BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN ORDER GRANTING APPROVAL OF NEW DISTRIBUTED GENERATION TARIFFS PURSUANT TO TITLE 17, SECTION 156 OF THE OKLAHOMA STATUTES	))))))	CAUSE NO. PUD 201500274

RESPONSIVE TESTIMONY

OF

JUSTIN R. BARNES

ON BEHALF OF

THE ALLIANCE FOR SOLAR CHOICE ("TASC")

November 3, 2015

Prepared Responsive Testimony of Justin R. Barnes
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I. INTRODUCTION

Q. Please state your name, business address and current position.

A. Justin R. Barnes, 401 Harrison Oaks Blvd Suite 100, Cary, North Carolina, 27513. My current position is Director of Research with EQ Research LLC.

Q. Please describe your educational and occupational background.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years, where I worked on the *Database of State Incentives for Renewables and Efficiency (DSIRE)* project, and several other projects related to state renewable energy and efficiency policy. In my current position I coordinate EQ Research's various research projects for clients, directly manage and perform research for a solar energy regulatory policy tracking service, contribute as a researcher to other standard policy service offerings, and perform customized research. I have testified on several occasions before the Public Service Commission of South Carolina as an expert in distribution generation and net metering policy. My *curriculum vitae* is attached as Exhibit JRB-1.

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

A. No.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of The Alliance for Solar Choice ("TASC"). TASC advocates for maintaining successful distributed solar policies nationwide. Founded by the largest rooftop companies in the nation, TASC represents the vast majority of the market, including Demeter Power; Silevo; SolarCity; Solar Universe; Sunrun; Verengo; and ZEP Solar. These companies are responsible for tens of thousands of residential, commercial, school, and government solar installations across the country, and are engaged at the local, state, and national level. TASC's interest in this proceeding is to encourage customer choice and fair rate setting practices for solar powered distributed generation.

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

A. The purpose of my testimony is to describe the deficiencies in the application of Oklahoma Gas and Electric ("OG&E" or the "utility") to implement distributed generation ("DG") tariff changes in response to 2014 Senate Bill No. 1456 ("S.B. 1456") and accompanying Executive Order 2014-07 ("E.O. 2014-07"), and offer recommendations for how the Commission should proceed in its consideration of the application. More specifically, I first discuss what S.B. 1456 and E.O. 2014-07 collectively require for DG tariffs. I then describe how OG&E's DG tariff proposal fails to meet these requirements on the basis of its overall design and the utility's failure to fully consider the benefits of DG to non-DG customers in its evaluation of the supposed "subsidy" being provided from non-DG customers to DG customers. Finally, I offer recommendations on how the Commission should proceed in its consideration of OG&E's proposal and any future applications from other Oklahoma utilities. Mark Garrett, TASC's other witness, will discuss more specific cost of service issues related to OG&E's application.

Q. **Please summarize the specific recommendations you make in your testimony.**

A. I recommend that the Commission take the following actions:

1. Reject OG&E's proposal for new DG tariffs because the utility fails to adequately demonstrate that: (a) such a subsidy exists, and (b) its proposed tariffs would not constitute a rate increase on DG customers that causes them to pay rates above their cost of service. Both elements are prerequisites for the adoption of new DG tariffs under S.B. 1456.

2. Require the development of a more complete analysis of the cost to serve DG customers and the benefits of DG that accrue to non-DG customers prior to implementing any tariff changes. This in turn would require the completion of an updated cost of service study with specific analysis of the cost to serve DG customers, as well as the development of comprehensive quantitative methodology for determining the value of DG benefits. The purpose of this exercise is to create a roadmap for reliably identifying the magnitude of any subsidy that exists between DG customers and non-DG customers.
3. Consider convening a renewed stakeholder process to arrive at the comprehensive valuation methodology I recommend. The focus of this process would be to define specific methods of calculating the various benefits of DG, including all of the necessary inputs and assumptions. The common methodology could be employed in future proceedings, and updated as necessary to ensure that tariffs for DG customers continue to comply with the strictures of S.B. 1456.
4. Upon reaching any conclusion that DG customers are being subsidized by non-DG customers, pursue rate reforms such as minimum bills or modifications to time-of-use tariffs to mitigate the issue. These reforms are superior to fixed charges and demand charges because they allow customers to retain substantial control over their energy bills. They therefore continue to encourage DG deployment in alignment with the directive in E.O. 2014-07 and the policy goals of the Oklahoma First Energy Plan.

II. REQUIREMENTS OF S.B. 1456 AND E.O. 2014-07

Q. Please summarize what S.B. 1456 requires.

A. S.B. 1456 obligates retail electric suppliers to, by December 31, 2015, implement tariffs for DG customers only in the case that DG customers are found to be subsidized by non-DG customers. Any DG tariff may recover no more than the costs necessary to serve those DG customers. This requirement only applies to customers that install DG systems on or after the November 1, 2014 effective date of the enacted bill. Based on the definition of "distributed generation" in S.B. 1456, it also does not apply to customers that are enrolled on demand-based rate schedules. S.B. 1456 further provides that "higher fixed charges" on DG customers, as compared to non-DG customers, are a means to avoid intra-class subsidies. It defines a fixed charge as "any fixed monthly charge, basic charge, or other charge not based on the volume of energy consumed by the customer, which reflects the actual fixed costs of the retail electric supplier."

Q. **Does S.B. 1456 require that new tariffs for DG customers be adopted by December 31, 2015?**

A. S.B. 1456 only requires the adoption of new tariffs if they are necessary in light of the law's other requirements. These requirements are that DG customers not be subsidized by non-DG customers in the same rate class, and that rates for DG customers not be increased above that necessary to recover their cost of service. This requires answers to the threshold questions of: (1) whether a long-term intra-class subsidy exists; (2) the magnitude of the subsidy; and (3) the direction in which any subsidy operates. Logically, appropriate tariffs cannot be devised until conclusions have been reached on these questions. Stated another way, the Commission cannot allow a subsidy to be present in a utility's tariffs after December 31, 2015, but it is under no obligation to require tariff revisions prior to answering the subsidy question to its satisfaction.

Q. **Does S.B. 1456 require the use of higher fixed charges to address any intra-class subsidies?**

A. No. S.B. 1456 simply states that higher fixed charges are a way to eliminate subsidies that may be determined to exist. It does not say that they are the only way to accomplish this, or even the preferred way. Moreover, the definition of a fixed charge used in S.B. 1456 is broad enough to include other means "not based on the volume of energy consumed by the customer," such as a minimum bill.

Q. **Please elaborate on why you use the term "long-term" in reference to an analysis of any intra-class subsidy?**

A. A typical DG system, such as a solar photovoltaic ("PV") system, has an operational lifetime of more than 25 years. Thus the operation of a DG system will affect the DG customer, non-DG customers (current and future), and the utility over that entire timeframe. Using an analytical timeframe consistent with the lifetime of a typical DG facility places current and future customers on the same playing field in terms of any benefits or costs they experience, and aligns with the long-term outlook used in utility resource planning.

Q. **Please describe E.O. 2014-07.**

A. E.O. 2014-07 provides direction to the Commission in its implementation of S.B. 1456. Among other things, it states that implementation requires "strict compliance…with the goals and intent of the Oklahoma First Energy Plan and this Bill [S.B. 1456]" and that S.B. 1456 allows the Commission to consider "prior to the implementation of any fixed charges…all available alternatives, including other rate reforms such as increased use of time-of-use rates, minimum bills and demand charges." It further provides guidance on how the Oklahoma First Energy Plan (the "State Energy Plan") relates to the implementation of S.B. 1456, as follows:

- The State Energy Plan promotes wind and solar power;
- DG is an essential element of the plan;
- S.B. 1456 "encourages" increased reliance by individuals and businesses on DG systems; and

- A proper examination of rate reforms will ensure appropriate implementation of the State Energy Plan while protecting future DG customers.

III. CONSIDERATION OF POTENTIAL DG COST SHIFTS IN OTHER JURISDICTIONS

Q. Please elaborate on how other states have addressed the potential cost-shift or DG subsidy issue.

A. Most states have approached the topic from the perspective of the relative costs and benefits of DG or the policy of net metering. The rationale for this type of framework is that if DG or net-metered installations yield long-term benefits that exceed the costs, non-participating ratepayers ultimately benefit from their deployment. Stated another way, if the long-term costs avoided by DG exceed the compensation provided to DG customers (e.g., retail rate compensation under net metering), there is no subsidy being provided by non-DG customers to DG customers. Rather, a net-benefit finding indicates that DG customers are subsidizing non-DG customers.

These studies and investigations have arisen for different specific reasons (e.g., legislative requirements, utility rate requests) but ultimately they can be seen as attempts to better understand the relative costs and benefits of DG as a precursor to any efforts to reform rates or net metering policies. Quantitative cost-benefit studies have been completed in states including California, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, Nevada, and Vermont, while investigatory proceedings are ongoing in Arizona, New York, Oregon, and Utah. The Colorado Public Utilities Commission also recently concluded an investigation into similar issues, though it did not conduct a formal quantitative study. Several of the completed studies were preceded by or involved regulatory proceedings intended to elicit stakeholder input on the appropriate cost-benefit methodology (e.g., in Maine and Minnesota) prior to the completion of the study. The ongoing proceedings in New York, Oregon and Utah are likewise devoted to this purpose.

Q. **Why do you believe that the investigations in other states are relevant in the context of the present proceeding?**

A. They are important because they point to an emerging set of best practices for evaluating the existence of cross-subsidies between DG customers and non-DG customers. These best practices include procedural elements, such as the solicitation of stakeholder input to define a methodology and the deferral of rate reforms until a reliable analysis can be completed. They also include the actual details of an appropriate methodology, the requisite inputs, and assumptions. While each of the completed studies employ somewhat different methodologies, they display many common elements and can serve as valuable resources for informing the Commission's own evaluation. A publication from the Interstate Renewable Energy Council ("IREC") provides an excellent qualitative description of a thorough cost-benefit methodology, the relevant cost-benefit components, and the different ways that values may be calculated for these components.[1] This guidance, which was co-authored by a former Commissioner with the Public Utilities Commission of Texas and utility executive, should be used in conjunction with the completed studies to establish a solid analytical approach for a cost-benefit evaluation.

Q. **What conclusions have the completed studies reached?**

A. By and large they have found that DG and net metering have positive net benefits for ratepayers, meaning that if anything DG customers are actually subsidizing

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[1] See IREC. A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation. October 2013. http://www.irecusa.org/a-regulators-guidebook-calculating-the-benefits-and-costs-of-distributed-solar-generation/

non-DG customers. Table 1 provides brief descriptions of the conclusions reached in several recent studies initiated or completed by state regulatory agencies.

Q. **Does the testimony of OG&E Witness Walkingstick accurately portray the scope of regulatory investigations of potential cost-shifts associated with DG deployment?**

A. No. Mr. Walkingstick references only a single proceeding, a general rate case request brought by We Energies in the state of Wisconsin.[2] He omits the many other similar investigations that have taken place in other states and produced different outcomes, as I describe above, and fails to note that the Wisconsin Public Service Commission did not conduct a full cost-benefit analysis of DG as part of the proceeding. This decision was vacated on October 30, 2015, on the basis that the record lacked sufficient evidence and justification for the additional charges.[3] Thus the relevance of this particular proceeding is confined to the fact that it failed to withstand judicial scrutiny.

Table 1: State Cost-Benefit Study Results

State (Year)	Summary of Outcome
Colorado[4] (2015)	Declined to make any changes to net metering or on-site solar generation rules upon the conclusion of an 18-month inquiry.
Maine[5] (2014)	After completing a stakeholder process on the appropriate methodology, a consultant developed study found a 25-year levelized value of 33.7 cents/kWh for solar DG resources.
Massachusetts[6] (2014)	Consultant study found that under two different policy scenarios, DG solar provides net benefits of 1.5 – 2.1 cents/kWh to ratepayers (excluding the cost of the state incentive programs).
Mississippi[7] (2014)	A consultant developed study found that net metering would have net benefits to

[2] See Walkingstick Direct, p. 12, lines 4-18.
[3] See Dane County Circuit Court, Case No. 15-cv-153.
[4] See Colorado Public Utilities Commission Decision C15-0990, September 15, 2015, Proceeding Number 14M-0235E.
[5] See "Maine Distributed Solar Valuation Study," Clean Power Research, Prepared for the Maine Public Utilities Commission, March 2015. Available at https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2014-00171.
[6] See "Massachusetts Net Metering and Solar Task Force: Final Report to the Legislature," see Task 3-Evaluating the Costs and Benefits of Alternative Net Metering and Solar Policy Options in Massachusetts, Grace, Robert, Michelman, Thomas, Sustainable Energy Advantage, April 27, 2015. Available at http://www.mass.gov/eea/docs/doer/renewables/final-net-metering-and-solar-task-force-report.pdf.

	all ratepayers in 10 of 11 sensitivity scenarios, and a 25-year levelized value of 17 cents/kWh for net metering generation in the base case scenario.
Minnesota[8] (2014)	Developed a value of solar methodology through a stakeholder process, and ultimately calculated a value of solar rate of 14.7 cents/kWh.
Nevada[9] (2014)	A consultant developed cost-benefit study found that net metering benefits exceeded costs by $37 million over 20 years, even with the inclusion of utility solar rebates separate from net metering as costs.
Vermont[10] (2014)	Found that net metering generation had a 20-year levelized value of 23.7 cents/kWh to ratepayers and 25.6 cents/kWh to society, leading to a conclusion that net metering holds net benefits for both.
California[11]	Consultant study found that the total net cost of the NEM program, at full subscription (5,256 MW) in the year 2020 would be $1.09B annually, though it noted that this is heavily influenced by the tiered rate design. The study also found that net metering customers in aggregate pay the cost of their electric service.

Q. **How do you respond to Mr. Walkingstick's reference to a recent Harvard paper suggesting that solar advocate studies overvalue solar DG?**

A. I believe that these collective studies and regulatory proceedings belie the inference Mr. Walkingstick makes in citing the paper from the Harvard Electricity Policy Group. Though solar and DG advocates have commissioned a number of such solar valuation studies, the proceedings and studies I note above were, or are, being conducted by neutral regulatory agencies, not solar advocates. They represent vetted, credible approaches to such an evaluation, not the type of skewed assessment that Mr. Walkingstick implies.

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[7] See "Net Metering in Mississippi: Costs, Benefits and Policy Considerations," Synapse Energy Economics, prepared for the Mississippi Public Service Commission, September 2014, at 36. Available at http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

[8] See "Minnesota Value of Solar: Methodology," Clean Power Research, Prepared for the Minnesota Department of Commerce, Division of Energy Resources, January 2014. Available at http://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf.

[9] See "Nevada Net Energy Metering Impacts Evaluation," Energy and Environmental Economics (E3) Consulting, July 2014. Available at http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.

[10] See "Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012," Vermont Public Service Department, January 15, 2013. The staff of the Vermont PSC performed an extensive literature search in its January 2013 Evaluation. Available at http://publicservice.vermont.gov/sites/psd/files/Topics/Renewable_Energy/Net_Metering/Act%20125%20Study%2020130115%20Final.pdf.

[11] See "California Net Energy Metering Ratepayer Impacts Evaluation," California Public Utilities Commission Energy Division and E3 Consulting, October 2013. Available at http://www.cpuc.ca.gov/NR/rdonlyres/75573B69-D5C8-45D3-BE22-3074EAB16D87/0/NEMReport.pdf.

Q. **Based on your preceding testimony, how would you describe the Commission's obligations in implementing S.B. 1456?**

A. In order to properly implement S.B. 1456 the Commission must first reliably determine whether a long-term subsidy from non-DG customers to DG customers exists, or vice versa. This should involve a long-term analysis consistent with the expected lifetime of a customer-sited DG installation, and should consider the full suite of potential costs and benefits consistent with the approaches used in other states and the aforementioned IREC guidance document. The Commission is not required to institute tariff revisions until after it determines to its satisfaction that a subsidy exists in one direction or the other.

Once the Commission has reached a conclusion on the subsidy question, it has substantial leeway to decide on the best way to address the subsidy. In this respect, the Commission is not bound by the proposal put forth by OG&E or any other utility. For instance, it could be that DG customers are subsidizing non-DG customers, in which case the OCC could take any number of remedial actions. That could include allowing rollover of credits for monthly net excess generation, as all other states with net metering policies do.[12] Alternately, it could be the case that any subsidy flowing from non-solar customers to solar customers, or vice versa, is less than the administrative costs of implementing rate reforms. In this case the Commission could simply opt to maintain current rates.

The Commission has however been directed by E.O. 2014-07 to ensure that its S.B. 1456 implementation efforts align with the goals of the state Energy Plan, which promotes the development of wind and solar power, including DG applications of these technologies. In light of this direction, I recommend that the Commission exercise great care in making sure that any rate reforms continue to encourage DG deployment. This could include exploring alternative rate design options such as minimum bills, or directing the revision of existing tariffs to

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[12] Monthly rollover rates differ among states, but all other states with net metering policies require utilities to compensate the customer in some way for monthly excess.

provide additional compensation to DG customers if the cost-benefit analysis shows that they are subsidizing non-DG customers.

Q. **Are you suggesting that the Commission should conduct a comprehensive DG cost-benefit analysis in the current proceeding?**

A. Not necessarily, for two reasons. First the present schedule does not allow enough time to complete a thorough study. Second, I think it is reasonable to question whether the magnitude of the alleged problem is sufficient to justify pursuing a comprehensive study in the near term.

Mr. Walkingstick indicates that as of July 31, 2015 only 15 DG installations would be subject to S.B. 1456.[13] Though I disagree with his calculation of the "excess compensation" provided to existing net metering customers, if one scales the calculations he makes for 68 existing net metering customers to 15 customers, the result is a purported subsidy of less than $3,000 annually. Divided among OG&E's roughly 740,000 Oklahoma customers, the cost shift, assuming OG&E's numbers, is negligible. Even under a significant increase in solar penetration in the next few years, such an alleged cross-subsidy would remain de minimis. The cost of the completion of a comprehensive DG cost-benefit analysis would likely be at least an order of magnitude greater than the $3,000 annual figure, while also requiring substantial time commitments on the part of staff, utilities, and other stakeholders. I do not believe that such a substantial cost is warranted or in the interest of ratepayers and other parties at this time.

Q. **How then do you recommend the Commission proceed in meeting the requirements of S.B. 1456?**

A. As I have already discussed, a comprehensive study is necessary if the Commission is to institute new tariffs that address any subsidy and do not result in rate increases on DG customers above that necessary to recover their cost of

[13] See Walkingstick Direct, p. 10, Table 1

service. With this in mind, the Commission could nevertheless conclude that it does not possess the information necessary to identify and quantify any subsidy with the degree of precision required to justify new tariffs for DG customers. It could then specify some type of benchmark (e.g., number of DG installations, installed capacity, next rate case) that would trigger reconsideration of the issue. It would be reasonable for the timing and frequency of reconsideration to take into account the legal and administrative costs of such a proceeding, which are ultimately passed to ratepayers.

In the meantime, I believe that it could be productive for the Commission to conduct a renewed stakeholder process to establish protocols for analyzing the existence of a subsidy. A process like this would create a common playing field for utilities subject to S.B. 1456, and identify the information the Commission needs to reach a decision. This would be beneficial because it would avoid the prospect of having to re-litigate similar issues in multiple proceedings, and provide utilities with a framework that they can rely upon in assembling information and evidence to support any proposed tariff changes. Since S.B. 1456 states that rate increases on DG customers may not result in the recovery of costs in excess of their cost of service, I believe that the appropriate venue for a final determination on tariff changes is a general rate case.

Q. **Didn't the Commission already conduct a stakeholder process in anticipation of utility filings in response to S.B. 1456, resulting in a "checklist" for utility tariff filings?**

A. It did, but what I envision is an extension of that process. The past process was an excellent first step in sorting through the various issues presented by S.B. 1456. However, with respect to analyzing the benefits of DG systems, it stopped short of precisely defining protocols and methods for how the specific benefit categories should be analyzed. While it may have seemed reasonable at the time to confine the output of this process to qualitative analytical issues, based on OG&E's DG tariff filing, it was evidently not sufficient to lead to a full and detailed benefits study. The supplemental process I suggest would be focused on defining a quantitative methodology for analyzing DG benefits, including the necessary inputs and assumptions used for each category. One possible output could be a formulaic framework for the benefits calculation that only requires the filling in of utility-specific numbers.

IV. DEFICIENCIES ON OG&E'S DG TARIFF APPLICATION

Q. **Please describe OG&E's DG tariff proposal.**

A. OG&E proposes to revise its existing tariffs to require DG installations placed in service after November 1, 2014 to take service under tariffs with increased customer charges, a demand component, and time-of-use ("TOU") energy charges that differ from existing tariffs. It also proposes to allow DG customers on these tariffs to enroll in either a net energy billing option ("NEBO-kW") or a new standard purchase rate schedule for systems of 300 kW or less, designated as rate RPPO.

The NEBO-kW option allows a customer to offset onsite energy needs using the DG system and be billed only for net energy purchases for each monthly billing period. It does not provide the customer with compensation for any production in excess of monthly use, and does not allow any excess production during a month to offset the monetary fixed or demand charges. The RPPO option is a buy-all, sell-all arrangement where the customer purchases all of their energy needs from the utility at the applicable residential or commercial tariff rate, and receives compensation for all energy produced by the system at the RPPO rate.

Under the residential version of the DG tariff, designated as R-TOU-kW, the customer would be subject to a fixed customer charge of $18.00/month, a $5.00/month increase compared to the utility's other residential rate schedules. Residential DG customers would also be subject to a demand charge of $2.68/kW of 15-minute maximum demand. Energy supply charges would be set at $0.173/kWh for on-peak periods and $0.0137 for off-peak periods. These differ substantially from the utility's existing residential TOU rates. Under the commercial version of the tariff, designated as COM-TOU-kW, a small General Service customer would be subjected to an increase of roughly $10/month in the fixed monthly charge (from $24.70 to $35.00/month), a 15-minute demand charge of $3.33/kW, and energy supply rates of $0.1875/kWh for on-peak periods and $0.0143/kWh for off-peak periods. The commercial energy supply rates likewise differ from the existing General Service TOU tariff rates.[14]

Q. **What problems do you foresee with OG&E's proposal to place DG customers on demand rates?**

A. First, I believe that there is reason to question whether S.B. 1456 even allows the use of demand rates for DG customers. The definition of "distributed generation" in S.B. 1456 excludes customers that receive service on rates with demand-based charges. If DG customers were required to enroll on demand-rate tariffs, they would fall outside of the definition of distributed generation, and hence not be subject to the requirements of the law. This is a legal issue that the Commission needs to resolve before it considers the other contents of OG&E's application. Mr. Garrett discusses the implications in greater detail.

Second, as I will elaborate on further, there are a number of reasons why mandatory demand rates on small customers are strongly disfavored nationally, and universally so in the residential context. OG&E's existing rates for residential and small commercial customers bear this out. The residential rate schedules do not contain demand rates – even as an option – and the non-residential tariffs allow customers with maximum annual demands of up to 400 kW to remain on non-demand rates.[15] Non-demand rate options are common for small non-residential customers throughout the country. I am aware of no state-regulated utility that imposes mandatory demand rates on residential customers as a whole, or imposes them universally on DG customers. OG&E seeks a rate design that is

[14] See Walkingstick Direct, Exhibits RDW-3, RDW-4 and RDW-5.
[15] See OG&E rate schedules R-1 & GS-1 for example.

unprecedented on a national level. Even if the Commission were to conclude that precedent in other states carries no weight, the reasons for this lack of precedent remain compelling.

Q. **Why are mandatory demand rates inappropriate for residential and small non-residential customers?**

A. The reasons are numerous. First, demand rates themselves will be difficult for many small customers to understand. The simple conceptual difference between a kW and a kWh is hard for these customers to grasp, let alone the meaning of a "15-minute average maximum demand," or how each individual electric load contributes to their electric demand.

This lack of understanding leads to the second drawback, the customer's inability to reliably manage electric demand and, as a consequence, their electricity bills. Any customer can be expected to understand that the more they use electric appliances, the greater their electricity bill will be. It is far harder for customers to understand that even if they set their thermostat at a high temperature, it could cycle on coincident with the compressor in their refrigerator and their use of a television, hair dryer, oven or other appliance. Even a knowledgeable, diligent customer who desires to reduce their electric demand could be saddled with a high electricity bill on the basis of a single lapse in attention during a month. The burden is likely to fall most heavily on families because as difficult as it may be for a single person to manage demand in this fashion, it is even harder to manage the actions of other users, including children. For many small customers, the effect of a demand charge is effectively equivalent to a higher fixed charge, an aspect I will address in more detail later in my testimony.

Third, demand charges directly and indirectly discourage energy conservation. Directly, the demand component reduces rates for the remaining volumetric components, making energy savings less valuable for the customer. Indirectly, a customer that makes efforts to reduce their electricity bill but sees little change due to high demand charges is likely to conclude that further efforts to invest in energy efficiency or conservation are unattractive.

Q. **Would these same drawbacks apply if demand rates were only made mandatory for DG customers?**

A. Yes. Residential and small non-residential DG customers are no different than a typical non-DG customer in these rate classes; accordingly, the rationale for not placing these classes on demand rates applies equally to DG customers. A customer that installs DG in an effort to manage their energy use is no different than a customer that installs a geothermal heat pump system, additional insulation, or energy efficient lighting. Like these types of energy efficiency improvements, a solar DG system is a low-maintenance improvement that allows customers who are not able or inclined to more actively manage their energy consumption to nevertheless save on energy costs.

DG customers rely *passively* on the improvement to produce cost savings. As "passive" customers, they are no different from a customer that chooses not to invest in energy saving technologies, or a customer that makes energy efficiency improvements that require little or no active management—for example, installing CFL or LED light bulbs. There is no basis for an assumption that DG customers are somehow superior to other customers in terms of energy management skills.

Q. **Are there elements in OG&E's DG demand tariff proposal that remedy any of these issues?**

A. No, and in fact there are components that exacerbate the problem and would make it even more difficult for customers to understand and manage their energy bills. As noted above, OG&E proposes a higher fixed charge, which itself diminishes the customer's ability to control their energy bills. Furthermore, the utility proposes a tariff that relies on a non-time-differentiated demand charge and TOU energy charges. This is problematic in two ways.

First, the flat, non-coincident demand charge does not reflect cost causation. A customer would be required to pay the same demand charge regardless of whether their demand is coincident with the system peak (i.e., transmission) or the local circuit peak (i.e., distribution). Both portions of the system are built to handle the respective maximum coincident peaks of all customers to which they are providing service. Charging a customer based on their non-coincident peaks for system costs that are caused by coincident peaks does not align the customer's rates with the cost to serve that customer.

Second, the combination of a TOU energy charge and non-time-differentiated demand charge will make it even more difficult for customers to manage their energy bills. The TOU energy rate motivates a customer to avoid using electricity during on-peak periods, defined as weekdays from 2 – 7 PM during the months of June – September. It therefore compels customers to concentrate their energy use during off-peak periods during the summer months or manage their consumption based on the real-time output of their DG system.

Yet concentrating energy use in certain time periods is likely to result in higher demand charges. This is particularly true in the late evening when a solar DG system will be producing little or no energy. It is likewise implausible that a customer could align consumption with DG system production day in and day out without deviating for a single 15-minute period during a month. Correspondingly, during the winter season, the energy rates are so low that a customer has little incentive to conserve energy or utilize self-generation.

Finally, since the NEBO-kW option does not allow for excess generation to be carried over from month to month or monetized at the end of a billing period and used to offset other monetary charges, the customer is unable to fully benefit even when they produce an excess of highly valuable on-peak energy. This could produce a somewhat counterintuitive response in customer behavior, where the customer attempts to avoid forfeiture of excess on peak energy by actually attempting to use more energy at on-peak times (i.e., reduce the bank to zero). This could actually exacerbate stress on the system during high load periods. The practical effect of these collective elements is to send the customer a mixed set of pricing signals, make it extremely difficult for a DG customer to avoid high energy bills during the summer, and minimize the value of the DG system during the winter months, while charging them for system use in a manner that is not aligned with their true cost of service.

Q. **What impact would the proposed R-TOU-kW tariff have on residential DG customers?**

A. The workpapers of Mr. Walkingstick indicate that on average the new tariff rate would reduce first year customer savings associated with a fixed tilt (i.e., rooftop) 4 kW residential solar PV system by roughly $13 per month, from $41 per month to $28 per month.[16] These workpapers are attached as Exhibit JRB-2.

This estimate is misleading due to the way in which OG&E performs the analysis, and uses assumptions that diminish its accuracy. It is *not* a comparison between what a customer's total average monthly electric bill would be under the existing tariff and the proposed tariff. Instead it compares only monthly savings after the installation of DG under the two tariffs without recognizing that the starting point (i.e., the customer's bill without DG) would be different. In other words, if a customer had an average bill before DG of $100 a month under the existing tariff, and would have average bill of $110 per month under the proposed tariff, the average bill after DG would be $57 per month under the existing tariff and $82 per month under the proposed tariff (i.e., a difference of $25 per month). An accurate estimate of the impact that the proposed tariffs would have on DG customers requires a comparison between average monthly customer bills under the existing DG tariff and the proposed DG tariff.

I have made such an estimate for residential customers modeled on the savings analysis and data provided by OG&E.[17] I estimate that compared to the current residential NEBO rate, the proposed R-TOU-kW tariff would reduce

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[16] See OG&E Response to TASC Data Request 1.5
[17] This is based on data and formulas supplied by OG&E in response to TASC Data Request 1.5.

customer savings by an average of roughly $24.50 per month for the reference 4 kW rooftop system. Thus the customer may still "save" $28 per month on R-TOU-kW compared to being on the same rate without DG, but the rate itself would increase the customer's bill compared to the standard residential TOU tariff by $11.50 per month. Thus $11.50 per month in savings is lost to the bill increase and the customer would pay only $16.50 less per month with DG under rate R-TOU-kW compared to what they would pay under the standard residential TOU rate without a DG system. Over the course of the life of a DG system, this would cost the customer thousands of dollars in foregone savings.

It should be noted that these calculations are based on an assumption that residential DG customers are identical to the average residential customer. A more precise estimate of DG customer impacts requires the use of data specific to DG customers.

Q. **Why is the comparison between monthly customer costs under the standard residential TOU tariff and R-TOU-kW important?**

A. First, as I describe above, this comparison more accurately describes the impact of the R-TOU-kW tariff on DG customers than the estimate Mr. Walkingstick includes in his testimony. Second, I think it creates a serious question on the design of the R-TOU-kW tariff as it relates to cost of service. I am not aware of precisely how the standard residential TOU rate was designed, but I would assume that it is more or less aligned with the cost to serve residential customers. If the same is true for R-TOU-kW, I would expect that an average residential customer's monthly bill under either rate would be similar. Yet by my calculations, an average residential customer's bill under R-TOU-kW would be meaningfully higher. This discrepancy is among the reasons why an updated cost of service study is needed to inform the development of any DG tariffs.

Q. **Has OG&E made any impact estimates using DG customer billing data?**

A. Yes, though from a slightly different perspective. OG&E performed an analysis of monthly bills for DG customers under the current net billing rider, compared to monthly bills under its proposed residential and non-residential DG tariffs.

It provided one analysis of this type in response to a request from the Public Utilities Division, showing that if the proposed DG tariff was applied to all net billing accounts that existed as of November 1, 2014, the average residential bill increase would be $19.87 per month ($238 per year), or 22.9%.[18] It separately provided TASC with an estimate that for residential DG customers that subject to the tariff, the bill increase would average $12.70 per month.[19] The $19.87 per month number is likely to be more accurate because it involves a sample size of 200 residential customers, while the latter is a partial year estimate for only eight residential customers.

Q. **Can you provide any examples that illustrate the effect that increased customer charges and demand charges can have on PV deployment?**

A. Examples are extremely limited, because as I have already noted, the design in unprecedented among major utilities. However, the Salt River Project ("SRP"), a self-regulated publicly owned utility in Arizona, has deployed a new rate for residential solar customers in that includes a demand charge and an increased customer charge. The new rate is effective for all residential solar interconnection applications submitted after December 9, 2014.

Unofficial statistics from Arizona Goes Solar, a collaborative effort by the Arizona Corporation Commission and the state's utilities, indicate that new interconnection applications in the SRP's territory fell by almost 96% after the imposition of the rate changes. Specifically, the generating capacity associated with new residential interconnection applications during the period from January

[18] See OG&E Response to Staff Data Request KJC-1, attached as Exhibit JRB-3.
[19] See OG&E Response to TASC Data Request 2.4, attached as Exhibit JRB-4.

– September 2015 was 4.2% of the residential capacity volume submitted from January – September 2014.[20]

Q. Does this outcome align with the requirements of S.B. 1456 and E.O. 2014-07?

A. No. It is contrary to the directive in E.O. 2014-07 that the implementation of S.B. 1456 should encourage DG deployment. There is also strong reason to question whether the proposed DG tariff establishes a rate increase on DG customers that would result in them paying more than their cost of service, which is contrary to Paragraph C of S.B. 1456.

Q. Please elaborate on your assertion that the proposed DG tariffs could result in DG customers paying more than their cost of service.

As I have already described, the residential DG tariff would increase customer costs by $11.50 per month relative to the standard residential TOU tariff before accounting for the effects of DG, and would increase DG customer costs relative to the current net billing tariff by an average of $20 per month. Attached Exhibit JRB-5 shows that according to OG&E's data, existing DG customers pay on average about $3 a month less than non-DG customers for electric service.[21] This leads to the conclusion that DG customers tend to be higher use customers that, under rates dominated by volumetric charges, would likely have been paying *more* than their cost of service. In other words, prior to the installation of DG, DG customers were likely subsidizing other customers.

The installation of a DG system in this instance simply reduces this built-in subsidy, bringing a DG customer back to the average residential usage profile upon which rates are based—an average that is based on a range of energy users including renters, rural residents, and vacation home owners. Based on this I think there is substantial reason to question whether a potential subsidy exists even if

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[20] See Arizona Goes Solar. Salt River Project: Installations. http://www.arizonagoessolar.org/UtilityIncentives/SaltRiverProject.aspx

[21] OG&E Response to TASC Data Request 1.9.

one only looks at the cost side of cost-benefit equation and entirely disregards the benefits that DG provides to other customers.

Yet under the new rates, DG customers would end up paying substantially *more* than non-DG customers. The intent of the S.B. 1456 was surely not to have DG customers paying more on average than non-DG customers. In fact, a DG customer would unavoidably be subsidizing non-DG customers every month for customer-related costs, because as a result of the increased fixed charge, they would be obligated to pay a greater fixed amount towards the customer-related cost of service.

Q. **If the Commission did determine that a subsidy exists from non-DG customers to DG customers, what rate reforms do you recommend for addressing it?**

A. First, I recommend that the Commission identify the existence or degree of such a subsidy after accounting for both the costs and benefits, and whether the administrative act of addressing it would in and of itself create a larger subsidy to non-DG customers. It may be the case that the outcome of an analysis of cross-subsidization leads to non-action and a commitment to revisit the topic in several years' time.

Above that, should the Commission elect to take immediate action, I believe any subsidy should be addressed using a minimum bill rate design as opposed to fixed charge increases and demand charges. A minimum bill operates in a manner similar to the way a minimum demand or contract demand clause would operate, except that it would be applied to customers on non-demand rates. It could be implemented with or without a fixed customer charge.

A minimum bill differs from a fixed charge insofar as it only increases the payments due from the customer if the charges otherwise due fall below the designated amount, while fixed charges are included in the customer's bill regardless of what they pay in other charges. For example, if a customer owed $20 in energy charges during a month and the minimum bill was $13 per month, the customer would pay only $20 because what they owe is above the minimum. If the same customer was subject to a $13 fixed customer charge instead of a $13 minimum bill, they would pay $20 in energy charges plus the $13 fixed charge, for a total of $33 for that month.

Minimum bills are superior to fixed charges and demand charges for the reasons below.

- They operate under a simple concept that would be more easily understood by customers than demand charges.
- They better allow the customer to manage their energy bill compared to fixed charges and demand charges, because they allow for bill reductions based on usage characteristics that a customer can actually control. In this respect, they can continue to encourage the customer to conserve energy and/or install DG if properly designed.
- They directly address the issue of DG cost avoidance since they create a minimum payment obligation (i.e., when energy use is low).
- They can ensure that the customer does not pay rates above their cost of service because they are only triggered when the customer avoids payments.

Because S.B. 1456 places a mutual non-subsidization obligation between DG and non-DG customers, I also recommend that this type of rate reform be used across an entire class of customers, not as a mechanism specific to DG customers.

Q. **Is there precedent to the use of minimum bills as opposed to fixed charges or increases in fixed charges in residential rates?**

A. The state of California recently decided that minimum bills were preferable to increases in fixed customer charges for investor-owned utility customers after completing an extensive residential rate reform proceeding.[22] Rate-regulated utilities in Alaska, the District of Columbia, Hawaii, Louisiana, Maine, Nebraska, and Utah also employ minimum bills, as do a number of unregulated competitive retailers in Texas. Minimum bills have a much greater precedent than residential demand rates.

Q. **Do you believe that OG&E's proposal to apply the demand rates to buy-all, sell-all customers that choose rate RPPO is reasonable?**

A. No, this element of the proposal does not make sense. A customer that elects this rate will continue to purchase all of their electricity requirements from the utility. Under this rate design the customer is not avoiding any purchases from the utility, has identical load characteristics before and after the installation of DG, and is simply being compensated for the energy produced by their DG system. There is no possibility that a subsidy could exist under this rate design and therefore no basis for subjecting these customers to different rates.

Q. **Has OG&E offered any rationale for applying the proposed DG tariffs to customers that do not offset on-site use with DG?**

A. In response to a data request from TASC Mr. Walkingstick stated, "It has always been appropriate to have a demand charge for any customer…" and that the only reason demand charges are not applied to all customers is because collecting demand data for mass customer classes has historically not been cost effective. He goes on to state that with the rollout of advanced metering infrastructure ("AMI"), this is no longer the case.[23]

Q. **How do you respond to these statements?**

A. As I have previously discussed, there are a number of other reasons why demand charges are disfavored for residential and small commercial customers. The

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[22] California Public Utilities Commission Decision 15-07-001. July 3, 2015.
[23] OG&E response to TASC Data Request 2.11, attached as Exhibit JRB-6.

appropriateness of demand charges for small customers is one of the primary issues in the current proceeding. Even if the statements made by Mr. Walkingstick were entirely accurate, the implementation of demand rate designs for all customers must be considered in a general rate case. If OG&E believes that demand charges are an appropriate measure for eliminating intra-class subsidies (associated with DG or otherwise), it should withdraw its present application and seek such a reform in its next rate case. I see little reason to force such a significant issue to be considered under the short time frame of the present proceeding, only to have it re-litigated in the larger context of a future rate case, especially since—as Mr. Garrett discusses—OG&E's rate case filing is imminent.

Q. **Since you claim that no subsidy is possible under this arrangement, are you suggesting that this design is appropriate for all DG customers in light the requirements of S.B. 1456?**

A. I do not recommend this rate design for all DG customers. Data from OG&E indicates that almost all current DG customers are enrolled in the NEBO rider as opposed to the existing qualifying facilities ("QF") rate. Only five out of the utility's 245 DG customers as of July 31, 2015 have chosen the QF rate.[24] DG customers clearly display a preference for net energy billing when given an option between it and a buy-all, sell-all arrangement. I agree with Mr. Walkingstick that a customer's "right-of-choice" is an important customer motivation for installing DG.[25] Requiring DG customers to take service under a buy-all, sell-all arrangement would likely act to discourage DG deployment by eliminating their option to generate *and use* clean energy.

Furthermore, TASC believes this rate structure could constitute a sale of electricity that would result in taxable income, and therefore increased income taxes for a DG customer.[26] This prospect is a significant drawback of the

[24] See Walkingstick Direct, p. 10, Table 1.
[25] See Walkingstick Direct, p. 11, line 9.
[26] See, *e.g.*, Arizona Corporation Commission Docket No. E-01345A-13-0248, Public Comment Letter of the Alliance for Solar Choice re Application of Arizona Public Service Company for Approval of Net

arrangement beyond concerns over limiting a customer's right of choice. Even just the prospect of additional taxes complicates the decision a customer makes to install a DG system. Many small DG customers, and residential customers in particular, likely do not possess the information or knowledge necessary to make informed decisions on tax issues.

V. DEFICIENCIES IN OG&E'S EMBEDDED BENEFITS AND SUBSIDY ANALYSIS

Q. **What does OG&E calculate as the "embedded benefit" of DG resources?**

A. Mr. Walkingstick never expressly identifies a value for the embedded benefit, but he does use a figure of 6.5 cents/kWh in his calculation of the uncompensated value of DG exports.[27] The context suggests that this represents an average value for embedded benefits though the lack of documentation makes it difficult to be certain.

Q. **Is the utility's analysis of the embedded benefits of DG sufficient to make a determination of whether a subsidy from non-DG customers to DG customers exists?**

A. No. OG&E's analysis appears to only include two components, avoided energy and avoided capacity costs. The utility disregards the series of other potential benefits that were listed in the benefits study checklist developed by the Commission, and that have been identified and quantified in other studies. These include line losses, avoided transmission and distribution costs, and reliability

Metering Cost Shift Solutions (Aug. 15, 2013) (filing a legal memorandum from Skadden, Arps, Slate, Meagher & Flom LLP, explaining that payments received by taxpayers for sale of electricity under feed-in tariffs likely fall within the definition of taxable gross income); Hawai'i Public Utilities Commission Docket No. 2014-0192, Hawai'i Solar Energy Association's, Hawai'i PV Coalition's, Hawai'i Renewable Energy Alliance's, Ron Hooson's, Life of the Land's, Sunpower's and the Alliance for Solar Choice's Final Statement of Position (2015) (filing a legal memorandum from Chun Kerr LLP explaining that feed-in tariff payments would likely be considered gross income).

[27] See Walkingstick Direct, p. 25, lines 26-28.

benefits. It supplies no meaningful information on how it determined that these benefits have a zero value. Moreover, virtually no information is provided on how it arrived at the values it did include, what those values are, and the time frame under which the analysis took place. As a whole, the treatment it gives to embedded benefits is superficial and insufficient.

Q. **Please discuss why OG&E's treatment of line losses as an embedded benefit is inappropriate.**

A. OG&E states that line losses are already reflected in retail rates based on service voltage, and therefore considers line losses avoided by DG to have no added value. In other words, the utility is arguing that because a customer avoids paying the retail rate for energy used for on-site consumption during a billing period, they are being compensated for these avoided line losses.[28] This argument is a red herring that distorts the purpose of assessing avoided line losses in the context of a cost-benefit analysis.

In a cost-benefit analysis, the retail rate compensation provided to a DG customer falls within the cost category, while avoided line losses fall within the benefit category. If the compensation provided to a DG customer is the ultimate cost basis it is inappropriate to eliminate the concurrent system benefit that avoided line losses have from the benefit category. Avoided line losses are a system benefit, regardless of whether they are reflected in some form in the compensation provided to a DG customer. They should ultimately be reflected as an adder to other benefit categories such as avoided energy, avoided capacity, and avoided transmission and distribution capacity. Furthermore, because line losses are influenced by system load, they should be accounted for on a basis that reflects higher loss avoidance during higher load periods (i.e., in terms of marginal line losses).

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[28] See Walkingstick Direct, p. 26, lines 6-8

Q. Does OG&E's analysis account for avoided transmission and distribution ("T&D") capacity benefits?

A. Mr. Walkingstick states that grid costs and benefits are specific to each individual grid circuit.[29] I agree that at distribution level benefits are location-specific and depend on how the output from a DG system correlates to local cost-causing conditions. However, the same is not true for the transmission system, which serves broad sections of the customer base with diverse load characteristics. Even small systems contribute to reduced demand at the transmission and substation level when system production is coincident with system peaks. This load reduction may allow a utility to defer upgrades and capital investments that ultimately cost money for all system users.

Moreover, even though some benefits are location-specific, it does not mean that they should be assigned a universal zero value. OG&E is proposing a DG tariff that would apply to all new DG customers on a system-wide basis regardless of whether they are installed in high or low value locations. The purpose of performing a cost-benefit study to identify a subsidy is to discover whether the benefits of DG outweigh the costs *on average*, over an extended time frame throughout the entire system. The concept of averaging is foundational to cost recovery and ratemaking. The same is true for an assessment of DG benefits that may be used to design future rates.

Recognizing that it may not be possible to develop granular location specific values for avoided T&D costs, the previously referenced IREC guidebook on solar DG value analysis lays out several methods for system-wide analysis of potential benefits. Several states, including California, Maine, Minnesota, Mississippi, and Vermont have used system-wide modeling to assign a value to avoided T&D capacity costs. OG&E has not provided any substantiation for its assertion that all grid benefits are location specific, or demonstrated any attempt to perform a system-wide analysis. These potential benefits should not be ignored, therefore I recommend that the Commission

[29] See Walkingstick Direct, p. 28, lines 24-29.

consider the use of a system-wide estimation methodology for avoided T&D capacity costs.

Q. **Does OG&E's application adequately address potential reliability-related benefits from DG?**

A. No. As with T&D capacity benefits, the utility suggests that reliability-related benefits are circuit specific, but fails to substantiate this assertion. Mr. Walkingstick even goes to far as to imply that inadequate maintenance of DG systems may be having detrimental impacts on safety and reliability.[30] The suggestion that DG systems may be having adverse impacts on safety and reliability is entirely unsupported.

Q. **How do you respond to the suggestion that lack of maintenance is contributing to adverse safety and reliability impacts from DG?**

A. If OG&E is aware of any specific safety or reliability issues associated with existing DG systems, due to lack of maintenance or otherwise, it has not documented them in its application or its responses to data requests. Moreover, the accusation defies common sense, insofar as customers only benefit from their DG system when it is functioning properly and compliant with existing standards for grid connection. Customers therefore have a substantial incentive to keep their DG system in good working order so as to avoid conditions that cause it to under-produce, result in on-site safety hazards, or subject it to potential disconnection for violating interconnection standards.

Q. **What sorts of reliability-related benefits might a DG system provide?**

A. Reliability-related benefits are a broad catch-all that may include potential benefits that are somewhat intangible and difficult to quantify, or are achievable only with the use of on-site energy storage. However, the proliferation of so-called "smart" inverters with advanced functionality has the potential to allow DG

[30] See Walkingstick Direct, p. 28, lines 15-21.

systems to provide some reliability-related services, most notably voltage support functions.[31] While existing DG systems may not be equipped with smart inverters, many newer inverters have advanced capabilities, even if they are not currently being used due to a lack of clearly defined technical standards.[32] In the long term, however, it can be expected that smart inverters will be installed on most new DG systems, as well as existing systems that require an inverter replacement.[33] A long-term cost-benefit analysis of the type I recommend needs to consider the value of these future benefits.

Q. **What other concerns do you have about OG&E's analysis of DG embedded benefits?**

A. OG&E does not provide any analysis of potential risk reduction attributable to DG or provide anything resembling a sensitivity analysis in its assessment of DG value. Risks could take many forms, but the most notable exclusions are purchased power price risks and the risk of future compliance costs under the EPA's Clean Power Plan or another carbon regulation scenario. The utility justifies the exclusion of purchased power risk on the basis that purchased power is available at the Southwest Power Pool ("SPP") market price. It is true that power would be available for purchase at the SPP market price, but OG&E ignores the potential for DG to contribute to reductions in the future market price for power. It likewise ignores possible future carbon risks by failing to consider the potential compliance value of DG in carbon regulation scenarios, or the effect that carbon regulations could have on market prices.

Q. **Does OG&E consider these risks in other contexts?**

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[31] See California Public Utilities Commission Decision 14-12-035. December 22, 2014. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K827/143827879.PDF

[32] See Greentech Media. California Launches Its First Real-World Smart Inverter Test. September 10, 2015. https://www.greentechmedia.com/articles/read/california-launches-its-first-real-world-smart-inverter-test?utm_source=Storage&utm_medium=Headline&utm_campaign=GTMDaily

[33] DG systems typically require an inverter replacement at least once during the lifetime of the system.

A. Yes. OG&E's 2014 Integrated Resource Plan ("IRP") filed with the Arkansas Public Service Commission addresses both issues. The IRP incorporates a sensitivity analysis of market prices under scenarios that include both a carbon tax scenario in 2020, and a low load scenario attributable to rapid adoption of distributed generation within the SPP footprint over the next 10 years. Both scenarios result in material changes to its market price forecasts.[34] OG&E further concludes that continuing to "aggressively pursue demand-side resources" will ultimately provide substantial benefits to its customers.[35] I see a profound disconnect between the analysis that OG&E uses to making long-term planning decisions -- and the conclusions it reaches -- and the superficial nature of the analysis it has presented in this proceeding.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations.

A. I recommend that the Commission take the following steps:

- Reject OG&E's proposal for new DG tariffs because the utility fails to adequately demonstrate that: (a) such a subsidy exists, and (b) its proposed tariffs would not conflict with the S.B. 1456 requirement that DG rates be based on the cost to serve DG customers.
- Require the development of a more complete analysis of the cost to serve DG customers and the benefits of DG that accrue to non-DG customers prior to implementing any tariff changes.

[34] See OG&E 2014 Integrated Resource Plan Update (pg. 38.) https://oge.com/wps/wcm/connect/342cf742-9bb6-48f1-aaa9-34a4174b8c16/2014+IRP+-+Oklahoma+Report.pdf?MOD=AJPERES&attachment=true&CACHE=NONE&CONTENTCACHE=NONE

[35] Ibid, (pg. 50).

- Consider renewing the past stakeholder process to arrive at the comprehensive valuation methodology I recommend, in order to identify all of the necessary inputs and assumptions involved in the requisite calculation.
- If the Commission reaches the conclusion that DG customers are being subsidized by non-DG customers—and that the identified subsidization necessitates immediate action—pursue rate reforms such as minimum bills or modifications to time-of-use tariffs that mitigate the issue while continuing to encourage DG deployment in line with E.O. 2014-07.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit JRB-1

Justin R. Barnes

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EDUCATION

Michigan Technological University Houghton, Michigan
Master of Science, Environmental Policy August 2006
Graduate-level work in Energy Policy.

University of Oklahoma Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

EXPERIENCE

EQ Research, LLC and **Keyes, Fox & Wiedman, LLP** Cary, North Carolina
Director of Research, July 2015 – present, *Senior Analyst & Research Manager,* March 2013 – July 2015
Oversee state legislative and regulatory policy tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage. Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on state solar market drivers such as net metering, incentives, and renewable portfolio standards. Provide expert witness testimony. Manage the development of a solar power purchase agreement (PPA) toolkit for local governments and the planning and delivery of associated outreach efforts.

North Carolina Solar Center, N.C. State University Raleigh, North Carolina
Senior Policy Analyst, January 2012-May 2013; *Policy Analyst,* September 2007-December 2011
Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States. Managed state-level regulatory tracking for private wind and solar companies. Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets. Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort. Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis. Authored the *DSIRE RPS Data Updates,* a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies. Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits. Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?.* September 2015. Published by EQ Research, LLC.

Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments.* July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. Department of Energy SunShot Solar Outreach Partnership.

Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts.* 2013. Article in Solar Today.

Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues.* 2013. For the U.S. Department of Energy SunShot Solar Outreach Partnership.

Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri.* 2013. Case Studies for the U.S. Department of Energy SunShot Solar Outreach Partnership.

Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On.* 2013. For Keyes, Fox & Wiedman.

Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar.* 2012. Guest Post in Greentech Media Solar.

Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends.* Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.

Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.

Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets.* 2011. American Solar Energy Society Conference Proceedings.

Barnes, J. *SREC Markets: The Murky Side of Solar.* 2011. Article in State and Local Energy Report.

Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues.* 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY

- South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015.
- South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015.
- South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015.
- South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Master's Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

Exhibit JRB-2

OG&E Response to TASC Data Request 1.5: Solar Model Res Sandbox - New Fixed Savings

FIXED Array Savings (4.0 kW DC)	GPSR TOU Pricing	Component Annual Savings
Average Fuel Costs (Summer Off Peak Fuel)	$ 0.02961	$ 61.98
Average Fuel Costs (Summer On Peak Fuel)	$ 0.05018	$ 21.30
Rate Design Winter Fuel (kWh)	$ 0.03281	$ 105.49
Rate Design Winter (All) Price (kWh)	$ 0.01370	$ 44.06
Rate Design Summer Off-Peak Price (kWh)	$ 0.01370	$ 28.68
Rate Design Summer On-Peak Price (kWh)	$ 0.1730	$ 73.43
Max Demand for T&D (kW)	$ 2.68	$ -
	Total	$ 334.93

Regular Residential Billing for Typical Residential Customer	Reg Residential Pricing Components	Component Costs
Average Fuel Costs Summer per kWh	$ 0.032805	$ 210.17
Average Fuel Costs Winter per kWh	$ 0.038050	$ 274.61
Rate Design Winter Price 1st 600 kWh	$ 0.057300	$ 206.28
Rate Design Winter Price > 600 kWh	$ 0.017300	$ 52.20
Rate Design Summer First 1400 kWh	$ 0.057300	$ 306.08
Rate Design Summer > 1400 kWh	$ 0.068000	$ 17.93
Rate Design Shoulder Price All kWh	$ 0.057300	$ 97.76
Customer Charge	$ 13.00	$ 156.00
	Total	$ 1,321.04

Rooftop Fixed Array Solar Savings (Approx 4 kW DC)	GPSR TOU Pricing	Component Annual Savings
Average Fuel Costs (Summer Off Peak Fuel)	$ 0.02961	$ 61.98
Average Fuel Costs (Summer On Peak Fuel)	$ 0.05018	$ 21.30
Rate Design Winter Fuel (kWh)	$ 0.03281	$ 105.49
Rate Design Winter > 600 kWh	$ 0.01730	$ -
Rate Design Winter <=600 kWh	$ 0.05700	$ 183.30
Rate Design Summer Off-Peak Price (kWh)	$ 0.02700	$ 56.52
Rate Design Summer On-Peak Price (kWh)	$ 0.1400	$ 59.42
Max Demand for T&D (kW)	$ 2.40	$ -
	Total	$ 488.01

Solar Rooftop Savings 4kW DC		
Solar Generated kWh Savings GPSR TOU	$	334.93
Mthly Bill Savings due to Solar 1st Yr	$	27.91
Benefit per kWh	$	0.058

SAXIS Savings (2.73 kW)		
Solar Generated kWh Savings GPSR TOU	$	382.86
Mthly Bill Savings due to Solar 1st Yr	$	31.91
Benefit per kWh	$	0.067

Exhibit JRB-3

OG&E'S RESPONSE TO STAFF'S DATA REQUEST KJC-1-1 ATT. 2

PUD 201500274 Data Request KJC-1 (1-1)

Net Energy Billing Option (NEBO) Customer Impact Analysis

Commercial NEBO Customers (bill amount excluding riders other than FCA)

	Under Current Tariff	Under Proposed Tariff	Change $	Change %
Monthly Impact - Average Bill	$ 273.87	$ 298.58	$ 24.72	9.0%

Residential NEBO Customers (bill amount excluding riders other than FCA)

	Under Current Tariff	Under Proposed Tariff	Change $	Change %
Monthly Impact - Average Bill	$ 86.92	$ 106.80	$ 19.87	22.9%

Exhibit JRB-4

OG&E Response to TASC 2-4: Summary

Potential Monthly Rate Impact

General Service Customers

Month	GS-001	GS-002	GS-003	GS-004	GS-005	GS-006
2014-11						
2014-12						
2015-01						
2015-02		$ 9.66	$ 12.56	$ 11.60		$ 6.70
2015-03		$ 11.11	$ 11.13	$ 12.19		$ 8.57
2015-04	$ (5.65)	$ 11.91	$ 11.63	$ 12.04		$ 7.02
2015-05	$ 11.38	$ 11.45	$ 10.71	$ 12.09		$ 8.84
2015-06	$ 17.70	$ 11.87	$ 11.06	$ 13.65	$ 29.63	$ 10.81
2015-07	$ 18.67	$ 12.03	$ 11.57	$ 12.47	$ 17.08	$ 9.21
2015-08	$ 20.90	$ 11.06	$ 10.87	$ 11.17	$ 31.31	$ 9.24

General Service Monthly Average $ 12.37

Residential Customers

Month	RES-001	RES-002	RES-003	RES-004	RES-005	RES-006	RES-007	RES-008
2014-11						$ 8.51		
2014-12						$ (0.01)		
2015-01					$ (7.13)	$ (4.02)		
2015-02		$ 8.33			$ (2.92)	$ 3.88		
2015-03		$ 12.05			$ (0.91)	$ (0.11)		
2015-04		$ 19.34			$ 2.40	$ 12.40		
2015-05	$ 2.42	$ 0.60	$ (7.22)	$ 8.33	$ (6.14)	$ 8.44	$ 17.62	
2015-06	$ 23.11	$ 23.53	$ 8.52	$ 23.82	$ 20.78	$ 18.59	$ 19.49	
2015-07	$ 26.05	$ 23.86	$ 15.24	$ 22.79	$ 21.72	$ 21.91	$ 22.65	$ 21.09
2015-08	$ 22.01	$ 16.28	$ 14.16	$ 23.49	$ 23.96	$ 26.97	$ 22.85	$ 7.50

Residential Monthly Average $ 12.70

Exhibit JRB-5

OG&E Response to TASC Data Request 1-9

Month	1-9a: Average kWh consumption per residential customer	1-9b: Average kWh consumption per DG residential customer	1-9c: Average bill per residential customer	1-9d: Average bill per DG residential customer	1-9e: Average maximum kW demand per residential customer	1-9f: Average maximum kW demand per DG residential customer
Jan-14	1,385	1,791	$ 110.29	$ 144.10	9.0	12.5
Feb-14	1,284	1,845	$ 104.67	$ 136.51	8.9	12.1
Mar-14	1,050	1,174	$ 90.87	$ 104.42	8.7	12.0
Apr-14	776	602	$ 74.81	$ 76.08	8.2	10.8
May-14	817	679	$ 88.95	$ 77.35	8.3	10.4
Jun-14	1,109	1,020	$ 115.44	$ 100.17	8.3	10.6
Jul-14	1,374	1,056	$ 141.92	$ 119.87	8.5	10.6
Aug-14	1,366	1,086	$ 150.47	$ 124.62	8.6	10.6
Sep-14	1,440	1,114	$ 154.94	$ 124.86	8.6	10.5
Oct-14	967	746	$ 103.41	$ 80.55	8.1	10.1
Nov-14	897	773	$ 85.54	$ 80.32	8.5	11.5
Dec-14	1,113	1,317	$ 98.90	$ 114.09	8.6	11.7
	13,577	13,204	$ 1,320.22	$ 1,282.96	8.55	11.11

Exhibit JRB-6

The Alliance for Solar Choice
Data Request TASC-2
Cause No. PUD 201500274

2-11 Please explain why a demand charge is an appropriate method of cost recovery for residential customers that will sell all energy generated by their DG system to OGE through the proposed RPPO tariff.

Response*: It has always been appropriate to have a demand charge for any customer. It is a component of providing service that has traditionally not been separately measured in the mass customer classes such as residential and general service customers because the cost of collecting customer demand data was not considered to cost effective. That is no longer the case since the deployment of the AMI on the OG&E system. Please refer to Page 16 lines 10 through 23 of Mr. Walkingstick's testimony.

Response provided by: Roger Walkingstick
Response provided on: September 21, 2015
Contact & Phone No: Bryan Scott 405-553-3452

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN ORDER GRANTING APPROVAL OF NEW DISTRIBUTED GENERATION TARIFFS PURSUANT TO TITLE 17, SECTION 156 OF THE OKLAHOMA STATUTES	))))))	CAUSE NO. PUD 201500274

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OF OKLAHOMA

SUMMARY OF RESPONSIVE TESTIMONY

OF

JUSTIN R. BARNES

ON BEHALF OF

THE ALLIANCE FOR SOLAR CHOICE ("TASC")

November 20, 2015

CAUSE NO. PUD 201500274

SUMMARY OF RESPONSIVE TESTIMONY
OF JUSTIN R. BARNES

On behalf of The Alliance for Solar Choice ("TASC"), Mr. Justin R. Barnes submitted responsive testimony on the proposal for new tariffs for customers of Oklahoma Gas & Electric Company ("OG&E") who choose to install and use onsite distributed generation facilities. Mr. Barnes is the Director of Research with EQ Research LLC, based in Cary, North Carolina.

TASC advocates for maintaining successful distributed solar policies nationwide. Founded by the leading rooftop solar companies in the nation, TASC represents some of the largest companies in the industry, including: SolarCity, Sunrun, Silevo, Demeter Power, Solar Universe, Verengo, and ZEP Solar.

The purpose of Mr. Barnes's testimony is to describe the deficiencies in OG&E's application to implement distributed generation ("DG") tariff changes in response 2014 Senate Bill No. 1456 ("S.B. 1456") and its accompanying Executive Order 2014-07 ("E.O. 2014-07"). OG&E's DG tariff proposal fails to meet the requirements of S.B. 1456 and E.O. 2014-07 on the basis of fundamental flaws in its design and the utility's failure to fully consider the benefits of DG to non-DG customers in its evaluation of the supposed "subsidy" being provided from non-DG customers to DG customers. Mr. Barnes discusses how mandatory demand charges are inappropriate for residential customers with distributed generation, as such customers are not accustomed to and ill equipped to deal with demand-based charges.

Mr. Barnes offers four primary recommendations for how the Commission should proceed in its consideration of the application. First, Mr. Barnes recommends that the Commission reject OG&E's proposal for new DG tariffs because the utility fails to adequately demonstrate the prerequisites of S.B. 1456 and E.O. 2014-07 that: (a) customers with distributed generation are currently being subsidized by customers without distributed generation and (b) that its proposed tariffs would not constitute a rate increase on DG customers that causes them to pay rates above their cost of service.

Second, Mr. Barnes recommends that the Commission require the development of a more complete analysis of the cost to serve DG customers and the benefits of DG that accrue to non-DG customers prior to implementing any tariff changes. This step will establish a roadmap for reliably identifying the magnitude of any subsidy that exists between DG customers and non-DG customers by requiring completion of an updated cost of service study and the development of a comprehensive quantitative methodology for determining the value of DG benefits.

Third, and related to his second recommendation, Mr. Barnes recommends a stakeholder process to arrive at the comprehensive valuation methodology for distributed generation resources.

Fourth, upon reaching any conclusion that DG customers are being subsidized by non-DG customers, Mr. Barnes recommends that the Commission pursue rate reforms such as minimum bills or modifications to time-of-use tariffs to mitigate the issue. These alternative reforms are superior to approaches that rely on increased fixed charges and or the imposition of demand charges (as proposed by OG&E) because these alternatives allow customers to retain substantial control over their energy bills. These recommendations encourage DG deployment and are in aligned with the directive in EO-2014-07 and the policy goals of the Oklahoma First Energy Plan.

CERTIFICATE OF SERVICE

On this 20th day November, 2015, a true and correct copy of the above and foregoing *Summary of Responsive Testimony of Justin R. Barnes* was sent via electronic mail to the following interested parties:

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