kahn recognizes this behavior by these entrants and summarizes the impact of this behavior by noting "the encouragement that *preferential subsidies and protections of this kind give to would-be competitors to devote their entrepreneurial energies primarily to seeking such preferences and ensuring their perpetuation by interventions before regulatory agencies* and the courts, rather than concentrating on being more efficient suppliers than the incumbents."[9] (Emphasis added.) I would merely note that the NHSEA board includes both a President and a Treasurer with interests in perpetuating subsides and protection of net metering with banking as being in their financial interests.

Q. Please comment on Bride's statement that "consumers deserve to be compensated for net metered generation commensurate with the value of that generation to the electric grid."

A. I agree with this statement so long as the term value is properly defined consistent with PURPA and FERC regulations implementing PURPA. That value is stated plainly as avoided cost at the time power is delivered to the utility by an intermittent resource. The definition of avoided cost has been fully discussed above and in my direct testimony.

Q. Does Bride mischaracterize the cost causation for transmission facilities?

[9] "Letting Go: Deregulating the Process of Deregulation", Alfred E. Kahn, 1998, MSU Public Utility Papers, p. 21

A. Yes. Bride says that transmission is built to meet summer peak load. That statement is not correct because he fails to understand that a transmission system is not just one component. There are three portions of the transmission system: Generation laterals, load laterals and the bulk transmission system. Generation laterals are designed to connect generation to the bulk system. Load laterals are designed to connect the bulk system to meet the peak loads of the substations that serve load. The bulk system is designed to move power within the system, from outside the system to inside the system, from inside the system to outside the system and completely through the system. In an integrated system like the ISO-NE, transmission is also built to alleviate congestion at nodes on the system. The limited view of transmission expressed by witness Bride causes him to reach incorrect conclusions related to transmission cost causation. This causes the witness to improperly determine potential avoided transmission costs. Since I have discussed avoided transmission cost above I will merely say that the facts of transmission cause Bride to use the same incorrect calculation of avoided transmission costs as witness Beach above.

Q. Is Bride correct that solar DG reduces the duration of peak loads on the distribution system?

A. No. The result of solar DG on the system is the CASIO "Duck Curve" that shifts the peak to a later hour and increases the duration of peak loads because solar reduces peak distribution loads by very small amounts in the later afternoon when the residential peak occurs. Also see Appendix E of my direct testimony to see the resulting load profile and the analysis provided by Mr. Meissner in his direct testimony regarding peak shifting.

Q. Do you agree with the assertion Bride makes on Page 4-5 of his testimony that the economics for solar PV in New Hampshire are marginal?

A. Absolutely not. I reviewed the analysis Bride provided in response to UES Data Request UES-NHSEA 1-3. His analysis overstates the payback period for the residential solar PV customer due to the following reasons: 1) he did not reflect the current banking provision that provides a customer the ability to bank exports against future imports; 2) he used an average PV installed size that is significantly lower than what is installed for UES; 3) his full load requirements profile is significantly lower than what we have calculated for UES solar PV customers using UES metered data; and 4) his solar production profile is not consistent with the UES service territory. In addition, it is entirely likely that many solar PV developers are able to share some of the value they receive from RECs as an added cost incentive for PV customers, yet Bride has not included that in his analysis. The combined effect of these flaws is to overstate the payback period by at least 3 years.

Q. Bride states that "A demonstrated cost shift has yet to be documented in the case record or in other related NH PUC proceedings." Is that statement correct?

A. No. There is more than sufficient evidence in my direct testimony to prove the existence of a substantial cost shift, including the existence of undue discrimination in favor of solar DG customers. It may be true that Bride does not like an inconvenient truth for his position. However, as I have discussed above and in my direct testimony, the cost studies filed demonstrate a cost shift under the most favorable operating circumstances for solar DG.

Q. Bride states that "it is illogical for utilities to claim that installation of solar PV fundamentally changes the customer to the point where they require a separate rate." Please comment on this statement.

A. To the contrary, the separate rate is cost based, logical and mandated by the just and reasonable standard for rates. While there is always some level of subsidy among different customers on the same rate schedule that result from averaging costs, a subsidy that results in customers using the same level of service paying annual bills that differ by hundreds of dollars represents undue discrimination, and not simply the discrimination of average costing. The subsidy between full and partial requirements customers is such that a kWh rate cannot adequately or fairly recover the costs the customer causes. There are two options available to address this issue: Change rate design for the whole class; or separate the class into two classes. As I have shown, the kWh based recovery of fixed delivery and customer costs cannot result in equitable rates for consumers as required by PURPA for a state to implement net metering. The simplest and most expedient option is to treat DG customers as separate classes of service, eliminate banking, and use demand charge based rates.

Q. Do fixed charges contravene energy efficiency goals as claimed by Bride?

A. No. Fixed charges actually improve energy efficiency and increase social welfare dramatically when they allow the energy charges to reflect short-run marginal costs. Contravention only occurs if the definition of energy efficiency is an absolute reduction in use, and that is decidedly not the definition of energy efficiency.

Q. How are peak load hours defined in an efficient utility as compared to Bride's use of a four hour on-peak period?

A. No efficient utility defines peak hours based on an arbitrarily determined time period. One of the most important uses of marginal cost analysis is to determine on-peak hours based on differences in marginal cost. ISO-NE defines on-peak or peak hours as "on-peak hours: From 7:00 a.m. through 11:00 p.m. on all nonholiday weekdays; same as peak hours." This is decidedly not an arbitrary set of hours and would be the period applicable to UES if it set on-peak hours for LMP. LMP is the only energy related cost that varies by time of use. A four hour on-peak is not efficient and decidedly not cost based.

VI. NHSEA Witness Epsen

Q. How does NHSEA witness Epsen define a just and reasonable rate of compensation for solar DG?

A. Epsen states "A just and reasonable net metering compensation rate result implies that utilities, customer-generators, and non-net metering customers are appropriately charged and/or compensated."

Q. Please comment on that definition.

A. This is the exact same position that UES has used to prepare its filing, with the caveat that there are legislative and regulatory constraints that set parameters for the determination of the appropriate charges and compensation for DG facilities.

Q. Does Epsen, like Bride, opine on the evidence to support this definition?

A. Yes. She makes the same claim as Bride, only in different words. Like Bride, she ignores inconvenient evidence and is likewise incorrect in her assessment of the record. She also makes other claims about the net benefits of solar, and that those benefits accrue to all customers. The inconvenient truth is that is not the case, as I have demonstrated in this testimony and in my direct.

Q. Epsen describes net metering as a "retail product." Please comment on that claim.

A. Net metering has two components. As it is used by the customer behind the meter, it is by nature a retail product under net metering. However, if the Commission were to establish a buy-all/sell-all arrangement, even that classification would be lost. Without the PURPA legislation that carved out sales for resale from QFs for state commission regulation, pursuant to rules issued by the FERC, the moment excess energy is delivered to the utility for resale it would have come under the jurisdiction of the FERC. Without QF status, utilities would have no obligation to purchase energy delivered to it and the Commission would have no rate jurisdiction over the sale of that energy.

Q. Please comment on Epsen's claim that more data is needed to address customer classes and cost causation.

A. This has been a standard claim made by solar DG advocates in an effort to avoid ever reaching a conclusion since delay maintains the status quo. The claim is not consistent with the evidence that provides clear load characteristics, clear cost causation and system impacts. There is more data in this case than would be found in a typical rate case. For example, the data includes hourly load, generation and marginal cost data. The case has multiple cost studies based on consistent and sound systemwide costing principles that reflect cost causation properly. No more data is needed.

VII. NHSEA Witness Phelps

Q. NHSEA witness Phelps states that he provides cost benefit analysis for various states and relies on work prepared by the Rocky Mountain Institute (RMI) to develop cost benefit analysis. Please comment on this approach.

A. As RMI has carefully pointed out in the report Phelps relies on for data and analysis, the results of these studies cannot and should not be used in different states or even different utilities in the same state. RMI states the following:

> "There is a significant range of estimated value across studies, driven primarily by differences in local context, input assumptions, and methodological approaches.
>
> Local context: Electricity system characteristics—generation mix, demand projections, investment plans, market structures —vary across utilities, states, and regions.
>
> Input assumptions: Input assumptions—natural gas price forecasts, solar power production, power plant heat rates— can vary widely.
>
> Methodologies: Methodological differences that most significantly affect results include (1) resolution of analysis and granularity of data, (2) assumed cost and benefit categories and stakeholder perspectives considered, and (3) approaches to calculating individual values."[10]

RMI correctly recognizes that results are not transferrable from one utility to the next. They also recognize that that assumed cost benefit categories vary as they must depending on the context of how those analyses are to be used. Phelps fails to recognize that in the context of ratemaking and determining cross subsidies, his recommendation to use only the societal cost test is incorrect. Further, to limit review in an IRP context to the societal cost test is incorrect as well.

Q. Is it permissible for the Commission to rely on the results of studies from other states to determine the level of cross subsidy?

A. No. There is no context where data from another state is useful to the Commission when it has data from UES that is based on a sound cost of service methodology that is consistent with the FERC regulations and demonstrates the

[10] A REVIEW OF SOLAR PV BENEFIT & COST STUDIES, 2nd Edition, Copyright Rocky Mountain Institute 2nd Edition, published September 2013, download at: www.rmi.org/elab_emPower, p. 4

magnitude of the cross subsidy. In addition, rate evidence confirms the level of undue discrimination between solar DG customers and full requirements customers who cause identical levels of average system costs.

Q. Why is it incorrect to use the societal cost test to assess subsidies in a ratemaking context?

A. There are a number of reasons why ratemaking requires a cost study and why the societal cost test does not comply with PURPA or the FERC regulations implementing PURPA as it relates to QFs. Simply, in the rate making context the concept of subsidy is determined in a test year. Further, the societal cost test includes costs that are not avoided costs and cannot meet the "but for" standard in PURPA. In response to UES-NHSEA- Phelps-3, Phelps acknowledges that the societal cost test is cost/benefit analysis and "not for the calculation of avoided costs."

Q. At page 10, Phelps states that DG does not use the transmission system. Is that correct?

A. Phelps is not correct in two contexts. DG customers do in fact use the transmission system on a continuous basis. First, it is obvious that when they purchase supplemental and standby services from the grid that they are using the transmission system. Second and less obviously, DG customers use the transmission system even when they are fully meeting their own load, in order to provide in rush current that comes from the grid and to provide needed reactive power on a continuous basis, since current inverter technology does not provide vars. As I discuss above, no transmission costs are avoided by DG for UES.

Q. Does Phelps provide any analyses that can be relied on to conclude that all customers benefit from rooftop solar DG?

A. No. His claim of benefits relies on erroneous analysis and ignores the simple evidence that adding a solar customer does not reduce UES costs as much as it reduces revenue. Other customers must pay for the lost revenue, and that is a clear subsidy. This position is consistent with the position of David Wright, former President of NARUC, whose article in the "Power Industry Professionals" of Energy Central included the following:

> "Net metering policies create a severe cost shift between net metering customers and those customers who do not receive their electricity from rooftop solar. This occurs because rooftop solar customers are given a subsidy for the energy they sell back to the grid, which is very small, while non-solar customers are picking up the tab for the energy they consume when the sun isn't shining. This means that rooftop solar customers avoid paying for the fixed costs that help maintain the wires, poles and other infrastructure that comprise the electric grid."[11]

As Commissioner Wright notes, net metering creates a cost shift.

IX. EFCA Witness Bean

Q. Did EFCA witness Bean prepare his own cost/benefit analyses?

A. No. Bean relies on the study prepared by Beach. As I have shown that study is incorrect in a number of areas, Bean has endorsed those same errors.

Q. Is Bean's review of the UES data response based on 2013 data appropriate for determining the actual rate subsidies in the current case?

[11] A Guide for the Future of Distributed Energy Resources | Energy Central, September 2016, p. 2, http://www.energycentral.com/c/pip/guide-future-distributed-energy-resources

A. No. My testimony provides later data and full cost of service analyses to assess cross subsidy and customer impacts.

Q. Has UES provided data that shows both the costs and benefits during the test year for ratemaking purposes?

A. Yes. Bean ignores the cost of service studies filed by UES that prove the magnitude of the cost shift. I have also shown that UES is correct that there is no avoided delivery costs associated with solar DG.

Q. At page 4 lines 11-17, witness Bean opines on the concept of subsidy in rates and concludes that solar DG subsidies are not unjust or unreasonable. Please comment on that discussion.

A. It is true that by the very nature of utility costs, matching costs and revenue for every customer cannot occur and rates are based on average costs. Examples of averaging include service costs that differ based on the side of the street the customer is located on compared to the service transformer. In most cases, the delivery system is on one side of the street and some customers are closer to the transformer and have a shorter service drop. As a practical matter it makes no sense to charge a customer based on the side of the street. It also is impractical to charge customers differently for urban and rural service, although the subsidy may not be for rural customers who are served overhead and urban customers who are served underground. The level and amount of subsidies that actually exist are influenced by line extension policies, customer load characteristics and expected revenues. As a result, the amount of any subsidy based on average costs is limited by Commission policy.

This is the point that Bean misses in his analysis of subsidy. If the cost of serving a customer falls within the parameters of the line extension policy, differences in costs are typically small and customers who cause more costs than their revenue supports are required to make a contribution in aid of construction to buy down the extra costs. When a customer switches from full requirements to partial requirements the revenue is no longer adequate to support the services provided. If these customers were new, the utility would require an up-front contribution. Since they are not new and the costs are sunk, the option for full cost recovery is a separate rate designed based on the average cost of all of the customers with partial requirements, as long as they are relatively homogeneous, as solar DG would be. As I have explained, the test of just and reasonable rates relies on the principle of cost causation, the matching principle and the avoidance of undue discrimination, which means equal treatment for customers causing equal costs. Since that equal treatment does not and cannot result from the rate proposals of DG advocates, the subsidies are not just and reasonable. Further, under the purposes of PURPA that apply to net metering, if other customers are required to absorb additional system costs they do not cause and solar DG customers do not avoid, the non-participating customers are not held harmless as PURPA requires.

Q. Please comment on Bean's claim that "the absence of relevant utility data in New Hampshire virtually eliminates the ability to make intelligent decisions about changing net metering."

A. As I have noted above, this is a frequent claim of solar DG advocates. Any delay in changing net metering perpetuates a subsidy that is critical to the solar developers' business model. Peter Rive, the Chief Technology Officer of Solar City, has acknowledged that the subsidies exist and that their business goal is to not rely on government subsidies. There is more than ample data in this case to address the issues of net metering and solar subsidies that produce undue discrimination in rates for solar DG customers.

X. OCA Witness Huber

Q. Do the proposals recommended by OCA witness Huber as rate design changes comply with PURPA and the FERC regulations implementing PURPA?

A. Neither the DG TOU Rate nor the fixed solar credit complies with PURPA or the FERC regulations for several reasons. First, the TOU rate is not cost based and does not address cost recovery from partial requirements customers, as I have demonstrated in detail above, even when the rate is cost based. Huber's rate designs are not cost based. Second, the solar credit proposal is not based on avoided cost at the time of delivery, as required for an intermittent resource. Third, Huber ignores the cost of service results that show the magnitude of the cost shift and continues to allow other non-participants to provide subsidies to solar DG customers, but at a reduced level. There is nothing appropriate about allowing subsidies to continue when net metering cannot be approved without a finding that it satisfies the purposes of PURPA.

Q. Please comment on Huber's value of solar analysis (VOS).

A. The analysis does not reflect proper calculation of avoided costs. It relies on the wrong value for avoided energy costs by using an average value, despite the fact that solar does not produce in many high cost hours. The value of solar is lower than the average LMP price, as shown in my testimony. The loss factor used in the calculation is also too high and thus inflates the avoided costs inappropriately. With respect to capacity value, the VOS overstates that value by assuming too large a claimed capability, just as TASC witness Beach did. Further, the FCM value overstates the avoided capacity cost for solar DG when a like resource should be used. Huber also uses the incorrect discount rate for future costs. The calculation uses an incorrect value of avoided transmission costs based on revenue requirement. As I note in my analysis of Acadia, DRIPE is not an avoided cost. The end result is that the VOS is significantly overstated and results in excess costs to other non-participating customers.

Q. Do you agree with Huber that rates need to be modernized?

A. Yes. I do not agree, however, that Huber's proposals represent modernizing rates. I have explained in detail how future rates need to be modernized in my direct testimony. Specifically, the two-part rate needs to be replaced with a three-part rate. The three part rate should have TOU energy charges based on determining pricing periods on cost, not load as suggested by Huber. I should also note that the emphasis on shifting load is not a consideration for TOU rate design. The economic theory behind the rate is to send correct price signals. If load shifts, that is an added benefit but not a necessary condition for implementing TOU rates.

Q. Is it possible that the monthly peak load contribution is 50%, as claimed by Huber?

A. No. The claim cannot be true, as the UES system peak in 6 months of the year is not during hours with solar insolation. In order for Huber to be correct, solar DG output would need to be 100% of capacity in the other months. That is not the case, so the peak contribution is overstated.

Q. Huber proposes an export charge related to distribution secondary costs. Please comment on that proposal.

A. Such a proposal is not cost based. Essentially, all secondary facilities for a modern electric utility are directly customer related. To reduce losses, most new installations and infrastructure replacement use primary facilities to the transformer. The correct value to use under such a proposal would be based on the primary requirements of solar customers who require excess primary capacity for delivery.

Q. Please comment on the TOU period proposed by Huber.

A. The proposal is arbitrary and not based on a proper analysis of marginal cost data. The magnitude of load in an hour is not the basis for setting time differentiated prices. As I note above, TOU rates should be designed to reflect marginal cost-based prices. Huber does not even mention costs except to claim incorrectly that high load causes high cost. Actually, in electric utility systems the highest marginal cost hour often occurs when loads are lowest. The reason for this is that marginal costs are driven by both load and resource availability. That combination is reflected in hourly marginal costs values, or in the case of UES, hourly LMPs. Failure to perform the correct analysis renders Huber's recommendation useless for rate design.

Q. Huber discusses the role of value of service in ratemaking and cites to Bonbright as an authority for his use of the concept. Please comment.

A. Huber misapplies the value of service concept in a mixed monopoly and competitive market model. Essentially, all rates in a market must be above marginal cost and below the value of service. These two concepts-marginal cost and value of service- are used as rational limits for pricing that must recover an embedded cost revenue requirement. That is the role of value of service plays in making rates.

Q. What would cost based TOU rates look like?

A. Such a rate would contain: 1) A non-time variant delivery charge; 2) LMP based default service cost that is time-varying; and 3) Depending on TOU structures selected, the difference between peak and off-peak rates would be 1.5 to 4 times, nowhere close to level suggested by Huber.

XI. OCA Witness Doherty

Q. Does the proposed basis for Community solar outlined by OCA witness Doherty comply with PURPA and the FERC regulations.

A. No. As proposed, both the environmental and the LMI adders are not permitted under the avoided cost standard. These types of considerations must be made completely apart from the avoided cost value, as noted by the FERC. This is simply because there is a mandated cap at avoided cost for compensation for generation. It is imperative that any community solar project must be a QF. In that event, the utility would purchase the output from the facility and deliver the power using the full current delivery rate. Effectively, community solar becomes just another energy provider in the market, but differs from others because it only provides for a portion of the customer's load.

Q. How is it possible to account for LMI in community solar?

A. The FERC has stated that if other considerations are required for solar DG, there must be a process separate from the compensation at avoided costs. For example, if the Commission were to authorize credits for LMI participation through an IRP program this would be an acceptable method. It has also been suggested that LMI participation could attract grants that would reduce the capital cost for facilities serving qualified LMI customers as determined by the Commission and implemented by rule. Certainly, the Commission has a duty to assure participants that the community solar facility is financially sound and the arrangements are reasonable and serve the public interest for LMI participation.

Q. Can you comment on witness Doherty's proposed "environmental adder"?

A. Yes. Witness Doherty's "environmental adder" is nothing more than an additional non-cost based subsidy being provided to customers of community solar programs to be borne by non-participating customers. In effect, her proposal requires non-participating customers to pay twice for RPS requirements: First through their cost of RPS compliance,[12] the company must incur and assess to its default service customers to meet its RPS requirements for that load, and second, through this additional charge supposedly also to recognize "environmental benefits to society." This proposal violates nearly every established tenant of just and reasonable ratemaking. Further, Witness Doherty's proposal for this charge, which requires solar customers to retire their RECs, would actually have the effect of dampening market acceptance of community solar. This is because the value a developer receives for the RECs associated with a community solar facility goes to offset his/her cost basis and in turn provide a sufficient return for the project. Witness Doherty's proposal would take those RECs away from the developer and, all else equal, make the development costs higher and payback period longer for developers. In addition, practical difficulties including the lack of any existing legal mechanism to transfer RECs from the developer to individual solar customers and the inability to accurately forecast REC values over a 10 year period make implementation of this charge wholly impractical in the near term. For these reasons, Witness Doherty's "environmental adder" should be rejected.

[12] The Company currently estimates its 2017 monthly RPS compliance costs (January – May) for non-G-1 customers to be about $300,000.

XII. Conclusions

Q. Please provide your conclusions.

A. I conclude that nothing in the testimony of these other parties provides a basis for any change in my original conclusions. The banking feature of net metering should be eliminated and excess generation should be compensated at avoided cost in the month when it is delivered. DG customers must be billed as their own class of service and have three-part, cost-based rates. The UES proposal is just and reasonable in that regard.

Q. Does this conclude your rebuttal testimony?

A. Yes.