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BEFORE THE ARIZONA CORPORATION COMMISSION

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DOUG LITTLE – CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	DOCKET NO. E-00000J-14-0023

OSBORN MALEDON
A PROFESSIONAL ASSOCIATION
ATTORNEYS AT LAW

ARIZONA INVESTMENT COUNCIL'S NOTICE OF FILING

Arizona Investment Council ("AIC") hereby provides notice of filing the Direct Testimony of Michael T. O'Sheasy in the above-referenced matter.

RESPECTFULLY SUBMITTED this 25 day of February, 2016.

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Arizona Corporation Commission
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this 25th day of February, 2016, to:

All Parties of Record

Debra Huss

6530941

BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF THE VALUE AND COST OF DISTRIBUTED GENERATION.	**DOCKET NO. E-00000J-14-0023**

Direct Testimony and Exhibits of

Michael T. O'Sheasy

on Behalf of

Arizona Investment Council

February 25, 2016

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I. INTRODUCTION AND PURPOSE

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

A. My name is Michael T. O'Sheasy. My business address is 5001 Kingswood Drive, Roswell, Georgia 30075. I am a Vice President with Laurits R. Christensen Associates, Inc.

Q. Briefly state your education, background, and experience.

A. I received a Bachelor of Industrial Engineering degree from the Georgia Institute of Technology in 1970. In 1974, I earned a Master's degree in Business Administration from Georgia State University. From 1971 to 1975, I was employed by the John W. Eshelman Company—Division of the Carnation Company as a plant superintendent in their Chamblee, Georgia operation. From 1975 to 1980, I worked for the John Harland Corporation, initially as an assistant plant manager and then as a plant manager in their Jacksonville, Florida plant, and finally as their plant manager in Miami, Florida. I joined Southern Company Services in 1980 as an engineering cost analyst and progressed through various positions to the position of supervisor, during which time I began serving as an expert witness in costing. In 1990, I became Manager of Product Design for Georgia Power Company and testified as an expert witness on rate design and pricing. I retired from Georgia Power Company on May 1, 2001 and became a consultant with Christensen Associates. In my current role, I serve as an expert witness and consultant on electric industry costing and pricing, and I manage related analytical work conducted by Christensen Associates Energy Consulting, an affiliate of Christensen Associates that focuses on the energy industry.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Arizona Investment Council ("AIC").

Q. Have you testified previously before the Arizona Corporation Commission?

A. No, I have not. Exhibit MTO-1 identifies a number of dockets in various jurisdictions where I have testified regarding ratemaking, cost-of-service, and rate design.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the appropriate costing and pricing methods for customers with renewable distributed generation ("DG"), specifically solar DG. I recommend against the use of a two-part rate design for solar DG customers. A two-part design includes a basic service charge to recover customer-related costs and energy charges to recover both energy-related and demand-related costs. Demand-related costs are caused by demand measured in kilowatts (kW). If demand-related costs are recovered through energy rates, the rate design will create prices that do not correspond to the way utility costs are incurred. Additionally, this can allow solar DG customers to shift their demand-related costs to other customers. I then explain why it is not appropriate to include "external" costs (i.e., costs that are not directly incurred by the utility in serving its customer, such as environmental costs associated with carbon dioxide emissions) or value-based pricing in regulated utility rates. Basing rates on the value of the service rather than its cost can lead to inappropriate customer incentives and cross-subsidies.

Q. How is your testimony organized?

A. Section II describes the established cost of service and rate design principles. Section III describes the ratemaking issues relevant for solar DG customers. Section IV describes rate design issues for solar DG customers.

Section V describes issues related to the Value of Solar ("VOS").

Section VI provides a summary of my recommendations.

II. ESTABLISHED COST OF SERVICE AND RATE DESIGN PRINCIPLES

Q. What is the purpose of this section of your testimony?

A. In this section I describe the ratemaking process for a regulated electric utility. It will serve as the foundation for the pricing of solar DG customers.

Q. What is the fundamental basis for ratemaking in the regulated electricity industry?

A. For more than 100 years, cost-of-service regulation has been the fundamental basis for setting rates for regulated electric utilities. In the late 19th Century, the United States Supreme Court held that certain economic activities were so important to modern society that the government must assert the right to oversee the prices charged to ensure that those services were provided to the public in a reasonable manner. The provision of electricity was considered one such activity, and, with some exceptions, power companies became subject to the oversight of public utility commissions. In attempt to ensure that the price of electricity appropriately balanced both customer and investor interests, a cost-of-service regulatory regime emerged – a system that allows customer rates to be based upon cost to serve and provides the utility the opportunity to recover its prudently incurred costs, including an opportunity to earn a reasonable, government-approved return. I shall refer in my testimony to this system as "ratemaking," comprised of two major activities: cost of service and rate design.

Q. Please describe generally how a "cost of service" analysis is performed.

A. Cost of service is, by nature, an objective, mathematical exercise. The "revenue requirement" is a key component of the cost of service, and is determined by the following formula:

(Rate Base x Allowed Rate of Return) + Expenses

The rate base is the net amount of investment, funded by investors, in utility plant and other assets devoted to the rendering of utility service. The rate of return is the percentage rate that the regulatory commission determines should be allowed on the rate base in order to cover the utility's cost of capital. Expenses include operation and maintenance costs, depreciation, and taxes. For any of these costs to be included in the revenue requirement, the regulator must deem them to be just and reasonable and prudently incurred.

Once the utility's revenue requirement is determined, a cost of service study is performed. A cost of service study apportions the total utility costs among the various customer rate classes in a fair and equitable manner, using <u>established cost of service principles</u>. There are several common steps: (a) functionalization of costs (assigning costs to generation, transmission, distribution, etc.), (b) levelization of these functional costs into service levels, (c) classification into cost components (customer-related costs, energy-related costs, and demand-related costs), and (d) assignment or allocation of these costs to rate classes. In a cost of service study, similar customers are grouped into rate classes and costs are assigned or allocated to those classes on the basis of how the costs are caused. That is, the cost of service study operates on the principle that the rate class that receives a particular service and causes the associated costs to be incurred should pay for that service. From there, time-tested <u>rate design principles</u> are used to create reasonable and sustainable rate designs. One rate design (perhaps including optional rates) is developed to apply to all customers in a rate class, as it is impractical to charge customer-specific rates (or develop customer-specific costs). This is called average ratemaking. As I will discuss below, departures from the established cost of service and rate design principles can lead to prices that do not correspond to the way utility costs are incurred, potentially resulting in cross-subsidies and inefficient customer decisions (such as choosing to consume energy when it is priced too low or failing to use the least expensive energy source because it is priced too high).

Q. You previously referenced established cost-of-service principles. To what were you referring?

A. When conducting a cost of service study, utilities try to adhere to some commonly accepted principles:

1. Costs must be approved by a regulator and based upon financial accounting costs adhering to General Accepted Accounting Principles ("GAAP") and the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts.
2. Costs should generally be known and measurable.
3. Cost allocation to customer rate groups should be based upon cost-causation. Where possible, they should align with the utility's system planning.

Q. Please explain how cost of service is used in rate design.

A. In addition to producing a cost-based revenue requirement for each rate class, the cost of service study classifies the types and amounts of the costs that are caused by each customer group (rate class). Again, this is a data-driven, mathematical exercise. As stated in the National Association of Regulatory Utility Commissioners cost allocation manual:[1]

> *The three principal cost classifications for an electric utility are demand costs (costs that vary with the KW demand imposed by the customer), energy costs (costs that vary with the energy or KWH that the utility*

[1] Electric Utility Cost Allocation Manual, January 1992, National Association of Regulatory Utility Commissioners.

provides), and customer costs (costs that are directly related to the number of customers served).

As a result of the functionalization, levelization, classification, and assignment or allocation of costs, the cost of service study produces unit costs, which are the allocated and assigned costs divided by the corresponding billing determinant (e.g., energy charges are based on the energy-related costs divided by the test-year amount of energy sold). While there may be arguments against charging these unit costs as the retail prices (e.g., pressures to recover customer-related costs through energy charges, possibly based upon a belief that low-use customers are also likely to be low-income customers), they do and should play an important role in the rate design process.

Q. **What are the rate design principles that you referenced earlier?**

A. The rate design for each rate class should reflect the costs and revenue requirements identified in the cost of service study as closely as possible. Subsidies should be avoided where possible and if they cannot be avoided they should be limited and transparent. The primary goal for rate design should then be to recover the class-specific revenue requirements and to consider the unit costs by component from the cost of service study for setting component prices. By basing the rates on unit costs (e.g., using monthly basic service charges to recover customer-related costs, energy charges to recover energy-related costs, and demand charges to recover demand-related costs), price signals are communicated to the customer that reflect the way in which utility costs are incurred, thus providing proper incentives for customer behavior.

Additionally, rates should be designed to be sustainable, stable, fair, and to enable efficient growth. They should be developed in a manner that maintains system reliability and power quality. Ratemaking should treat rate classes consistently. That is, if two different rate classes cause similar costs to be incurred or avoided, they should have similar treatment in rate design unless there is a compelling reason to do otherwise (and any exceptions should apply for a limited time period). These revenue requirements and subsequent rates should provide the utility with the opportunity to recover its costs and earn a rate of return sufficient to ensure its financial integrity.

Q. Does average ratemaking result in some customers paying more or less than their actual cost to serve?

A. Because cost of service studies and rate designs are conducted for customer groups (rate classes) rather than for each individual customer, it is inevitable that some customers will pay more or less than their actual cost to serve. However, the objective is to define classes such that the customers in the rate class are similarly situated, thus reducing the extent of intra-class cross subsidies.

Q. In the principles above, you have described cost of service as the basis for setting rates. Should the *value* of energy services be used as a basis for ratemaking instead of cost of service?

A. No, ratemaking should not incorporate the value of energy in lieu of the cost of service. A value basis for ratemaking has numerous shortcomings compared to cost-based rates. Cost-based rates send price signals to customers that are consistent with the way the utility costs are incurred. As stated in NARUC's report, "Aligning Rate Design Policies with Integrating Resource Planning", using cost-based rates produces desirable outcomes:

> *In practice, equity and efficiency come down to the notion that electric utility customers should pay cost-based rates. For a utility rate design, "cost-based" means based to a substantial extent on a cost-of-service study. Cost studies provide the formal and explicit linkage between the*

demands that customers place on the system and the charges they face. It is this linkage that permits the development of cost-based rates, rather than rates based for example on value of service or willingness to pay. Central to both embedded and marginal cost studies is the notion that customers should, insofar as is practical, be assigned the costs which they cause the utility to incur.

In addition, the value of energy services can be subjective and/or contentious while costs are more concrete and quantifiable. While it is true that utility-supplied electricity may provide significant value beyond its cost (e.g., economic development, etc.), it is inappropriate to include this value in the ratemaking process.

III. RATEMAKING ISSUES RELEVANT FOR SOLAR DG CUSTOMERS

Q. Please describe the ratemaking issues associated with pricing solar DG customers.

A. There are three types of pricing issues that are unique to solar DG customers:

1. How to account for the fact that solar DG tends to reduce the customer's energy by much more than it reduces its demand requirement, and how this affects the recovery of demand-related costs under standard two-part rates (in which demand-related costs are recovered through energy charges).
2. How to price the energy exported onto the grid when the solar DG system generates more load than is being used by the customer.[2]
3. How to account for additional utility grid costs that may be incurred by a solar DG system.

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[2] This effect is not relevant if the customer is served under a "buy-all/sell-all" arrangement. Under this method, the customer is treated as two separate entities, paying standard retail rates for all of its energy and receiving payment (at something other than the retail rate, such as avoided energy costs) for the separately metered solar DG output.

Q. Please expand on the ratemaking impact of the first issue.

A. Under net metering, the output from solar DG is used to offset the billed energy of the customer, with the amount of the energy offset dependent on the size of the solar DG installation and its intermittent operation. However, the solar DG output is likely to have a much larger effect on the customer's net energy usage than on the customer's net demand requirement, for two reasons. First, the hourly profile of the solar DG output may not match the customer's usage profile. That is, the customer's peak usage may come at a time in which the solar DG produces little or no electricity. Second, the solar DG is an intermittent resource (e.g., not producing as much energy on a cloudy day) and when the solar DG is not producing, the customer will fully rely upon the utility's infrastructure.

Q. You described above how solar DG is likely to reduce a net metered customer's billed energy by much more than it reduces the customer's demand requirement. How does this affect the customer's bill relative to its cost to serve?

A. As described in Section II, the cost to serve a customer has three components: customer-related costs, energy-related costs, and demand-related costs. Traditionally, residential net metered customers face "two-part" rates that include only a basic service charge and energy charges. Because there is no demand charge to recover demand-related costs (for reasons I describe later), those costs are recovered through energy charges. In this case, the two-part rate is designed on the basis of the average load factor of the customers in the class, where "load factor" is defined as a customer's average usage over some period of time (e.g., a month or year) divided by its maximum hourly usage over that same time. Therefore, when a net metered solar DG customer reduces its energy without a commensurate reduction in demand, it avoids paying a (perhaps significant) portion of the demand-related costs associated with its service. Additionally, there may be a second cost effect due to the need for the utility to have available capacity in the event that the solar DG stops producing electricity. These reserve capacity costs will not show up in the solar DG customer's bill under the standard rate.

At some point (either in the next rate case or through something like a lost fixed cost recovery mechanism, or "LFCR"), the under-recovery of these demand-related costs is passed on to other customers. In summary, net metering with two-part rates leads to a cross-subsidy benefiting net metered customers to the detriment of non-net metered customers.

Q. Please discuss the second issue you described above, regarding excess rooftop solar generation that flows onto the grid during certain time periods.

A. The energy generated from solar DG is non-firm, which means that it cannot be relied upon by the utility as a source to serve load. Solar DG output flows onto the grid periodically depending upon the operations of the rooftop solar system and the site load requirements of the customer. This excess energy saves the utility from incurring some costs to serve, such as avoided fuel, variable operations and maintenance charges, and losses that would have occurred had the excess solar DG generated energy been otherwise produced by the utility. In addition, solar DG may impose some additional costs such as integration cost to accommodate the two-way flow of power on the distribution grid. In Section IV, I discuss the appropriate method for pricing the solar DG customer's excess generation.

Q. Please explain the third issue that you describe above with respect to the cost impacts of solar DG.

A. As more and more customers choose to install solar DG systems, the utility may experience integration issues that have to be addressed, such as voltage control and frequency response. If these issues lead to increased costs, the question of who pays for the cost increase will arise. The Commission may conclude that solar DG customers cause the increased costs and should be responsible for them, or it may conclude that public policy supports the socialization of those costs to all customers.

Q. Would it be unusual in ratemaking to separate out an abnormal cost consequence for recovery by the causing party?

A. No. An example of where this has been done for years is charging customers for having a poor power factor. If a customer has a poor power factor beyond a pre-specified threshold, there is usually a charge to the customer for the additional capacitors that may need to be added to the distribution network to correct it.

IV. RECOMMENDED RATE DESIGN CONSIDERATIONS FOR SOLAR DG CUSTOMERS

Q. What is the purpose of this section of your testimony?

A. In this section, I will describe how the issues described in Section III should be considered for rate design.

Q. In Section III you described three types of effects that solar DG customers can have on costing and pricing. Please explain how these effects should be addressed in rate design.

A. The first effect I described in Section III dealt with the under-recovery of demand-related costs from net metered solar DG customers who pay two-part rates (with only a basic service charge and energy charges). Even when the solar DG output during a billing month fully offsets the customer's site load, the customer still requires the utility to provide demand-related capacity for which the solar DG customer should be responsible. Distribution capacity demand costs pertain to the cost of equipment needed to serve the maximum amount of load that the utility expects the customer to require, with a margin for the variance in loads. When the solar DG system is operating and serving some of the customer's peak load requirements, the utility must have distribution capacity available to serve the solar DG customer whenever output from the system becomes unavailable. Additionally, there are generation and transmission reliability requirements for utility capacity to be available in the event that the solar DG is not producing output. The cost of service and rate design principles I mentioned above would require solar DG customers be responsible for these costs.

Q. Please continue discussing the generation and transmission reliability costs that you mention above.

A. Generation and transmission reliability costs are driven by the utility's system demand requirements. Generation costs for many utilities are thereby allocated by a combination of the utility's system coincident peak (CP) and the non-coincident class peaks (NCP). Transmission is usually allocated with CPs. While it is possible that the utility's CP may occur when the customer's solar DG unit is generating and reducing the utility's CP, the utility must still maintain available generation and transmission capacity for the event that the solar DG ceases to produce. This reserve requirement is a cost for which the solar DG customer should be responsible.

Q. How are distribution-capacity, generation-reliability, and transmission-reliability costs usually recovered in utility rates?

A. In traditional residential and small commercial tariffs, these demand costs are usually included in the energy charge. This is referred-to as a two-part design. A $ per kW demand charge has often been used to recover demand-related costs for medium to large commercial and industrial customers. This is referred to as a three-part design.

Q. What is the problem with two-part rates?

A. There are two primary consequences of charging two-part rates that recover demand-related costs through energy charges. First, two-part rates lead to an intra-class cross-subsidy to *all* low load factor customers (including those that have a low load factor due to net metered solar DG) from higher load factor customers. Second, two-part rates fail to provide customers with an incentive to manage their demand, which can result in some decisions that are not in the interest of all customers (e.g., plugging in an electric vehicle during peak hours). The cross subsidy and incentive issues can be corrected through improvements in rate design, such as applying three-part rates (including customer, energy, and demand charges) to all customers in the class.

Q. If two-part rates produce the intra-class cross subsidy you describe, why have they often been used for residential and small commercial customers?

A. There are two main reasons that two-part rates have often been used for residential and small commercial customers despite their shortcomings. First, meters that are capable of recording both a customer's demand and its energy use have been more expensive than meters that only record a customer's energy use. This has created a cost justification to use energy-only meters for smaller customers. Secondly, there was little interest on the part of residential and small commercial customers for demand-based rates, and two-part tariffs worked reasonably well for both customers and the utility. However, with the advent of solar DG and introduction of other behind-the-utility-meter technologies, there is a significant and growing segment of customers for whom a two-part design does not work well. New rate designs, such as a three part rate with a demand charge, should be considered as viable alternatives to the no longer tenable two-part rate structure.

Q. Can TOU energy-only rates solve the shortcomings of a two-part rate for solar DG customers?

A. No, a two-part rate that recovers demand-related costs through energy prices can allow solar DG customers to avoid paying their demand-related costs, regardless of whether the energy rates vary by time-of-use.

Q. How should solar DG customers be compensated for the excess generation that flows from the rooftop solar system onto the utility's distribution grid?

A. This excess self-generation should be considered non-firm and therefore lacking any material capacity value. As such, it should be compensated at avoided energy costs (primarily avoided fuel, O&M, and losses). These avoided costs for the utility should be credited to the solar DG customer for his or her generation, ideally on an hour-by-hour basis.[3] The credits should be based upon the specific hour in which the customer's solar DG output flowed onto the utility grid. Compensating solar DG customers at avoided energy costs prevents a subsidy that would have occurred had solar DG output been prices at above-market rates. Compensation at avoided cost would thus be fair and equitable to all stakeholders and sustainable as a tariff.

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[3] To be clear, it is preferable to define "excess generation" as the amount of solar DG output in excess of a customer's site load *in each hour*. Using the difference between the solar DG output and native load across an entire billing month (which is the current practice in Arizona) does not provide as accurate a depiction of the solar DG's energy value or its effect on the utility's costs.

Q. Instead of using avoided cost to compensate a solar DG customer, should the payment for excess generation simply be based off of the customer's standard utility tariff?

A. No, the payment for excess generation should not be based upon a bundled standard utility tariff. A bundled tariff contains cost recovery associated with generation, transmission, and distribution costs. Solar DG customers' generation output does not avoid most of these costs, and giving such customers credit for costs their systems do not avoid would create a subsidy in which non-participants' cost responsibility would increase beyond cost causation.

Q. Would the use of avoided cost as the basis of compensation for a solar DG system's excess generation be a change in Arizona from the current net metering tariff, in which excess generation is compensated using the standard tariff?

A. Yes it would, and the change would be done for the right reasons, consistent with long-standing cost of service and ratemaking principles. The resulting compensation mechanism would be sustainable and fair to all stakeholders

V. ISSUES RELATED TO THE VALUE OF SOLAR

Q. What do you see as the value of solar DG generation?

A. There is much debate in the industry as to the value of solar DG output, as it includes a subjective element with varying opinions (across stakeholders and over time) on its components and the associated monetary values. Therefore, I suggest the following guidelines for pricing solar DG:

a. Consider the VOS within two frameworks:
    i. Its value as it affects Commission-approved financial accounting costs used during rate proceedings.
    ii. Its value from an external perspective, outside of ratemaking.

b. For regulated ratemaking, avoid using the VOS from external perspectives which could otherwise result in permanent subsidies in fully approved tariffs.

Q. Please expand upon the meaning of VOS as it pertains to a utility's financial accounting costs.

A. The traditional meaning of "value" generally relates to the economic demand for a product or service beyond its pure cost. As I described in Section II, value-based pricing has no place in a cost of service ratemaking proceeding. Rather, this VOS for a possible ratemaking context relates to a determination of the effect of solar DG on the utility's incremental costs of those commonly accepted financial accounting costs employed in ratemaking and revenue requirements, such as generation, transmission, and distribution capacity cost, O&M, fuel, and losses. These incremental costs depend upon the characteristics of solar DG, including its intermittency, coincidence with the utility's demand cost drivers, physical location of the solar DG on the grid, and panel orientation.

Q. What do you mean when you refer to the VOS from an "external perspective," outside of ratemaking?

A. By "external" to ratemaking, I refer to benefits and cost valuations that are not readily found within a cost of service regulatory proceeding. This includes items such as potential environmental benefits or demand-based economic values such as an increase (or decrease) in regional employment. Other examples of these types of externalities include health benefits, reduced CO_2, and wholesale market price suppression. These types of valuations are not explicit components in ratemaking, and for good reason. The evaluation of such items is almost certainly subjective, lacking any real agreement as to the appropriate monetary figure that should be assigned. The subjectivity of the "value" analysis on such externalities can and would result in changing value over time.

Q. Please explain further your comment about avoiding the use of VOS from an external perspective in fully approved tariffs.

A. Fully approved tariffs should not be designed to include anything but approved financial accounting cost items. To include externalities such as a credit associated with the contention that solar DG creates jobs in Arizona (resulting in charges that are less than the cost to serve) could create a permanent subsidy. VOS should include only approved financial accounting costs and their impact upon a utility's incremental costs. Such costs could be used to influence rates, but only if the included incremental costs were: 1) regulator-approved, 2) already included in the design of similar electricity products such as energy efficiency, and 3) applied only to the extent that the tariff was cost-based and designed to recover the utility's embedded revenue requirements.

Using elements outside of the cost of service regime in order to benefit one particular resource or industry could result in inter- and intra-class cross-subsidies, skewed price signals, and rate instability. Rates are primarily set against the backdrop of a mathematically-determined cost regime, and it could prove quite harmful to allow a fully approved rate to contain a subjective and qualitative "value" element.

Q. Do you have other concerns that would arise in the event that the Commission were to decide, against your advice, to incorporate external costs or the value of electricity services in ratemaking for solar DG?

A. If the Commission chooses to include external costs or the value of electricity services in ratemaking (e.g., environmental benefits or regional employment effects), it could be argued that those costs and benefits should be applied uniformly. Ratemaking should avoid asymmetric treatment of specific costs and benefits, which could result in a distortion and skewing of behavioral incentives. If these external costs or sources of value were to be considered in the solar DG context, it could be proposed that the same costs and sources of value should be included in the pricing of all similar utility products that are sources of those costs and value. In other words, if there is an important source of external value that solar DG provides, and if it were deemed to be appropriate to include a "value" assessment in a cost-based rate structure, it may seem only fair that the same should be done across all similar sources of that value. To be clear, I don't believe that rates should incorporate value-based pricing or external costs, regardless of whether they are applied only to solar DG or uniformly across all sources of the cost of benefit. I simply point out the fact that asymmetric treatment of solar DG with respect to such costs and benefits leads to its own difficulties. Regulated rates cannot accurately reflect value. All sources of electricity have value. Many of these externalities are attributes of the utility's generation today—they are simply not included as explicit factors in ratemaking, nor should they be.

VI. CONCLUSIONS

Q. Do you have any concluding observations?

A. Yes, I recommend the following approaches for the pricing of solar DG customers:

1. Regulated ratemaking is and should continue to be based upon sound costing principles using approved financial accounting costs.
2. Regulated electricity rate designs that recover demand-related costs through energy charges (two-part rates) allow solar DG customers to

avoid paying the demand-related costs to serve them. The resulting cross-subsidies and improper behavioral incentives can be avoided through improved rate design. Permanent subsidies should be avoided wherever possible.

3. Excess generation from solar DG should be compensated at utility avoided costs.

4. Neither the "value" of electricity nor external costs (such as increased regional employment from solar DG subsidies) should be considered in regulated ratemaking.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit MTO-1

Michael T. O'Sheasy

RESUME

January 2016

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Academic Background:

MBA, Georgia State University, 1974
Bachelors of Industrial Engineering, Georgia Institute of Technology, 1970

Positions Held:

Vice President, Laurits R. Christensen Associates, Inc., May 2001-present
Manager, Product Design, Georgia Power Company, 1990-April 2001
Economic and Costing Analysis Dept, Southern Company Services, 1980-1990

Professional Experience:

I help utilities develop successful rate cases and new tariff filings based on both embedded and marginal cost of service and contemporary ratemaking principles. Expert testifying is available for both costing and pricing. Clients are encouraged to review and revise their retail portfolios to take advantage of the opportunities of improved pricing efficiency. I advise clients in developing and implementing innovative pricing products that extend utility customers' choices and improve the utility's bottom line and margin coverage. Some other examples of the expertise provided to clients are real time pricing, graduated fixed charges, cost-effective self-generation, advanced marginal costing, more accurate cost allocations methodologies, and fuel cost recovery clause enhancements. Prior to joining Christensen Associates, I directed real-time pricing and other innovative break-through rate structures including Price Protection Products, Daily Energy Credits, and FlatBill at Georgia Power Company, the largest operating company in the Southern Company system. I was responsible for retail and other regulatory requirements. I have routinely testified before various commissions on both costing and pricing. I have published numerous articles on pricing in many journals including *Natural Gas and Electricity, TAPPI Journal, Public Utilities Fortnightly, Electric Perspectives, EPRI Journal, Energy Customer Management*, and *The Electricity Journal*. On a national media level, I have been interviewed in *USA Today, Newsweek*, and National Public Radio. I have been featured on the front page of the *Wall Street Journal*, and I have appeared in a live interview on CNN FN.

Major Projects:

May 2001–Present: Vice President, Christensen Associates Energy Consulting

Expert Witness on Rate Design regarding distributed energy generation and net energy metering for South Carolina Electric & Gas in their 2014 filing and eventual settlement.

Expert Witness on Rate Design for Wisconsin Electric Company's 2014 rate case.

Expert Witness on Cost of Service for Georgia Power Company's 2013 rate case.

Advised Duke Energy Carolinas regarding redesign of their large business tariff.

Expert Witness on Cost of Service for Gulf Power Company's 2013 rate case.

Expert Witness on Rate Design for Progress Energy Company's 2012 rate case.

Expert Witness on Cost of Service for Gulf Power Company's 2011 rate case.

Advised large mid-west investor owned utility and presented report to the regulatory commission on distribution costing 2012.

Advised a mid-west regulatory commission staff on Base-Intermediate-Peaking (BIP) philosophy.

Expert Witness and Project Manager on costing and pricing for Bermuda Electric Light Company's 2011 rate case.

Project Manager for municipality investigating best applications of energy efficiency and demand response products.

Advised large Midwest IOU and presented to Commission staff and other stakeholders the advantages and disadvantages of performance-based and formulary-based ratemaking.

Led a cost of service and rate redesign project for a Midwest municipality.

Project Manager for a rate strategy project for TVA.

Project Manager and witness for Barbados Light and Power Company for their rate case filing.

Expert witness on cost of service for Georgia Power Company's 2007 rate case.

Consultant to Nova Scotia Power Inc. on Real Time Pricing.

Expert witness for EKPC for their Real Time Pricing pilot filing with the Kentucky Public Service Commission.

Expert witness on cost of service for Gulf Power's rate case.

Consultant to major IOU in Southwest for a retail rate case filing in 2007.

Consultant to Lincoln Electric Service on a cost of service audit.

Consultant to Georgia Power Company on a fixed bill product for mid-size business customers including product design, market research, approval, marketing, and training.

Witness and consultant to Oklahoma Gas & Electric on fixed bill project. Design was completed and approved for implementation.

Consultant to the Electric Power Board on fixed bill design, approval, and tracking.

Consultant to two separate Southeastern utilities on pricing strategy and pricing portfolio design.

Project Manager for Southeastern utility on design of an economic development rate for their largest customer.

Witness for large commercial customers in a major rate case requesting implementation of Real Time Pricing.

Consultant to large Pacific Northwestern utility on Real Time Pricing pilot program.

Consultant and witness to several mid-western utilities on the design and approval of a fixed bill product.

Consultant to utility on Real Time Pricing price response project.

Project Manager for Southeastern utility's research into a time of use fuel clause.

Consultant to mid-Atlantic utility on fixed bill in their competitive electricity market.

Consultant to two mid-west utilities on Real Time Pricing.

Consultant to Georgia Power, Duke Power, Gulf Power Company, and Progress Energy on the design, approval, and implementation of fixed bill products.

Consultant to California Energy Commission on the advancement of Real Time Pricing in California.

Consultant to Caribbean utility on pricing products and rate case filing.

1990–April 2001, Manager, Product Design, Georgia Power Company

Responsible for managing the pricing and rates research activities of the Company. Activities included pricing strategy development and future rate planning; rate research, design, and evaluation; the preparation and filing of retail rates with the Georgia Public Service Commission and the forecast of base rate revenues for the corporate budget.

Supported all regulatory proceedings by preparing rate case filings, including rate designs and testimony, training witnesses and briefing counsel for regulatory proceedings. Worked with the Public Service Commission staff and various customer/intervenor groups, providing adequate supporting evidence for obtaining PSC approval and customer acceptance of the proposed tariffs, rules, and regulations.

Developed embedded and marginal cost-of-service by rate or customer group and used these estimates and projections in the profitability assessments needed for innovative pricing strategies, such as demand-side rate options and market-based pricing.

Directed the rate research, design, and evaluation activities of the Company to develop a rate package, which contributed to the Company's marketing, financial, and corporate goals while satisfying the requirements of the Georgia PSC.

Developed innovative rate concepts which support the Company's marketing efforts and contribute to the competitiveness and profitability goals of the Southern Company. Developed long-term competitive pricing strategies and designed rate research programs for potential future rate options for evaluation and implementation. Created innovative pricing methodologies including Real Time Pricing, Multiple Load Management, Multiple Account Management, Interruptible Exchange Service, Flat Bill, and Price Protection Products. Also, directed efforts of "Pricing for the '90s" which will produce the most optimal, efficient pricing methods for Georgia Power Company's needs during the exciting, competitive 2000's.

Managed Real Time Pricing Program. Designed a customer specific profitability model (CPM). Presented over 100 speeches on pricing in state, national, and international forums.

1980–1990, Economic and Costing Analysis Department, Southern Company Services

Progressed through various levels of responsibility. Positions and activities include:

Engineer:

Assisted in the development of Cost-of-Service Studies for rate case filing. Developed jurisdictional and class analysis on individual projects such as PURPA and individual company analysis for internal purpose. Model development such as the Standard Load Flow Model, Georgia Power Cost of Service Model, and CSSM (Cost of Service Simulation Model). Manage the department's Issue File. Training of departmental employees, operating company personnel, and representatives of the Commission.

Senior Engineer:

Coordinator for Rate Case filings. Liaison between operating company and rate department. Internal analysis for operating companies and more development of those responsibilities listed under Engineer. Testified as cost expert in rate cases.

Supervisor:

Provided economic research and cost of service capability to Gulf Power and Mississippi Power Companies to support retail and wholesale rate filings and other regulatory requirements, and to provide management with pertinent information relative to their rate and regulatory affairs. This position was responsible for supervising the planning, development, evaluation, and formulation of effective economic analysis and related studies to present to internal management or to regulatory agencies, and to marketing for development marketing strategies.

Professional Papers:

"Parsing Poles and Towers: Customer Cost Allocations Using the Minimum Distribution System Method," *Public Utilities Fortnightly*, pp. 20-22, January 2016.

"Room for Fixed Billing in the World of Conservation?" *Natural Gas and Electricity,* August 2008.

"Are We On the Yellow Brick Road to the Land of Oz? The Wisdom of Rate Cases Today," EUCI, November 7, 2007.

"An Analysis of the Effects of Renewable Portfolio Standards on Retail Electricity Prices," presented in a webinar on 12/7/07 and EUCI Conference *Rate Case Essentials*, 11/7/07.

"Do You Want to Increase Your Utility's Demand Response and Consider it as a Bigger Player in Resource Planning," Energy Central, August 10 and August 17, 2007.

"Building a Risky Business," *Public Utilities Fortnight,* March 2007.

"The Fixed Bill: Newborn Becomes Toddler!" Energy Central's EnergyPulse.net, January 3 and January 11, 2005, Cybertech, Inc.

"Building a Better Pricing System," *Public Utilities Fortnightly*, May 2004.

"Demand Response: Not Just Rhetoric, It Can Truly Be the Silver Bullet," *The Electricity Journal*, Vol. 16, Issue 10, pp. 48–60, December 2003.

"How to Perform Efficient TOU Design," *Energy Central's EnergyPulse.net*, July 23, 2003, *CyberTech, Inc.*

"Who's Afraid of the Fixed-Bill?," *Energy Central's EnergyPulse.net,* April 2003, *CyberTech, Inc.*

"Is Real-Time Pricing a Panacea? If So, Why Isn't It More Widespread?," *The Electricity Journal*, December, 2002.

"Flat Prices for Peak Hedging," *Public Utilities Fortnightly*, November 1, 2002.

"RTP Customer Demand Response – Empirical Evidence on How Much Can You Expect," in *Electricity Pricing in the Transition*, A. Faruqui and K. Eakin, eds., Kluwer Academic Publishers, 2002.

"Flat Bills, Peak Satisfaction," *Energy Customer Management*, January/February, 2002.

"The New Pricing Organization," EPRI International Pricing Conference, co-authored with Robert Camfield, 2000.

"Roll the Dice, Set a Price," *Public Utilities Fortnightly*, May 15, 1999.

"5-cent Sundays....The Future of Electricity Prices?" *Electric Perspectives*, January/February 1999.

"Real-Time Pricing—Supplanted by Price-Risk Derivatives," *Public Utilities Fortnightly*, March 1, 1997.

"Customers Can Buy Low, Sell High," *The Electricity Journal*, February 1998.

"Real-Time Pricing for Purchased Electricity: An Innovative Pricing Option for Electricity as Used by the Pulp and Paper Industry," TAPPI Journal, April 1996.

"Reaping the Benefits of RTP: Georgia Power's RTP Evaluation Case Study," Volumes 1 and 2, Electric Power Research Institute (EPRI), December 1995.

Speeches and Presentations:

"Changes to the Regulatory Framework—a Key Enabler," Panel Moderator; Rate Design Workshop Instructor; October 2010, Electricity Pricing Strategies, EUCI.

"Customer Response to Dynamic Pricing: Who Responds and How," webinar, December 2009, EUCI-CAEC.

"Formulary Based Ratemaking for Retail Application," cost of service workshop, October 2008, Electricity—A Rising Cost Industry, EUCI.

"Rate Design Tools, Hedging, and the Proper Price Signal," rate design workshop, February, 2008, Managing Electric Price Volatility, EUCI.

"Will Renewable Portfolio Standards Increase Rates?" December 2007, EUCI webinar.

"Cost of Service—Are We Doing It Right?" "Providing the Customers Ultimate Bill Security—Fixed Bill," rate design workshop, cost-of-service workshop, November 2007, Rate Case Essentials, EUCI.

"Dynamic and Innovative :Pricing of Electricity," Electricity Pricing in Continuously Changing Environments, EUCI, February 2007.

"Lets Examine How It's Been Done for one of our Industry's Most Risky Products—Fixed Bill," cost-of-service workshop, October 2006, Rate Case 101—How to Produce a Successful Case, EUCI.

"Why Perform a Cost of Service Study? What Value does it bring to a Rate Case? What are its Limitations?" "How Can you Obtain Regulatory Approval for Innovative and Novel Rate Designs that Possess Little Industry Exposure?" Cost-of-Service Workshop, May 2006, Rate Case 101—How to Produce a Successful Rate Case, EUCI.

"How to Obtain Approval for a Novel, Innovative but Risky Pricing Product like Fixed Bill," Witness Preparation Workshop, November 2005, Utility Rate Case Management, INFOCAST.

"How Can You Obtain Internal and Regulatory Approval for Innovative and Novel Rate Designs that Possess Little Industry Exposure?," Cost-of -Service Workshop, October 2005, "Rate Case 101-How to Produce a Successful Case," EUCI.

"How to Obtain Regulatory Approval for Fixed Bill Type Products," Cost-of-Service Workshop, April 2005, Rate Case 101: How to Produce a Successful Case, EUCI.

"The Fixed Bill: Innovative Energy, Innovative Rate Option," April 2005, Developing New Products and Services for Utilities, EUCI.

"Digging In—Getting a Fixed-Bill Product Approved and Marketed," "Are There Any New Silver Bullets or Have We Used the Last One?," September 2004, Innovative Products and Services for the Energy Industry.

"Analyze This! The Fixed Bill Case," Successful Retail Products from the People Who Made Them, August 2004.

"Real Time Pricing Coupled with Risk Management at Georgia Power Company. It Keeps on Going and Going!" Peak Load Management Alliance, April 2005, PLMA.

"Introducing Fixed Bill," June 2004, UCI National Conference.

"Real-Time Pricing, Do Customers Really Price Respond?" April 2004, E Source 6th Annual Large C&I Summit.

"Fixed Bill," November 2003, E Source Annual Summit.

"A Summary of the Why's and How's of Real-Time Pricing," October 2003, GAO.

"The Fantasmic Fixed Bill," October 2003, EMAC's 2003, Chartwell's 6th International Energy Marketing and Customer Service Conference Expo.

"The Electricity Business Needs A New Sheriff to Keep Law and Order and Maintain Peace; and Here's His Silver Bullet," October 2003, American Bar Association, Section of Environment, Energy, and Resources, 11th Section Fall Meeting.

"The Need for Demand Response and Critical Peak Pricing," September 2003, Gulf Power Company's 3rd Annual Price Responsive Load Management Conference.

"The Fixed Bill: Innovative Energy, Innovative Rate Option," June 2003, EUCI.

"The Flat Bill Phenomenon," May 2003, Edison Electric Institute/American Gas Association Customer Service Conference and Exposition.

"Fixed Bill Product in an Uncertain Market," and Comments on Demand Response Versus Product Pricing of Electricity, May 2003, AESP/EPRI Pricing Conference.

"Financial Folly or Smart Pricing, Fixed-Bill Options for the Energy Business," April 2003, Energy Central Web Cast.

"The Dollars and Sense of Fixed Bills in a Volatile Wholesale Market," April 2003, EUCI, *Connecting Wholesale and Retail Electricity Markets.*

"Flat Billing—Will It Take the Country by Storm?" February 2003, AESP Brown Bag Seminar.

"Selected Demand Response Programs," October 2002, Committee on Regional Electric Power Cooperation, Vancouver, British Columbia.

"Existing Dynamic Pricing Programs: Lessons Learned and Best Practices," August 2002, *Time-Sensitive Pricing for a Competitive Electricity Marketplace*, NYSERDA.

"Amend Response—A Vital Element of Competitive Markets," July 2002, EEI, *Market Design and Transmission Pricing School.*

"Successful Demand Response Products for Competitive Markets: They Really Work!" May 2002, *New Developments in Electric Market Restructuring* Sponsored by U.S. Association of Energy Economics and the International Energy and Environment Program.

"Customer Pricing Research and Its Critical Role in Designing Pricing—Products for a Regulated Utility," April 2002, American Marketing Association.

"The Price Builder's Workshop,"—Instructor, December 2001, EPRI.

"Innovative Pricing and Load Response: A California Energy Commission Proposal for Giving the Customer a Seat at the Table!" September 2001, International Facility Management Association's World Workplace 2001.

"Real-Time Pricing—How it Works, Benefits and Risks," September 2001, The Center for Business Intelligence, *Pricing in Electric Markets.*

"Real-Time Pricing Overview," June 2001, EMF Workshop on Retail Participation in Competitive Power Markets, Stamford University.

"Real-Time Pricing: Offering Incentives, Caps and Collars," March 2001, Infocast, *Retail Pricing for Competitive Power Markets.*

"Retail Pricing For Competitive Markets,"—Instructor, February 2001, Infocast.

"Real-Time Pricing and Resultant Load Management," November 2000, E-Source, *Energy for a New Era.*

"The Fundamentals of Unbundled Pricing,"—Instructor, September 2000, Infocast.

"Retail Pricing for Competitive Power Markets,"—Instructor, September 2000, Infocast/EPRI.

"International Energy Pricing Conference 2000,"—Program Advisor and Speaker, July 2000, EPRI.

"Pricing in Competitive Markets: Will Customers Accept 'Real-Time' Risks?" November 1999, E-Source, *Dynasties, Dinosaurs, and Dynamos: Energy Services in the 21st Century.*

"Cost of Service and Rate Design Workshop," August 1999, Tenega Nasional Berhad, Kuala Lumpur, Malaysia.

"Retail Pricing: Innovative, Proactive, Value-Based Pricing Strategies for the Competitive Era,"—Instructor, June 1999, Infocast.

"How to Buy Low and Sell High or Why is RTP so Popular?" June 1998, EPRI Fifth Biannual Innovative Pricing Conference.

"Innovative Rate Design," July 1997, *Training Programme for IAS Officers on Public Policy Analysis*, Indian Institute of Management, Ahmedabad, India.

Testimony

Docket No. 2014-246-E before the Public Service Commission of South Carolina on behalf of South Carolina Electric & Gas Company as an expert witness on Costing and Rate Design.

Docket No. 05-UR-107 before the Public Service Commission of Wisconsin on behalf of Wisconsin Electric Power Company as an expert witness on Rate Design.

Docket No. 36989-U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on Cost of Service.

Docket No. 13-0387 before the Illinois Commerce Commission on behalf of Commonwealth Edison Company as their expert witness on Cost of Service.

Docket No. 130140-EI before the Florida Public Service Commission on behalf of Gulf Power Company as their expert witness on Cost of Service.

Docket No. 130007-EI before the Florida Public Service Commission on behalf of Gulf Power Company as their expert witness on Cost of Service.

Docket No. E-2, Sub 1023 before the North Carolina Utilities Commission on behalf of Progress Energy Carolinas, Inc. as their expert witness on Rate Design.

Docket No. E-7, Sub 1026 before the North Carolina Utilities Commission on behalf of Duke Energy Carolinas, LLC as their expert witness on Rate Design regarding the redesign of commercial and industrial OPT tariffs.

Docket No. E-100, Sub 73 before the North Carolina Utilities Commission on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, Inc. as their expert witness on Rate Design regarding a Jobs Retention Rider(JRT).

Docket No. 110138–EI before the Florida Public Service Commission on behalf of Gulf Power Company as their expert witness on cost of service.

Base Rate Tariff Filing – October 26, 2011 before The Energy Commission, Bermuda on behalf of Bermuda Electric Light Company Limited, as expert witness on rate design.

Docket No. 25060–U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on Cost of Service.

Docket No. 31958–U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on Cost of Service.

Docket No. 010949–EI before the Florida Public Service Commission on behalf of Gulf Power Company as their expert witness on Cost of Service.

Docket No. 881167–EI before the Florida Public Service Commission on behalf of Gulf Power Company as their expert witness on Cost of Service.

Docket No. 4147–U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

Case No. 2006–00045 Commonwealth of Kentucky before the Public Service Commission on behalf of East Kentucky Electric Cooperative as their expert witness on rate design.

Docket No. 050078–EI before the Florida Public Service Commission on behalf of the Commercial Group as their expert witness on cost of service and rate design.

Docket No. 16896–U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

Case No. 2004 Commonwealth of Kentucky before the Public Service Commission on behalf of East Kentucky Electric Cooperative as their expert witness on rate design.

Cause No. PUD 200500151 before the Corporation Commission of the State of Oklahoma on behalf of Oklahoma Gas and Electric as their expert witness on rate design.

Docket No. 4132–U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

Docket No. 4755–U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

Docket No. 11708–U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

Docket No. 13140–U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

Docket No. 16896–U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

FTC-02/09 BL&P–RADJ before the Barbados Fair Trading Commission on behalf of Barbados Light & Power Company as their expert witness on cost of service and rate design.