EXHIBIT
#9
DE 16-576

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

H. Edwin Overcast

New Hampshire Public Utilities Commission

Docket No. DE 16-576

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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. By whom and in what capacity are you employed?

A. I am a Director, Black & Veatch Management Consulting, LLC.

Q. Please describe your educational background and business experience.

A. A detailed summary of my educational and professional experience is provided in Appendix A to this testimony. I have a B. A. degree in economics from King College and a Ph.D. degree in economics from Virginia Polytechnic Institute and State University. My fields of study include microeconomic theory, industrial organization and public finance. I have been employed in the energy industry for over 40 years in various rate, regulatory and planning positions. My industry employers include the Tennessee Valley Authority, Northeast Utilities (now Eversource) an electric and gas holding company and AGL Resources (now a subsidiary of the Southern Company). I have been employed as a utility consultant since 1998 providing rate, regulatory, strategic and other consulting services to utility clients. In my various positions, I have testified before state and federal regulatory bodies, Canadian provincial regulatory bodies, state and federal legislative bodies and in various courts. I have previously testified before the Federal Energy Regulatory Commission ("FERC") on a number of electric, gas pipeline and oil pipeline issues.

Q. On whose behalf are you submitting this testimony?

A. I am testifying on behalf of UNITIL Energy Systems, Inc. (UES or the Company).

Q. Have you previously testified before the New Hampshire Public Utilities Commission?

A. Yes. I have filed testimony on behalf of UES in their most recent rate case.

Q. Please provide a list of State and Canadian jurisdictions in which you have testified.

A. I have testified in Connecticut, Massachusetts, Georgia, Tennessee, Montana, Missouri, New York, Ohio, Michigan, Arkansas, New Jersey, Oklahoma, Kansas, Arizona and Maryland. In Canada I have testified before the Ontario Energy Board, the Alberta Energy and Utilities Board, the New Brunswick Energy and Utilities Board and the British Columbia Utilities Commission. My testimony has been related to issues such as cost of service, rate design, prudence, rate of return, regulatory risk, performance based regulation, competition and unbundling.

Q. During your career have you made presentations to energy related training and other programs?

A. Yes. I have been an instructor for the Edison Electric Institute's Rate Fundamentals and Advanced Rate School related to cost of service. I have been an instructor in both the American Gas Association's Rate Fundamentals and Advanced Rate courses. I have been an instructor for the Southern Gas Association's Intermediate Rate Course and for the RMEL providing training related to regulation. I have made numerous presentations to trade association meetings including the EEI Rate Committee, the AGA Rate Committee, the AEIC Load Research Committee, SURFA, SEPA and other industry sponsored programs. I have made presentations to NARUC events and events sponsored by academic institutions. I have also written broadly on various subjects related to utility regulation, including issues related to the integration of distributed generation into a utility system and the design of rates for the 21st century.

Q. Have you provided expert testimony on cost of service and rate design related to net metering, rates for Distributed Generation (DG) customers and development of rates for purchase of energy from DG customers?

A. Yes. My testimony in both Maryland and Arizona rate cases and the Arizona Investigation of Value and Cost of Distributed Generation addressed these issues and more related to cost of service, rate design, net metering impacts and the impact of purchasing excess generation1. My testimony developed specific measures of the level of subsidy created by net metering and demonstrated that the current net metering rule in each jurisdiction resulted in undue discrimination based on the factual circumstances for both of the utilities. I have also testified extensively in PURPA related proceedings in Connecticut and Massachusetts for the Northeast Utilities operating companies on issues such as avoided cost and the purchase of energy and capacity from non-utility generators.

Q. What is the purpose of your testimony in this proceeding?

A. UES asked that I discuss determination of the cost shift from DG customers to non DG residential customers based on principles of cost causation and using cost of service analysis. UES has stated its position on net metering in the testimony of Thomas P. Meissner Jr. where UES concludes that it supports net metering so far as other customers

[1] Before The Public Service Commission Of Maryland, Case No. 9396

Arizona Corporation Commission (ACC) UNS Electric Rate Case, DOCKET NO. E-04204A-15-0142

ACC, TEP and UNS Electric, IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION, DOCKET NO. E-00000J-14-0023 do not provide a subsidy for the DG customers use of the grid, rates are just and reasonable, avoid undue discrimination and comply with the purposes of PURPA as they relate to net metering and the services provided to QFs. I will also address the issue of current net metering with energy banking and how it serves to create unwarranted subsidies for DG customers including rates that are not just and reasonable. I will discuss the valuation of solar DG based on sound economic and regulatory principles including Federal regulations implementing PURPA. Finally, I will provide an evaluation of the role and value of the electric grid as it relates to rooftop solar, other forms of distributed generation, and customer-sited technology generally. By combining sound regulatory and economic principles I will address certain issues identified in the Notice of Order in this docket, questions raised during technical sessions in this docket to date and the balancing of interests required by a prudent and least cost approach to utility service under the new mixed monopoly and competition model that has become the reality for utility service. Where possible, I will identify analytical frameworks that can address the issues of this docket and provide a foundation for the most efficient and economic provision of safe, reliable and cost effective end-use services required by customers.

Q. How is your testimony organized?

A. My testimony is organized by sections beginning with this introduction and followed by the following sections:

I. The New Hampshire Public Utilities Commission (“the Commission”) Generic Docket Order

II. Changes to Net Metering

III. Cost of Service

IV. Appendices

A. H. Edwin Overcast Short Biography

B. Marginal Cost Studies Are Not Useful In Determining Avoided Costs or Level of Intraclass Subsidy

C. The Acadia Study: Value of Distributed Generation

D. The Mixed Monopoly and Competition Model

E. DG Customer Load Shapes and System Impact

Each of these sections will be discussed below.

Q. Please summarize your conclusions and recommendations.

A. Using embedded cost of service studies for fixed costs and energy costs, I demonstrate the level of revenue requirement subsidy that results from both fixed costs and energy costs associated with net metering and energy banking. The level of subsidy is large and represents undue discrimination between residential solar DG customers and the other full requirements, residential customers.

The subsidy is large on a per customer basis and in aggregate exhibits rapid growth in the number of DG customers installing increasingly larger facilities that further increase the subsidy from full requirements customers. Individual subsidies will vary based on the size of the DG system and the strategy used when installing the system. As such these subsidies are far larger than the subsidies that result from averaging costs over a class of customers. Based on this analysis, the current net metering with energy banking and the use of a less than compensatory customer charge and kWh billing makes it impossible to conclude that the resulting rates are just, reasonable, equitable and non-discriminatory.

I explain why solar DG customers need to be treated as a separate class for cost of service to properly reflect cost causation. I also show that there are no avoided distribution costs as the result of solar DG customers on the system. This conclusion is theoretically sound because the non-coincident peak demand on the distribution system does not occur when solar DG customers are delivering excess generation to the system, and there is no time diversity of solar DG production as there is with customer load. This is equivalent to stating that DG customers have their highest class NCP based on generation delivered to the system rather than net load on the system.

My testimony explains that economically efficient rates need to be unbundled and each utility service priced separately so that customers make efficient decisions about the services they use. The unbundled rates include customer charges, demand charges and all energy related costs recovered outside base rates on a TOU basis that reflects the differences in marginal cost by season and by period for each day of the season.

I also show that efficient, market based capital avoided cost payments should be based on a proper calculation of avoided capacity costs and reset annually as the lower of the capacity market or the utility avoided cost. Further, I show that reasonable rate treatment for partial requirements DG customers requires a separate class of service and a three part rate.

Q. In addition to the support you have provided in your testimony, have you provided additional information to support your conclusions?

A. Yes. I have provided four Appendices (B-E) in addition to Appendix A which presents a summary of my background and professional experience. Appendix B provides economic and regulatory rationale that highlights the significant challenges marginal cost pricing presents to evaluating cost questions related to distributed generation; Appendix C details significant flaws I have identified in the "Acadia Study"[2] (which had been circulated in the Technical Sessions) which prevent it from providing any relevant direction for the purposes of setting a rate for distributed generation in this proceeding; Appendix D discusses the economic fundamentals supporting the current regulatory paradigm for setting rates and why the current net metering policies conflict with those fundamentals; and, Appendix E presents empirical evidence from my analysis of actual metered load data, bill frequencies, load factor analysis and other analytics for the Company's net metering customers for the Calendar Year 2015. These clearly demonstrate that the Company's net metering customers impose significantly different usage profiles on the system than full requirements customers, impose additional levels of costs, and cannot be expected to defer or avoid any meaningful level of fixed distribution capacity costs for the Company. These Appendices should be closely reviewed with my main testimony.

[2] Acadia Center, "Value of Distributed Generation, Solar PV in New Hampshire, October 2015

I. THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION'S GENERIC DOCKET ORDER

Q. Have you reviewed DE 16-576 Electric Distribution Utilities Development of New Alternative Net Metering Tariffs and/or other regulatory mechanisms and tariffs for customer-generators Order of Notice?

A. Yes. The Order of Notice provided the Commission's proposed framework for responding to the legislative requirements of a new paragraph XVI of RSA 362-A:9 added to the net metering provisions for the state. The Commission states that the objective of this review has a twofold purpose: "*to develop new alternative net metering tariffs*, which may include other regulatory mechanisms and tariffs for customer-generators, and *determine whether and to what extent such tariffs should be limited in their availability within each electric distribution utility's service territory*." (Emphasis added.) These two purposes are consistent with a full review net metering.

Q. Has the Commission identified in that Notice the substantive considerations that the legislation requires as part of reaching a conclusion in this case?

A. Yes. The Order of Notice identifies the following considerations:

1. The costs and benefits of customer-generator facilities;
2. An avoidance of unjust and unreasonable cost shifting;
3. Rate effects on all customers;
4. Alternative rate structures, including time based tariffs;

5. Whether there should be a limitation on the amount of generating capacity eligible for such tariffs;

6. The size of facilities eligible to receive net metering tariffs;

7. Timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism; and

8. Electric distribution utilities' administrative processes required to implement such tariffs and related regulatory mechanisms.

Q. Are there other considerations that the Commission must take into account as it considers the changes to net metering?

A. Yes. There are Federal standards associated with the adoption of net metering under PURPA, as amended, when the net metering standard was added to Section 113, Adoption of Certain Standards, one of which is net metering. There are also standards under PURPA Section 210 and the resulting Federal Energy Regulatory Commission (FERC) regulations issued to implement this section. Essentially, these standards provide for automatic QF status for small DG installations less than 1 MW. This is an important point since it is QF status that allows the Commission regulatory authority over the sale of energy from the QF to the state regulated utility. Regulation of the QF must still comply with PURPA as recognized by the legislature in RSA 362-A:9.

Q. Please briefly discuss the eight considerations for the new net metering provisions.

A. Each of the eight is discussed at a high level in the following:

The costs and benefits of customer-generator facilities

A detailed discussion of costs and benefits is provided later in my testimony. Essentially, our evidence proves that there are no avoided transmission or distribution costs and that the avoided cost for a solar DG QF is the cost as measured by the default service charge only. The costs of service for delivery services of a solar DG customer are no less than the cost for a comparable full requirements customer and, in the context of allocating costs for rate making, are actually higher because of the way these customers use the delivery system.

An avoidance of unjust and unreasonable cost shifting

Solar DG customers shift costs to other customers for recovery of delivery system costs. They also shift default energy service costs to other customers through fuel arbitrage by delivering power during lower marginal cost hours and using the banked energy volumes in higher marginal cost hours. This cost shifting is significant, results in undue discrimination and is unjust and unreasonable.

Rate effects on all customers

My testimony specifically quantifies the impact of cost shifting. That total dollar impact on UES's non-DG customers is not large currently simply because there are few customers on the current rate and the magnitude of the cost shift dollars cannot be large relative the costs for non-DG customers. For that reason alone, this is the optimal time to address this issue: before other customers are bearing significant inequitably allocated costs and elimination of this cost shifting would require dramatic increases on the DG customer class.

Alternative rate structures, including time based tariffs

My testimony demonstrates that the current two-part rate can never produce reasonable cost recovery from DG, partial requirements customers. Below, I demonstrate that only a three part rate consisting of a compensatory customer charge, a delivery demand charge and a time differentiated default service charge will produce non-discriminatory rates for DG customers.

Whether there should be a limitation on the amount of generating capacity eligible for such tariffs

There is no reason to limit the amount of small QF capacity added to the system under a fully unbundled, cost based rate. The purpose of rate limits is typically to control the level of cross subsidy or to avoid adverse system impacts, including stranded costs. In restructured markets, and with unbundled, three-part rates, these concerns are addressed. The more important limitation is to limit the size of facilities based on the customer's load requirements so as not to adversely impact the operation of the delivery system. For example, limiting the installed kW of DG to no more than the amount required to produce the customer's annual consumption. Even at that limit, the distribution system will face adverse operating conditions such as over-voltage and higher NCP demands.

The size of facilities eligible to receive net metering tariffs

Net metering should not be the preferred option for any small customer DG. Rather, the buy all/sell all is the most efficient option for managing DG. Under this arrangement, the current rate would be adequate for the buy all load. The sell all provision would need a requirement to reflect the higher demand on the delivery system. That would be based on the connected load per kW of DG capacity that could be deducted monthly from the sell all payment to be sure that solar customers covered the cost of delivery service for high coincident load on delivery facilities. In addition, if State policy is to provide for net metering, then the policy should limit the size of the facilities to those that are sized up to (and no greater than) the size needed to meet the load requirements of the customer. Without such a limit, the State risks creating an undue incentive for customers to over-size equipment for the sake of not only avoiding all responsibility for distribution cost recovery but earning additional profits at the expense of non-solar customers. This outcome could not reasonably be reconciled with the spirit of any State policy that requires just and reasonable rates.

Timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism

The utility would still need a full decoupling provision that operated in close to real time to provide a reasonable opportunity to recover its authorized revenue requirement, or in the alternative, Straight-Fixed-Variable rates. Without one of these two provisions the utility would not be provided with a reasonable opportunity to earn its allowed return.

Electric distribution utilities' administrative processes required to implement such tariffs and related regulatory mechanisms

The proposed rates tend to simplify the administration process if properly designed and implemented. It is also reasonable to recognize that DG operations are likely to create added costs for serving customers based on the solar outputs when coupled with conservation voltage control and volt var optimization. These technical issues need to be addressed as part of the administration of DER.

Q. Has UES addressed the issues it finds critical for this proceeding?

A. Yes. At the June 10, 2016 pre-hearing conference, UES addressed five "key points" for consideration in this docket. I have provided these points from the UES opening statement and expanded upon them below.

1. It is only through transparent, efficient and cost based rate designs that a viable and sustainable long-term model will be developed that provides sufficient revenue to support the significant investments needed to modernize the grid, while also incenting the appropriate behaviors and assuring fairness and equity among customers. Net metering tariffs and other regulatory considerations must adhere to long-standing and well-established ratemaking principles that recognize the importance of recognizing cost causation when setting rates.

2. Any new rate or approach for Net Metering must recognize the new costs and strains that DG places on the distribution system. These include but are not limited to the effects of the following:

    - Intermittent generation that requires more spinning reserves and other ancillary services,
    - Inability to monitor and control systems,
    - Bi-directional power flow on a distribution system designed for one-way power flows, and

- Distribution system impacts including power factor adjustments (added capacitors), and more voltage regulation.

3. Any new rate approach or mechanism must address the fact that with the introduction of DG customers into the residential class – the residential class should no longer be viewed as homogenous; that is, the class is comprised of partial and full requirements customers with the same end uses who impose the same or higher costs on the delivery system, but produce and use energy across the delivery system in much different ways.

   - Partial requirements DG customers impose nearly the same load capacity demands on the system and even greater exports demands on delivery capacity, and in turn fixed costs (distribution related costs), but are billed for much less energy.

   - Two part rate structures (customer charge and energy charge) only apply when customer profiles and loads within a class are homogenous.

   - The existing two part rate structure for Residential customers results in an undue cost shift between non-DG and DG residential customers since mostly all of the utility's costs are fixed and the only real avoided costs attributable to DG customers are energy costs of which the default service rate serves as a proxy.

   - End result is that current two-part rates are no longer just and reasonable.

4. The only way to adequately evaluate the differences in embedded fixed costs and energy costs between partial and full requirements customers is to conduct a cost of service analysis that treats full and partial requirements customers as separate classes.

    - This conforms to long-established rate principles since the cost profiles of DG and full requirements customers differ significantly, including different load factors, different patterns of energy consumption and very different impacts on the distribution system.

5. The new rate approaches must address significant fixed cost subsidies that are currently occurring between the two set of customers in the Residential class.

    - The current net metering policies essentially permit the DG customers to receive a full retail rate credit for excess power in any month; and cumulative excess power from month to month can be banked for future delivery offset. This credit is much more than the wholesale market value of the energy and even more than the cost of acquiring the same renewable energy from large scale facilities.

    - Since the only avoided costs DG customers provide to the utility system are energy related (e.g. default service), the maximum credit DG customers should receive for any excess power provided in a month should be based on the current default rate.

- The Commission should consider the elimination of banking of cumulative excess energy since this provision only exacerbates the fixed cost shifts.

Each of these five issues is integral to the determination the Commission is required to make and is discussed in detail below.

II. PROPOSED CHANGES TO NET METERING WITH RATIONALE

Q. Please describe the economic principles you apply in evaluating rate design

A. The matching principle of cost causation is a fundamental principle for setting just and reasonable rates. That is, rates must be set so that customers pay for those costs they cause on the system. As Mr. Meissner describes in his testimony, under the Company's current two-part rate design for Residential customers and net energy metering requirements, the energy produced from PV facilities of DG "Prosumers" is not charged any distribution costs. This condition fundamentally violates the principle of matching and cost causation since DG "Prosumers" customers indeed rely on the Company's distribution system to serve its load requirements.

Q. Does the company avoid any distribution costs by serving DG customers?

A. No. It is important to note that the electric distribution system is designed, constructed and operated to provide safe and reliable service to all customers and to serve their maximum demand on the delivery system. More specifically, distribution system planners size the requirements of transformers, circuits, and feeders in order to meet the system's maximum demand and the bulk of these costs are fixed. The Company must have personnel and equipment and facilities in place to serve all customer demands 24 hours a day, 365 days a year. Because the majority of these costs are fixed, a rate design that recovers costs primarily on a volumetric basis (i.e., kWh) will always violate the matching principle since no delivery costs will vary based on changes in energy consumption.

Q. Does an economic rationale exist for a two-part rate design for partial requirements customers?

A. No. The load characteristics and, in turn, the production and use of energy by DG customers (by their nature partial requirements customers) are much different than those for full requirements customers. Under two-part rates, the assumption that is required for rates to reflect cost causation is that load characteristics are relatively homogeneous as to cost causation and to load patterns. Relative homogeneity existed when kWh rates were first used for residential customers in the late 19th century because the only electric load was lighting. The demand was a function of the number of fixtures and kWh consumption was a function of average operating hours. Thus, a simple two-part rate with a customer or access charge and a flat kWh charge represented a reasonable rate because the cause of cost and the load characteristics were the same. Over time, the end use load profiles of residential customers has changed and electric rates evolved to reflect different load characteristics through declining block rates and through separate rate classes for different end-use residential loads, such as all electric rates or special provisions for specific end-uses such as a water heating block for customers with electric water heating. The trend away from these rate provisions to flat and/or inverted rate designs and fewer special provisions made rates less cost based as end-use load profiles continued to be more diverse, because larger groups of customers were served under rates that were simple but not capable of reflecting costs for less homogeneous groups. With the addition of partial requirements customers within a class, customers are no longer homogeneous as the following Table 1 illustrates by comparing two identical premises with the same demographic characteristics: the Full Requirements customer peak demand is 8 kW and the Partial Requirements customer has the same peak demand and a PV facility sized to meet its peak demand.[3]

Table 1 Comparison of Full and Partial Requirements Customers

Measures	Full Requirements	Partial Requirements
Customer Maximum Dema	8 kW	8 kW
Annual Energy Consumpti	21,024 kWh	21,024 kWh
Annual Billed kWh	21,024 kWh	7,708 kWh*
Load Factor-Customer	30 %	15%

* Based on 21,024 kWh less the energy produced by an 8 kW Solar PV system operating at a 19% annual capacity factor.

From a cost perspective, the delivery cost is the same for these two customers based on the assumption of identical demand. Actually, it is likely that the solar DG customer will cause a higher demand on the system in export mode than in load mode. This is a conservative assumption. The difference in cost recovery under the current UES rates is calculated in Table 2 below based on the current local delivery component (Distribution Charge) of the current unbundled rate alone. This calculation ignores any subsidy through default energy services. The annual delivery subsidy under current rates is nearly $65 per kW of installed solar capacity. This subsidy is based on equal treatment for equal cost causing delivery characteristics and is not tied directly to a measure of the cost subsidy which may be even larger as a result of the current inverted block rate where excess costs are recovered from the largest non-DG customers.

[3] This size assumption represents an atypical installation in that solar facilities are typically sized larger than the customer's maximum demand to reduce kWh consumption to close to zero. This requires a larger kW installation because of the lower capacity factor for solar generation as compared to customer load factor.

Table 2 Comparison of Customer Bills Partial vs Full Requirements

Billing Determinants	Full Requirements	Partial Requirements
Customer Charge	$123.24	$123.24
Energy Charge*		
Block 1 (<250 kWh)	$102.12	$102.12
Block 2 (Excess 250 kW	$703.66	$183.83
Annual Bill	$929.02	$409.19
Billed Usage	21,024 kWh	7,709 kWh
Difference	$519.83	
Difference per installed (8kW)	$64.98	
*Priced using Distribution Charge only ($0.03404 kWh, $.03904 kWh); assumes energy netted from Block 2.		

In addition, on the basis of cost causation there will be a subsidy in the generation and transmission portion of the rate simply because the solar PV capacity of 8 kW will not be coincident with the system or class peak demand. Instead, only a portion of the installed kW will be coincident with an afternoon peak as it occurs currently. The coincident amount will be between 2% and 24% of the installed kW on average and even lower on a peak day because of the extreme high temperature. The contribution to the system peak will also be lower as the class NCP shifts later into the evening as it has when solar penetration increases. This implies a further subsidy for the remainder of the base charge. It should be noted that this result occurs because of the current price signal based on energy that incents the customer to install a system that maximizes energy production without regard to the capacity value of the solar facility.[4] This means that solar panels would face south in the Northern Hemisphere to maximize energy production instead of west to maximize summer peaking capacity contribution.[5] In that event, the capacity contribution of solar and the later timing of the solar customers class NCP would result in no distribution cost savings and potentially even higher distribution costs associated with the class NCP for DG customers occurring at a later hour. Under the most favorable circumstances, a 5 kW solar facility would reduce the class NCP by about 0.5 kW and that would not be enough to result in smaller distribution facilities such as a transformer or conductor even if all of the customers using the same equipment had installed solar DG.

Q. What rate design do you recommend for the partial requirement customers?

A. Under the current two-part rate design, there is no possibility of avoiding undue subsidies between DG and non-DG customers. This situation exists because the current rate design fundamentally ignores the fact that most of the system's delivery costs to serve its customers are fixed and do not vary with the units of energy sold. The current net metering provisions as described in Mr. Meissner's testimony, in which surplus energy produced by a PV facility is credited against the next month's deliveries for that customer, further exacerbates this inequity. To resolve this inequity, I proposed the Company implement a three- part rate structure for its DG customers as a class of service

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[4] A generation and transmission on-peak demand charge would provide an incentive to consider both the capacity and the energy value when installing solar and also for investments in EE.

[5] See for example "9% of solar homes are doing something utilities love. Will others follow?", OPOWER Blog December 1, 2014.

consisting of a kW demand charge (the rate would be based on a 15-minute integrated demand reading as captured by the Company's AMI system), a customer charge and the energy charge billed per kWh (including TOU based energy charges in the future). The actual rate design will be filed at a later point in this case.

Q. Is this proposal of a three part rate consistent with current views on best practices?

A. Yes. It is actually consistent with the best practices approach to designing rates for DG as noted by a number of organizations such as e-Labs of the Rocky Mountain Institute who states:

> "These technologies can provide to or require from the grid energy, capacity, and ancillary services based on individual capabilities. But these characteristics vary along many dimensions that are not reflected in block, volumetric rates. For example, when a customer is exposed to a high marginal price tier in an inclining block rate structure, rates can both reinforce and skew the message that price signals should send. Rooftop PV can look more competitive with retail rates based on the higher credit received for energy production."[6]

This is the exact conclusion reached above relative to the inefficient orientation of solar panels relative to actual avoided costs because of the energy-only price signal. A report from the MIT Center for Energy and Environmental Policy Research states the following:

> Allocating network costs primarily on the basis of volumetric energy consumption presents inefficiencies in distribution systems evolving to incorporate a growing number of DER and a growing list of new stakeholders. These inefficiencies include: few price signals to incentivize optimal network utilization; cross-subsidization among network users; and business model arbitrage of rate structures.[7]

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[6] "RATE DESIGN FOR THE DISTRIBUTION EDGE: ELECTRICITY PRICING FOR A DISTRIBUTED RESOURCE FUTURE", e-Lab Rocky Mountain Institute, August 2014, p.15 http://www.rmi.org/elab_rate_design

[7] "A Framework for Redesigning Distribution Network Use of System Charges Under High Penetration of Distributed Energy Resources: New Principles for New Problems" Ignacio Pérez-Arriaga and Ashwini Bharatkumar, October 2014, p.6 https://mitei.mit.edu/system/files/20141028_UOF_DNUoS-FrameworkPaper.pdf

That same report supports the use of a customer component of the distribution system and demand charges for customers based on the capacity component of the system.[8]

In a report prepared for EEI titled "Retail Cost Recovery and Rate Design" Kenneth Gordon (the former Chairman of both the Massachusetts Department of Public Utilities and the Maine Public Utilities Commission) and Wayne P. Olson make the following statement:

> To the greatest extent possible, customer- or demand-related fixed costs should not be rolled into energy charges. The end-use customer often sees too high a price for energy and too low a price for demand and customer charges. Hence, the customer never receives the economically efficient price signal for either one.[9]

Each of these references correctly recognizes the role of multi-part rates in addressing the issues of efficient pricing and reflecting cost causation. The subsidies under net metering with two part rates create undue discrimination that needs to be addressed in the current case, not postponed and not to wait on implementation of a phased approach to multi-part rates that would do little or nothing to address the problem for years to come.

Q. How does a multi-part rate provide efficient price signals for customers?

A. Since energy charges are not adequate for reflecting cost causation (virtually all economists agree that this is the correct objective for rates) it is necessary to understand all of the components that cause costs on the distribution system. It is a fundamental proposition that costs are caused by customers, demand and energy. In fact, all cost studies use these three elements to classify costs. To match pricing with cost causation

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[8] Ibid. p. 16-20

[9] "Retail Cost Recovery and Rate Design" Kenneth Gordon and Wayne P. Olson, Prepared for the Edison Electric Institute, December 2004, p. viii. See also p. 26. http://www.ksg.harvard.edu/hepg/Papers/Gordon.Olson.Retail.Cost.Recovery.pdf

would require at least three parts- a customer charge, a demand charge and an energy charge. Customers cause distribution demand costs not based on the coincident peak demand but on non-coincident peak demands. It is common for utilities to have a greater investment in substation capacity than in generation capacity and more transformer capacity then in substation capacity. The reason is simple. There is more load diversity at the system peak load then there is as the loads move closer to customers. In fact, it is not at all uncommon that substation peaks occur at different times and in some cases even different seasons from the system peak. It is even unusual for more than a few substations to peak coincident with the system peak. As with substations, feeder circuits also peak at different times than the substation that serves the feeder. To correctly reflect the matching principle, I recommend using maximum customer demand whenever it occurs to recover distribution costs. This will solve the subsidy problem for delivery service and do so without any prolonged delay. It will also be easily implemented and result in a lower per unit charge that will be easier to phase in with a lower impact on bills.

Q. How would a distribution demand charge be determined?

A. First, it will be necessary to set the time interval over which demand is measured. 15 minute intervals are more stable over time so customers do not see large swings in their demand measurements. Second, the 15 minute intervals are also more reflective of cost causation since transformers and circuits have longer life if they do not experience overload conditions with any frequency. Third, the shorter interval results in a lower per unit demand charge to recover the distribution related costs. While the same dollars are recovered regardless of the demand interval, the shorter interval benefits both customers and the utility through stable more predictable charges on a monthly basis. Customers also benefit because a one-time peak does not significantly change the bill. This demand charge could be based on a contract demand rather than a measured demand in the future since this would reflect the sizing of the local facilities installed to serve the customer and would actually be a separate facilities charge. Some utilities have used this approach for demand billed customers. This charge could also be based on a 100% ratchet to further minimize the charge and reflect cost causation because these costs are a function of the customer's maximum demand, whenever it occurs. That is, for distribution demand there is no time dimension. Once the interval is determined and the charge is based on maximum demand whenever it occurs subject to a 100% ratchet, the kW charge would send the appropriate price signal and would be economically efficient.

Q. Is it reasonable to expect that customers can and will respond to more complex price signals?

A. Yes. In terms of complex price signals, the proposals in this case are comparable to rates in other parts of the world. For many years electric utilities have had more complex rate schedules for customers. The first marginal cost based TOU rates were introduced for large customers in the 1950s. It is common to see separate supply and delivery charges with supply charges consisting of multiple blocks or TOU periods. Some rates have a customer charge that is tied to the maximum capacity that can be served by the utility. Under this arrangement the maximum delivery capacity is limited. This is a rate equivalent to a customer charge and a demand rate. In Italy, residential demand rates have been used for many years. Italy is an example of a demand charge that is based on maximum delivery capacity.

Australia is addressing the issue of residential demand charges to address both the issue of cost recovery for solar DG and added loads from air-conditioning in the residential class. The important point is that there is broad recognition of demand charges as a means to fairly recover distribution related costs based on maximum customer demand whenever it occurs.

Q. Do you believe the Company's current non-bybassable charges should considered for the purpose of determining displaced energy revenues?

A. Yes. As explained by Mr. Meissner, under the Company's existing net metering provisions, all energy that is produced by PV facilities avoids paying the current energy based charges, including both the Distribution Charge and the set of five separate non-bypassable charges (External Delivery Charge, Stranded Cost Charge, Storm Recovery Adjustment Factor, System Benefits Charge, and Electricity Consumption Tax). The sum of the non-bypassable charges including the Electricity Consumption Tax is $.0312/kWh, which is higher than each of the block rates for the Distribution Charge. These costs should be borne in full by solar DG customers based on their total electric consumption. Under a separate rate schedule this can be accomplished by adding monthly generation to load as the appropriate billing determinate. Alternatively, the charges may be converted to a capacity charge per kW of installed capacity and bill for kWh used and a capacity charge for DG capacity.

Q. Does any economic rationale exist for not including these charges in the Company's determination of displaced energy revenues?

A. No. This treatment violates the matching principle of rate theory. As is the case with distribution system costs, none of the costs collected by these charges is avoided by the

Company due to the presence of PV facilities on its system. In fact, the only verifiable avoided costs related to the presence of PV on the system is avoided purchase power costs related to the production of PV solar energy, and those costs, or default service costs, are treated outside of the Company's delivery rate schedule. For this reason, I believe that these costs must be reflected in the Company's displaced revenue calculation to truly capture the level of fixed cost recovery erosion that is related to solar PV. In addition, I recommend for ease of rate administration that if the Commission decides to adopt the Company's proposed three part demand rate, that these non-bypassable charges to the extent possible be consolidated and also set on a demand or other fixed charge recovery basis. This treatment will avoid creating additional intra-class subsidies between DG and non-DG customers.

Q. Please summarize the required changes that should be made to net metering provisions.

A. The net metering provision should be changed to meet the purposes of PURPA that net metering must meet to be approved. Those purposes are as follows:

1) Conservation of energy supplied by electric utilities;
2) The optimization of the efficiency of use of facilities and resources by electric utilities; and
3) Equitable rates to electric consumers.

Under findings, the act states these purposes as follows: a program providing for increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers. While the purposes of PURPA are expressed with slight differences, PURPA requires that the net metering standard not be implemented unless it meets these standards. With respect to solar DG, net metering cannot result in equitable rates for retail customers under the current two-part rate structure where predominately fixed costs are recovered on a volumetric basis. The proposed modifications to net metering that are required to comply with PURPA and with the purchase of and sale of energy to a QF are as follows:

1. Create a separate rate class for DG customers;
2. Use a three part net metering rate for the solar DG customers consisting of a cost based customer charge, a distribution demand based on the maximum demand on the delivery system and a time differentiated energy charge based on the default supply charges;
3. Do not permit banking of energy (kWh); and
4. Require a monthly cashout for excess generation equal to the LMP price in each hour when generation was delivered to the system.

With these provisions the rate inequities will be eliminated, and customers will be paid for excess generation as required under the FERC regulations implementing PURPA for an “as available” QF generator. By basing rates on the system-wide cost of service study the rates will comply with the FERC regulations associated with sales to the QF. The result will be full compliance with the law, including the calculation of avoided costs.

Q. Does this proposal preserve the net feature of net metering?

A. Yes. The customer receives the full credit for the energy reduced by the netting in each month. In addition, the customer receives the full avoided cost in the current period as a further bill credit.

III. COST OF SERVICE ANALYSIS

Q. Please describe the cost of service studies developed for this filing.

A. Cost of service studies may be based on either the embedded cost revenue requirement or marginal cost. Marginal cost studies cannot address three issues raised in the notice of hearing as follows: (1) the costs and benefits of customer-generator facilities; (2) an avoidance of unjust and unreasonable cost shifting; (3) rate effects on all customers. There is no practical way to assess the costs caused or the distribution revenue requirements for full and partial requirements customers without developing a cost of service study that identifies these two classes of residential customers in separate subclasses of the residential class. I have prepared three different cost studies to allocate the delivery costs of UES based on the cost study filed in the current UES rate case. I will refer to these three studies collectively as the delivery cost studies.

Q. Please describe the three delivery cost studies.

A. Based on a decision by the Public Service Commission of Utah in Docket No. 14-035-114 issued November 10, 2015, the Utah PSC adopted a methodology of comparing two cost studies to determine the costs of serving solar customers for ratemaking purposes. This proceeding is particularly germane since its goal to establish “an analytical framework for assessing the costs and benefits of net metering” is very similar to the goals set for this proceeding.[10] The findings in the Utah order culminated an extensive and robust process that spanned nearly 18 months and involved participation from numerous parties representing various viewpoints on this issue including public comments from 33 members of the public (who were willing to provide their comments under oath). This approach has also recently been proposed in a recent rate proceedings involving net metering topics in Arizona.[11] The first cost study is the standard cost study with the solar net energy metered customers' allocated costs, just like the residential class, based on actual load characteristics of the class- Case 1. Schedule HEO-1 provides the detailed results of that study. The study in Case 1 is identical to the study filled in the Company's rate case, DE 16-384, except for the impact of breaking out solar customers as a subclass in the Residential class. The second cost study under this methodology is referred to as counterfactual cost study (CFCOS) and assumes that the solar customers did not adopt DG but rather were full requirements customers allocated costs in the same way as the residential class- Case 2. Schedule HEO-2 provides the detailed results of that study. This study is essentially an embedded cost study that assumes all other things being equal except for the addition of solar PV at the customer premise. By comparing these two studies it is possible to identify the way total embedded costs change for both full and partial requirements customers assuming that the load characteristics in terms of

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[10] The proceeding was initiated to fulfill statutory requirements set for the Commission in Utah Code Ann. §54-15-105.1 that requires Commission to: 1) determine, after appropriate notice and opportunity for public comment, whether costs that the electrical corporation or other customers will incur from a net metering program will exceed the benefits of the net metering program, or whether the benefits of the net metering program will exceed the costs; and, (2) determine a just and reasonable charge, credit, or ratemaking structure, including new or existing tariffs, in light of the costs and benefits. See Public Service Commission of Utah, *Order, Docket No. 14-035-114, In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program, November 10, 2015, page 1.*

[11] Before the Arizona Corporation Commission, Tucson Electric Power Company, Dockets No. E-1933A-15-0239; and 15-0322, filed July 25, 2016.

both load and delivery capacity requirements are no different. All other things are not equal when viewed from the factors that cause costs,since we know that the load characteristics are not the same for DG customers and full requirements customers. I recommend a separate class for evaluating the embedded costs of solar DG customers rather than using the counterfactual study alone with its inherently biased assumption about cost causation. That is the third fixed cost study I have included, and is labeled the solar class study –Case 3. Schedule HEO-3 provides the detailed results of that study.

For each cost study we use the same fixed costs for the system based on the 2015 rate case costs as filed in the UES cost study. Those fixed costs are allocated using the same basic methodology of the minimum system customer costs and class NCP for demand related delivery costs. We also use the same customer cost allocations. Using the same customer cost allocations is a conservative approach because UES has made no adjustments to account for the higher level of transaction costs for solar DG customers associated with storage accounting, billing adjustments and other customer service considerations. The study is also conservative because we have made no attempt to identify any system investments designed to address power factor issues or other distribution related investments, such as voltage control and frequency control. There is also no adjustment for higher losses associated with the power factor issue noted above or the higher losses from excess generation in low load periods. Finally, revenues are calculated using the individual customer billed kWhs and current rates.

Q. Please summarize the residential class returns in each of the costs studies.

A. Table 3 provides the earned return for both the full requirements residential customers and the partial requirements solar DG customers.

Table 3 Earned Return by Customer Group and Cost Study

	Residential	Solar
Base	-1.48%	-12.27%
Counterfactual	-1.48%	6.08%
Solar Class	-1.46%	-15.55%

The magnitude of the negative return for solar DG customers is further evidence of the undue discrimination between full requirements residential customers and the partial requirements solar DG customers who pay much less for comparable service. In the base case, a full requirements customer produces 8.3 times higher a return than solar and in the case where solar is properly treated as a separate class the full requirements customers produce a return 10.7 times the solar class. It is useful to note that the solar DG customers have a higher positive return in the counterfactual study because of the inverted rate block for most of the customers' usage. The current rate design provides an unsustainable cost subsidy from the customers who have elected solar DG to all other residential customers when the customer charge does not equal customer costs and the energy rate is inverted. That rate subsidy cannot exist in a mixed monopoly and competitive market and must be eliminated for full requirement rates to be efficient as well. Simply, solar DG customers use the delivery system more as partial requirements customers than they did as full requirements customers. This occurs because there is no solar DG diversity when output peaks and that peak coincide with an otherwise low load for those customers. The table also proves that the inverted block rate for residential customers is not cost based and is a major driver of the customer switching to solar just as it is in the western states.

Q. Please explain how you developed allocation factors for the three cost studies.

A. To develop the allocation factors for the cost studies it was necessary to make a basic assumption that the load shape of residential solar DG customers was, on average, the same load shape as the residential load shape prior to the installation of solar DG. That is, the basic assumption is that the hourly usage pattern for DG customers is no different from the residential class as a whole. The only difference is that solar DG customers provide some of their own energy to satisfy that load shape based on the operation of solar DG.

Using this assumption it is possible to develop a full requirements load shape for solar DG customers using the following data: actual metered kWhs used by solar customers per month, actual excess kWhs delivered to the utility by month, the installed kW capacity of the solar DG, the solar output load shape based on metered data for a fixed axis, south facing solar DG installation, and the load research based residential hourly load shape. With this data, the process consisted of a number of logical steps as follows:

1. Using basic number properties of mathematics, we calculated the monthly full requirements load for each solar DG customer as the sum of the actual metered kWh plus the monthly solar generation given by the installed capacity times the hourly output load profile less the metered excess energy delivered back to the

system. From this calculation we saved both the premise load and the excess energy for use in the various analyses.

2. In this step we modeled the average solar DG customer as a full requirements customer with the system average load shape. Using monthly total energy consumption of the premise and the residential hourly load shape based on the customer's monthly premise use, an hourly load shape of premise use is calculated for each month by taking the ratio of the customer's monthly use to the monthly use of the load shape.

3. This process was repeated for each residential DG customer and the data aggregated into the DG customers' counter factual load shape for use in the counterfactual cost study.

4. The solar DG class is based on all customers with twelve months of data and a non-zero capacity value.

5. For the counterfactual study the full requirements customer load shape is calculated by subtracting the net load shape of solar DG from the residential load shape used in the base cost study and adding back the full requirements load shape.

6. The solar net load shape is the premise hourly load shape minus the generation output shape. The net load shape excluding excess generation is used to develop the solar contribution to the residential load shape for the base cost study.

7. We now have three load profiles for solar DG customers: the counterfactual no solar DG load profile, the generation output profile and the solar customer net load profile.

8. Using this data it is possible to calculate the solar customers demand allocation factors for each cost study.

9. For the counterfactual profile we calculate the residential class NCP allocation factors and rerun the cost of service study. We also use the net load profile and the higher of the positive or negative class maximum NCP. The allocation factor for NCP is the absolute value of the class NCP. This is consistent with the maximum requirement for distribution facilities and cost causation.

This data provides a solid, if conservative, basis for assessing the relative revenue requirements differences between the between full and partial requirements customers.

Q. Please explain why the three studies are useful.

A. Since cost of service is a zero sum methodology, all costs must go to some class and any change in allocation to one class must be reflected as an opposite change to one or more of the other classes. In order to understand the costs for residential DG customers, they must be separated from the full class. The portion of the residential class costs allocated to solar DG customers as part of that class are shown in the base study. The counterfactual study shows the amount of costs that would be allocated to full requirements customers prior to customers choosing to install solar DG and capture the benefits of net metering. Even though no changes occurred in the class cost and no changes occurred in the fixed costs[12] for utility service to the solar DG customers, the solar DG customers are allocated less plant than would be allocated before they chose DG as shown by the counterfactual study. This result is not surprising since one would expect that these customers were larger on average than the average customer. Finally, the interesting note is that because solar DG customers use much more distribution capacity to deliver load to the system, they cause more cost for the system than when they were full requirements customers.

Q. Why does the solar class study allocate more costs to solar customers than the base study?

A. For the demand related portion of the distribution system, the base case under allocates distribution system costs to the solar DG customers because it uses the load demand rather than the actual maximum demand which is based on delivery demand. The different NCP for delivery compared to the residential class coincident NCP for solar DG customers is less than half of the delivery NCP. That difference is based on the difference in the load diversity and the absence of diversity with respect to excess generation. It also reflects the higher output for solar DG in periods when the ambient temperature is lower than 25 degrees centigrade. Thus, it is the delivery service that establishes the maximum demand on the distribution system. The net result is that the solar class's allocation increases compared to the base case.

Q. Please summarize the cost of service results.

A. Several conclusions are worth noting as follows:

[12] Solar DG customers still have the same distribution facilities to serve night time loads.

1. The total full requirements, residential class, fixed cost of service is higher for the base case and the solar case than if the solar DG customers had not invested in DG. This results from a cost shift within the class to full requirements customers.

2. All three studies produce a customer charge for both full and partial requirements customers of about $38.00 per month. If the company were to analyze and adjust for the extra costs associated with solar DG associated with record keeping and billing it is likely that the solar DG charge would be above this average level.

3. It is critical to understand cost causation on the distribution system results in higher costs for solar DG even without the consideration of the added costs associated with lower power factor, more frequent voltage control events, higher losses when exporting power and other impacts on distribution system costs.

4. The evidence is conclusive that there are no avoided distribution costs for UES and likely none for any utility in New Hampshire based on the patterns of customer load and solar DG generation.

5. The magnitude of the base rate charges for solar customers would be much higher than the kWh charges for full requirements customers thus necessitating recovery of the fixed charges in demand charges because the kWh charge under a two-part rate would further distort the solar DG sizing decision.

6. The large negative return provided conclusive evidence that the solar DG customers are subsidized by other customers at amounts that are significant even

compared to the modest return from the residential class. There is no equity argument for customers who cause costs to provide such a large negative return and particularly when Commission policy has justified a higher return within the class for these customers prior to the installation of DG.

Q. What conclusions do you reach from the cost of service studies as they relate to solar DG, net metering, banking and rates?

A. The conclusions related to cost of service are as follows:

1. Solar DG customers must be treated as a separate class of service in the cost study.

2. The two-part rate with net metering cannot ever produce equitable treatment of full requirements customers and solar DG customers who have different demand profiles and load factors.

3. Energy banking adds to the subsidy that result under current rates and a cost study that reflects cost causation.

4. Rate design must be unbundled so that each utility service is priced separately (the Commission has made a good start on unbundled rates by identifying delivery services and default service charges) and the rate design must be a multi-part rate to meet the principles of cost causation and matching.

5. Solar DG customers should produce at least the residential average return and rates for partial requirements, solar DG customers should be designed to produce the solar class return equal to the residential average.

Q. Does this conclude your testimony?

A. Yes, it does.