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AZ CORP COMMISSION

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TO: THE COMMISSION

FROM: Utilities Division

DATE: September 30, 2013

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RE: ARIZONA PUBLIC SERVICE COMPANY – APPLICATION FOR APPROVAL OF NET METERING COST SHIFT SOLUTION (DOCKET NO. E-01345A-13-0248)

On July 12, 2013, Arizona Public Service Company ("APS") filed an application ("Application") for approval of a Net Metering Cost Shift Solution. Subsequent to APS's filing, several parties requested and were granted intervenor status in this docket, including The Alliance for Solar Choice ("TASC"), Lewis M. Levenson, Tucson Electric Power Company, UNS Electric, Inc., the Residential Utility Consumer Office ("RUCO"), the Solar Energy Industry Alliance ("SEIA"), Western Resource Advocates, and the Interstate Renewable Energy Council, Inc. ("IREC").

TASC filed a formal Protest in the Docket on July 29, 2013, urging the Arizona Corporation Commission ("Commission") to reject APS's application and institute an alternative proposal. On August 20, 2013, SEIA filed a Protest and Motion to Dismiss asserting that there is no cost-shift between customer classes as a result of net metering ("NM"), and that the Application represents an attempt at ratemaking outside of a general rate case. TASC joined SEIA's Protest and Motion to Dismiss on August 30, 2013.

IREC filed a formal Protest in the Docket on August 29, 2013, asserting that the instant docket is not the appropriate venue for analysis of APS's NM program. IREC states that further discussion and analysis is required to obtain a comprehensive understanding of the benefits and costs of distributed solar photovoltaics in Arizona. IREC urges the Commission to reject APS's Application and defer discussion of its proposals to a future general rate case.

Numerous letters from customers voicing both support and opposition regarding NM programs in general, and APS's proposed NM cost-shift solutions in particular, have been filed in this Docket.

Background

APS's Application states that rooftop solar installations have increased significantly each year in APS's service territory since January 2009. The Application states that as of January 2009, there were approximately 900 systems installed. As of June 2013, that number had grown to over 18,000 and continues to grow by approximately 500 new rooftop solar systems each month. Much of this recent growth is attributable to Arizona's Net Metering Rules, which were implemented in May 2009, under Title 14, Chapter 2, Article 23 of the Arizona Administrative

Code ("A.A.C."). The impetus for establishing Net Metering Rules was to incent the deployment of customer-sited DG.

As defined by these rules, NM allows electric utility customers to be compensated for generating their own electric energy from renewable resources, fuel cells, or Combined Heat and Power systems (collectively "distributed generation" or "DG"). If the customer's energy production exceeds the energy supplied by the electric utility during a billing period, the customer's bill for subsequent billing periods is credited for the excess generation. That is, the excess kWh generated during the billing periods. Effectively, this credit process compensates the customer (and incents the development of distributed generation) by requiring the electric utility company to acquire the customer's excess generation at the customer's current effective retail rate. In order to prevent abuse of the NM incentive, the Arizona NM Rules limit the size of customer DG systems to a maximum of 125 percent of the NM customer's total connected load.

Once each year (or for a customer's final bill upon discontinuance of service), the electric utility credits the customer for the balance of any remaining excess kWh. The payment for the purchase of these year-end excess kWh is at the electric utility's annual average avoided cost, which is specified on the electric utility's NM Tariff. A.A.C. R14-2-2302(1) defines avoided cost as "the incremental cost to an Electric Utility for electric energy or capacity or both which, but for the purchase from the NM facility, such utility would generate itself or purchase from another source."

As the participation in Arizona NM has grown, so have APS's concerns regarding the issue of cross-subsidization between customers that participate in NM programs and those that do not. APS asserts that while the NM customers benefit from the NM policy incentives, the non-participants are burdened with a disproportionate share of the subsidies required to fund the NM incentives. In the case of APS's system, this cross-subsidization is most apparent for the Residential consumer class. APS states that, on average, the cost shift each year is approximately \$1,000 per residential NM system, with total annual costs shifting to non-NM customers of approximately \$18 million. This alleged cross-subsidy is the basis of APS's Application.

The Application

APS filed the instant Application on July 12, 2013, in an effort to provide a solution to the NM cost-shift issue. The broader issue of DG cross-subsidization has been mentioned in a past rate case, specifically APS's 2005 general rate case¹. APS's most recent (2011) general rate case did not specifically address the NM cross-subsidization issue.

APS emphasizes that the instant application is proffered as a solution to the crosssubsidization of customers with Net-Metered DG systems by those customers without such systems. In this context, APS asserts that the issue is one of fairness to all customers and is not related to a loss of revenue by APS because of NM.

¹ See e.g., Decision No. 69663, pp. 87-89 (June 2007)

In preparation for filing the Application, APS hosted a multi-session technical conference ("Technical Conference") in the first half of 2013 to evaluate the costs and benefits of Distributed Energy² and NM. Over the course of the Conference, 175 people attended representing a diverse group of stakeholders including solar installers, developers, policy advocates, customers, utility representatives, academics, consultants, researchers, consumer advocates, and Commission representatives. The results of the Technical Conference, including detail regarding the various stakeholder perspectives, were attached to the Application as Exhibit 4.

Informed by input received at the Technical Conference, together with analyses conducted by other jurisdictions, and an update of a previous study of DG benefits, APS developed a range of potential solutions which fell into two broad categories. The first solution group were options that continued the use of NM and emphasized the use of the basic service charge, a demand charge, or a standby charge. The second group of potential solutions involved moving from NM to a mechanism by which DG customers pay for all of the energy they consume, but receive a bill credit for 100 percent of the energy produced by their DG system. The key variable in this group of potential solutions concerned the method for setting the price paid to customers for the DG energy they produced. Those methods generally involved setting either a market-based price, or a price based on values and non-market concepts.

Drawing from each group, APS proposes two possible solutions and requests that the Commission select one of the proposed solutions. Based on the Commission's selection, any new APS residential customer installing DG would either: (1) take service under APS's existing ECT-2 rate and use NM ("the NM Option"); or (2) take full requirements service under the customer's existing rate and receive a bill credit for 100 percent of the DG system's production at a market-based price for power ("the Bill Credit Option").

1. The NM Option - ECT-2 Plus NM

Under this option, all residential customers installing a new DE system would only be eligible to take electric service under APS's existing ECT-2 rate. The ECT-2 rate is a demand-based rate with Time-of-Use ("TOU") features. APS states that the ECT-2 rate better balances the collection of fixed costs between usage-based energy charges and demand-based charges, and would allow APS to more accurately charge DE customers for the services they use.

2. The Bill Credit Option

Under this option, customers could remain on any APS rate plan for which they are otherwise eligible. Instead of NM, APS would compensate customers through a bill credit for all of the power produced by their DG system. The amount of credit would be based on the forward market at the Palo Verde hub with adjustments. APS asserts that this price would send a more accurate price signal for the true cost of the electrical services provided to potential DG customers.

² In this Memorandum, the terms "Distributed Generation ("DG")" and "Distributed Energy" or "DE" are used interchangeably.

Under either option, APS proposes that all existing NM customers would be grandfathered under the customer's existing arrangement. Specifically, APS proposes grandfathering existing rate constructs (i.e. a customer's existing rate and use of NM) for residential customers who either have DG installed on their homes now, or who submit an application and a signed contract with a solar installer to APS by October 15, 2013. The grandfathering would extend for a maximum of 20 years from the effective date of the Commission's decision in this matter and would not be transferable to a new customer at the same premise.

APS states "...both options will change the economics of DE transactions and could result in a slower pace of residential rooftop solar installations." APS suggests that direct cash up-front incentives ("UFIs") could be authorized by the Commission to encourage additional DE penetration. APS favors the use of UFIs as they provide a transparent, flexible means to incentivize DE installations.

APS's Application is supported by the direct testimony of Jeffrey Guldner, Vice President, Customers and Regulation, Gregory L. Bernosky, Manager of Renewable Energy, and Charles A. Miessner, Pricing Manager.

- 1. Select either the NM Option or the Bill Credit Option;
- 2. Grandfather the rates and use of NM by existing and immediately pending DE customers;
- 3. Implement an incentive structure as described in the Application and attached testimony, should the Commission choose to order the direct payment of cash to incentivize residential DE installation;
- 4. Address this matter on an expedited basis; and
- 5. Grant any waivers or other forms of relief that the Commission deems appropriate.

Staff Analysis

Arizona's NM policy is designed to incent the deployment of customer-sited DG through the use of NM bill credits at the customer's retail rate, the NM method favored by a majority of states allowing NM. The recent rapid increase in NM installations, despite declining up-front incentives, validates the success of the NM incentive.

With increasing levels of DG penetration, the potential of shifting costs from customers with DG systems to those customers without such systems becomes apparent. As more customers offset a portion of their monthly bills by using energy produced by their DG systems, they purchase less energy from the utility. Because residential rates are typically designed to

recover much of the utility's fixed costs³ through volumetric energy rates, DG customers effectively pay less of these fixed costs. The additional fixed costs then must be picked up by non-DG customers either through higher energy rates or through other mechanisms such as APS's Lost Fixed Cost Recovery mechanism ("LFCR"). The magnitude and significance of this cost shift increases as more and more DG systems are added to the utility's system. However, base rates are not changed until the utility's next rate case. Therefore, for systems installed after APS's last test year (2010), the cost shift has not yet occurred (except for that in the LFCR).

Based on responses to Staff's several Data Requests, APS provided a table of residential and commercial DG incentive applications and installations from January 2011 through July 2013. These data responses confirm APS's assertion that DG installations have risen over the reporting period to a current rate of approximately 500 per month. APS also provided additional data that indicate the magnitude of the cost shift within the residential ratepayer class is within the range of \$800 to \$1,000 per year per DG customer.

APS also supplied Staff with a map depicting the location of all customer-sited DG systems within its service territory. Staff notes that while the distribution of DG systems appears relatively even across the urbanized areas within APS's service territory, there may be a tendency for DG systems to be located in areas of higher income for two reasons: first, financial barriers to entry (i.e. up-front costs for purchased systems and credit scores for leased systems); second, NM benefits are greater for high energy users who would otherwise consume energy in higher-priced tiers than they are for low energy users who consume energy in lower priced tiers.

The Value of DG

APS's application focuses on the costs associated with increasing levels of DG installations. However, integral to the discussion of DG is the question of what *value* DG offers to APS's electric system and thereby to the customers served by that system. Staff believes that there are two forms of value inherent in DG systems. The first form of value we call "Objective Value" which we define as measurable benefits. An example of Objective Value is avoided fuel costs. Even objective value can be difficult to predict in future time periods.

The second form of value we call "Subjective Value". Subjective Value requires the subjective assignment of monetary values to anticipated future benefits that are not easily measureable. Examples of Subjective Value offered by DG are increased grid security and air quality improvements.

While Objective Values of DG may be determined more easily, even though Objective Values can be difficult to predict in future time periods, the assignment of Subjective Values is by its nature often controversial. Complicating the debate is the wide variety of approaches and methodologies used by various parties in their analysis of this issue. These variations in study approach and conclusions are evident from two recent studies that have been filed in this docket.

³ Fixed costs typically recovered through volumetric energy rates include costs associated with the utility's generation, transmission and distribution infrastructure.

The study prepared by SAIC Energy, Environment & Infrastructure, LLC ("SAIC Report"⁴) on behalf of APS states that the primary value of DG is principally the avoided fuel costs. In contrast, the study prepared by Crossborder Energy ("Crossborder Study"⁵) and filed in the docket by TASC finds that the benefits of DG on the APS system exceed the costs, to the extent that TASC recommends the creation of a System Benefit Credit mechanism to further compensate DG customers beyond the existing NM incentive.

A recent report by the Electricity Innovation Lab and the Rocky Mountain Institute⁶ reviewed 15 distributed PV ("DPV") benefit/cost studies that were prepared by utilities, national laboratories, and other organizations. The goal of this study was to "...assess what is known and unknown about the categorization, methodological best practices, and gaps around the benefits and costs of DPV...". This study concluded that none of the 15 studies reviewed had comprehensively evaluated the benefits and costs of DPV. The study further states that "There is a significant range of estimated value across studies, driven primarily by differences in local context, input assumptions, and methodological approaches." The study states that there is significant disagreement over capacity value methodologies and the "...currently unmonetized values including financial and security risk, environment, and social value."

Staff concludes that assignment of a Subjective Value to the presently unmonetized components of DG value is a public policy issue. Such public policy decisions necessarily require a subjective assignment of values consistent with policy goals.

Staff further concludes that the objective value aspects of DG to the APS system can best be determined in the context of a general rate case when all of APS's costs can be considered. Therefore, a precise determination of DG costs and benefits to APS's system is beyond the scope of Staff's analysis of the instant application. Instead, Staff has developed a range of proxy values for DG as a basis for its alternative recommendations (see *Staff Recommendations* section below) which are intended to be bridge solutions that begin to address the cost-shift issue.

Once the costs and benefits of DG have been adequately quantified and valued, the allocation of these costs and benefits equitably among customers is a matter of rate design. Recovery of fixed costs through volumetric rates may conflict with the intra-rate-class equity of NM. Staff further notes that the equitable distribution of DG costs and benefits ideally requires all NM customers to have some form of demand-based charges. Development of equitable rate structures that address the inherent disconnect between NM and volumetric rates can best be accomplished in a general rate case.

Staff notes that during general rate cases and as part of the rate design process, it is common practice to analyze matters of cost-shifts and cross-subsidizations within individual rate classes. Some rate designs commonly utilize subsidies to promote various public policy goals. The discount provided to low-income customers is a classic example of this intentional crosssubsidy. Another common example is the subsidy given to rural customers at the expense of

⁴ SAIC Energy, Environment & Infrastructure, LLC, 2013 Updated Solar PV Value Report, dated May 10, 2013, and filed in this docket May 17, 2013.

⁵ Crossborder Energy, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service*, dated May 8, 2013, and filed in this docket on July 2, 2013.

⁶ Rocky Mountain Institute, A Review of Solar PV Benefit & Cost Studies, undated.

urban customers to cover the higher cost of service to the more dispersed rural customers. Staff believes that the cross-subsidy discussed in the instant Application has explicit public policy considerations, and therefore would be most appropriately addressed in the setting of a general rate case.

Staff's Analysis of APS's Proposed Alternatives

ETC-2 Plus NM Option

The ECT-2 Plus NM Option relies on a demand charge within the ECT-2 rate schedule to partially collect fixed costs. However, APS notes that because the ECT-2 rate also partially relies on usage charges to collect fixed costs, this Option is an imperfect solution. In addition, the ECT-2 Plus NM Option is not revenue neutral, as the rate's demand charge would collect additional revenue. APS has not proposed a method by which all additional revenue would be returned to non-DG ratepayers. In addition, Staff believes that forcing certain customers to use a specific rate schedule removes a basic choice from the customer – the choice of the rate schedule that works best for their usage pattern and lifestyle. The impact of the ECT-2 Plus NM Option proposal to the average APS residential DG customer is presented below in Table I.

While Staff does not recommend the ECT-2 tariff for all solar customers, customers that voluntarily select this rate should be exempt from any additional cost-shift surcharges as the ECT-2 rate design addresses the collection of lost-fixed costs through a demand charge.

Bill Credit Option

The Bill Credit Option is very similar to a "buy all – sell all" Feed-In-Tariff ("FIT"), which is quite different than a NM arrangement. FITs are typically implemented to incent generation facilities with higher production output than is typically seen in residential DG, and are more often directed towards Qualifying Facilities ("QF") as defined under Public Utility Regulatory Policy Act ("PURPA"). Staff notes a docket filing by TASC⁷ that opines that a residential FIT may have negative (and unexpected) tax implications for the residential FIT customer.

The Bill Credit Option is not equivalent to a NM arrangement because it denies the residential customer the right to offset energy purchases from the utility with self-generation on a one-to-one basis. Staff believes that residential customers should have the ability to receive such an offset. In addition, the Bill Credit Option is not revenue-neutral and APS again offers no guidance on how additional revenues produced under this Option would be returned to non-DG ratepayers.

⁷ See the letter filed August 16, 2013 in this docket from Skadden, Arps, et al filed by TASC that states in part: "Under current law, residential FITs jeopardize the Section 25D credit because electricity generated by such residential solar systems is sold to the utility, rather than used in a personal residence of the taxpayer. Further, payments received by a taxpayer under FITs are likely includable in taxable gross income." TASC summarizes this matter with the statement: "...such a requirement will essentially exchange federal tax credits for federal taxes, reversing the existing flow of money into Arizona."

The estimated bill impact of APS's two proposed options to the average APS residential DG customer is presented below in Table I. Note that in this Table, the terms "IB Rate" means inclining block rate, and "TOU E Rate" means time-of-use energy rate. These terms are intended to broadly describe the two basic types of residential rate designs utilized by APS.

	Curi	ent NM Prog	ram	Proposed Option - ECT-2 Rate			Propose	Proposed Option - Bill Credit		
IB Rate	Summer	Winter	Annual	Summer Winter		Annual	Summer Winter		Annual	
Bill before solar	\$	\$	\$	\$	\$	\$	\$	\$	\$	
(w/tax)	275.22	115.91	195.57	275.22	115.91	195.57	275.22	115.91	195.57	
	\$	\$	\$	\$	\$	\$	\$	\$	\$	
Bill with solar	92.64	30.65	61.65	156.78	82.95	119.87	235.22	85.91	160.57	
	\$	\$	\$	\$	\$	\$	\$	\$	\$	
Savings	182.58	85.26	133.92	118.44	32.96	75.70	40.00	30.00	35.00	
% savings	66.3%	73.6%	68.5%	43.0%	28.4%	38.7%	14.5%	25.9%	17.9%	
TOU E Rate	Summer	Winter	Annual	Summer	Winter	Annual	Summer	Winter	Annual	
Bill before solar	\$	\$	\$	\$	\$	\$	\$	\$	\$	
(w/tax)	224.63	115.13	169.88	224.63	115.13	169.88	224.63	115.13	169.88	
	\$	\$	\$	\$	\$	\$	\$	\$	\$	
Bill with solar	72.19	40.48	56.34	156.78	82.95	119.87	184.63	85.13	134.88	
	\$	\$	\$	\$	\$	\$	\$	\$	\$	
Savings	152.44	74.65	113.55	67.85	32.18	50.02	40.00	30.00	35.00	
% savings	67.9%	64.8%	66.8%	30.2%	28.0%	29.4%	17.8%	26.1%	20.6%	

Table IEstimated Customer Bill Impact

APS suggests that the continued use of UFIs could be used to help offset any slowdown in DG installations caused by APS-proposed NM cost-shift solution options. Staff believes that the level of UFI incentives should not be established in this docket, but rather in APS's annual Renewable Energy Standard Tariff ("REST") implementation plan.

Both NM cost-shift solutions proffered by APS include provisions for "grandfathering" the NM situations of existing (and customers that apply before APS's suggested deadline of October 15, 2013) NM customers. Under APS's grandfathering concept, NM customers would maintain their existing rate constructs (i.e. a customer's existing rate and use of NM) for a maximum of 20 years from the effective date of the Commission's decision in this matter and would not be transferable to a new customer at the same premise.

Based on the analysis discussed above, Staff recommends that the Commission not approve either of APS's proposed NM cost-shift solutions.

Staff further recommends that any consideration of grandfathering existing NM situations to existing NM customers should view the grandfathering as pertaining to the DG system and premises where the DG system is sited (in other words, "runs with the land"), versus a "right" that resides with a specific customer.

Stakeholder Proposals

Three alternative cost-shift solution proposals have been received from intervenors in this case. The first alternative proposal was docketed on July 2, 2013, by TASC. TASC proposes the creation of a System Benefit Credit to reward DG for the excess value that TASC believes DG customers provide to the grid. The TASC proposal relies on the Crossborder study. The TASC proposal suggests that credits could be either demand (kW) or energy (kWh) based and would be paid over the life of the DG system, rather than upfront, in order to link the credit to the long-term performance of the DG system. The credit could be implemented through the existing NM tariff, or through a new rate rider schedule, similar to APS's critical peak pricing rider (CPP-RES). TASC concludes its proposal by suggesting that details of the System Benefit Credit could be developed collaboratively by the Commission, APS, TASC, and other stakeholders.

Staff believes that establishing a System Benefit Charge outside a rate case would have to be established as part of the incentives available through the Renewable Energy Standard Tariff ("REST") program.

The second alternative proposal was informally proffered to Staff by RUCO during several meetings in late July and early August 2013. RUCO proposed the establishment of a market-based adjustor mechanism that links the value of DG to a defined set of market metrics. Implementation of this cost adjustor would be through APS's REST Implementation Plan and would be updated annually. RUCO states that this approach could be utilized by all utilities that are subject to the Commission's REST Rules.

The third alternative proposal was proffered by IREC in its Protest filing. IREC suggests that the Commission and stakeholders develop a common set of assumptions and inputs regarding the costs and benefits of NM during APS's next general rate case. Utilizing the common set of assumptions and data inputs, IREC suggests that a neutral third party, such as Clean Power Research, be retained to model the benefits and costs of NM on the APS electric system. IREC asserts that this modeling would produce a fair and neutral set of data upon which the Commission and stakeholders could rely to evaluate APS's NM program.

Unfortunately the three suggested options set forth above present legal challenges that would be avoided if the Commission were to adopt one of Staff's recommended options discussed below.

Staff believes that the development of a common set of assumptions and inputs will be fundamental in any future analysis of NM costs and benefits as in APS's next rate case.

The NM Cost-Shift Issue in Other Jurisdictions

Arizona is not unique in confronting the NM cost-shift issue. Currently, some form of NM has been adopted in 43 states. Several other states that have experienced relatively rapid penetration of customer-sited DG have recognized the cost-shift issue and addressed it in varying ways. A brief synopsis of several recent Public Utility Commission actions and utility company programs that have parallels to the cost-shift issue in Arizona, and that may help inform the Commission on its decision on the instant Application is located in Appendix I of this Memorandum.

Staff Recommendations

Staff recommends that the Commission not approve either of the NM cost-shift solutions proffered by APS in the instant application for the reasons discussed above. Instead, Staff recommends that no changes be made at this time, but instead, this issue be evaluated during APS's next rate case. However, if the Commission wishes to address this issue immediately, Staff proposes two alternative recommendations as bridge solutions that begin to address the NM cost-shift issue until such time as the Commission is able to address the issue more completely in APS's next rate case.

Staff's Recommendation

Address in Next Rate Case

Staff believes that any cost-shift issue created by NM is fundamentally a matter of rate design. The appropriate time for designing rates that equitably allocate the costs and benefits of NM is during APS's next general rate case. Data on all of APS's costs are available within a rate case. In addition, the Commission has more options available within a rate case than it has outside of a rate case. Therefore, Staff recommends that the Commission take no action on the instant application and defer the matter for consideration during APS's next rate case.

Staff further recommends that the Commission hold workshops with all stakeholders to help inform future Commission policy on the value that DG installations bring to the grid. In addition, Staff recommends that within the workshops, the Commission investigate the currently non-monetized benefits of DG with the goal of developing a methodology for assigning DG values, as the NM cost-shift issue will be faced by all Arizona electric utilities as the penetration level of DG increases in each of the company's individual service territories. The Commission may achieve this goal by opening a generic docket to investigate the value of DG and hold workshop meetings to obtain stakeholder input.

Staff believes this recommended course of action is the most effective and appropriate method of dealing with the APS NM cost-shift issue. However, should the Commission wish to apply the concept of rate-making gradualism to this matter, Staff offers the following two alternative recommendations as bridge solutions that begin to address the NM cost-shift issue until the matter can be more comprehensively resolved in a future general rate case.

Additionally, Staff believes that its alternative recommendations, which both involve adjustments to APS's Lost Fixed Cost Recovery ("LFCR") adjustor mechanism, lend themselves to implementation outside of a rate case. The provisions regarding the LFCR, which was adopted by Decision No. 73183 (May 24, 2012), expressly acknowledge that the Commission may review the LFCR and that suspension, termination or modification may result from such review. Likewise, Staff's two recommendations do not change the overall lost fixed cost revenues that APS recovers through the LFCR adjustor mechanism. Rather, they adjust which customers the lost fixed costs are recovered from through the LFCR. Consequently, Staff's two alternative recommendations are also revenue neutral.

<u>Staff Recommended Alternative #1</u> <u>LFCR Flat Charge for All New DG Customers</u>

Staff's first recommended alternative utilizes APS's LFCR adjustor mechanism that was approved by the Commission on May 24, 2012, under APS's last rate case Decision No. 73183. The LFCR adjustor provides for the recovery of lost fixed costs, as measured by revenue, associated with the amount of energy efficiency savings and DG that is authorized by the Commission and determined to have occurred. Costs recovered through the LFCR include the portion of transmission costs included in base rates and a portion of distribution costs, other than what is recovered by (1) the Basic Service Charge, and (2) 50 percent of demand revenues associated with distribution and the base rate portion of transmission. The LFCR adjustment is calculated by dividing Lost Fixed Cost Revenue by the Applicable Company Revenues. This adjustment percentage is applied to all customer bills, excluding both those on excluded rate schedules and those that have chosen the Flat Charge of the standard LFCR calculation. The LFCR adjustment collection is subject to an annual one-percent year over year cap based on Applicable Company Revenue.

The LFCR adjustor provides a Flat Charge provision for customers that prefer to pay through an optional Basic Service Charge. Rather than calculate the LFCR charge as a percentage of a customer's total bill, the Flat Charge provision sets the LFCR charge, based on a customer's kWh consumption, times the number of days in the month. Most customers (both with and without DG) currently select the percentage of bill LFCR charge because it is currently less expensive than the Flat Charge option. The LFCR Flat Charge tiered consumption rates are presented in the following Table II:

Total Monthly Metered kWh	· · ·	
0-400 kWh	\$	0.020
401-800 kWh	\$	0.040
801-2000 kWh	\$	0.092
2001 kWh and		
greater	\$	0.217

Table II LFCR Flat Charge Rates

The following Table III illustrates the difference between the LFCR percent of bill charge and the LFCR Flat Charge for a typical APS customer. In this example, Staff assumes the customer consumes 1,600 kWh during summer months and 900 kWh during winter months, or 14,200 kWH annually. This customer's average monthly consumption would therefore be 1,192 kWh. The LFCR percent of bill charge is currently assessed at the rate of 0.2 percent of the customer's monthly bill. For simplicity, the customer's monthly bill is presented before on-site generation is netted from the bill. The LFCR Flat Charge is assessed at the tiered rates presented

above in Table II times the number of billing days in the month. For purposes of this example, a 30-day billing month is assumed.

Rate Design Type	Average Monthly Bill	Average Monthly LFCR Percent of Bill	Average Monthly LFCR Flat Charge
	\$195.57 before solar	\$0.39	\$2.76
IB - Inclining Block	\$61.65 after solar	\$0.12	\$2.76
TOU - Time of Use	\$169.88 before solar	\$0.34	\$2.76
Energy	\$56.34 after solar	\$0.11	\$2.76

Table IIILFCR Monthly Charge Comparison

Staff proposes that the LFCR Flat Charge provision become mandatory for all new APS DG customers, unless the customer chooses the ETC-2 rate. New DG customers would pay into the LFCR account at the flat rates set in the LFCR, thereby reducing the aggregate LFCR account needing to be repaid by non-DG customers. In this way, the LFCR Flat Charge provision provides a revenue-neutral method of shifting a portion of the NM-shifted costs back to the customer with newly-installed DG, and away from the non-DG customer.

Staff believes that the LFCR adjustor mechanism is an appropriate near-term bridge solution to APS's NM cost-shift issue as this adjustor was specifically designed to address lost fixed costs. Staff notes that LFCR mechanisms have been approved by the Commission in several recent electric and gas utility rate cases⁸. In addition, APS's LFCR mechanism was constructed with a certain amount of flexibility that accommodates this proposal.

Staff has calculated the customer bill impact for Staff's Recommended Alternative #1 for a hypothetical APS customer with DG and without DG and these results are presented below in Table IV. For purposes of this example, Staff has utilized a customer consumption profile depicting a summer consumption of 1,600 kWh / month and a winter consumption of 900 kWh / month.

⁸ LFCR mechanisms have recently been approved by the Commission in these general rate cases: Tucson Electric Power Company, Decision No.73912 (2013); APS, Decision No. 73732 (2012); and UNS Gas, Decision No. 73142 (2012). In addition, an LFCR mechanism is proposed in UNS Electric's Settlement Agreement, Docket No. E-04204A-12-0504.

Estimated Bill Impacts from Staff's Recommended Alternative #1								
	Curr	ent NM Pro	gram	Staff Option 1 -LFCR Flat Charge Rate				
IB Rate	Summer	Winter	Annual	Summer	Winter	Annual		
Bill before solar (w/tax)	\$275.22	\$115.91	\$195.57	\$275.22	\$115.91	\$195.57		
Bill with solar	\$92.64	\$30.65	\$61.65	\$95.47	\$31.90	\$63.69		
Savings	\$182.58	\$85.26	\$133.92	\$179.75	\$84.01	\$131.88		
% savings	66.3%	73.6%	68.5%	65.3%	72.5%	67.4%		
TOU E Rate	Summer	Winter	Annual	Summer	Winter	Annual		
Bill before solar (w/tax)	\$224.63	\$115.13	\$169.88	\$224.63	\$115.13	\$169.88		
Bill with solar	\$72.19	\$40.48	\$56.34	\$75.07	\$41.72	\$58.40		
Savings	\$152.44	\$74.65	\$113.55	\$149.56	\$73.41	\$111.49		
% savings	67.9%	64.8%	66.8%	66.6%	63.8%	65.6%		

 Table IV

 Estimated Bill Impacts from Staff's Recommended Alternative #1

Staff Recommended Alternative #2 LFCR DG Premium for All New DG Customers

As noted above, the various stakeholders that participated in the Technical Conference had vastly differing estimates regarding the *value* of DG solar. In response to the Crossborder Study's estimated value of 22 to 24 cent per kWh for DG solar, APS made the following argument: Assuming, *arguendo*, that DG solar creates the value estimated in the Crossborder Study, APS can replicate that value by interconnecting small 1 to 5 MW PV systems at the subtransmission level throughout its distribution system utilizing wholesale purchase power agreements ("PPA") at a significantly lower cost than acquiring the same amount of solar capacity via DG.

Utilizing APS's rationale of acquiring the most value at the lowest cost, Staff's second recommended alternative would establish a cap on the NM incentive to ensure that it is no greater than the price APS would pay to acquire the same amount of solar via a wholesale PPA. This would ensure that APS's non-DG customers attain the value of solar, at the lowest cost. The LFCR DG Premium would be based on the difference between APS's cost for purchasing a DG customer's excess generation, and its cost to purchase an equivalent amount of energy from a wholesale PPA. The calculated difference would, in effect, establish the "DG Premium."

The following example illustrates Staff's calculation of the DG Premium and resultant charge for a hypothetical APS residential DG customer:

A.	Customer DG System Size:	6.4 kW
B.	Assumed Annual Rate of Production:	1,641 kWh / kW
C.	Calculated Annual Production:	10,502 kWh (A x B)
D.	Assumed Customer Retail Rate:	\$0.125/kWh

E. Annual Retail Cost of Production:	\$1,312.75 (C x D)
F. Assumed Utility Scale PPA Rate:	\$0.10/kWh
G. Annual PPA Cost of Production:	\$1,050.20 (C x F)
H. Annual DG Premium:	\$262.55 (E – G)
I. Monthly DG Premium:	\$21.88 (H/12)
J. LFCR DG Premium per kW:	\$3.42 (I/A)

Staff understands that utility scale solar PV generation can be obtained in Arizona for between 7 and 10 cents per kWh under a PPA arrangement. Staff has picked conservative values for the Assumed Retail Rate and the Assumed Utility Scale PPA Rate in the example presented above. See Appendix III for examples of the DG Premium calculated using a range of values for the retail rate and PPA rates. In the above example (6.4 kW DG system size), Staff calculates the proposed DG Premium as \$3.42 / kW.

If the Commission chooses, it could implement the DG Premium on a gradual basis so as to minimize the immediate impact on future DG customers. This could be done by initially setting the DG Premium at \$2.75 / kW. The DG Premium calculated in the above example would be the cap for the monthly charge under this Alternative. The Commission may wish to lower or increase the DG Premium annually based on the effect it has on new DG installations. The Commission may also wish to adopt an approach wherein the DG Premium is initially set at a lower amount than that recommended by Staff, and phase-in the total DG Premium over a period of years.

Staff has calculated the DG Premium for a range of DG system sizes, and this information is presented in the following Table V:

A. Customer DG System Size (kW)	4	6.4	8	10	12
B. Assumed Annual Rate of Production (kWh)	1641	1641	1641	1641	1641
C. Calculated Annual Production (kWh)	6,564	10,502.40	13,128	16,410	19,692
D. Assumed Customer Retail Rate (\$/kWh)	\$	\$	\$	\$	\$
	0.125	0.125	0.125	0.125	0.125
E. Annual Retail Cost of Production	\$	\$	\$	\$	\$
	820.50	1,312.80	1,641.00	2,051.25	2,461.50
F. Assumed Utility Scale PPA Rate (\$/kWh)	\$	\$	\$	\$	\$
	0.10	0.10	0.10	0.10	0.10
G. Annual PPA Cost of Production	\$	\$	\$	\$	\$
	656.40	1,050.24	1,312.80	1,641.00	1,969.20
H. Annual DG Premium	\$	\$	\$	\$	\$
	164.10	262.56	328.20	410.25	492.30
I. Monthly DG Premium	\$	\$	\$	\$	\$
	13.68	21.88	27.35	34.19	41.03

Table VMonthly DG Premium By DG System Size

Staff proposes that the LFCR DG Premium be collected through the LFCR. Relatively minor modifications would be required to the LFCR Plan of Administration to implement collection of the DG Premium.

New DG customers would pay into the LFCR account at the DG Premium established by the Commission, thereby reducing the aggregate LFCR account needing to be repaid by non-DG customers. In this way, the LFCR DG Premium provision provides a revenue-neutral method of shifting a portion of the NM shifted costs back to the customer with newly-installed DG, and away from the non-DG customer.

Staff has calculated the customer bill impact for Staff's Recommended Alternative #2 for APS customer with DG (6.4 kW DG system size and estimated consumption of 1,600 kWh / month in Summer and 900 kWh / month in Winter) and without DG and these results are presented below in Table VI.

	Current NM Program			Staff Option 2 -Standby Cap. Charge			
IB Rate	Summer	Winter	Annual	Summer	Winter	Annual	
Bill before solar (w/tax)	\$275.22	\$115.91	\$195.57	\$275.22	\$115.91	\$195.57	
Bill with solar	\$92.64	\$30.65	\$61.65	\$108.64	\$46.65	\$77.65	
Savings	\$182.58	\$85.26	\$133.92	\$166.58	\$69.26	\$117.92	
% savings	66.3%	73.6%	68.5%	60.5%	59.8%	60.3%	
TOU E Rate	Summer	Winter	Annual	Summer	Winter	Annual	
Bill before solar (w/tax)	\$224.63	\$115.13	\$169.88	\$224.63	\$115.13	\$169.88	
Bill with solar	\$72.19	\$40.48	\$56.34	\$88.19	\$56.48	\$72.34	
Savings	\$152.44	\$74.65	\$113.55	\$136.44	\$58.65	\$97.55	
% savings	67.9%	64.8%	66.8%	60.7%	50.9%	57.4%	

 Table VI

 Estimated Bill Impacts from Staff's Recommended Alternative #2

Staff believes that any DG customers that are presently taking service under the ECT-2 rate should be allowed to remain on the ECT-2 rate and be exempt from either of Staff's Recommended Alternatives, should they decide to install a DG system prior to APS's next general rate case.

Grandfathering

If the Commission chooses either Staff Alternative #1 or Staff Alternative #2 (or any form of either), Staff recommends that any residential customers who either have a DG system installed on their homes now, or who submit an application and a signed contract with a solar installer to APS by October 31, 2013, be grandfathered under the current NM policies. Staff further recommends that any consideration of grandfathering existing NM situations should view

the grandfathering as pertaining to the DG system and premises where the DG system is sited (in other words "runs with the land"), versus a "right" that resides with a specific customer.

Staff's Proposed Consumer Protection Advisory

Regardless of which option the Commission chooses, Staff recommends that APS be directed to separate and isolate on a separate page of the Interconnection Agreement⁹ the existing language found on Page 9, Paragraph 10.6, of said agreement, plus Staff's additional language, as shown in Appendix IIA.

Staff makes this recommendation in an attempt to ensure that customers purchasing and installing PV systems on their premises are fully aware that current rates applying to their PV system are not permanent. If the Commission believes the language contained in Appendix IIA is too onerous in tone, Staff recommends the language in Appendix IIB.

Steven M. Olea Director Utilities Division

 $SMO:RBL:sms \MAS$

ORIGINATOR: Rick Lloyd

⁹ See APS's Interconnection Agreement posted at http://www.aps.com/library/solar%20renewables/ResInterconnAgreeSample.pdf)

California

The California State Legislature passed Assembly Bill 2514¹⁰ in September 2012 that directed the California Public Utilities Commission ("CPUC") to complete a study analyzing the full costs and benefits of the state's NM program. The bill further requires the CPUC to determine the extent to which NM customers pay for the full costs of electric services provided by the utilities. Specifically, the bill requires a study "...to determine who benefits from, and who bears the economic burden, if any, of the net energy metering program, and to determine the extent to which each class of ratepayers and each region of the state receiving service under the net energy metering program is paying the full cost of the services provided to them by electrical corporations, and the extent to which those customers pay their share of the costs of public purpose programs." The CPUC is required to complete the report by October 1, 2013, and deliver the results of the report to the Legislature within 30 days of its completion.

A second California State Legislature bill, AB 327, was recently passed by the state Assembly and forwarded to the California Governor for signature. This bill addresses residential electric rate reforms and provides a vehicle for extending the state's solar NM program, which otherwise faced expiration in 2014. The bill sets up a specific process for developing a new state-wide NM program. In addition, the bill authorizes the CPUC to: (1) lower the ramp on California's tiered energy rates; (2) increase monthly customer charges by up to \$10 per month; and (3) clarifies the methodology of calculating each utility company's NM capacity cap.

<u>Idaho</u>

On November 30, 2012, Idaho Power Company ("IPC") applied to the Idaho Public Utilities Commission ("IPUC") to modify its NM service. IPC's application requested that IPUC approve four changes to IPC's NM service:

- 1. <u>Increasing the NM capacity cap</u>. IPC requested that the ceiling for the amount of NM capacity be raised from 2.9 megawatts ("MW") to 5.8 MW.
- 2. <u>Changing the NM pricing structure</u>. IPC proposed to change the NM pricing structure for residential and small general service customers from a system of full retail payment for customer generated power. IPC stated that paying the full retail energy rate to NM customers enables NM customers to unduly reduce what they pay IPC for its costs associated with the non-generation-related components of IPC's revenue requirement. IPC further stated that this situation is unfair to standard service customers, who must then compensate IPC for any revenue shortfall.

IPC proposed to reduce this inequity by removing recovery of all distribution-related fixed costs from the energy charge and the creation of two new NM tariffs, one for the residential class and one for the small general service class. The new tariffs would (1) increase the monthly service charge from \$5.00 to \$22.49 for residential service and from \$5.00 to \$22.49 for small general service; (2) set up a basic load capacity charge ("BLC") of \$1.48.per kW for residential service and \$1.37 per kW for small general service to

¹⁰ See bill text at http://legiscan.com/CA/text/AB2514/id/665151

reflect the full cost-of-service associated with their use of the distribution system; and (3) uniformly reduce the energy charges for residential and small general service to target the same level of total revenue recovery that would exist under the standard service rate design.

- 3. <u>Changing how excess net energy is billed</u>. IPC proposed to stop paying customers for excess net energy and instead provide them with a kWh credit for the excess energy they generate in each billing period. The credit would carry forward until the end of the December billing period at which time any remaining credits would expire.
- 4. <u>Changing tariff provisions regarding interconnection with NM customers</u>. IPC proposed to better define the NM application process and address unauthorized NM installations.

The IPUC reviewed IPC's application at a public hearing held on June 11, 2013. At this hearing, the IPUC entered an order that:

- 1. Declined to increase the NM cap and instead directed IPC to periodically report on its NM service;
- 2. Declined to modify the NM pricing structure or move residential and small general service customers into new classes;
- 3. Required IPC to issue a per kWh credit for excess generation, with credits to expire only when the customer ends service; and
- 4. Approved revised NM interconnection language.

Louisiana

The Louisiana Public Service Commission ("LPSC") first established rules for NM in November 2005. The LPSC revisited the NM rules in 2011 and made several changes to the rules including a requirement that the LPSC review the rules at such time as a utility's purchase of NM energy reached 0.5 percent of its jurisdictional peak load. The LPSC re-opened the docket in late 2011 to address issues of meter aggregation, and cross-subsidization by non-NM customers. A proposed recommendation was issued by LPSC Staff in November 2012, recommending that in order to remedy the "purchased power subsidy" occurring when a NM customer is credited at retail rate for energy supplied to the grid, the NM customer should only be compensated at the utility's avoided cost, similar to the treatment of Qualifying Facilities ("QFs") under the Public Utility Regulatory Policy Act ("PURPA").

As related to the cross-subsidization issue, the LPSC Staff Report identified three separate subsidies provided to NM customers. These subsidies were categorized as a subsidy for installation (of NM equipment), a purchased power subsidy, and distribution system cost recovery. The Staff Report included recommendations to address each of the indentified subsidies as follows:

1. Utilities should begin charging the incremental difference between the cost of a standard electric meter and a net meter;

- 2. After stating that LPSC Staff believes it is inappropriate to require electric utilities to purchase wholesale power from NM customers at retail rates, LPSC Staff offers four Options to address the purchased power subsidy:
 - a. Option 1 <u>An excess NM generation rate less than the utility's avoided</u> <u>cost</u>. Under this Option customers would be compensated at a rate \$0.01 less than avoided cost to reflect the fact that NM energy is not dispatchable.
 - b. Option 2 <u>An excess NM generation rate equal to avoided cost</u>. Rationalized as the rate that best recognizes the offsetting impacts of nondispatchable energy from NM customers against the benefits of sharply reduced line losses from NM generators.
 - c. Option 3 <u>An excess NM generation rate above avoided cost, but less</u> <u>than retail.</u> Values the reduced line losses and locational attributes of NM at a recommended \$0.01per kWh premium above avoided cost.
 - d. Option 4 <u>An excess net meter generation rate equal to the retail rate (i.e.</u> the existing NM situation). The LPSC Staff note that the cost of NM energy is included in the utility's fuel adjustor and charges to all customers.
- 3. With regard to distribution cost subsidies, the LPSC Staff recommended that the LPSC wait until the next rate case for each utility before specifically addressing this category of subsidy. However, LPSC staff noted that the most efficient way to alleviate distribution cost subsidies might be to rely less on energy usage rates and instead appropriately adjust the monthly customer charges.

On July 26, 2013, the LPSC ordered that if a utility's NM purchases exceed 0.5 percent of its LPSC jurisdictional peak load, the utility no longer has to accept NM applications. Although LPSC discussed other aspects of its staff's recommendation, the LPSC took no further action.

<u>Virginia</u>

In July 2011, a Virginia state law took effect that allows power companies to collect a standby charge from customers with home NM systems of 10 kilowatts or larger. Dominion Virginia Power ("Dominion") subsequently filed an application with the Commonwealth of Virginia State Corporation Commission ("SCC") to implement such a standby charge. Dominion proposed a standby charge of 4.19 / kW for a DG customer's average peak usage each month for customer systems sized between 10 and 20 kW. Dominion estimated that the average monthly standby charge would be approximately \$59.55 per month for a 20 kW¹¹ DG system. The standby charge would be in addition to the standard \$7 monthly connection fee assessed to all customers. The average retail electric rate for such DG customers is approximately \$0.11 / kWh. Dominion noted in its application to SCC that the new standby charge would apply to one customer (at the time of the application). Staff has received anecdotal

¹¹ Virginia state law limits the maximum size of residential NM systems to 20 kW.

information that there are now four Dominion customers that are subject to this standby charge. The SCC approved Dominion's application in November 2011.

Austin Energy (City of Austin, TX)

Austin Energy ("AE") which provides service to the greater Austin, Texas area takes an unusual approach to valuing the benefits of DG solar installations within its service territory. In October 2012, AE implemented a new production-based incentive, in the form of a residential solar rider tariff that acts as an alternative to NM. This rider applies to any customer receiving residential electric service who owns and operates an on-site solar photovoltaic system with a capacity of 20 kW or less that is interconnected with Austin Energy's electric distribution system.

Billable kWh under this rate schedule are based on the customer's total energy consumption during the billing month, including energy delivered by Austin Energy's electric system and energy consumed from an on-site solar system. All non-kWh-based charges under this rate schedule remain unaffected by the application of this rider.

For each billing month, the customer receives a non-refundable credit equal to the metered kWh output of the customer's photovoltaic system, times the current Value-of-Solar Factor plus any carry-over credit from the previous billing month. The Value-of-Solar Factor was initially set at \$0.128 per kWh, and is administratively adjusted annually, beginning with each year's January billing month, based upon the marginal cost of displaced energy, avoided capital costs, line loss savings, and environmental benefits. Any amount of solar credit in excess of the customer's total charges for electric service under the residential rate schedule shall be carried forward and applied to the customer's next electric bill. The customer's carry-over credit, if any, shall be reset to zero in the first billing month of each calendar year.

To explain its unique approach to valuing solar DG, and its concerns with traditional NM approaches, AE states:

"Austin Energy's solar energy incentive programs seek value parity between distributed solar PV options and so-called "conventional generation" options. Austin Energy's approach therefore differs significantly from the traditional "grid parity" objective of equivalent levelized cost of energy between solar and the average utility cost of energy from fully commercialized conventional resources. The goal for Austin Energy is parity in value, not just cost. Beginning with the federal Public Utility Regulatory Act passed by Congress in 1978, utilities generally paid an "avoided cost" value for customer-generated energy, typically set at the marginal price of fuel for an incremental unit of energy. Many states implemented NM policies as an improvement over traditional marginal avoided cost approaches for valuing distributed solar generation, in order to reflect the added value of energy generated at or near the point of consumption. While NM represents a significant improvement in reflecting the value of distributed solar energy compared to the avoided cost approach, problems remain. First, the retail price paid by the customer and credited for solar energy under NM (the value of "spinning the meter backwards") does not necessarily represent and likely underrepresents the full value of distributed solar generation."

"Second, NM induces two unintended consequences:

- 1. Solar customers size their solar systems against their baseload level of energy consumption because NM systems typically pay the old avoided cost value for excess generation. This is a practical reflection of the fact that solar capacity is fairly expensive and that excess generation rewards the customer at a very low rate. Of course, most of a solar system's excess generation is delivered to the utility at a time when the value of that energy often greatly exceeds the avoided cost rate.
- 2. NM value is coupled with consumption. That is, the value to the customer for a kWh of solar energy that offsets a unit of energy consumption is much greater that (sic) the value of excess generation, which is only credited at the avoided cost rate. Austin Energy's experience is that many solar customers recognize and respond to this signal to use more energy, based upon some sense that their consumption is "free" when a solar system is installed."

"Austin Energy designed its new "value of solar" rate to address these unintended consequences and offer an improved, decoupled NM approach."¹²

AE developed a PV Solar Value Calculator ("Calculator") that it uses to annually calculate the Value-of-Solar Factor for application in its production-based incentive. The Calculator is an algorithm that factors in values for system losses, energy savings, generation capacity savings, fuel price hedge value, T&D capacity savings, environmental benefits, and the impacts of nodal pricing in the Electric Reliability Council of Texas ("ERCOT") market.

¹² Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator, Rabago, Norris et al

DISCLAIMER

POSSIBLE FUTURE RULES and/or RATE CHANGES EFFECTING YOUR ROOFTOP PHOTOVOLTAIC SYSTEM

The following is a supplement to Paragraph 10.6 of the Interconnection Agreement ("Agreement") you signed with Arizona Public Service Company ("APS"):

I understand that notwithstanding any other provisions of this Agreement, Arizona Public Service Company ("APS") may file with the Arizona Corporation Commission ("Commission"), pursuant to the Commission's rules and regulations, an application for a change in the requirements, charges, classification, or service, and any rule or regulation relating to APS's interconnection with my rooftop photovoltaic system. In other words, I understand that in the future, upon application by APS or at the Commission's own initiative, the Commission may alter APS's rates, rules or regulations concerning rooftop photovoltaic systems which may affect the cost and/or savings relating to my rooftop photovoltaic system.

By signing below, I acknowledge that I have read and understand the above disclaimer.

Print Name

Signature

Date

DISCLAIMER POSSIBLE FUTURE RULES and/or RATE CHANGES EFFECTING YOUR ROOFTOP PHOTOVOLTAIC SYSTEM

The following is a supplement to Paragraph 10.6 of the Interconnection Agreement ("Agreement") you signed with Arizona Public Service Company ("APS"):

I understand that notwithstanding any other provisions of this Agreement, APS may file with the Arizona Corporation Commission ("Commission"), pursuant to the Commission's rules and regulations, an application for a change in the requirements, charges, classification, or service, and any rule or regulation relating to this rooftop photovoltaic system, as all utility customers are subject to such changes relating to their energy service. The Commission may also, of its own initiative, alter the rates, rules or regulations that pertain to this rooftop photovoltaic system.

By signing below, I acknowledge that I have read and understand the above disclaimer.

Print Name

Signature

Date

1641 kWh/kW

6.4 kW	Customer DG System Size
\$0.125	Retail Rate
1641 kWł	Assumed Annual Rate of Production

خ	A. Customer DG System Size	6.4 kW		Å.	
8	Assumed Annual Rate of Production	1,641 kwh/kw		в.	
ن	C. Calculated Annual Production	10,502 kwh (A*B)		ن	
ď	D. Assumed Customer Retail Rate	\$0.125 /kWh		D.	
ui 🛛	Annual Retail Cost of Production	\$1,312.80 (C*D)		щ	
L.	Assumed Utility Scale PPA Rate	\$0.10 /kWh		F.	
σ	G. Annual PPA Cost of Production	\$1,050.24 (C*F)	_	5	
H.	Annual DG Premium	\$262.56 (E-G)		H.	
	Monthly LFCR DG Premium	\$21.88 (H/12)		Ι.	
	 Monthly LFCR DG Premlum Per kW 	\$3.42 (I/A)		1.	
j	Assumed Annual Rate of Production	1641 kWh/kW			

Assumed Annual Rate of Production Retall Rate

\$0.130

خ	A. Customer DG System Size	6.4	6.4 kW	Ŕ	A. Customer DG System Size	_
e,	Assumed Annual Rate of Production	1,641	1,641 kWh/kW	æ	Assumed Annual Rate of Production	-
ن	C. Calculated Annual Production	10,502	10,502 kwh (A*B)	ن	Calculated Annual Production	
d	D. Assumed Customer Retail Rate	\$0.130 /kWh	/kWh	0	D. Assumed Customer Retail Rate	-
ш	E. Annual Retail Cost of Production	\$1,365.31 (C*D)	(c*D)	wi	Annual Retail Cost of Production	
<u> </u>	F. Assumed Utility Scale PPA Rate	\$0.10	\$0.10 /kWh	u.	F. Assumed Utility Scale PPA Rate	-
ق	G. Annual PPA Cost of Production	\$1,050.24 (C*F)	(C*F)	υ	G. Annual PPA Cost of Production	-
Ŧ	H. Annual DG Premium	\$315.07 (E-G)	(E-G)	Ŧ	H. Annual DG Premium	
<u>-</u>	Monthly LFCR DG Premlum	\$26.26 (H/12)	(H/12)	<u></u>	Monthly LFCR DG Premium	-
	Monthly LFCR DG Premium Per kW	\$4.10 (I/A)	(I/A)	÷	Monthly LFCR DG Premium Per kW	
1	ج Assumed Annual Rate of Production	1641	1641 kWh/kW			

Assumed Annual Rate of Production	Retail Rate
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\$0.135

6.4 kW	1,641 kWh/kW	10,502 kwh (A*B)		\$0.135 /kWh	\$0.135 /kWh \$1,417.82 (C*D)	0.135 /kWh 17.82 (C*D) \$0.10 /kWh	\$0.135 /kWh \$1,417.82 (C*D) \$0.10 /kWh \$1,050.24 (C*F)	\$0.135 /kWh 1,417.82 (C*D) \$0.10 /kWh 1,050.24 (C*F) \$367.58 (E-G)	\$0.135 /kWh 417.82 (C*D) \$0.10 /kWh 050.24 (C*F) 367.58 (E-G) \$30.63 (H/12)	0.135 /kWh 17.82 (C*D) 50.10 /kWh 50.24 (C*F) 50.258 (E-G) 30.65 (H/12) 30.65 (H/12)	7.125 / WWh 1.128 (C*P) 0.24 (C*F) 0.24 (C*F) 0.25 (F-G) 0.65 (H/12) 0.65 (H/12) 1.61 WWh/WW
A. Customer DG System Size	Assumed Annual Rate of Production	C. Calculated Annual Production	D. Assumed Customer Retail Rate		E. Annual Retail Cost of Production	Annual Retail Cost of Production Assumed Utility Scale PPA Rate	 E. Annual Retail Cost of Production F. Assumed Utility Scale PPA Rate G. Annual PPA Cost of Production 	 E. Annual Retail Cost of Production F. Assumed Utility Scale PPA Rate G. Annual PPA Cost of Production H. Annual DG Premlum 	Amual Retail Cost of Production Assumed Utility Scale PPA Rate Amual DG Premium Annual DG Premium	E. Amnual Retail Cost of Production Assumed Utility Scale PPA Rate G. Amnual PPA Cost of Production H. Amnual DG Premium Amothy LFCR DG Premium Production Amothy LFCR DG Premium Production Amothy LFCR DG Premium	Annual Retail Cost of Production Assumed Utility Scale PPA Rate Annual PPA Cost of Production Annual DG Premium Wonthly LFCR DG Premium Per kW Assumed Annual Rate of Production Assumed Annual Rate of Production
٩	в.	ن	0.		1	ш ш	<u>ы</u> щ ю	<u>ы</u> щ щ т			

 A.
 Customer DG System Size

 B.
 Assumed Annual Rate of Production

 B.
 Assumed Customer Retails at each annual Production

 D.
 Castumed Customer Retails at each annual Retail Cost of Production

 F.
 Annual Retail Cost of Production

 F.
 Annual Production

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 Annual Production

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ł	Customer DG System Size	6.4	6.4 kW
ai.	Assumed Annual Rate of Production	1,641	1,641 kWh/kW
ن	Calculated Annual Production	10,502	10,502 kwh (A*B)
Ŀ.	Assumed Customer Retail Rate	\$0.140 /kWh	/kWh
نس	Annual Retail Cost of Production	\$1,470.34 (C*D)	(c*D)
<u> </u>	Assumed Utility Scale PPA Rate	\$0.10	\$0.10 /kWh
ى	Annual PPA Cost of Production	\$1,050.24 (C*F)	(C*F)
Ŧ	Annual DG Premium	\$420.10 (E-G)	(E-G)
	Monthly LFCR DG Premium	\$35.01 (H/12)	(H/12)
	Monthly LFCR DG Premium Per kW	\$5.47 (I/A)	(1/A)

	A.	A. Customer DG System Size	6.4 kW	kW	4	ι.
	æ	Assumed Annual Rate of Production	1641	1641 kwh/kw	μ.	
	ن	Calculated Annual Production	10,502	10,502 kwh (A*B)	ن	
	à	Assumed Customer Retail Rate	\$0.125 /kWh	/kwh	۵	
	ш	Annual Retail Cost of Production	\$1,312.80 (C*D)	(c*b)	шi	
	F.	Assumed Utility Scale PPA Rate	4Wh/ 60.02	/kWh	ц	i .I
	ن	Annual PPA Cost of Production	\$945.22 (C*F)	(C*F)	U	!
	Η.	Annual DG Premium	\$367.58 (E-G)	(E-G)	I	
	-	Monthly LFCR DG Premium	\$30.63 (H/12)	(H/12)		
·	١.	Monthly LFCR DG Premium Per kW	\$4.79 (I/A)	(I/A)	<u> </u>	
						Ł

		10,502 kWh (A*B)	10,502 kWh (A*B) \$0.125 /kWh	10,502 kwh (A*B) \$0.125 /kwh \$1,312.80 (C*D)	10,502 kWh (A*B) \$0.125 /kWh \$1,312.80 (C*D) \$0.08 /kWh	10,502 kWh (A*B) \$0.125 /kWh \$1,312.80 (C*D) \$0.08 /kWh \$840.19 (C*F)	10,502 kWh (A*B) \$0.125 /kWh \$1,312.80 (C*D) \$0.08 /kWh \$840.19 (C*F) \$472.61 (F-G)	10,502 kwh (A*B) 50.125 /kwh 50.125 (C*P) 50.08 /kwh 5840.19 (C*F) 539.38 (H/12) 539.38 (H/12)
	10,502 kV		\$0.125 /k	\$0.125 /k \$1,312.80 (C	\$0.125 /k \$1,312.80 (C \$0.08 /k	\$0.125 /k \$1,312.80 (C \$0.08 /k \$840.19 (C	\$0.125 /k \$1,312.80 (C \$0.08 /k \$40.19 (C \$472.61 (F	\$0.125 /k \$1,312.80 (C \$0.08 /k \$40.19 (C \$472.61 (E \$39.38 (H
02 01		\$0.12		\$1,	\$1,	\$1,	\$1,	\$1
	tion	Rate		duction	duction A Rate	duction A Rate uction	duction A Rate uction	duction A Rate uction
	Calculated Annual Production	Assumed Customer Retall Rate		Annual Retail Cost of Production	Annual Retail Cost of Productio Assumed Utility Scale PPA Rate	Annual Retail Cost of Productio Assumed Utility Scale PPA Rate Annual PPA Cost of Production	t of Produ cale PPA of Produc um	Annual Retail Cost of Produ Assumed Utility Scale PPA F Annual PPA Cost of Product Annual DG Premium Monthly LFCR DG Premium
	d Annual	Custome		etail Cost	etail Cosi Utility Si	etail Cosi Utility S	etail Cosi Utility So PA Cost o G Premiu	etail Cosl Utility So PA Cost o G Premiu
	alculated	ssumed		nnual Re	unual Re ssumed	onual Re ssumed I onual PP	Annual Retail Cost o Assumed Utility Scaf Annual PPA Cost of F Annual DG Premium	unual Re ussumed 1 unual PP unual DC fonthly L
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Ī	6		_					
	10,502 kWh (A*B)	kwh	(a₊)		kwh	kwh C*F)	kwh C*F) F-G)	kWh C°F) E-G) H/12)
	0,502 k	\$0.125 /kWh	\$1,312.80 (C*D)		\$0.09 /kWh	\$0.09 /kWl \$945.22 (C*F)	\$0.09 /kWh \$945.22 (C*F) \$367.58 (E-G)	\$0.09 /kWh 945.22 (C*F) 367.58 (E-G) \$30.63 (H/12)
	2	ŝ	\$1,3			5	55 ES	65 E\$
			uo		a	a -	a) _	a) _
	tion	Rate	uction		Rate	Rate	Rate	Rate

	6.4	6.4 kW	A.	A. Customer DG System Size	6.4	6.4 kW	Ś	A. Customer DG System Size	_
tion	1,641	1,643. kWh/kW	8	Assumed Annual Rate of Production	1,641	kWh/kW	æ	Assumed Annual Rate of Production	-
	10,502	10,502 kWh (A*B)	ن	Calculated Annual Production	10,502	10,502 kWh (A*B)	ن	Calculated Annual Production	
	\$0.130 /kWh	/kWh	0	Assumed Customer Retail Rate	\$0.130 /kWh	/kWh	Ċ	Assumed Customer Retail Rate	
	\$1,365.31 (C*D)	(c*b)	ш	Annual Retail Cost of Production	\$1,365.31 (C*D)	(c*b)	w	Annual Retail Cost of Production	5
	\$0.05	\$0.09 /kWh	ц.	Assumed Utility Scale PPA Rate	\$0.08	\$0.08 /kwh	u.	Assumed Utility Scale PPA Rate	
	\$945.22 (C*F)	(C*F)	<u>.</u>	Annual PPA Cost of Production	\$840.19 (C*F)	(C*F)	ى	Annual PPA Cost of Production	
	\$420.10 (E-G)	(E-G)	H.	Annual DG Premium	\$525.12 (E-G)	(E-G)	Ŧ	Annual DG Premium	-
	\$35.01 (H/12)	(H/12)	-	Monthly LFCR DG Premium	\$43.76 (H/12)	(ZT/H)	<u></u>	Monthly LFCR DG Premium	
N	\$5.47 (I/A)	(I/A)	1.	Monthly LFCR DG Premium Per kW	\$6.84 (I/A)	(v/v)		Monthly LFCR DG Premium Per kW	
3	14:00	II/A	<u>-</u>	Monthly LFLK UG Fremium Per KW	56-84	(/A)	-	MONTHLY LFLK DG Pre	emium Per kw

6.4 kw

	6.4 kW	kW	Ŕ	A. Customer DG System Size	6.4	6.4 kW
1	641	1,641 kWh/kW	æi	Assumed Annual Rate of Production	1,641	1,641 kWh/kW
10,	502	10,502 kWh (A*B)	ڼ	Calculated Annual Production	10,502	10,502 kWh (A*B)
\$0	135	\$0.135 /kWh	ġ	Assumed Customer Retail Rate	\$0.135 /kWh	/kwh
\$1,417.82 (C*D)	7.82	(c+0)	ய்	Annual Retail Cost of Production	\$1,417.82 (C*D)	(c*D)
ŝ	0.09	\$0.09 /kWh	Ľ.	Assumed Utility Scale PPA Rate	\$0.08	\$0.08 /kWh
\$94	\$945.22 (C*F)	(C*F)	υ	Annual PPA Cost of Production	\$840.19 (C*F)	(C*F)
\$47	\$472.61 [E-G]	(E-G)	Ŧ	Annual DG Premium	\$577.63 (E-G)	(E-G)
ĘŞ	9.38	\$39.38 (H/12)		Monthly LFCR DG Premium	\$48.14	\$48.14 (H/12)
v	\$6.15 (I/A)	[I/A]	l	Monthly LFCR DG Premium Per kW	\$7.52 (I/A)	(I/A)

6.4 kW 1.641 kWh/kW 10,502 kWh (A*B) \$0.440 /kWh (A*B) \$0.240 /kWh \$1,470 34 (C*P) \$95.25 12 (E-G) \$35.25 (H/12) \$525.12 (E-G)

	_	_		_	_			_			
_	A. Customer DG System Size	Assumed Annual Rate of Production	Calculated Annual Production	Assumed Customer Retail Rate	Annual Retail Cost of Production	Assumed Utility Scale PPA Rate	G. Annual PPA Cost of Production	H. Annual DG Premium	Monthly LFCR DG Premium	Monthly LFCR DG Premium Per kW	
	</td <td>μĖ.</td> <td>ا ت</td> <td>ان</td> <td>ш</td> <td>щĽ</td> <td>രി</td> <td>Ξ</td> <td>-</td> <td></td> <td></td>	μĖ.	ا ت	ان	ш	щĽ	രി	Ξ	-		

خ	Customer DG System Size	6.4 kW	kν	×	Custome
	Assumed Annual Rate of Production	1,641	1,641 kWh/kW	æ	Assumed
ن	Calculated Annual Production	10,502	10,502 kwh (A*B)	ن	Calculate
d	Assumed Customer Retail Rate	\$0.140 /kWh	/kWh	٥	Assumed
ᆈ	Annual Retail Cost of Production	\$1,470.34 (C*D)	(C*D)	ш	Annual F
Ľ.	Assumed Utility Scale PPA Rate	\$0.0\$	\$0.09 /kWh	ш.	Assumed
υj	Annual PPA Cost of Production	\$945.22 (C*F)	(C*F)	σ	Annual F
Ŧ	Annual DG Premium	\$525.12 (E-G)	(E-G)	Ŧ	Annual D
	Monthly LFCR DG Premium	\$43.76 (H/12)	(H/12)		Monthly
	Monthly LFCR DG Premium Per kW	\$6.84 (I/A)	(i/A)		Monthly

	Ś	A. Customer DG System Size	6.4	6.4 kW	¢,	Customer DG System Size	6.4	kw
kWh/kW	<u>ت</u> م	Assumed Annual Rate of Production	1,641	kWh/kW	æ.	Assumed Annual Rate of Production	1,641	kWh/kW
kWh (A*B)	ن	C. Calculated Annual Production	10,502	kWh (A*B)	ن	Calculated Annual Production	10,502	kWh (A*B)
-	ó	. Assumed Customer Retail Rate	\$0.125	\$0.125 /kWh	ġ	 Assumed Customer Retall Rate 	\$0.125 //	/kWh
	ئىر	. Annual Retail Cost of Production	\$1,312.80 (C*D)	(c*D)	ш	Annual Retail Cost of Production	\$1,312.80 (C*D)	(C*D)
	ц	. Assumed Utility Scafe PPA Rate	\$0.08	\$0.08 /kWh	بد	Assumed Utility Scale PPA Rate	\$0.07	\$0.07 /kWh
	ຜ່	Annual PPA Cost of Production	\$840.19 (C*F)	(C*F)	υ	Annual PPA Cost of Production	\$735.17 (C*F)	(C*F)
	ŕ	Annual DG Premium	\$472.61 (E-G)	(E-G)	Ï	Annual DG Premium	\$577.63 (E-G)	(E-G)
7		Monthly LFCR DG Premium	\$39.38	\$39.38 (H/12)		Monthly LFCR DG Premium	\$48.14	(H/12)
	-	Monthly LFCR DG Premium Per kW	\$6.15	\$6.15 (I/A)	-	Monthly LFCR DG Premium Per kW	\$7.52 (1	(I/A)

uo	1,641	1,641 kWh/kW	æ	Assumed Annual Rate of Production	1,641	1,641 kWh/kW
	10,502	10,502 kWh (A*B)	ن	Calculated Annual Production	10,502	10,502 kWh (A*B)
	\$0.130 /kWh	/kWh	Ö	Assumed Customer Retail Rate	\$0.130 /kWh	/kWh
	\$1,365.31 (C*D)	(c*D)	w	Annual Retail Cost of Production	\$1,365.31 (C*D)	(c*D)
	\$0.08	\$0.08 /kwh	L.	Assumed Utility Scale PPA Rate	\$0.07 /kWh	/kWh
	\$840.19 (C*F)	(C*F)	σ	Annual PPA Cost of Production	\$735.17 (C*F)	(C*F)
	\$525.12 (E-G)	(E-G)	Ξ	Annual DG Premium	\$630.14 (E-G)	(E-G)
	\$43.76 (H/12)	(H/12)	<u></u>	Monthly LFCR DG Premium	\$52.51 (H/12)	(H/12)
N	\$6.84 (I/A)	(I/A)		Monthly LFCR DG Premium Per kW	\$8.21 (I/A)	(I/A)
	6.4	6.4 kW	4	Customer DG System Size	6.4 kW	×W
ou	1,641	1,641 kWh/kW	æ	Assumed Annual Rate of Production	1,641	1,641 kWh/kW
	10,502	10,502 kWh (A*B)	ij	Calculated Annual Production	10,502	10,502 kWh (A*B)
	\$0.135 /kWh	/kWh	0	Assumed Customer Retail Rate	\$0.135 /kWh	/kWh
	\$1,417.82 (C*D)	(c*D)	ш	Annual Retail Cost of Production	\$1,417.82 (C*D)	(c*D)
	\$0.08	\$0.08 /kWh	Ŧ.	Assumed Utility Scale PPA Rate	\$0.07 /kWh	/kWh
	\$840.19 (C*F)	(C*F)	υ	Annual PPA Cost of Production	\$735.17 (C*F)	(C*F)
	\$577.63 (E-G)	(E-G)	π	Annual DG Premium	\$682.66 (E-G)	(E-G)
	\$48.14 (H/12)	(H/12)	<u>_</u> :	Monthly LFCR DG Premium	\$56.89 (H/12)	(H/12)
2	\$7.52 (I/A)	(I/A)	-	Monthly LFCR DG Premlum Per kW	\$8.89 (I/A)	(I/A)

	6.4	6.4 kW	Ŕ	Customer DG System Size	6.4 kW	κw
Production	1,641	1,641 kWh/kW	æ	Assumed Annual Rate of Production	1,641 k	1,641 kWh/kW
tion	10,502	10,502 kwh (A*B)	ن	Calculated Annual Production	10,502 4	10,502 kWh (A*B)
Rate	\$0.140	\$0.140 /kWh	<u>ا</u>	Assumed Customer Retail Rate	\$0.140 /kWh	/kWh
duction	\$1,470.34 (C*D)	(c*D)	ய்	Annual Retail Cost of Production	\$1,470.34 (C*D)	C*D)
k Rate	\$0.08	\$0.08 /kWh	ш.	Assumed Utility Scale PPA Rate	\$0.07 /kwh	/kwh
ction	\$840.19 (C*F)	(C*F)	ġ	Annual PPA Cost of Production	\$735.17 (C*F)	(C*F)
	\$630.14 (E-G)	(E-G)	Ŧ	Annual DG Premium	\$735.17 (E-G)	() 10
F	\$52.51	\$52.51 (H/12)	_:	Monthly LFCR DG Premium	\$61.26 (H/12)	H/12)
n Per kW	\$8.21 [(I/A)	(I/A)		Monthly LFCR DG Premium Per kW	\$9.57 (I/A)	1/A)

1641 kWh/kW

\$0.145

Assumed Annual Rate of Production Retail Rate

B. Assumed Annual Rate of Production 1,641 Wh/KW B. Assumed Annual Rate of Production C. Calculated Annual Production 10,502 kWh (A*B) D. Assumed Annual Production C. Calculated Annual Production 10,502 kWh (A*B) D. Assumed Customer Retail Rate Annual Retail Cost of Production 50,146 KWh F. Assumed Utility Scale Production F. Assumed Utility Scale PPA Rate 50,10 KWh F. Assumed Utility Scale PPA Rate G. Annual Retail Cost of Production 54,050,24 (C*F) H. Annual Production H. Annual DG Premium 54,250,14 (C*F) H. Annual DG Premium H. Monthy LCR OG Premium 53,33 (H/12) I. Monthy LCR OG Premium J. Monthy LCR OG Premium 54,31 (JA) J. Monthy LCR OG Premium Per KW	¢	A. Customer DG System Size	6.4 kW	kW	خ	A. Customer DG System Size	
10,502 kwh (A*B) C \$0.455 kwh D D \$0.455 krwh D D D \$1,0502 kwh (A*B) C D D D \$1,0502 kwh (A*B) C D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D D	æ	Assumed Annual Rate of Production	1,641	kWh/kW	8	Assumed Annual Rate of Production	Ł.
\$0.145 Kwhh D. \$1,522.85 \$1,050 F. \$3,200 Kwh F. \$3,200 Kwh F. \$3,300 Kwh F. \$4,050.24 (C*f) F. \$39.38 (H.12) H. \$53.51 (H.12) H. \$53.51 (K.5) H. \$53.51 (K.5) H. \$53.51 (K.4) J.	ن	Calculated Annual Production	10,502	kWh (A*B)	ن	Calculated Annual Production	.
\$1,52.48 (° t° b) E. \$0.10 /kwh F. \$41,52.48 (° t° b) F. \$41,050.24 (C t°) F. \$427.56 (E t°) H. \$5338 (H/12) I. \$54.51 (VA) J.	Ċ.	Assumed Customer Retail Rate	\$0.145	/kWh	ġ	Assumed Customer Retail Rate	
\$0.10 /kwh F. \$1,050.24 (C*F) G. \$472.61 (C*F) H. \$533.81 (H/12) I. kw \$5.13 (I/12)	w	Annual Retall Cost of Production	\$1,522.85	(c*D)	نس	Annual Retail Cost of Production	s a
\$1,050.24 {C*F} G. \$472.61 {E-G} H. \$39.38 {H/12} I. kw \$6.15 {I.	u.	Assumed Utility Scale PPA Rate	\$0.10	/kwh	u.	Assumed Utility Scale PPA Rate	
\$472.61 (E-G) H. emlum \$39.38 (H/12) 1. emlum Per kW \$6.15 (I/A) 1.	ບ່	Annual PPA Cost of Production	\$1,050.24	(C*F)	ט	Annual PPA Cost of Production	
Per kW \$6.15 (I/A) 1.	ŕ	Annual DG Premium	\$472.61	(E-G)	Ţ	Annual DG Premium	
\$6.15 (I/A) 1.	-	Monthly LFCR DG Premlum	\$39.38	(H/12)		Monthly LFCR DG Premium	
		Monthly LFCR DG Premlum Per kW	\$6.15	(I/A)		Monthly LFCR DG Premlum Per kW	

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umed Annual Rate of Production	Retail Rate
Assume	

1641 kWh/kW \$0.150

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ć	A. Juustomer un aystern aize	# 0	D.4 XY	٢.
B)	B. Assumed Annual Rate of Production	1,641	1,641 kwh/kw	l mi
ن	C. Calculated Annual Production	10,502	10,502 kWh (A*B)	 ن ا
Ŀ.	D. Assumed Customer Retall Rate	\$0.150 /kWh	/kWh	 Ġ
ш	Annual Retail Cost of Production	\$1,575.36 (C*D)	(c•b)	 ι ui
Т.	Assumed Utility Scale PPA Rate	\$0.10	\$0.10 /kWh	 L.
υ	Annual PPA Cost of Production	\$1,050.24 (C*F)	(C*F)	σ
Ŧ	H. Annual DG Premium	\$525.12 (E-G)	(E-G)	Ξ
	Monthly LFCR DG Premium	\$43.76 (H/12)	(H/12)	
	Monthly LFCR DG Premium Per kW	\$6.84 (I/A)	(I/A)	

Ŕ	A. Customer DG System Size	6.4	6.4 kW	4	A. Customer DG System Size
mi	Assumed Annual Rate of Production	1,641	1,641 kWh/kW	a d	Assumed Annual Rate of Production
ں	Calculated Annual Production	10,502	10,502 kWh (A*B)	ن	Calculated Annual Production
ė	D. Assumed Customer Retail Rate	\$0.150 /kWh	/kWh	d	Assumed Customer Retall Rate
ц,	Annual Retail Cost of Production	\$1,575.36 (C*D)	(c*b)	ui	Annual Retail Cost of Production
<u>u</u>	Assumed Utility Scale PPA Rate	\$0.09	\$0.09 /kwh	u.	Assumed Utility Scale PPA Rate
σ	G. Annual PPA Cost of Production	\$945.22 (C*F)	(C*F)	U	Annual PPA Cost of Production
Ŧ	Annual DG Premium	\$630.14 (E-G)	(E-G)	Ŧ	Annual DG Premium
-	Monthly LFCR DG Premium	\$52.51 (H/12)	(H/12)	:	Monthly LFCR DG Premium
	 Monthly LFCR DG Premium Per kW 	\$8.21 (I/A)	(I/A)	J.	Monthly LFCR DG Premium Per kW

10,502 kwh (A*B) \$0.150 /kwh \$1,575.36 (C*D) \$0.08 /kwh \$840.19 (C*F)

\$735.17 (E-G) \$61.26 (H/12) \$9.57 (I/A)

6.4 kW 1,641 kWh/kW

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¥	 Customer DG System Size 	6.4	6.4 kW	¢	A. Customer DG System Size	6.4 kW	X
ġ	Assumed Annual Rate of Production	1,641	1,641 kWh/kW	B	B. Assumed Annual Rate of Production	1,641 kWh/	κwh
ن	C. Calculated Annual Production	10,502	10,502 kwh (A*B)	ن	C. Calculated Annual Production	10,502 kWh	ł¥,
О.	. Assumed Customer Retail Rate	\$0.106	\$0.106 /kWh*	o.	D. Assumed Customer Retail Rate	\$0.106 /kWh	/kw
ш,	Annual Retall Cost of Production	\$1,113.25 (C*D)	(c*b)	шi	E. Annual Retail Cost of Production	\$1,113.25 (C*D)	5
Ľ.	F. Assumed Utility Scale PPA Rate	\$0.08	\$0.08 /kWh	u.	F. Assumed Utility Scale PPA Rate	\$0.07 /kWh	Š
σ	Annual PPA Cost of Production	\$840.19 (C*F)	(C*F)	ق	G. Annual PPA Cost of Production	\$735.17 (C*F)	5
Ŧ	. Annual DG Premium	\$273.06 (E-G)	(E-G)	Ŧ	H. Annual DG Premium	\$378.09 (E-G)	9-9
-	Monthly LFCR DG Premium	\$22.76 (H/12)	(H/12)	-	Monthly LFCR DG Premium	\$31.51 (H/12	E
	Monthly LFCR DG Premium Per kW	\$3.56 (I/A)	(I/A)		 Monthly LFCR DG Premium Per kW 	\$4.92 (I/A)	

Customer DG System Size	6.4	6.4 kW
Assumed Annual Rate of Production	1,641	1,641 kWh/kW
Calculated Annual Production	10,502	10,502 [kWh (A*B)
Assumed Customer Retail Rate	\$0.106 /kWh*	/kwh*
Annual Retail Cost of Production	\$1,113.25 (C*D)	(C*D)
Assumed Utility Scafe PPA Rate	\$0.07	\$0.07 /kWh
Annual PPA Cost of Production	\$735.17 (C*F)	(C*F)
Annual DG Premium	\$378.09 (E-G)	(E-G)
Monthly LFCR DG Premium	\$31.51 (H/12)	(H/12)
Monthly LFCR DG Premium Per kW	\$4.92 (I/A)	(I/A)

اغاناه	Assumed Annual Rate of Production Calculated Annual Production	1,641 kWh/kW	LAND ALLAN
di di	Calculated Annual Production		KWN/KW
d	Assumed Customer Retail Date	10,502	10,502 kWh (A*B)
	Assume Lustomer Retail Rate	\$0.145 /kWh	/kWh
ا ن	Annual Retail Cost of Production	\$1,522.85 (C*D)	(c*b)
Ŀ	Assumed Utility Scale PPA Rate	\$0.07	\$0.07 /kWh
ق	Annual PPA Cost of Production	\$735.17 (C*F)	(C°F)
H.	Annual DG Premium	\$787.68 (E-G)	(E-G)
	Monthly LFCR DG Premium	\$65.64	\$65.64 (H/12)
÷	Monthly LFCR DG Premium Per kW	\$10.26 (I/A)	(I/A)
ė	Customer DG System Size	6.4	6.4 kW
Β.	Assumed Annual Rate of Production	1,641	kwh/kw
	Calculated Annual Production	10,502	kWh (A*B)
р.	Assumed Customer Retail Rate	\$0.150 /kWh	/kWh
Е.	Annual Retall Cost of Production	\$1,575.36 (C*D)	(C*D)
٣.	Assumed Utility Scale PPA Rate	\$0.07	/kWh
G.	Annual PPA Cost of Production	\$735.17 (C*F)	(C*F)
н.	Annual DG Premium	\$840.19 (E-G)	(E-G)
1	Monthly LFCR DG Premium	\$70.02 (H/12)	(H/12)
	and a second sec	410 00 000	

1,641 (WI/KW 10,502 (WI/ (A*B) 10,502 (WI/ 10,502 (WI/ 10,124 (AWI) 50,08 (AWI) 50,08 (AWI) 56,685 (H/12) 56,685 (H/12) 58,689 (H/12) 58,689 (H/12)

 A.
 Customer DG System Site

 8.
 Assumed Annual Rate of Production

 8.
 Calculated Annual Production

 0.
 Calculated Annual Production

 0.
 Assumed Customer Retail Rate

 1.
 Ansumed PPA Cost of Production

 6.
 Ansumed PPA Cost of Production

 6.
 Ansumed Utility Scale PPA Rate

 6.
 Annual PPA Cost of Production

 1.
 Monthly LCR DG Premium

6.4 kW 6.4 kWh/kW 1.641 kWh/kW 10,502 kWh (A*B) \$0.145 /Wh \$1,522.81 (C*D) \$1,522.81 (C*D) \$995,221 (C*F) \$48,14 (H/12) \$48,14 (H/12) \$7,52 (J/A)

6.4 kW

Customer DG System Size Assumed Annual Rate of Production

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Ŕ	Customer DG System Size	6.4 kW	2
8	Assumed Annual Rate of Production	1,800 kWh/kW	Wh/kW
ن	Calculated Annual Production	11,520 kWh (A*B)	Vh (A*B)
d	Assumed Customer Retail Rate	\$0.150 /kWh	Wh
ш	Annual Retail Cost of Production	\$1,728.00 (C*D)	(a.
Ľ.	Assumed Utility Scale PPA Rate	\$0.07 /kWh	Wh
υj	Annual PPA Cost of Production	\$806.40 (C*F)	E.
H.	Annual DG Premium	\$921.60 (E-G)	Ģ
	Monthly LFCR DG Premium	\$76.80 (H/12)	(12)
۲.	Monthly LFCR DG Premium Per kW	\$12.00 (I/A)	(4)

1	BEFORE THE ARIZONA CORPORATION COMMISSION								
2	BOB STUMP Chairman								
3	GARY PIERCE Commissioner								
4	BRENDA BURNS Commissioner BOB BURNS								
5									
6	Commissioner SUSAN BITTER SMITH								
7	Commissioner								
8	IN THE MATTER OF ARIZONA PUBLIC) DOCKET NO. E-01345A-13-0248								
9	SERVICE COMPANY'S APPLICATION								
	FOR APPROVAL OF NET METERING DECISION NO. COST SHIFT SOLUTION ORDER								
10									
11									
12	Open Meeting October 16 and 17, 2013								
13	Phoenix, Arizona								
14	BY THE COMMISSION:								
15	FINDINGS OF FACT								
16	1. Arizona Public Service Company ("APS") is certificated to provide electric service								
17	as a public service corporation in the State of Arizona.								
18	2. On July 12, 2013, APS filed an application ("Application") for approval of a Net								
19	Metering Cost Shift Solution. Subsequent to APS's filing, several parties requested and were								
20	granted intervenor status in this docket, including The Alliance for Solar Choice ("TASC"), Lewis								
21	M. Levenson, Tucson Electric Power Company, UNS Electric, Inc., the Residential Utility								
22	Consumer Office ("RUCO"), the Solar Energy Industry Alliance ("SEIA"), Western Resource								
23	Advocates, and the Interstate Renewable Energy Council, Inc. ("IREC").								
24	3. TASC filed a formal Protest in the Docket on July 29, 2013, urging the Arizona								
25	Corporation Commission ("Commission") to reject APS's application and institute an alternative								
26	proposal. On August 20, 2013, SEIA filed a Protest and Motion to Dismiss asserting that there is								
27	no cost-shift between customer classes as a result of net metering ("NM"), and that the Application								
28									

represents an attempt at ratemaking outside of a general rate case. TASC joined SEIA's Protest
 and Motion to Dismiss on August 30, 2013.

4. IREC filed a formal Protest in the Docket on August 29, 2013, asserting that the
instant docket is not the appropriate venue for analysis of APS's NM program. IREC states that
further discussion and analysis is required to obtain a comprehensive understanding of the benefits
and costs of distributed solar photovoltaics in Arizona. IREC urges the Commission to reject
APS's Application and defer discussion of its proposals to a future general rate case.

8 5. Numerous letters from customers voicing both support and opposition regarding NM
9 programs in general, and APS's proposed NM cost-shift solutions in particular, have been filed in
10 this Docket.

11 Background

6. APS's Application states that rooftop solar installations have increased significantly 12 each year in APS's service territory since January 2009. The Application states that as of January 13 14 2009, there were approximately 900 systems installed. As of June 2013, that number had grown to over 18,000 and continues to grow by approximately 500 new rooftop solar systems each month. 15 16 Much of this recent growth is attributable to Arizona's Net Metering Rules, which were 17 implemented in May 2009, under Title 14, Chapter 2, Article 23 of the Arizona Administrative 18 Code ("A.A.C."). The impetus for establishing Net Metering Rules was to incent the deployment 19 of customer-sited DG.

20 7. As defined by these rules, NM allows electric utility customers to be compensated 21 for generating their own electric energy from renewable resources, fuel cells, or Combined Heat 22 and Power systems (collectively "distributed generation" or "DG"). If the customer's energy 23 production exceeds the energy supplied by the electric utility during a billing period, the 24 customer's bill for subsequent billing periods is credited for the excess generation. That is, the 25 excess kWh generated during the billing period is used to reduce the kWh billed by the electric 26 utility during subsequent billing periods. Effectively, this credit process compensates the customer 27 (and incents the development of distributed generation) by requiring the electric utility company to 28 acquire the customer's excess generation at the customer's current effective retail rate. In order to

prevent abuse of the NM incentive, the Arizona NM Rules limit the size of customer DG systems 1 2 to a maximum of 125 percent of the NM customer's total connected load.

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8. Once each year (or for a customer's final bill upon discontinuance of service), the electric utility credits the customer for the balance of any remaining excess kWh. The payment for 4 5 the purchase of these year-end excess kWh is at the electric utility's annual average avoided cost, 6 which is specified on the electric utility's NM Tariff. A.A.C. R14-2-2302(1) defines avoided cost as "the incremental cost to an Electric Utility for electric energy or capacity or both which, but for 7 the purchase from the NM facility, such utility would generate itself or purchase from another 8 9 source."

9. As the participation in Arizona NM has grown, so have APS's concerns regarding 10 the issue of cross-subsidization between customers that participate in NM programs and those that 11 do not. APS asserts that while the NM customers benefit from the NM policy incentives, the non-12 participants are burdened with a disproportionate share of the subsidies required to fund the NM 13 In the case of APS's system, this cross-subsidization is most apparent for the 14 incentives. 15 Residential consumer class. APS states that, on average, the cost shift each year is approximately 16 \$1,000 per residential NM system, with total annual costs shifting to non-NM customers of approximately \$18 million. This alleged cross-subsidy is the basis of APS's Application. 17

18 The Application

APS filed the instant Application on July 12, 2013, in an effort to provide a solution 19 10. to the NM cost-shift issue. The broader issue of DG cross-subsidization has been mentioned in a 20 past rate case, specifically APS's 2005 general rate case¹. APS's most recent (2011) general rate 21 case did not specifically address the NM cross-subsidization issue. 22

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11. APS emphasizes that the instant application is proffered as a solution to the crosssubsidization of customers with Net-Metered DG systems by those customers without such 24 25 systems. In this context, APS asserts that the issue is one of fairness to all customers and is not related to a loss of revenue by APS because of NM. 26

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¹ See e.g., Decision No. 69663, pp. 87-89 (June 2007)

1 12. In preparation for filing the Application, APS hosted a multi-session technical conference ("Technical Conference") in the first half of 2013 to evaluate the costs and benefits of 2 Distributed Energy² and NM. Over the course of the Technical Conference, 175 people attended 3 representing a diverse group of stakeholders including solar installers, developers, policy 4 5 advocates, customers, utility representatives, academics, consultants, researchers, consumer advocates, and Commission representatives. The results of the Technical Conference, including 6 7 detail regarding the various stakeholder perspectives, were attached to the Application as Exhibit 4. 8

9 13. Informed by input received at the Technical Conference, together with analyses 10 conducted by other jurisdictions, and an update of a previous study of DG benefits, APS developed 11 a range of potential solutions which fell into two broad categories. The first solution group were 12 options that continued the use of NM and emphasized the use of the basic service charge, a 13 demand charge, or a standby charge.

14 14. The second group of potential solutions involved moving from NM to a mechanism 15 by which DG customers pay for all of the energy they consume, but receive a bill credit for 100 16 percent of the energy produced by their DG system. The key variable in this group of potential 17 solutions concerned the method for setting the price paid to customers for the DG energy they 18 produced. Those methods generally involved setting either a market-based price, or a price based 19 on values and non-market concepts.

20 15. Drawing from each group, APS proposes two possible solutions and requests that the 21 Commission select one of the proposed solutions. Based on the Commission's selection, any new 22 APS residential customer installing DG would either: (1) take service under APS's existing ECT-2 23 rate and use NM ("the NM Option"); or (2) take full requirements service under the customer's 24 existing rate and receive a bill credit for 100 percent of the DG system's production at a market-25 based price for power ("the Bill Credit Option").

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^{28 &}lt;sup>2</sup> In this Memorandum, the terms "Distributed Generation ("DG")" and "Distributed Energy" or "DE" are used interchangeably.

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1		
2	• The NM Option - ECT-2 Plus NM	
3	Under this option, all residential customers installing a new DE system would only be eligible to take electric service under APS's existing ECT-2 rate. The ECT-2	
4 5	rate is a demand-based rate with Time-of-Use ("TOU") features. APS states that the ECT-2 rate better balances the collection of fixed costs between usage-based	
6	 energy charges and demand-based charges, and would allow APS to more accurately charge DE customers for the services they use. The Bill Credit Option 	
7 8	Under this option, customers could remain on any APS rate plan for which they are otherwise eligible. Instead of NM, APS would compensate customers through a bill	
9	credit for all of the power produced by their DG system. The amount of credit would be based on the forward market at the Palo Verde hub with adjustments.	
10	APS asserts that this price would send a more accurate price signal for the true cost of the electrical services provided to potential DG customers.	
11	16 Under either ention ADS properts that all existing NIM systemers would be	
12	16. Under either option, APS proposes that all existing NM customers would be	
13	grandfathered under the customer's existing arrangement. Specifically, APS proposes	
14	grandfathering existing rate constructs (i.e. a customer's existing rate and use of NM) for	
15	residential customers who either have DG installed on their homes now, or who submit an	
16	application and a signed contract with a solar installer to APS by October 15, 2013. The	
17	grandfathering would extend for a maximum of 20 years from the effective date of the	
18	Commission's decision in this matter and would not be transferable to a new customer at the same	
19	premise.	
20	17. APS states "both options will change the economics of DE transactions and could	
21	result in a slower pace of residential rooftop solar installations." APS suggests that direct cash up-	
22	front incentives ("UFIs") could be authorized by the Commission to encourage additional DE	
23	penetration. APS favors the use of UFIs as they provide a transparent, flexible means to	
24	incentivize DE installations.	
25	18. APS's Application is supported by the direct testimony of Jeffrey Guldner, Vice	
26	President, Customers and Regulation, Gregory L. Bernosky, Manager of Renewable Energy, and	
27	Charles A. Miessner, Pricing Manager.	

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19. APS concludes its application by requesting that the Commission:

Docket No. E-01345A-13-0248 Page 6 1 Select either the NM Option or the Bill Credit Option; Grandfather the rates and use of NM by existing and immediately pending DE 2 customers: 3 Implement an incentive structure as described in the Application and attached testimony, should the Commission choose to order the direct payment of cash to 4 incentivize residential DE installation; 5 Address this matter on an expedited basis; and 6 Grant any waivers or other forms of relief that the Commission deems appropriate. 7 8 Staff Analysis 9 20. Arizona's NM policy is designed to incent the deployment of customer-sited DG 10 through the use of NM bill credits at the customer's retail rate, the NM method favored by a 11 majority of states allowing NM. The recent rapid increase in NM installations, despite declining 12 up-front incentives, validates the success of the NM incentive. 13 21. With increasing levels of DG penetration, the potential of shifting costs from 14 customers with DG systems to those customers without such systems becomes apparent. As more 15 customers offset a portion of their monthly bills by using energy produced by their DG systems. 16 they purchase less energy from the utility. Because residential rates are typically designed to 17 recover much of the utility's fixed costs³ through volumetric energy rates, DG customers 18 effectively pay less of these fixed costs. The additional fixed costs then must be picked up by non-19 DG customers either through higher energy rates or through other mechanisms such as APS's Lost 20Fixed Cost Recovery mechanism ("LFCR"). The magnitude and significance of this cost shift 21 increases as more and more DG systems are added to the utility's system. However, base rates are 22 not changed until the utility's next rate case. Therefore, for systems installed after APS's last test 23 year (2010), the cost shift has not yet occurred (except for that in the LFCR). 24 22. Based on responses to Staff's several Data Requests, APS provided a table of 25 residential and commercial DG incentive applications and installations from January 2011 through 26 27

^{28 &}lt;sup>3</sup> Fixed costs typically recovered through volumetric energy rates include costs associated with the utility's generation, transmission and distribution infrastructure.

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July 2013. These data responses confirm APS's assertion that DG installations have risen over the
 reporting period to a current rate of approximately 500 per month. APS also provided additional
 data that indicate the magnitude of the cost shift within the residential ratepayer class is within the
 range of \$800 to \$1,000 per year per DG customer.

5 23. APS also supplied Staff with a map depicting the location of all customer-sited DG 6 systems within its service territory. Staff notes that while the distribution of DG systems appears 7 relatively even across the urbanized areas within APS's service territory, there may be a tendency 8 for DG systems to be located in areas of higher income for two reasons: first, financial barriers to 9 entry (i.e. up-front costs for purchased systems and credit scores for leased systems); second, NM 10 benefits are greater for high energy users who would otherwise consume energy in higher-priced 11 tiers than they are for low energy users who consume energy in lower priced tiers.

12 The Value of DG

APS's application focuses on the costs associated with increasing levels of DG
installations. However, integral to the discussion of DG is the question of what *value* DG offers to
APS's electric system and thereby to the customers served by that system. Staff believes that there
are two forms of value inherent in DG systems.

17 25. The first form of value we call "Objective Value" which we define as measurable
18 benefits. An example of Objective Value is avoided fuel costs. Even objective value can be
19 difficult to predict in future time periods.

20 26. The second form of value we call "Subjective Value". Subjective Value requires the 21 subjective assignment of monetary values to anticipated future benefits that are not easily 22 measureable. Examples of Subjective Value offered by DG are increased grid security and air 23 quality improvements.

24 27. While Objective Values of DG may be determined more easily, even though
25 Objective Values can be difficult to predict in future time periods, the assignment of Subjective
26 Values is by its nature often controversial. Complicating the debate is the wide variety of
27 approaches and methodologies used by various parties in their analysis of this issue. These

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variations in study approach and conclusions are evident from two recent studies that have been
 filed in this docket.

3 28. The study prepared by SAIC Energy, Environment & Infrastructure, LLC ("SAIC 4 Report"⁴) on behalf of APS states that the primary value of DG is principally the avoided fuel 5 costs. In contrast, the study prepared by Crossborder Energy ("Crossborder Study"⁵) and filed in 6 the docket by TASC finds that the benefits of DG on the APS system exceed the costs, to the 7 extent that TASC recommends the creation of a System Benefit Credit mechanism to further 8 compensate DG customers beyond the existing NM incentive.

A recent report by the Electricity Innovation Lab and the Rocky Mountain Institute⁶ 9 29. reviewed 15 distributed PV ("DPV") benefit/cost studies that were prepared by utilities, national 10 laboratories, and other organizations. The goal of this study was to "...assess what is known and 11 unknown about the categorization, methodological best practices, and gaps around the benefits and 12 costs of DPV...". This study concluded that none of the 15 studies reviewed had comprehensively 13 evaluated the benefits and costs of DPV. The study further states that "There is a significant range 14 of estimated value across studies, driven primarily by differences in local context, input 15 assumptions, and methodological approaches." The study states that there is significant 16 disagreement over capacity value methodologies and the "...currently unmonetized values 17 including financial and security risk, environment, and social value." 18

30. Staff concludes that assignment of a Subjective Value to the presently unmonetized
components of DG value is a public policy issue. Such public policy decisions necessarily require
a subjective assignment of values consistent with policy goals.

- 31. Staff further concludes that the objective value aspects of DG to the APS system can
 best be determined in the context of a general rate case when all of APS's costs can be considered.
 Therefore, a precise determination of DG costs and benefits to APS's system is beyond the scope
 of Staff's analysis of the instant application. Instead, Staff has developed a range of proxy values
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⁶ Rocky Mountain Institute, A Review of Solar PV Benefit & Cost Studies, undated.

⁴ SAIC Energy, Environment & Infrastructure, LLC, 2013 Updated Solar PV Value Report, dated May 10, 2013, and filed in this docket May 17, 2013.

⁵ Crossborder Energy, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service*, dated May 8, 2013, and filed in this docket on July 2, 2013.

for DG as a basis for its alternative recommendations (see *Staff Recommendations* section below)
 which are intended to be bridge solutions that begin to address the cost-shift issue.

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3 32. Once the costs and benefits of DG have been adequately quantified and valued, the 4 allocation of these costs and benefits equitably among customers is a matter of rate design. 5 Recovery of fixed costs through volumetric rates may conflict with the intra-rate-class equity of 6 NM. Staff further notes that the equitable distribution of DG costs and benefits ideally requires all 7 NM customers to have some form of demand-based charges. Development of equitable rate 8 structures that address the inherent disconnect between NM and volumetric rates can best be 9 accomplished in a general rate case.

10 33. Staff notes that during general rate cases and as part of the rate design process, it is 11 common practice to analyze matters of cost-shifts and cross-subsidizations within individual rate classes. Some rate designs commonly utilize subsidies to promote various public policy goals. The 12 discount provided to low-income customers is a classic example of this intentional cross-subsidy. 13 Another common example is the subsidy given to rural customers at the expense of urban 14 15 customers to cover the higher cost of service to the more dispersed rural customers. Staff believes that the cross-subsidy discussed in the instant Application has explicit public policy 16 17 considerations, and therefore would be most appropriately addressed in the setting of a general rate 18 case.

19 Staff's Analysis of APS's Proposed Alternatives

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ETC-2 Plus NM Option

21 34. The ECT-2 Plus NM Option relies on a demand charge within the ECT-2 rate schedule to partially collect fixed costs. However, APS notes that because the ECT-2 rate also 22 partially relies on usage charges to collect fixed costs, this Option is an imperfect solution. In 23 addition, the ECT-2 Plus NM Option is not revenue neutral, as the rate's demand charge would 24 collect additional revenue. APS has not proposed a method by which all additional revenue would 25 be returned to non-DG ratepayers. In addition, Staff believes that forcing certain customers to use 26 27 a specific rate schedule removes a basic choice from the customer – the choice of the rate schedule 28

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that works best for their usage pattern and lifestyle. The impact of the ECT-2 Plus NM Option
 proposal to the average APS residential DG customer is presented below in Table I.

3 35. While Staff does not recommend the ECT-2 tariff for all solar customers, customers 4 that voluntarily select this rate should be exempt from any additional cost-shift surcharges as the 5 ECT-2 rate design addresses the collection of lost-fixed costs through a demand charge.

Bill Credit Options

7 36. The Bill Credit Option is very similar to a "buy all – sell all" Feed-In-Tariff ("FIT"), 8 which is quite different than a NM arrangement. FITs are typically implemented to incent 9 generation facilities with higher production output than is typically seen in residential DG, and are 10 more often directed towards Qualifying Facilities ("QF") as defined under Public Utility 11 Regulatory Policy Act ("PURPA"). Staff notes a docket filing by TASC⁷ that opines that a 12 residential FIT may have negative (and unexpected) tax implications for the residential FIT 13 customer.

14 37. The Bill Credit Option is not equivalent to a NM arrangement because it denies the 15 residential customer the right to offset energy purchases from the utility with self-generation on a 16 one-to-one basis. Staff believes that residential customers should have the ability to receive such 17 an offset. In addition, the Bill Credit Option is not revenue-neutral and APS again offers no 18 guidance on how additional revenues produced under this Option would be returned to non-DG 19 ratepayers.

38. The estimated bill impact of APS's two proposed options to the average APS residential DG customer is presented below in Table I. Note that in this Table, the terms "IB Rate" means inclining block rate, and "TOU E Rate" means time-of-use energy rate. These terms are intended to broadly describe the two basic types of residential rate designs utilized by APS.

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money into Arizona."

^{26 &}lt;sup>7</sup> See the letter filed August 16, 2013 in this docket from Skadden, Arps, et al filed by TASC that states in part: "Under current law, residential FITs jeopardize the Section 25D credit because electricity generated by such residential solar systems is sold to the utility, rather than used in a personal residence of the taxpayer. Further, payments received by a taxpayer under FITs are likely includable in taxable gross income." TASC summarizes this matter with the statement: 28 "…such a requirement will essentially exchange federal tax credits for federal taxes, reversing the existing flow of

1	Table I										
2					ted Customer Bill Impact						
	IP Pate		rrent NM Prop Winter			ed Option - EC			ed Option - Bil		
3	IB Rate Bill before solar (w/tax)	Summer \$275.22	\$ 115.91	Annual \$ 195.57	Summer \$ 275.22	Winter \$ 115.91	Annual \$ 195.57	Summer \$ 275.22	Winter \$ 115.91	Annual \$ 195.57	
4	Bill with solar	\$ 92.64	\$ 30.65	\$ 61.65	\$ 156.78	\$ 82.95	\$ 119.87	\$ 235.22	\$ 85.91	\$ 160.57	
5	Savings	\$182.58	\$ 85.26	\$ 133.92	\$ 118.44	\$ 32.96	\$ 75.70	\$ 40.00	\$ 30.00	\$ 35.00	
6	% savings	66.3%	73.6%	68.5%	43.0%	28.4%	38.7%	14.5%	25.9%	17.9%	
. 7	TOU E Rate Bill before	Summer	Winter	Annual	Summer	Winter	Annual	Summer	Winter	Annual	
8	solar (w/tax)	\$224.63	\$ 115.13	\$ 169.88	\$ 224.63	\$ 115.13	\$ 169.88	\$ 224.63	\$ 115.13	\$ 169.88	
9	Bill with solar Savings	\$ 72.19 \$ 52.44	\$ 40.48 \$ 74.65	\$ 56.34 \$ 113.55	\$ 156.78 \$ 67.85	\$ 82.95 \$ 32.18	\$ 119.87 \$ 50.02	\$ 184.63 \$ 40.00	\$ 85.13 \$ 30.00	\$ 134.88 \$ 35.00	
10	% savings	67.9%	64.8%	66.8%	30.2%	28.0%	29.4%	17.8%	26.1%	20.6%	
10	39. APS suggests that the continued use of UFIs could be used to help offset any										
12	slowdown in DG installations caused by APS-proposed NM cost-shift solution options. Staff										
13	believes that the level of UFI incentives should not be established in this docket, but rather in										
14	APS's annual Renewable Energy Standard Tariff ("REST") implementation plan.										
15	40. Both NM cost-shift solutions proffered by APS include provisions for										
16	"grandfathering" the NM situations of existing (and customers that apply before APS's suggested								uggested		
17	deadline of October 15, 2013) NM customers. Under APS's grandfathering concept, NM										
18	customers would maintain their existing rate constructs (i.e. a customer's existing rate and use of									nd use of	
19	NM) for a maximum of 20 years from the effective date of the Commission's decision in this								n in this		
20	matter and v	would no	ot be trans	ferable to a	a new cust	omer at th	ie same pr	emise.			
21	41.	Based	on the ar	alysis dis	cussed abo	ove, Staff	recomme	nds that th	ne Commi	ssion not	
22	approve eith	ner of AI	PS's propo	osed NM c	ost-shift s	olutions.					
23	42.	Staff	further re	commend	s that any	v consider	ation of	grandfathe	ering exist	ting NM	
24	situations to existing NM customers should view the grandfathering as pertaining to the DG										
25	system and premises where the DG system is sited (in other words, "runs with the land"), versus a										
26	"right" that resides with a specific customer.										
27											
28											
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1 **Stakeholder Proposals**

2 43. Three alternative cost-shift solution proposals have been received from intervenors in this case. The first alternative proposal was docketed on July 2, 2013, by TASC. TASC 3 4 proposes the creation of a System Benefit Credit to reward DG for the excess value that TASC 5 believes DG customers provide to the grid. The TASC proposal relies on the Crossborder study. 6 The TASC proposal suggests that credits could be either demand (kW) or energy (kWh) based and 7 would be paid over the life of the DG system, rather than upfront, in order to link the credit to the long-term performance of the DG system. The credit could be implemented through the existing 8 9 NM tariff, or through a new rate rider schedule, similar to APS's critical peak pricing rider (CPP-10 RES). TASC concludes its proposal by suggesting that details of the System Benefit Credit could 11 be developed collaboratively by the Commission, APS, TASC, and other stakeholders.

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44. Staff believes that establishing a System Benefit Charge outside a rate case would have to be established as part of the incentives available through the Renewable Energy Standard 13 Tariff ("REST") program. 14

15 45. The second alternative proposal was informally proffered to Staff by RUCO during 16 several meetings in late July and early August 2013. RUCO proposed the establishment of a market-based adjustor mechanism that links the value of DG to a defined set of market metrics. 17 18 Implementation of this cost adjustor would be through APS's REST Implementation Plan and 19 would be updated annually. RUCO states that this approach could be utilized by all utilities that 20 are subject to the Commission's REST Rules.

21 46. The third alternative proposal was proffered by IREC in its Protest filing. IREC 22 suggests that the Commission and stakeholders develop a common set of assumptions and inputs 23 regarding the costs and benefits of NM during APS's next general rate case. Utilizing the common 24 set of assumptions and data inputs, IREC suggests that a neutral third party, such as Clean Power 25 Research, be retained to model the benefits and costs of NM on the APS electric system. IREC asserts that this modeling would produce a fair and neutral set of data upon which the Commission 26 27 and stakeholders could rely to evaluate APS's NM program.

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47. Unfortunately the three suggested options set forth above present legal challenges
 that would be avoided if the Commission were to adopt one of Staff's recommended options
 discussed below.

4 48. Staff believes that the development of a common set of assumptions and inputs will
5 be fundamental in any future analysis of NM costs and benefits as in APS's next rate case.

The NM Cost-Shift Issue in Other Jurisdictions

49. Arizona is not unique in confronting the NM cost-shift issue. Currently, some form of NM has been adopted in 43 states. Several other states that have experienced relatively rapid penetration of customer-sited DG have recognized the cost-shift issue and addressed it in varying ways. A brief synopsis of several recent Public Utility Commission actions and utility company programs that have parallels to the cost-shift issue in Arizona, and that may help inform the Commission on its decision on the instant Application is located in Appendix I of this Order.

13 Staff Recommendations

50. Staff recommends that the Commission not approve either of the NM cost-shift solutions proffered by APS in the instant application for the reasons discussed above. Instead, Staff recommends that no changes be made at this time, but instead, this issue be evaluated during APS's next rate case. However, if the Commission wishes to address this issue immediately, Staff proposes two alternative recommendations as bridge solutions that begin to address the NM costshift issue until such time as the Commission is able to address the issue more completely in APS's next rate case.

21 Staff's Recommendation

22 Address in Next Rate Case

51. Staff believes that any cost-shift issue created by NM is fundamentally a matter of rate design. The appropriate time for designing rates that equitably allocate the costs and benefits of NM is during APS's next general rate case. Data on all of APS's costs are available within a rate case. In addition, the Commission has more options available within a rate case than it has outside of a rate case. Therefore, Staff recommends that the Commission take no action on the instant application and defer the matter for consideration during APS's next rate case.

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Staff further recommends that the Commission hold workshops with all stakeholders 1 52. to help inform future Commission policy on the value that DG installations bring to the grid. In 2 addition, Staff recommends that within the workshops, the Commission investigate the currently 3 4 non-monetized benefits of DG with the goal of developing a methodology for assigning DG values, as the NM cost-shift issue will be faced by all Arizona electric utilities as the penetration 5 level of DG increases in each of the company's individual service territories. The Commission 6 7 may achieve this goal by opening a generic docket to investigate the value of DG and hold 8 workshop meetings to obtain stakeholder input.

Staff believes this recommended course of action is the most effective and 9 53. appropriate method of dealing with the APS NM cost-shift issue. However, should the 10 Commission wish to apply the concept of rate-making gradualism to this matter, Staff offers the 11 following two alternative recommendations as bridge solutions that begin to address the NM cost-12 shift issue until the matter can be more comprehensively resolved in a future general rate case. 13

Additionally, Staff believes that its alternative recommendations, which both involve 14 54. adjustments to APS's Lost Fixed Cost Recovery ("LFCR") adjustor mechanism, lend themselves 15 16 to implementation outside of a rate case. The provisions regarding the LFCR, which was adopted by Decision No. 73183 (May 24, 2012), expressly acknowledge that the Commission may review 17 18 the LFCR and that suspension, termination or modification may result from such review. Likewise, Staff's two recommendations do not change the overall lost fixed cost revenues that 19 APS recovers through the LFCR adjustor mechanism. Rather, they adjust which customers pay 20 lost fixed costs through the LFCR. Consequently, Staff's two alternative recommendations are also 21 22 revenue neutral.

- Staff Recommended Alternative #1 23
- 24

LFCR Flat Charge for All New DG Customers

55. Staff's first recommended alternative utilizes APS's LFCR adjustor mechanism that 25 was approved by the Commission on May 24, 2012, under APS's last rate case Decision No. 26 73183. The LFCR adjustor provides for the recovery of lost fixed costs, as measured by revenue, 27 associated with the amount of energy efficiency savings and DG that is authorized by the 28

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1 Commission and determined to have occurred. Costs recovered through the LFCR include the 2 portion of transmission costs included in base rates and a portion of distribution costs, other than what is recovered by (1) the Basic Service Charge, and (2) 50 percent of demand revenues 3 4 associated with distribution and the base rate portion of transmission. The LFCR adjustment is calculated by dividing Lost Fixed Cost Revenue by the Applicable Company Revenues. This 5 6 adjustment percentage is applied to all customer bills, excluding both those on excluded rate 7 schedules and those that have chosen the Flat Charge of the standard LFCR calculation. The 8 LFCR adjustment collection is subject to an annual one-percent year over year cap based on 9 Applicable Company Revenue.

56. The LFCR adjustor provides a Flat Charge provision for customers that prefer to pay
through an optional Basic Service Charge. Rather than calculate the LFCR charge as a percentage
of a customer's total bill, the Flat Charge provision sets the LFCR charge, based on a customer's
kWh consumption, times the number of days in the month. Most customers (both with and
without DG) currently select the percentage of bill LFCR charge because it is currently less
expensive than the Flat Charge option. The LFCR Flat Charge tiered consumption rates are
presented in the following Table II:

17 18

Table II LFCR Flat Charge Rates

Total Monthly Metered kWh	Rate	R Flat Charge e (Per No. of vs in Billing Cycle)
0-400 kWh	\$	0.020
401-800 kWh	\$	0.040
801-2000 kWh	\$	0.092
2001 kWh and		
greater	\$	0.217

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57. The following Table III illustrates the difference between the LFCR percent of bill
charge and the LFCR Flat Charge for a typical APS customer. In this example, Staff assumes the
customer consumes 1,600 kWh during summer months and 900 kWh during winter months, or
14,200 kWh annually. This customer's average monthly consumption would therefore be 1,192

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kWh. The LFCR percent of bill charge is currently assessed at the rate of 0.2 percent of the 1 customer's monthly bill. For simplicity, the customer's monthly bill is presented before on-site 2 generation is netted from the bill. The LFCR Flat Charge is assessed at the tiered rates presented 3 above in Table II times the number of billing days in the month. For purposes of this example, a 4 5 30-day billing month is assumed.

Table III LFCR Monthly Charge Comparison

8 9	Rate Design Type	Average Monthly Bill	Average Monthly LFCR Percent of Bill	Average Monthly LFCR Flat Charge
		\$195.57 before solar	\$0.39	\$2.76
10	IB - Inclining Block	\$61.65 after solar	\$0.12	\$2.76
	TOU - Time of Use	\$169.88 before solar	\$0.34	\$2.76
11	Energy	\$56.34 after solar	\$0.11	\$2.76

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58. Staff proposes that the LFCR Flat Charge provision become mandatory for all new 13 APS DG customers, unless the customer chooses the ETC-2 rate. New DG customers would pay 14 into the LFCR account at the flat rates set in the LFCR, thereby reducing the aggregate LFCR 15 account needing to be repaid by non-DG customers. In this way, the LFCR Flat Charge provision 16 provides a revenue-neutral method of shifting a portion of the NM-shifted costs back to the 17 customer with newly-installed DG, and away from the non-DG customer. 18

Staff believes that the LFCR adjustor mechanism is an appropriate near-term bridge 59. 19 solution to APS's NM cost-shift issue as this adjustor was specifically designed to address lost 20 fixed costs. Staff notes that LFCR mechanisms have been approved by the Commission in several 21 recent electric and gas utility rate cases⁸. In addition, APS's LFCR mechanism was constructed 22 with a certain amount of flexibility that accommodates this proposal. 23

24 25

Staff has calculated the customer bill impact for Staff's Recommended Alternative 60. #1 for a hypothetical APS customer with DG and without DG and these results are presented

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⁸LFCR mechanisms have recently been approved by the Commission in these general rate cases: Tucson Electric 27 Power Company, Decision No.73912 (2013); APS, Decision No. 73732 (2012); and UNS Gas, Decision No. 73142 (2012). In addition, an LFCR mechanism is proposed in UNS Electric's Settlement Agreement, Docket No. E-28

⁰⁴²⁰⁴A-12-0504.

below in Table IV. For purposes of this example, Staff has utilized a customer consumption 1 2 profile depicting a summer consumption of 1,600 kWh / month and a winter consumption of 900 3 kWh / month.

				Staff Opti		I -LFCR Flat Charge	
	L Curr	ent NM Pro	gram		<u>Rate</u>		
IB Rate	Summer	Winter	Annual	Summer	Winter	Annual	
Bill before solar (w/tax)	\$275.22	\$115.91	\$195.57	\$275.22	\$115.91	\$195.5	
Bill with solar	\$92.64	\$30.65	\$61.65	\$95.47	\$31.90	\$63.6	
Savings	\$182.58	\$85.26	\$133.92	\$179.75	\$84.01	\$131.8	
% savings	66.3%	73.6%	68.5%	65.3%	72.5%	67.4%	
TOU E Rate	Summer	Winter	Annual	Summer	Winter	Annual	
Bill before solar (w/tax)	\$224.63	\$115.13	\$169.88	\$224.63	\$115.13	\$169.8	
Bill with solar	\$72.19	\$40.48	\$56.34	\$75.07	\$41.72	\$58.4	
Savings	\$152.44	\$74.65	\$113.55	\$149.56	\$73.41	\$111.4	
% savings	67.9%	64.8%	66.8%	66.6%	63.8%	65.6%	

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14 Staff Recommended Alternative #2 LFCR DG Premium for All New DG Customers 15

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As noted above, the various stakeholders that participated in the Technical 61. Conference had vastly differing estimates regarding the value of DG solar. In response to the 17 Crossborder Study's estimated value of 22 to 24 cent per kWh for DG solar, APS made the 18 following argument: Assuming, arguendo, that DG solar creates the value estimated in the 19 Crossborder Study, APS can replicate that value by interconnecting small 1 to 5 MW PV systems 20 at the subtransmission level throughout its distribution system utilizing wholesale purchase power 21 agreements ("PPA") at a significantly lower cost than acquiring the same amount of solar capacity 22 via DG. 23

Utilizing APS's rationale of acquiring the most value at the lowest cost, Staff's 62. 24 second recommended alternative would establish a cap on the NM incentive to ensure that it is no 25 26 greater than the price APS would pay to acquire the same amount of solar via a wholesale PPA. This would ensure that APS's non-DG customers attain the value of solar, at the lowest cost. The 27 LFCR DG Premium would be based on the difference between APS's cost for purchasing a DG 28

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customer's excess generation, and its cost to purchase an equivalent amount of energy from a
 wholesale PPA. The calculated difference would, in effect, establish the "DG Premium."
 63. The following example illustrates Staff's calculation of the DG Premium and

4 resultant charge for a hypothetical APS residential DG customer:

A. Customer DG System Size:	6.4 kW
B. Assumed Annual Rate of Production:	1,641 kWh / kW
C. Calculated Annual Production:	10,502 kWh (A x B)
D. Assumed Customer Retail Rate:	\$0.125/kWh
E. Annual Retail Cost of Production:	\$1,312.75 (C x D)
F. Assumed Utility Scale PPA Rate:	\$0.10/kWh
G. Annual PPA Cost of Production:	\$1,050.20 (C x F)
H. Annual DG Premium:	\$262.55 (E – G)
I. Monthly DG Premium:	\$21.88 (H/12)
J. LFCR DG Premium per kW:	\$3.42 (I/A)

64. Staff understands that utility scale solar PV generation can be obtained in Arizona
for between 7 and 10 cents per kWh under a PPA arrangement. Staff has picked conservative
values for the Assumed Retail Rate and the Assumed Utility Scale PPA Rate in the example
presented above. See Appendix III for examples of the DG Premium calculated using a range of
values for the retail rate and PPA rates. In the above example (6.4 kW DG system size), Staff
calculates the proposed DG Premium as \$3.42 / kW.

65. If the Commission chooses, it could implement the DG Premium on a gradual basis 18 so as to minimize the immediate impact on future DG customers. This could be done by initially 19 setting the DG Premium at \$2.75 / kW. The DG Premium calculated in the above example would 20 be the cap for the monthly charge under this Alternative. The Commission may wish to lower or 21 increase the DG Premium annually based on the effect it has on new DG installations. The 22 Commission may also wish to adopt an approach wherein the DG Premium is initially set at a 23 lower amount than that recommended by Staff, and phase-in the total DG Premium over a period 24 of years. 25

26 66. Staff has calculated the DG Premium for a range of DG system sizes, and this
27 information is presented in the following Table V:

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Table VMonthly DG Premium By DG System Size

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		A. Customer DG Sys	tem Size (kW)	4	6.4	8	10	12
;	I	3. Assumed Annual	Rate of Production (kWh)	1641	1641	1641	1641	1641
		C. Calculated Annua	al Production (kWh)	6,564	10,502.40	13,128	16,410	19,692
;	Γ	D. Assumed Custom	er Retail Rate (\$/kWh)	\$ 0.125	\$ 0.125	\$ 0.125	\$ 0.125	\$ 0.125
5	1	E. Annual Retail Co	st of Production	\$ 820.50	\$ 1,312.80	\$ 1,641.00	\$ 2,051.25	\$ 2,461.50
,	I	F. Assumed Utility	Scale PPA Rate (\$/kWh)	\$ 0.10	\$ 0.10	\$ 0.10	\$ 0.10	\$ 0.10
		G. Annual PPA Cost	of Production	\$ 656.40	\$ 1,050.24	\$ 1,312.80	\$ 1,641.00	\$ 1,969.20
3		H. Annual DG Premi	um	\$ 164.10	\$ 262.56	\$ 328.20	\$ 410.25	\$ 492.30
		. Monthly DG Pre	mium	\$ 13.68	\$ 21.88	\$ 27.35	\$ 34.19	\$ 41.03

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67. Staff proposes that the LFCR DG Premium be collected through the LFCR.
Relatively minor modifications would be required to the LFCR Plan of Administration to
implement collection of the DG Premium.

14 68. New DG customers would pay into the LFCR account at the DG Premium
15 established by the Commission, thereby reducing the aggregate LFCR account needing to be
16 repaid by non-DG customers. In this way, the LFCR DG Premium provision provides a revenue17 neutral method of shifting a portion of the NM shifted costs back to the customer with newly18 installed DG, and away from the non-DG customer.

19 69. Staff has calculated the customer bill impact for Staff's Recommended Alternative
20 #2 for APS customer with DG (6.4 kW DG system size and estimated consumption of 1,600
21 kWh/month in Summer and 900 kWh / month in Winter) and without DG and these results are
22 presented below in Table VI.

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Table VI
Estimated Bill Impacts from Staff's Recommended Alternative #2

	Curre	Current NM Program			Staff Option 2 -Standby Cap. Cha		
IB Rate	Summer	Winter	Annual	Summer	Winter	Annual	
Bill before solar (w/tax)	\$275.22	\$115.91	\$195.57	\$275.22	\$115.91	\$195.57	
Bill with solar	\$92.64	\$30.65	\$61.65	\$108.64	\$46.65	\$77.65	
Savings	\$182.58	\$85.26	\$133.92	\$166.58	\$69.26	\$117.92	
% savings	66.3%	73.6%	68.5%	60.5%	59.8%	60.3%	

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TOU E Rate	Summer	Winter	Annual	Summer	Winter	Annual
Bill before solar (w/tax)	\$224.63	\$115.13	\$169.88	\$224.63	\$115.13	\$169.88
Bill with solar	\$72.19	\$40.48	\$56.34	\$88.19	\$56.48	\$72.34
Savings	\$152.44	\$74.65	\$113.55	\$136.44	\$58.65	\$97.55
% savings	67.9%	64.8%	66.8%	60.7%	50.9%	57.4%

5 70. Staff believes that any DG customers that are presently taking service under the 6 ECT-2 rate should be allowed to remain on the ECT-2 rate and be exempt from either of Staff's 7 Recommended Alternatives, should they decide to install a DG system prior to APS's next general 8 rate case.

9 Grandfathering

10 71. If the Commission chooses either Staff Alternative #1 or Staff Alternative #2 (or 11 any form of either), Staff recommends that any residential customers who either have a DG system 12 installed on their homes now, or who submit an application and a signed contract with a solar 13 installer to APS by October 31, 2013, be grandfathered under the current NM policies. Staff 14 further recommends that any consideration of grandfathering existing NM situations should view 15 the grandfathering as pertaining to the DG system and premises where the DG system is sited (in 16 other words "runs with the land"), versus a "right" that resides with a specific customer.

17 Staff's Proposed Consumer Protection Advisory

18 72. Regardless of which option the Commission chooses, Staff recommends that APS
19 be directed to separate and isolate on a separate page of the Interconnection Agreement⁹ the
20 existing language found on Page 9, Paragraph 10.6, of said agreement, plus Staff's additional
21 language, as shown in Appendix IIA.

Staff makes this recommendation in an attempt to ensure that customers purchasing
and installing PV systems on their premises are fully aware that current rates applying to their PV
system are not permanent. If the Commission believes the language contained in Appendix IIA is
too onerous in tone, Staff recommends the language in Appendix IIB.

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28 ⁹ See APS's Interconnection Agreement posted at <u>http://www.aps.com/library/solar%20renewables/ResInterconnAgreeSample.pdf</u>)

	Page 21 Docket No. E-01345A-13-0248
1	CONCLUSIONS OF LAW
2	1. Arizona Public Service Company is an Arizona public service corporation within
3	the meaning of Article XV, Section 2, of the Arizona constitution.
4	2. The Commission has jurisdiction over Arizona Public Service Company and over
5	the subject matter of the application.
6	3. The Commission, having reviewed Arizona Public Service Company's application
7	and Staff's Memorandum dated September 30, 2013, concludes that addressing the net metering
8	cost-shift issue would benefit from a detailed analyses of the costs and benefits of distributed
9	generation systems, and therefore, it is in the public interest to consider this issue in Arizona
10	Public Service Company's next general rate case.
11	ORDER
12	IT IS THEREFORE ORDERED that the Commission will take no action on the instant
13	application and defer the matter for consideration during Arizona Public Service Company's next
14	rate case.
15	IT IS FURTHER ORDERED that the Commission will open a generic docket on the net
16	metering issue and hold workshops with all stakeholders to help inform future Commission policy
17	on the value that DG installations bring to the grid.
18	IT IS FURTHER ORDERED that the workshops shall investigate the currently non-
19	monetized benefits of DG with the goal of developing a methodology for assigning DG values, as
20	the NM cost-shift issue will be faced by all Arizona electric utilities as the penetration level of DG
21	increases in each of the company's individual service territories.
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1	IT IS FURTHER ORDERED that Arizona Public Service Company shall separate and							
2	isolate on a separate page of its Interconnection Agreement the existing language found on Page 9,							
3	Paragraph 10.6, of said agreement, plus Staff's additional language, as shown in Appendix IIA.							
4	IT IS FURTHER ORDERED that this Order shall become effective immediately.							
5								
6	BY THE ORDER OF	BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION						
7								
8	CHAIRMAN	COMM	IISSIONER					
9								
10								
11	COMMISSIONER	COMMISSIONER	COMMISSIONER					
12								
13			, I, JODI JERICH, Executive Corporation Commission, have					
14		hereunto, set my hand and	caused the official seal of this at the Capitol, in the City of					
15		Phoenix, this day of	f, 2013.					
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17								
18		JODI JERICH EXECUTIVE DIRECTOR						
19		DALCOTIVE DIRECTOR						
20	DISSENT:							
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	Page 23	Docket No. E-01345A-13-0248
1	SERVICE LIST FOR: Arizona Public Service Con	mpany
2	DOCKET NO. E-01345A-13-0248	
3		
	Mr. Kevin Fox	Mr. Court Rich
4	Ms. Erica Schroeder Mr. Tim Lindl	Rose Law Group 6613 N. Scottsdale Rd., Ste. 200
5	Keyes, Fox & Wiedman LLP	Scottsdale, Arizona 85250
C	436 14th St 1305	
6	Oakland, California 94612	Ms. Patty Ihle
7	Mr. Timothy Hogan	304 E. Cedar Mill Rd Star Valley, Arizona 85541
8	Arizona Center for Law in the Public Interest	Star Vancy, Arizona 65541
-	202 E. McDowell Rd 153	Mr. Hugh Hallman
9	Phoenix, Arizona 85004	Hallman & Affiliates, PC
10	Mr. Thomas Loquvam	2011 N. Campo Alegre Rd 100 Tempe, Arizona 85281
11	Ms. Deborah R. Scott	Tempe, Arizona 65261
11	Pinnacle West Capital Corporation	Mr. John Wallace
12	400 N. 5Th St, MS 8695	2210 South Priest Dr
13	Phoenix, , Arizona 85004	Tempe, Arizona 85282
	Mr. Michael Patten	Mr. Lewis Levenson
14	Mr. Jason Gellman	1308 E. Cedar Lane
15	Roshka DeWulf & Patten, PLC One Arizona Center	Payson, Arizona 85541
16	400 E. Van Buren St 800	Mr. Bradley Carroll
17	Phoenix, Arizona 85004	Ms. Kimberly A. Ruht
1/	Mr. Greg Patterson	88 E. Broadway Blvd. MS HQE910 P.O. Box 711
18	916 W. Adams - 3	Tucson, Arizona 85702
19	Phoenix, Arizona 85007	
		Mr. Todd Glass
20	Mr. Daniel Pozefsky RUCO	Mr. Keene M. O'Connor Wilson Sonsini Goodrich & Rosati, PC
21	1110 West Washington, Suite 220	701 Fifth Ave 5100
22	Phoenix, Arizona 85007	Seattle, Washington 98104
23	Mr. Giancarlo Estrada	Mr. David Berry
	Estrada-Legal, PC	Western Resource Advocates
24	One E. Camelback Rd, - 550 Phoenix, Arizona 85012	PO Box 1064 Scottsdale AZ 85252-1064
25		
26	Mr. Garry Hays	Mr. Mark Holohan, Chairman
27	1702 E. Highland Ave 204 Phoenix, Arizona 85016	Arizona Solar Energy Industries Association 2221 West Lone Cactus Drive, Suite 2
		Phoenix, Arizona 85027
28	· · · · ·	

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	Dama 24	Destrot No. E 01245 A 12 0249
	Page 24	Docket No. E-01345A-13-0248
1	Ms. Anne Smart, Exec. Director Alliance for Solar Choice	
2 3	45 Fremont Street, 32nd Floor San Francisco, CA 94105	
4	Mr. Steven M. Olea	
5	Director, Utilities Division Arizona Corporation Commission	
6	1200 West Washington Street Phoenix, Arizona 85007	
7	Ms. Janice M. Alward	
8	Chief Counsel, Legal Division Arizona Corporation Commission	
9	1200 West Washington Street Phoenix, Arizona 85007	
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<u>California</u>

The California State Legislature passed Assembly Bill 2514¹⁰ in September 2012 that directed the California Public Utilities Commission ("CPUC") to complete a study analyzing the full costs and benefits of the state's NM program. The bill further requires the CPUC to determine the extent to which NM customers pay for the full costs of electric services provided by the utilities. Specifically, the bill requires a study "...to determine who benefits from, and who bears the economic burden, if any, of the net energy metering program, and to determine the extent to which each class of ratepayers and each region of the state receiving service under the net energy metering program is paying the full cost of the services provided to them by electrical corporations, and the extent to which those customers pay their share of the costs of public purpose programs." The CPUC is required to complete the report by October 1, 2013, and deliver the results of the report to the Legislature within 30 days of its completion.

A second California State Legislature bill, AB 327, was recently passed by the state Assembly and forwarded to the California Governor for signature. This bill addresses residential electric rate reforms and provides a vehicle for extending the state's solar NM program, which otherwise faced expiration in 2014. The bill sets up a specific process for developing a new state-wide NM program. In addition, the bill authorizes the CPUC to: (1) lower the ramp on California's tiered energy rates; (2) increase monthly customer charges by up to \$10 per month; and (3) clarifies the methodology of calculating each utility company's NM capacity cap.

<u>Idaho</u>

On November 30, 2012, Idaho Power Company ("IPC") applied to the Idaho Public Utilities Commission ("IPUC") to modify its NM service. IPC's application requested that IPUC approve four changes to IPC's NM service:

- 1. <u>Increasing the NM capacity cap</u>. IPC requested that the ceiling for the amount of NM capacity be raised from 2.9 megawatts ("MW") to 5.8 MW.
- 2. <u>Changing the NM pricing structure</u>. IPC proposed to change the NM pricing structure for residential and small general service customers from a system of full retail payment for customer generated power. IPC stated that paying the full retail energy rate to NM customers enables NM customers to unduly reduce what they pay IPC for its costs associated with the non-generation-related components of IPC's revenue requirement. IPC further stated that this situation is unfair to standard service customers, who must then compensate IPC for any revenue shortfall.

IPC proposed to reduce this inequity by removing recovery of all distribution-related fixed costs from the energy charge and the creation of two new NM tariffs, one for the residential class and one for the small general service class. The new tariffs would (1) increase the monthly service charge from \$5.00 to \$22.49 for residential service and from \$5.00 to \$22.49 for small general service; (2) set up a basic load capacity charge ("BLC") of \$1.48.per kW for residential service and \$1.37 per kW for small general service to

¹⁰ See bill text at http://legiscan.com/CA/text/AB2514/id/665151

reflect the full cost-of-service associated with their use of the distribution system; and (3) uniformly reduce the energy charges for residential and small general service to target the same level of total revenue recovery that would exist under the standard service rate design.

- 3. <u>Changing how excess net energy is billed</u>. IPC proposed to stop paying customers for excess net energy and instead provide them with a kWh credit for the excess energy they generate in each billing period. The credit would carry forward until the end of the December billing period at which time any remaining credits would expire.
- 4. <u>Changing tariff provisions regarding interconnection with NM customers</u>. IPC proposed to better define the NM application process and address unauthorized NM installations.

The IPUC reviewed IPC's application at a public hearing held on June 11, 2013. At this hearing, the IPUC entered an order that:

- 1. Declined to increase the NM cap and instead directed IPC to periodically report on its NM service;
- 2. Declined to modify the NM pricing structure or move residential and small general service customers into new classes;
- 3. Required IPC to issue a per kWh credit for excess generation, with credits to expire only when the customer ends service; and
- 4. Approved revised NM interconnection language.

Louisiana

The Louisiana Public Service Commission ("LPSC") first established rules for NM in November 2005. The LPSC revisited the NM rules in 2011 and made several changes to the rules including a requirement that the LPSC review the rules at such time as a utility's purchase of NM energy reached 0.5 percent of its jurisdictional peak load. The LPSC re-opened the docket in late 2011 to address issues of meter aggregation, and cross-subsidization by non-NM customers. A proposed recommendation was issued by LPSC Staff in November 2012, recommending that in order to remedy the "purchased power subsidy" occurring when a NM customer is credited at retail rate for energy supplied to the grid, the NM customer should only be compensated at the utility's avoided cost, similar to the treatment of Qualifying Facilities ("QFs") under the Public Utility Regulatory Policy Act ("PURPA").

As related to the cross-subsidization issue, the LPSC Staff Report identified three separate subsidies provided to NM customers. These subsidies were categorized as a subsidy for installation (of NM equipment), a purchased power subsidy, and distribution system cost recovery. The Staff Report included recommendations to address each of the indentified subsidies as follows:

1. Utilities should begin charging the incremental difference between the cost of a standard electric meter and a net meter;

- 2. After stating that LPSC Staff believes it is inappropriate to require electric utilities to purchase wholesale power from NM customers at retail rates, LPSC Staff offers four Options to address the purchased power subsidy:
 - a. Option 1 <u>An excess NM generation rate less than the utility's avoided</u> <u>cost</u>. Under this Option customers would be compensated at a rate \$0.01 less than avoided cost to reflect the fact that NM energy is not dispatchable.
 - b. Option 2 <u>An excess NM generation rate equal to avoided cost</u>. Rationalized as the rate that best recognizes the offsetting impacts of nondispatchable energy from NM customers against the benefits of sharply reduced line losses from NM generators.
 - c. Option 3 <u>An excess NM generation rate above avoided cost, but less</u> <u>than retail.</u> Values the reduced line losses and locational attributes of NM at a recommended \$0.01per kWh premium above avoided cost.
 - d. Option 4 <u>An excess net meter generation rate equal to the retail rate (i.e.</u> the existing NM situation). The LPSC Staff note that the cost of NM energy is included in the utility's fuel adjustor and charges to all customers.
- 3. With regard to distribution cost subsidies, the LPSC Staff recommended that the LPSC wait until the next rate case for each utility before specifically addressing this category of subsidy. However, LPSC staff noted that the most efficient way to alleviate distribution cost subsidies might be to rely less on energy usage rates and instead appropriately adjust the monthly customer charges.

On July 26, 2013, the LPSC ordered that if a utility's NM purchases exceed 0.5 percent of its LPSC jurisdictional peak load, the utility no longer has to accept NM applications. Although LPSC discussed other aspects of its staff's recommendation, the LPSC took no further action.

Virginia

In July 2011, a Virginia state law took effect that allows power companies to collect a standby charge from customers with home NM systems of 10 kilowatts or larger. Dominion Virginia Power ("Dominion") subsequently filed an application with the Commonwealth of Virginia State Corporation Commission ("SCC") to implement such a standby charge. Dominion proposed a standby charge of \$4.19 / kW for a DG customer's average peak usage each month for customer systems sized between 10 and 20 kW. Dominion estimated that the average monthly standby charge would be approximately \$59.55 per month for a 20 kW¹¹ DG system. The standby charge would be in addition to the standard \$7 monthly connection fee assessed to all customers. The average retail electric rate for such DG customers is approximately 0.11 / kWh. Dominion noted in its application to SCC that the new standby charge would apply to one customer (at the time of the application). Staff has received anecdotal

¹¹Virginia state law limits the maximum size of residential NM systems to 20 kW.

information that there are now four Dominion customers that are subject to this standby charge. The SCC approved Dominion's application in November 2011.

Austin Energy (City of Austin, TX)

Austin Energy ("AE") which provides service to the greater Austin, Texas area takes an unusual approach to valuing the benefits of DG solar installations within its service territory. In October 2012, AE implemented a new production-based incentive, in the form of a residential solar rider tariff that acts as an alternative to NM. This rider applies to any customer receiving residential electric service who owns and operates an on-site solar photovoltaic system with a capacity of 20 kW or less that is interconnected with Austin Energy's electric distribution system.

Billable kWh under this rate schedule are based on the customer's total energy consumption during the billing month, including energy delivered by Austin Energy's electric system and energy consumed from an on-site solar system. All non-kWh-based charges under this rate schedule remain unaffected by the application of this rider.

For each billing month, the customer receives a non-refundable credit equal to the metered kWh output of the customer's photovoltaic system, times the current Value-of-Solar Factor plus any carry-over credit from the previous billing month. The Value-of-Solar Factor was initially set at \$0.128 per kWh, and is administratively adjusted annually, beginning with each year's January billing month, based upon the marginal cost of displaced energy, avoided capital costs, line loss savings, and environmental benefits. Any amount of solar credit in excess of the customer's total charges for electric service under the residential rate schedule shall be carried forward and applied to the customer's next electric bill. The customer's carry-over credit, if any, shall be reset to zero in the first billing month of each calendar year.

To explain its unique approach to valuing solar DG, and its concerns with traditional NM approaches, AE states:

"Austin Energy's solar energy incentive programs seek value parity between distributed solar PV options and so-called "conventional generation" options. Austin Energy's approach therefore differs significantly from the traditional "grid parity" objective of equivalent levelized cost of energy between solar and the average utility cost of energy from fully commercialized conventional resources. The goal for Austin Energy is parity in value, not just cost. Beginning with the federal Public Utility Regulatory Act passed by Congress in 1978, utilities generally paid an "avoided cost" value for customer-generated energy, typically set at the marginal price of fuel for an incremental unit of energy. Many states implemented NM policies as an improvement over traditional marginal avoided cost approaches for valuing distributed solar generation, in order to reflect the added value of energy generated at or near the point of consumption. While NM represents a significant improvement in reflecting the value of distributed solar energy compared to the avoided cost approach, problems remain. First, the retail price paid by the customer and credited for solar energy under NM (the value of "spinning the meter backwards") does not necessarily represent and likely underrepresents the full value of distributed solar generation."

"Second, NM induces two unintended consequences:

- 1. Solar customers size their solar systems against their baseload level of energy consumption because NM systems typically pay the old avoided cost value for excess generation. This is a practical reflection of the fact that solar capacity is fairly expensive and that excess generation rewards the customer at a very low rate. Of course, most of a solar system's excess generation is delivered to the utility at a time when the value of that energy often greatly exceeds the avoided cost rate.
- 2. NM value is coupled with consumption. That is, the value to the customer for a kWh of solar energy that offsets a unit of energy consumption is much greater that (sic) the value of excess generation, which is only credited at the avoided cost rate. Austin Energy's experience is that many solar customers recognize and respond to this signal to use more energy, based upon some sense that their consumption is "free" when a solar system is installed."

"Austin Energy designed its new "value of solar" rate to address these unintended consequences and offer an improved, decoupled NM approach."¹²

AE developed a PV Solar Value Calculator ("Calculator") that it uses to annually calculate the Value-of-Solar Factor for application in its production-based incentive. The Calculator is an algorithm that factors in values for system losses, energy savings, generation capacity savings, fuel price hedge value, T&D capacity savings, environmental benefits, and the impacts of nodal pricing in the Electric Reliability Council of Texas ("ERCOT") market.

¹² Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator, Rabago, Norris et al

APPENDIX IIA Docket No. E-01345A-13--0248

DISCLAIMER POSSIBLE FUTURE RULES and/or RATE CHANGES EFFECTING YOUR ROOFTOP PHOTOVOLTAIC SYSTEM

The following is a supplement to Paragraph 10.6 of the Interconnection Agreement ("Agreement") you signed with Arizona Public Service Company ("APS"):

I understand that notwithstanding any other provisions of this Agreement, Arizona Public Service Company ("APS") may file with the Arizona Corporation Commission ("Commission"), pursuant to the Commission's rules and regulations, an application for a change in the requirements, charges, classification, or service, and any rule or regulation relating to APS's interconnection with my rooftop photovoltaic system. In other words, I understand that in the future, upon application by APS or at the Commission's own initiative, the Commission may alter APS's rates, rules or regulations concerning rooftop photovoltaic systems which may affect the cost and/or savings relating to my rooftop photovoltaic system.

By signing below, I acknowledge that I have read and understand the above disclaimer.

Print Name

Signature

Date

DISCLAIMER POSSIBLE FUTURE RULES and/or RATE CHANGES EFFECTING YOUR ROOFTOP PHOTOVOLTAIC SYSTEM

The following is a supplement to Paragraph 10.6 of the Interconnection Agreement ("Agreement") you signed with Arizona Public Service Company ("APS"):

I understand that notwithstanding any other provisions of this Agreement, APS may file with the Arizona Corporation Commission ("Commission"), pursuant to the Commission's rules and regulations, an application for a change in the requirements, charges, classification, or service, and any rule or regulation relating to this rooftop photovoltaic system, as all utility customers are subject to such changes relating to their energy service. The Commission may also, of its own initiative, alter the rates, rules or regulations that pertain to this rooftop photovoltaic system.

By signing below, I acknowledge that I have read and understand the above disclaimer.

Print Name

Signature

Date

10,502 kwh (A*B) \$0.125 /kwh kWh/kW

6.4 kW

1,641

6.4 kW 1,641 kWh/kW 10,502 kWh (A*B)

\$1,312.80 (C*D) \$0.07 /kwh \$735.17 (C*F) \$577.63 (E-G) \$48.14 (H/12)

 A. Customer DG System Size

 B. Assumed Annual Rate of Production

 C. Calculated Annual Production

 D. Assumed Custer Rate

 E. Annual Retail Cost of Production

 F. Assumed Utility Scale PPA Rate

 G. Annual PPA Cost of Production

 H. Annual OC Premium

 H. Annual OC Premium

 J. Monthly LCK DG Premium

\$0.125 /kWh \$1,312.80 (C*D) \$0.08 /kWh \$840.19 (C*F) \$472.61 (E-G) \$39.38 (H/12)

 A.
 Customer DG System Size

 B.
 Assumed Annual Rate of Production

 B.
 Assumed Customer Retail Rate

 D.
 Assumed Customer Retail Rate

 E.
 Annual Retail Cost of Production

 F.
 Assumed Customer Retail Rate

 F.
 Annual Retail Cost of Production

 F.
 Assumed Utility Scale PPA Rate

 Annual Retail Cost of Production
 Homorphy LFCR DG Fremium

 I.
 Monthly LFCR DG Fremium

10,202 kWh/kW 10,502 kWh (A*B) \$0,125 /kWh \$1,312.80 (C*D) \$0,09 /kWh

6.4 kW

\$945.22 (C*F) \$367.58 (E-G) \$30.63 (H/12) \$4.79 (I/A)

\$6.15 (I/A)

\$7.52 (I/A)

1641 kWh/kW

\$0.125 Assumed Annual Rate of Production Retail Rate

k	A. Customer DG System Size	6.4	6.4 kW	Ŕ	A. Customer DG System Size
	B. Assumed Annual Rate of Production	1,641	1,641 kwh/kw	æi	B. Assumed Annual Rate of Production
ن	C. Calculated Annual Production	10,502	10,502 kWh (A*B)	ن	. Calculated Annual Production
o	D. Assumed Customer Retail Rate	\$0.125 /kWh	/kWh	ġ	. Assumed Customer Retail Rate
ш	E. Annual Retail Cost of Production	\$1,312.80 (C*D)	(C*D)	ш	E. Annual Retail Cost of Production
ш	F. Assumed Utility Scale PPA Rate	\$0.10	\$0.10 /kWh	F.	. Assumed Utility Scale PPA Rate
υ	G. Annual PPA Cost of Production	\$1,050.24 (C*F)	(C*F)	ۍ	G. Annual PPA Cost of Production
Ī	H. Annual DG Premium	\$262.56 (E-G)	(E-G)	ŗ	H. Annual DG Premium
	Monthly LFCR DG Premium	\$21.88	\$21.88 (H/12)		Monthly LFCR DG Premium
-	1. Monthly LECR DG Premium Per kW	\$3.42 (I/A)	(I/A)	J.	 Monthly LFCR DG Premium Per kW
]	

Monthly LFCR DG Premium Per kW

Assumed Annual Rate of Production **Retail Rate**

1641 kwh/kw

\$0.130

L					Custom DC Custom Ciao
¢	A. Customer DG System Size	6.4 KW	Ň	ť	A. LUSTOTIEL DU SYSTEILI SIZE
l mi	B. Assumed Annual Rate of Production	1,641	1,641 kWh/kW	щ	Assumed Annual Rate of Production
ن ا	C. Calculated Annual Production	10,502	10,502 kWh (A*B)	ن	Calculated Annual Production
d	D. Assumed Customer Retail Rate	\$0.130 /kWh	/kwh	o.	D. Assumed Customer Retail Rate
ني	E. Annual Retail Cost of Production	\$1,365.31 (C*D)	(C*D)	ш	E. Annual Retail Cost of Production
u.	F. Assumed Utility Scale PPA Rate	\$0.10	\$0.10 /kWh	u.	Assumed Utility Scale PPA Rate
6	G. Annual PPA Cost of Production	\$1,050.24 (C*F)	(C*F)	ى	G. Annual PPA Cost of Production
Í	H. Annual DG Premium	\$315.07 (E-G)	(E-G)	ŗ	H. Annual DG Premium
	Monthly LFCR DG Premium	\$26.26 (H/12)	(H/12)		Monthly LFCR DG Premium
-	J. Monthly LFCR DG Premium Per kW	\$4.10 (I/A)	(i/A)	l.	Monthly LFCR DG Premium Per kW

1641 kWh/kW
Assumed Annual Rate of Production

\$0.135	
Retail Rate	

6.4 kW 1,641 kWh/kW 10,502 kWh (A*B)

\$0.135 /kWh \$1,417.82 (C*D) \$0.07 /kWh \$735.17 (C*F)

 A. (customer DG System Size

 B. Assumed Annual Rate of Production

 D. Calculated Annual Production

 D. Assumed Customer Retail Rate

 E. Annual Retail Cost of Production

 F. Annual Retail Cost of Production

 F. Annual Retail Cost of Production

 F. Annual Retail Cost of Production

 H. Annual DG Premium

 I. Monthly LCR DG Premium Per kW

6.4 Krv 1.64 Krv 1.64 Krvh(W 30.135 (Kvh (A*B) 50.135 (Kvh 51.417.82 (C*D) 50.135 (Kvh 58.0.19 (C*F) 58.0.19 (C*F) 58.0.19 (C*F) 58.0.19 (H/12) 58.0.19 (H/12)

 A.
 Customer DG System Size

 8.
 Assumed Amual Rate of Production

 9.
 Calculated Amual Production

 0.
 Calculated Amual Production

 0.
 Calculated Amual Production

 0.
 Assumed Customer Retail Rate

 1.
 Assumed Utility Scale PPA Rate

 6.
 Amual Retail Cost of Production

 1.
 Monthly LCR DG Premium

\$945.22 (C*F) \$472.61 (E-G) \$39.38 (H/12) \$6.15 (I/A)

1,641 kWh/kW 10,502 kWh (A*B)

6.4 kW

\$0.135 /kWh \$1,417.82 (C*D) \$0.09 /kWh

\$56.89 (H/12) \$8.89 (I/A)

\$682.66 (E-G)

1,641 kWh/kW 10,502 kWh (A*B) \$0.130 /kWh \$1,365.31 (C*D)

6.4 kW

\$0.07 /kWh

 A.
 Customer DG System Size

 B.
 Assumed Amual Rate of Production

 D.
 Calculated Amual Production

 D.
 Assumed Customer Retail Rate

 D.
 Assumed Customer Retail Rate

 E.
 Amual Retail Cost of Production

 F.
 Assumed Utility Scale PPA Rate

 G.
 Annual DC Premium

 I.
 Monthly LFCR DG Premium

\$1,365.31 (C*D) \$0.08 /kWh \$840.19 (C*F) \$525.12 (E-G)

 A.
 Customer DG System Size

 B.
 Assumed Annual Rate of Production

 C.
 Calculated Annual Rate of Production

 D.
 Annual Retail Cost of Production

 D.
 Annual Retail Cost of Production

 D.
 Annual Retail Cost of Production

 F.
 Annual Retail Cost of Production

 F.
 Annual Production

 F.
 Annual Post of Production

 H.
 Annual Post of Premium

 I.
 Monthly LFCR OG Premium

\$1,365.31 (C*D) \$0.09 /kWh \$0.130 /kWh

\$43.76 (H/12) \$6.84 (I/A)

\$945.22 (C*F) \$420.10 (E-G) \$35.01 (H/12) \$5.47 (I/A)

1,641 kWh/kW 10,502 kWh (A*B)

6.4 kW 1,641 kWh/kW 10,502 kWh (A*B)

6.4 kW

\$0.130 /kWh

\$735.17 (C*F)

\$630.14 (E-G) \$52.51 (H/12) \$8.21 (I/A)

Ŕ	A. Customer DG System Size	6.4 kW	kw	4	A. Customer DG System Size
8	Assumed Annual Rate of Production	1,641	1,641 kWh/kW	ai.	B. Assumed Annual Rate of Production
ن	C. Calculated Annual Production	10,502	10,502 kWh (A*B)	ن	C. Calculated Annual Production
d	D. Assumed Customer Retail Rate	\$0.135 /kWh	/kWh	0	D. Assumed Customer Retail Rate
L ui	E. Annual Retail Cost of Production	\$1,417.82 (C*D)	(c*D)	ш	E. Annual Retail Cost of Production
L LL	F. Assumed Utility Scale PPA Rate	\$0.10	\$0.10 /kWh	u.	F. Assumed Utility Scale PPA Rate
U U	G. Annual PPA Cost of Production	\$1,050.24 (C*F)	(C*F)	σ	G. Annual PPA Cost of Production
1 I	H. Annual DG Premium	\$367.58 (E-G)	(E-G)	Ξ	H. Annual DG Premium
-	Monthly LFCR DG Premium	\$30.63 (H/12)	(H/12)	<u>-</u>	Monthly LFCR DG Premium
	Monthly LFCR DG Premium Per kW	(I/A) \$4.79	(I/A)	<u> </u>	 Monthly LFCR DG Premium Per kW
]	Assumed Annual Rate of Production	1641	1641 kWh/kW		

of Production
Rate
Annual
Assumed

Production	
Annual Rate of P	il Rate
I Annual	Retail
nmed	

\$0.140

ď	A. Customer DG System Size	6.4	6.4 kW
B	Assumed Annual Rate of Production	1,641	1,641 kWh/kW
ن ا	C. Calculated Annual Production	10,502	10,502 kwh (A*B)
l di	Assumed Customer Retail Rate	\$0.140 /kWh	/kWh
Ŀ.	Annual Retail Cost of Production	\$1,470.34 (C*D)	(c*D)
1	Assumed Utility Scale PPA Rate	\$0.10	\$0.10 /kWh
ۍ ا	Annual PPA Cost of Production	\$1,050.24 (C*F)	(C*F)
÷	Annual DG Premium	\$420.10 (E-G)	(E-G)
<u> </u>	Monthly LFCR DG Premium	\$35.01	\$35.01 (H/12)
	Monthly LFCR DG Premium Per kW	\$5.47 (I/A)	(I/A)

k	Customer DG System Size	6.4	6.4 kW	4	
6	Assumed Annual Rate of Production	1,641	1,641 kWh/kW	æ	
ن ا	Calculated Annual Production	10,502	10,502 kWh (A*B)	ن	
1.	Assumed Customer Retail Rate	\$0.140 /kWh	/kWh	۵	٩.
1	Annual Retail Cost of Production	\$1,470.34 (C*D)	(c*D)	<u>ш</u> і	
I .	Assumed Utility Scale PPA Rate	\$0.09	\$0.09 /kWh	<u> </u>	
υ	Annual PPA Cost of Production	\$945.22 (C*F)	(C*F)	G	
Ŧ	Annual DG Premium	\$525.12 (E-G)	(E-G)	T	
	Monthly LFCR DG Premium	\$43.76	\$43.76 (H/12)	÷	
	Monthly LFCR DG Premium Per kW	\$6.84 (I/A)	(I/A)	<u></u>	~

					[
6.4 kW	kw	4	A. Customer DG System Size	6.4 kw	Ä	A. Customer DG System Size
141	641 kwh/kw	6	B. Assumed Annual Rate of Production	1,641 kWh/kW		B. Assumed Annual Rate of Production
6	502 kWh (A*B)	ں إن	C. Calculated Annual Production	10,502 kWh (A*B)		C. Calculated Annual Production
140	140 /kWh		Assumed Customer Retail Rate	\$0.140 /kWh		D. Assumed Customer Retail Rate
0.34	0.34 (C*D)	<u> </u> <u>u</u> i	E. Annual Retail Cost of Production	\$1,470.34 (C*D)	шì	Annual Retail Cost of Production
20	0.00 /kwh	<u>u</u>	F Assumed Utility Scale PPA Rate	\$0.08 /kWh		 Assumed Utility Scale PPA Rate
5 23	5 22 (C*E)	10	G Annual PPA Cost of Production	\$840.19 (C*F)	5	G. Annual PPA Cost of Production
113	5.12 (F-G)	T	H. Annual DG Premium	\$630.14 (E-G)	Ŧ	H. Annual DG Premium
3.76	R 76 (H/12)	<u> </u>	Monthly LFCR DG Premium	\$52.51 (H/12)	<u>.</u>	Monthly LFCR DG Premium
6.84	6.84 (1/A)	: 	Monthly LFCR DG Premium Per kW	\$8.21 (I/A)	<u>-</u>	 Monthly LFCR DG Premium Per kW

1,641 kwh/kw 10,502 kwh (A*B) \$0.140 /kwh \$1,470.34 (C*D) \$0.07 /kwh

6.4 kW

\$735.17 (E-G) \$61.26 (H/12) \$9.57 (I/A)

\$735.17 (C*F)

6.4 KW 1.61 kWh/KW 1.0502 kWh (A*9) 90.162 kWh (A*9) 51.522 85 (C 0) 51.522 85 (C 0) 5735.17 (C*F) 5735.66 (F,G) 565.66 (H,(Z2) 5585.66 (H,(Z2)

 A.
 Customer DG System Size

 B.
 Assumed Amnual Rate of Production

 C.
 Calculated Amnual Rate of Production

 D.
 Cascumed Customer Retail Rate

 E.
 Amnual Retail Cost of Production

 F.
 Assumed Utility Scale PPA Rate

 G.
 Annual Production

 F.
 Annual Production

 H.
 Annual DPA Cost of Production

 H.
 Annual DPA Cost of Production

 H.
 Monthly UFCR DG Premium

 J.
 Monthly UFCR DG Premium

6.4 kW 1.64 kWh/W 1.641 kWh/W 10,502 kWh (4*8) \$0.145 /KWh \$1,222.85 (*0) \$1,222.85 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2285 (*0) \$2,2

\$10.25 (1/A)

1641 kWh/kW Assumed Amnual Rate of Production

\$0.145 Retail Rate

Ŕ	A. Customer DG System Size	6.4	6.4 kW	¥	A. Customer DG System Size
6	Assumed Annual Rate of Production	1,641	1,641 kWh/kW	œ	Assumed Annual Rate of Pro
υ	C. Calculated Annual Production	10,502	10,502 kWh (A*B)	ن	Calculated Annual Production
Ġ	D. Assumed Customer Retail Rate	\$0.145 /kWh	/kwh	ġ	D. Assumed Customer Retail R.
ய்	E. Annual Retail Cost of Production	\$1,522.85 (C*D)	(c*D)	цi	E. Annual Retail Cost of Produ
щ,	F. Assumed Utility Scale PPA Rate	\$0.10	\$0.10 /kWh	¥,	Assumed Utility Scale PPA R
ن ن	G. Annual PPA Cost of Production	\$1,050.24 (C*F)	(C*F)	σ	G. Annual PPA Cost of Product
Ŧ	H. Annual DG Premium	\$472.61 (E-G)	(E-G)	Ŧ	H. Annual DG Premium
	 Monthly LFCR DG Premium 	\$39.38	\$39.38 (H/12)	<u>.</u>	Monthly LFCR DG Premium
4	 Monthly LFCR DG Premium Per kw 	\$6.15 (I/A)	(I/A)		J. Monthly LFCR DG Premium

ö	A. Customer DG System Size	6.4	6.4 kW	¥	A. Customer DG System Size		
nua	Assumed Annual Rate of Production	1,641	1,641 kWh/kW	<u> m</u>	Assumed Annual Rate of Production	roduction	
Tuu	C. Calculated Annual Production	10,502	10,502 kWh (A*B)	ن	Calculated Annual Production	tion	
Isto	Assumed Customer Retail Rate	\$0.145 /kWh	/kWh	<u> </u>	Assumed Customer Retail Rate	Rate	
0	Annual Retail Cost of Production	\$1,522.85 (C*D)	(c*D)	ui	E. Annual Retail Cost of Production	uction	
ility	Assumed Utility Scale PPA Rate	\$0.09	\$0.09 /kwh	u.	F. Assumed Utility Scale PPA Rate	Rate	
ů	G. Annual PPA Cost of Production	\$945.22 (C*F)	(C*F)	ڻ ن	G. Annual PPA Cost of Production	tion	
rer	Annual DG Premium	\$577.63 (E-G)	(E-G)	Ξ	Annual DG Premium		
Ř	Monthly LFCR DG Premium	\$48.14 (H/12)	(Z1/H)	<u> </u>	Monthly LFCR DG Premium	-	
R.	 Monthly LFCR DG Premium Per kW 	\$7.52 (I/A)	(I/A)	<u> </u>	Monthly LFCR DG Premium Per kW	n Per kw	

1641 kwh/kw	\$0.150
Assumed Annual Rate of Production	Retail Rate

۲	A. Customer DG System Size	6.4	6.4 kW	ځ	A. Custome
B.	B. Assumed Annual Rate of Production	1,641	1,641 kWh/kW	æ.	Assumed
ن	Calculated Annual Production	10,502	10,502 kWh (A*B)	ن	Calculate
ġ	Assumed Customer Retail Rate	\$0.150 /kWh	/kWh	ġ	D. Assumed
ш	Annual Retail Cost of Production	\$1,575.36 (C*D)	(C*D)	ш	E. Annual F
ц.	F. Assumed Utility Scale PPA Rate	\$0.10	\$0.10 /kWh	щ	F. Assumed
с ^ј	G. Annual PPA Cost of Production	\$1,050.24 (C*F)	(C*F)	σ	G. Annual F
Í	H. Annual DG Premium	\$525.12 (E-G)	(E-G)	Ŧ	Annual L
<u>.</u>	Monthly LFCR DG Premium	\$43.76 (H/12)	(H/12)		Monthly
-;	 Monthly LECR DG Premium Per kw 	\$6.84 (I/A)	(I/A)	-	Monthhy

Ŕ	Customer DG System Size	6.4	6.4 kW
æ.	Assumed Annual Rate of Production	1,641	1,641 kWh/kW
ن	Calculated Annual Production	10,502	10,502 kwh (A*B)
o.	Assumed Customer Retail Rate	\$0.150 /kWh	/kwh
:	Annual Retail Cost of Production	\$1,575.36 (C*D)	(c*D)
	Assumed Utility Scale PPA Rate	\$0.05	\$0.09 /kWh
υ	Annual PPA Cost of Production	\$945.22 (C*F)	(C*F)
ŕ	Annual DG Premium	\$630.14 (E-G)	(E-G)
	Monthly LFCR DG Premium	\$52.51 (H/12)	(H/12)
	Monthly LFCR DG Premium Per kW	\$8.21 (I/A)	(I/A)

å
Average
From
Subtracted
Cost
Fuel
arginal

Ŕ	A. Customer DG System Size	6.4	6.4 kW	4	-	A. Customer DG System Size	
ť	B. Assumed Annual Rate of Production	1,641	1,641 kwh/kw			Assumed Annual Rate of Production	1,64
ن ا	. Calculated Annual Production	10,502	10,502 kwh (A*B)	0		Calculated Annual Production	10,50
ġ	D. Assumed Customer Retail Rate	\$0.106 /kWh*	/kwh*		-	D. Assumed Customer Retail Rate	\$0.10
шi	E. Annual Retail Cost of Production	\$1,113.25 (C*D)	(c*D)	ш		E. Annual Retail Cost of Production	\$1,113.2
ш	F. Assumed Utility Scale PPA Rate	\$0.08 /kWh	/kWh	щ	-	Assumed Utility Scale PPA Rate	
σ	G. Annual PPA Cost of Production	\$840.19 (C*F)	(C*F)	10	1	Annual PPA Cost of Production	\$735.1
r	H. Annual DG Premium	\$273.06 (E-G)	(E-G)	Ŧ	4	Annual DG Premium	\$378.0
<u>.</u>	Monthly LFCR DG Premium	\$22.76 (H/12)	(H/12)		-	Monthly LFCR DG Premium	\$31.5
	Monthly LFCR DG Premium Per kW	\$3.56 (I/A)	(I/A)	<u> </u>		 Monthly LFCR DG Premium Per kW 	

-	-		_	•••								_				-	-			-
Customer DG System Size	Assumed Annual Rate of Production	Calculated Annual Production	Assumed Customer Retail Rate	Annual Retail Cost of Production	Assumed Utility Scale PPA Rate	Annual PPA Cost of Production	Annual DG Premium	Monthly LFCR DG Premium	Monthly LFCR DG Premium Per kW	Low End	Customer DG System Size	Assumed Annual Rate of Production	Calculated Annual Production	Assumed Customer Retail Rate	Annual Retail Cost of Production	Assumed Utility Scale PPA Rate	Annual PPA Cost of Production	H. Annual DG Premium	Monthly LFCR DG Premium	 Monthly LFCR DG Premium Per kW
÷	œ.		Ŀ.	نس	<u>ـــ</u>	ۍ	ŕ		J.		Ä	á	ن	Ġ	шi		υj	÷		
6.4 kW	1,641 kWh/kW	10,502 kwh (A*B)	\$0.150 /kWh	5 (C*D)	\$0.09 /kWh	2 (C*F)	t (E-G)	\$52.51 (H/12)	\$8.21 (I/A)		6.4 kW	1,641 kWh/kW	10,502 kwh (A*B)	\$0.106 /kWh*	5 (C*D)	\$0.07 /kWh	7 (C*F)	9 (E-G)	\$31.51 (H/12)	\$4.92 (I/A)
6.4	1,641	10,502	\$0.150	\$1,575.36 (C*D)	\$0.05	\$945.22 (C*F)	\$630.14 (E-G)	\$52.51	\$8.21		6.4	1,641	10,502	\$0.106	\$1,113.25 (C*D)	\$0.03	\$735.17 (C*F)	\$378.09 (E-G)	\$31.51	\$4.92
	nual Rate of Production								R DG Premium Per kW			nual Rate of Production			I Cost of Production					R DG Premium Per kW

				1	ł	1
Ż	Customer DG System Size	6.4	6.4 kW	¥.		Cust
å	Assumed Annual Rate of Production	1,641	1,641 kWh/kW	8	_	Asst
ن	Calculated Annual Production	10,502	10,502 kwh (A*B)	ن		Calc
Ŀ	Assumed Customer Retail Rate	\$0.150 /kWh	/kWh	d		Assi
ш	Annual Retail Cost of Production	\$1,575.36 (C*D)	(c*D)	iu		Ann
ц.	Assumed Utility Scale PPA Rate	\$0.0\$	\$0.08 /kWh	ц		Assi
ы	Annual PPA Cost of Production	\$840.19 (C*F)	(C*F)	ن		Ann
ŕ	Annual DG Premium	\$735.17 (E-G)	(E-G)	Ŧ		Ann
<u></u>	Monthly LFCR DG Premium	\$61.26 (H/12)	(H/12)	-1	-	Mor
<u></u> ;	Monthly LFCR DG Premium Per kW	\$9.57 (I/A)	(I/A)	<u> </u>		ΝÖ
L	Low End			L.,		
خ	Customer DG System Size	6.4	6.4 kW	¥		Cust
ю	Assumed Annual Rate of Production	1,480	1,480 kWh/kW	mi	- 1	Assi
ن	Calculated Annual Production	9,472	9,472 kwh (A*B)	0		Gal
ġ	Assumed Customer Retail Rate	\$0.125 /kWh	/kWh	ف	_	Assi
ш	Annual Retail Cost of Production	\$1,184.00 (C*D)	(c*D)	ш	_	Ann
ш	Assumed Utility Scale PPA Rate	\$0.10 /kWh	/kWh	u.		Assi
σ	Annual PPA Cost of Production	\$947.20 (C*F)	(C*F)	ن		An
π	Annual DG Premium	\$236.80 (E-G)	(E-G)	픤	Ξ	Ann
	Monthly LFCR DG Premium	\$19.73 (H/12)	(H/12)	<u> - </u>	-	Mo
	Monthly LFCR DG Premium Per kW	\$3.08 (I/A)	(I/A)			Mo
				:		

Ŕ	Customer DG System Size	6.4 P.W	PAN .
8.	Assumed Annual Rate of Production	1,641	1,641 kWh/kW
ن	Calculated Annual Production	10,502	10,502 kwh (A*3)
ġ.	Assumed Customer Retail Rate	\$0.150 /kWh	/kWh
ய்	Annual Retail Cost of Production	\$1,575.36 (C*D)	(c*b)
Ľ,	Assumed Utility Scale PPA Rate	\$0.07 /kWh	/kWh
ن ن	Annual PPA Cost of Production	\$735.17 (C*F)	(C*F)
Η.	Annual DG Premium	\$840.19 (E-G)	(E-G)
	Monthly LFCR DG Premium	\$70.02 (H/12)	(H/12)
	Monthly LFCR DG Premium Per kW	\$10.94 (I/A)	(I/A)

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	6.4	6.4 kW	4	A. Customer DG System Size	6.4	6.4 kW
Production	1,480	1,480 kWh/kW	m	Assumed Annual Rate of Production	1,800	1,800 kwh/kW
tion	9,472	9,472 kwh (A*B)	ن	C. Calculated Annual Production	11,520	11,520 kwn (A*B)
Rate	\$0.125 /kWh	/kWh	Ó	D. Assumed Customer Retail Rate	\$0.150 /kwn	/kwn
duction	\$1,184.00 (C*D)	(c*D)	ш	Annual Retail Cost of Production	\$1,728.00 (C*D)	(c*b)
A Rate	\$0.10	\$0.10 /kWh	u.	Assumed Utility Scale PPA Rate	\$0.07	\$0.07 /kwh
iction	\$947.20 (C*F)	(C*F)	ю.	G. Annual PPA Cost of Production	\$806.40 (C*F)	(C*F)
	\$236.80 (E-G)	(E-G)	Ŧ	H. Annual DG Premium	\$921.60 (E-G)	(E-G)
E	\$19.73	\$19.73 (H/12)		Monthly LFCR DG Premium	\$76.80	\$76.80 (H/12)
m Per kW	(A/I) 80.E\$	(I/A)		Monthly LFCR DG Premium Per kW	\$12.00 (1/2)	(1/2)
		DeDDecision No.	No.		n 5	