September 7, 2007

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Re. Arizona Public Service Company General Rate Case, E-56 & E-57 filing
Docket Nos. E-01345A-05-0816, E-01345A-05-0826, E-01345A-05-0827

COMMENTS OF THE VOTE SOLAR INITIATIVE AND THE SOLAR ALLIANCE ON THE AUGUST 28 FILING OF RATE SCHEDULES E-56 AND E-57 BY ARIZONA PUBLIC SERVICE COMPANY

Introduction

The Vote Solar Initiative and the Solar Alliance[1] appreciate the opportunity to comment on the proposed E-57 standby rates filed August 27 by Arizona Public Service Company (APS). The Vote Solar Initiative is a non-profit organization with the mission of stopping global warming and increasing energy independence by bringing solar energy into the mainstream. The Solar Alliance is a state-focused alliance of manufacturers, integrators and installers that are dedicated to accelerating the promise of solar energy in the United States.

We want to recognize the work and commitment of the Arizona Corporation Commission (Commission) to develop sustainable renewable resources in the state. We also want to especially commend the Commission for its foresight in promoting distributed resources through a comprehensive set of policy initiatives including the Renewable Energy Standard and Tariff (REST), interconnection standards, net metering rules, and the uniform credit purchase program. While we recognize that not all policies are fully in place at this time, we believe that the result will be a dynamic and vibrant distributed renewable energy market in Arizona that creates jobs and other economic benefits locally and statewide, and sets the stage for Arizona to become a national leader.

The purpose of these comments is to address the policy implications of the standby tariff filed unilaterally by APS, as well as the impact on the economics of distributed photovoltaic (PV) generation. The filing by APS was precipitated by the following ordering paragraph in the Commission Decision:

> 48. APS' proposed Partial Requirement Schedules E-56 and E-57 need further discussion and revision and APS should meet with Staff and the interested parties and submit a revised E-56 and E-57 tariffs within 60 days of the date of this Decision.

Our comments will be limited to the proposed E-57 rate, as it is designed for PV, whereas the proposed E-56 rate applies to other distributed resource types. In this regard, we attended the meeting regarding the proposed E-57 rate on August 6, tele-conferenced in to the follow-up

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[1] The Solar Alliance (www.solaralliance.org) members include American Solar Electric, BP Solar, Conergy, DT Solar, Energy Innovations, Evergreen Solar, First Solar, Kyocera, Mitsubishi Electric, MMA Renewable Ventures, REC Solar, Sanyo, Schott Solar, Sharp, SolarWorld, SPG Solar, SunEdison, SunPower, Suntech, and Uni-Solar.

meeting on August 17, and met with APS one-on-one to express our concerns in depth on August 23. The issues raised in these comments are the same as those raised with APS at the aforementioned meetings.

In regards to the E-57 rate, we take issue with APS's characterization that "substantial changes have been made…" As far as we can tell, the only changes made were to (1) correct some inconsistencies, (2) correct some grammar, punctuation and spelling, and (3) allow for case by case negotiation for purchased energy rates for systems larger than one megawatt. Our larger concerns relating to justification of such a rate, detailed below, have not been addressed.

Application of the proposed E-57 rate

It's useful to begin with an explanation of the application of the proposed E-57 rate. There are three essential elements to the rate: applicability, energy charges, and demand charges.

Applicability

The proposed E-57 rate is applicable to commercial customers of APS that install a photovoltaic system larger than 100 kW. In effect, this rate applies to customers whose PV system exceeds the current limitation of the net metering policy adopted in the recent APS rate proceeding. APS has proposed to cap the applicability of this rate at one megawatt, and to negotiate similar charges on a case by case basis for system sizes of one megawatt or larger. Thus, to the extent that the applicability of the net metering rules ultimately adopted by the Commission exceeds 100 kW, or other changes are made by the ACC, application of this tariff would need to be modified accordingly.

Energy service

The APS proposal is confusing in a number of respects. First, it defines supplemental energy as equal to all energy supplied to customer as determined from readings of the supply meter. In other words, the customer pays for energy it purchases from APS in accordance with the rate levels contained in the customer's applicable General Service rate schedule, otherwise known as *business as usual*. Second is the purchase of energy from the customer: APS "will pay the Customer for any energy purchased at the per kWh monthly non-firm purchase rates as shown in rate schedule EPR-2." However, determination of the amount of "energy purchased" is not specified in the rate, but was clarified by APS personnel for us on August 23. Here is how it works:

- On an <u>hourly</u> basis (thus necessitating a two register bi-directional meter APS would install *at customer's expense*), APS separately records (1) energy flows through the meter to the customer from the grid, and (2) energy flows through the meter from the customer to the grid.
    - APS charges for the energy it supplies in accordance with the rate levels contained in the customer's applicable General Service retail rate schedule,
    - APS pays the customer for its energy generated in excess of its consumption at the avoided cost rates contained in EPR-2.

To put this in the context of best practice policies that promote distributed generation in other states, most effective net metering policies pay for excess customer generation on an annual basis at an avoided cost rate. That is, the utility pays at its avoided cost for any generation in excess of consumption at the end of a calendar year. In Colorado, the customer is compensated for excess generation at the end of the year at the utility's average hourly incremental cost of electricity supply over the prior twelve months. Some less-effective policies (and most net-billing policies) require the utility to pay at avoided cost rates for excess customer generation on a monthly basis. APS's proposed policy goes even further than this by paying for excess customer generation on an *hourly* basis. Each reduction in time frame effectively reduces the value of PV to the customer, harms the economics, and results in less distributed resources on the system, higher incremental costs for the distributed resources, or both.

This treatment by APS would be appropriate if the customer-sited PV were a merchant generating plant. Any excess generation that leaves the site would be purchased by the utility at its avoided cost rates, as it does with qualifying facilities. In this instance however, we are dealing with customers that are attempting to meet a portion of their own load by making a capital investment, or partnering with a third party to do the same. To the extent that a customer's PV system generates more energy than the customer consumes at any point in time, that energy is not then dispatched by APS – it flows into the neighboring business. To APS, it looks like load reduction on a particular distribution circuit. But for the openness of the customer and the regulatory process, the utility would not be able to tell if the load reduction was due to a customer-sited PV system, new efficient appliances, a store shut-down, or a host of other reasons.

The load reduction results in energy cost savings ranging from fuels costs, to variable O&M, to other overheads related to the commodity. Indeed the fuel cost savings is a significant benefit to the utility and other ratepayers. Reduction of consumption will reduce the marginal fuel cost for the utility, i.e. the most expensive kWhs produced. Yet the customer-generator will only experience a reduction in its bill of average fuel costs. The difference can be quite significant.

Even if the avoided cost rate was properly applied, the rate itself is questionable in this application. As we understand the determination of the EPR-2 rate, it is based on the historical non-firm hourly energy rate at Palo Verde, assembled into peak and of-peak timeframes. This rate is market-based on history, can be as much as two years old, and is not reflective of actual cost-savings.

Standby capacity charge

Here again, there is confusion about the capacity for which APS proposes to charge the customer. On the one hand, the terms and conditions indicate:

> Customer will be required to contract for adequate standby power to cover the total output of all the customer's generators unless adequate facilities have been installed, to the satisfaction of APS, that isolate portions of the customer's load from APS' system so that APS will in no event be providing standby service in excess of Contracted Standby Capacity.

This language implies that the contract standby capacity is equal to the capacity of the customer's PV system. Yet the section titled "Determination of Contract Standby Capacity" is contradictory:

> For each specific customer generating unit for which the Company is providing Standby Service, monthly Contract Standby Capacity shall be the simultaneous 15 minute integrated kW demand as

> recorded on the Generator Meter(s) at the time the customer's Supply Meter registers the highest 15 minute integrated kW demand during the billing period.

This language implies that capacity provided by the customer's PV system at the time of its monthly peak demand from APS is the contract standby capacity. In other words, any capacity being provided by the customer's generating system at the time of its peak will be viewed as standby capacity for which the customer must pay a charge to APS. That charge is equal to the unbundled delivery charge in the customer's applicable general service rate schedule, according to the tariff.

Based on our conversations with APS, we believe it was the company's intent to utilize the latter definition. In any case, this charge is improper for a variety of reasons, not the least of which is that the customer has already paid for the capacity once when it purchased its own PV generating system. Requiring a payment to APS for the same capacity would amount to double charging.

The standby capacity charge requires the customer generator to pay for "delivery costs" associated with capacity provided by the customer's on-site generation. First, we point out that clearly no delivery is needed as the energy is, by definition, generated on-site. Second, we note that any additional costs charged to the customer will in all likelihood be passed back through REC prices to APS in order to make the economics work for the customer. Finally, the Commission's REST definition 1801(K) for "Market Cost of Comparable Conventional Generation"[2] explicitly recognizes that avoided costs include "any avoided transmission and distribution costs and any avoided environmental compliance costs." To our knowledge, APS has performed no analysis of transmission and distribution costs that might be avoided by the implementation of distributed generation, thus presents no basis for charging customer-generators *additional* costs over and above the customer's demand placed on the system for delivery through the standby capacity charge.

These comments point to the fact that there has been no cost justification provided for the E-57 capacity charge. While we recognize that certain rate forms are sometimes implemented which may not necessarily be completely cost justified to further other state goals such as providing price breaks to certain industrial customers for economic development reasons or for time of day pricing, no such over-riding policy goals are evident here. Indeed, APS's justification for the capacity charge appears to be the lost revenue argument – that any reduction in the revenue from the capacity charge requires compensation through the proposed *standby* charge. Yet reductions in capacity payments that result from installation of energy efficiency technologies and other factors such as factory shutdowns, store closures, vacations, and weather effects are not similarly charged a standby capacity charge – the customer in those examples is charged for the demand placed on the system. The same should hold true for demand reductions related to PV.

Benefits of Distributed Generation

To look at this issue more broadly, we should step back and evaluate the transactions taking place. Customers of utilities like APS are willing to invest their own capital in generating facilities that serve a portion of their own consumption for a variety of reasons – be it economic, environmental, or otherwise. The result of this action by the customer is to reduce the amount of

[2] R14-2-1801(K)

energy that needs to be generated by the utility or for the utility through a purchase contract. In addition to the renewable generation premium, which is only partially supported by rate-payer funded REC payments, a customer-generator pays the avoided cost generation. REST rules stipulate that only the *excess* value over avoided cost can be supported by REST tariffs. In the absence of such a contribution, all rate-payers would contribute to the capital cost of the generation otherwise avoided. Penalizing customer-generators with additional non-cost based charges reduces the ability of the general body of rate-payers to access such sources of low-cost capital from dispersed and diverse sources, factors which reduce overall risk and contribute to lower cost of capital overall and more optimal capital allocation.

In addition, the reduction in the amount of energy that needs to be transmitted and delivered by the utility mitigates the electrical burden on the wires. Each of those reductions has a value which may be experienced currently, in the future, or both. In addition, the customer's PV generating system also reduces to some extent the amount of capacity needed to meet the needs of its customers. This also represents a value.

The proposed E-57 does not recognize all of these values. However, in APS's defense, it did recognize the capacity benefits on its generating and transmission system by only seeking to recover capacity costs for its distribution system. It's also important to note that determining the benefits of distributed PV generation for a particular utility system is difficult. However, there have been many studies performed on other utility systems with fairly consistent results. A few of these are summarized below:

Update: Effective Load Carrying Capability Of Photovoltaics In The United States (Perez, et al., presented at the American Solar Energy Society Annual Conference, July 2006)

This study is an update and an expansion of the original work of Perez et al. (1993, 1996). In the original work, selected utility loads from the late 1980s and early 1990s were analyzed in conjunction with PV output simulated from low resolution satellite data. The results from the selected utility sample were extrapolated to all US utilities by modeling Effective Load Carrying Capability[3] (ELCC) from the robust relationship observed between ELCC and utility summer to winter peak load (SWP) ratio. Using a higher resolution and more accurate satellite model to simulate site/time specific PV output, the emphasis of the present work is placed on reporting state-by-state potential and on assessing the impact of grid penetration and array geometry on ELCC. The potential for Arizona was based on extrapolated data for APS.

Results show that overall regional trends identified in the early 1990s remain pertinent today, while noting a significant increase in PV ELCC the Western and Northern US, and a modest decrease in the central and eastern US. The main conclusions reached in the original study remain valid: PV's effective capacity is significant – and considerably higher than PV's capacity factor – for much of the United States. Data for APS indicates that the ELCC is in the 70-75%

[3] The ELCC of a power generator represents its ability to effectively increase the generating capacity available to a utility or a regional power grid without increasing the utility's loss of load risk. For instance, a utility with a current peaking capability of 2.5 GW could increase its capability 2.55 GW with the same reliability by adding 100 MW PV, provided the ELCC of the 100 MW PV is 50 MW, or in relative terms, 50%.

range for a two-axis tracking system. The underlying data was used to develop the following estimates of ELCC for various system geometries and penetration levels for Arizona:

Geometry:	2-axis tracking				Horizontal				South 30° tilt				Southwest 30° tilt			
Penetration:	2%	5%	10%	15%	2%	5%	10%	15%	2%	5%	10%	15%	2%	5%	10%	15%
ELCC:	71%	68%	61%	53%	55%	52%	47%	42%	57%	54%	47%	41%	65%	61%	55%	48%

The data from this study clearly shows that PV provides significant capacity value to the electrical grid – value that as not been recognized in the proposed E-57 rate.

The Value of Distributed Photovoltaics to Austin Energy and the City of Austin (Clean Power Research, March 17, 2006)

Austin Energy (AE) has a strong commitment to integrating solar electric generation into its power generation and distribution system emphasized by its goal of installing 15 MW of solar generation by the end of 2007 and 100 MW by 2020. AE initiated this study to ensure that the cost of solar generation was commensurate with its value.

There were two primary objectives of this study:

1. Quantify the comprehensive value of distributed PV to AE in 2006
2. Document evaluation methodologies to assist AE in performing the analysis as conditions change and applying it to other technologies

The results indicate that the value for 15 MW of distributed PV to AE is $2,312 per kW (11.3¢ per kWh) for the best fixed configuration - SW facing at a 30° tilt, which is only slightly higher than a South facing, 30° tilt configuration. The system with the highest value overall is the single axis, 30° tilt tracking system and is worth $2,938 per kW (10.9¢ per kWh). AE can use these results of this study to determine the value of a larger amount of PV.

The best fixed and tracking configurations at the 100 MW penetration level are worth $2,196 per kW (10.7¢ per kWh) and $2,791 per kW (10.4¢ per kWh), respectively. The fuel cost component of these figures is approximately 6.5¢ per kWh.

Mid Atlantic States Cost Curve Analysis (JBS Energy, 12/5/2000)

This report was prepared to analyze the impact of load reduction on reducing the cost of electricity in the context of the PJM utility system. In essence, when consumption is reduced, particularly during peak periods, the market price of electricity is reduced for all consumers. The consumers who reduce their usage receive the benefit of reducing their total consumption multiplied by the market price (with a real time pricing meter), or the load reduction multiplied by a monthly average price (for load-profiled customers), even though they are providing greater benefits to the system as a whole.

The report concluded that the value of load reduction from the perspective of ratepayers (in reducing the prices paid by everyone) is at least twice as great as the market prices themselves, and it rises dramatically as load increases. It is clearly in the best interest of society to spend money and send price signals beyond the market price to encourage energy efficiency and load shifting, particularly during the summer peak. Distributed photovoltaic generation, with its relatively strong correlation with peak loads, could be particularly important in this regard. This finding that conservation not only benefits the conserver but everyone else should become the cornerstone of a new public goods imperative and the associated rate design policy.

The Integration of Renewable Energy Resources into Electric Power Distribution Systems (Oak Ridge National Laboratory, June 1994)

As a result of the Energy and Water Development Appropriations Act of 1992, a study was performed to evaluate the use of distributed utility power generation, utilizing renewable energy systems, for improving power system performance, and generating transmission and distribution savings. The study included both a national assessment which developed values for the various benefits that are representative, at the regional level, for providing an indication of the potential for renewable energy systems, and case studies using actual power distribution system data for seven electric utilities[4] with the participation of those utilities.

Integrating renewable energy systems into electric power distribution systems increased the value of the benefits by about 20% to 55% above central station benefits in the national regional assessment. In the case studies, the range was larger: from a few percent to near 80% for a case where costly investments were deferred. In general, additional savings of at least 10 to 20% can be expected by integrating at the distribution level.

The report found *generation* benefits included the following:

- savings in the cost of fuel,
- credit for avoided generation capacity, and
- savings associated with avoided atmospheric emissions.

It further found that the benefits associated with integrating renewable sources into the *distribution* system would add to the generation benefits listed above. Some of these benefits are difficult to quantify and are utility-specific; insight into these benefits is provided by the case studies. The distributed utility benefits considered in this study are not necessarily a complete set. They are as follows:

- enhanced fuel savings and avoided emissions because of avoided T&D losses,
- deferred T&D facilities,
- voltage and reactive power (VAR) control,
- enhanced reliability, and
- additional capacity credit.

[4] Lenoir City Utilities Board (LCUB) in Lenoir City, Tenn., Southern California Edison (SCE), Public Service Company of New Mexico (PNM), Georgia Power Company (GPC), Green Mountain Power (GMP) in Vermont, Florida Power and Light (FPL) in southern Florida, and Orcas Power and Light Company (OPALCO) on Orcas Island near Seattle, Wash.

The report summarized the following benefits for distributed photovoltaic systems, expressed on a $/kW basis:

Lenoir City Utilities Board	$450
Southern California Edison	$3237
Public Service Company of New Mexico	$2723
Georgia Power Company	$1124
Green Mountain Power	$1444
Florida Power and Light	$1203
Orcas Power and Light Company	$579

The total benefits found for the utilities in closest proximity to Arizona are similar to those found by the Austin Energy Study.

Economic effects of E-57

Special rates and tariffs like E-57, fundamentally solar unfriendly, increase complexity and are a step backward in the march to optimal economics, making the PV selling and financing transaction more complex. In addition, they create another variable for the potential customer-generator to consider, and another consideration for banks and financiers.

Effects on the Customer:

At its heart, E-57 is designed to ensure that installing a solar electric system can not reduce unbundled delivery demand charges. Under E-32R, which E-57 will replace, if peak demand happened while the solar system is active, the system would have the effect of reducing overall demand to some degree. In contrast, E-57 measures solar system generation at the 15 minute peak demand interval and charges the customer for generation coming from their own solar system. This offsets any potential delivery demand charge reductions that solar might have created. This bears repeating. *The more the solar system produces during the peak demand interval the more the customer is charged.* In this manner APS has eliminated one of the primary benefits to customers installing large-scale solar systems.

Below is sample data from a large PV system located near Prescott, Arizona. In the yellow column we see demand charges incurred by the customer in the year before the PV system was installed. The blue column represents demand charges incurred during the subsequent year after the solar had been installed. The third column predicts what unbundled delivery demand charges plus standby charges, would have been incurred during the second year, had the customer been on the E-57 rate plan. It is assumed that the difference in demand between yellow and blue columns represent a reasonable estimation of the peak demand reduction provided by the solar system. This example assumes the customer never exports any self-generated solar energy.

	Without Solar		With Solar under E-32		With Solar under E-57		
Billing or Read Date	kW Demand Without Solar	Unbundled Delivery Charges	kW Demand the Following Year With Solar	Unbundled Delivery Charges	kW Demand With Solar Under E-57	Integrated Solar Generation During Peak Demand	Unbundled Delivery Charges + Charges For Solar Generation
Jul	74	$509.86	54	$372.06	54	20	$509.86
Aug	70	$482.30	62	$427.18	62	8	$482.30
Sep	65	$447.85	56	$385.84	56	9	$447.85
Oct	62	$427.18	54	$372.06	54	8	$427.18
Nov	46	$316.94	54	$372.06	54	0	$316.94
Dec	41	$282.49	46	$316.94	46	0	$282.49
Jan	41	$282.49	42	$289.38	42	0	$282.49
Feb	36	$248.04	42	$289.38	42	0	$248.04
Mar	45	$310.05	42	$289.38	42	3	$310.05
Apr	42	$289.38	36	$248.04	36	6	$289.38
Totals	522	$3,596.58	488	$3,362.32	488	54	$3,596.58

Secondary Service Unbundled Delivery Charge	Charge for 15 minute integrated kW measured on the Generator Meter during the customers monthly peak demand interval (**Charges for Solar Generation**)
$6.89	$6.89

Solar unfriendly rates such as E-57 can have a significant impact on the renewable customer-generators and the industry. Every additional cost that is imposed upon the development of a customer-sited PV system will result in one of several outcomes. First the customer-generator may have to pay more for her system than she was anticipating, leaving the customer either poorer for the experience, less excited about her decision to self-generate, dissatisfied with APS for imposing additional charges, or all of the above.

A second possibility is that the PV industry will absorb the additional cost, having the effect that Arizona becomes a less desirable place to invest its resources. The solar industry is not a high margin business. Companies that work in multiple states will focus more effort and resources in states with utilities that have more solar-friendly policies. The end result is higher costs for Arizona customers in relation to surrounding states.

The third outcome is that any additional costs would be compensated by the customer or the PV developer requiring a higher payment under the UCPP to make the economics work for the project. Thus, implementation of the REST becomes more expensive and APS is able to recover additional costs indirectly through the REST surcharge. Higher cost means fewer systems installed.

Effects on the Utility:

But what of the impact on the utility? Does the economic impact of the additional revenue obtained by APS justify its adoption? Put another way, is the economic impact of not recovering these costs between rate cases rise to a severity level that requires its implementation?

APS indicated that it intends to have rate cases every two years. Thus, on average, there will be a one year lag prior to recovery of any necessary costs. Typically, most commissions allow "forward-looking adjustments" that allow a utility to adjust its test year for expected future costs. APS should be allowed in the context of a rate proceeding to make a showing that there are unrecovered costs related to the development of customer-sited PV systems larger than those allowed under the net metering rule. At the same time, it is important to re-emphasize that any loss of cost recovery claimed by the utility does not take into account the unaccounted benefits noted above, and these should be examined in the same context.

For the first five years of the REST, the following chart provides an indication of the approximate order of magnitude of revenue to be recovered through E-57. We make no representation that the revenue in any way matches the costs. This is up to APS to demonstrate in the appropriate forum.

		2008	2009	2010	2011	2012
Non-residential DG MWh		25,809	45,886	78,996	122,281	176,593
Est. Portion > 100 kW	50%	12,905	22,943	39,498	61,140	88,297
MW @ 2000 MWh/MW		6	11	20	31	44
MWh exported	10%	1,290	2,294	3,950	6,114	8,830
MW Standby capacity	10%	0.64	1.15	1.97	3.05	4.41
MWh revenue		**$77,428**	**$137,657**	**$236,987**	**$366,842**	**$529,780**
MW revenue		**$1,887**	**$3,354**	**$5,775**	**$8,939**	**$12,909**
Total revenue		**$79,315**	**$141,011**	**$242,761**	**$375,781**	**$542,689**

For a utility with annual revenue (2006) of $3,401,748,000 and earnings of about $327,255,000, these figures (not in thousands) seem to pale in comparison. Indeed, the recent rate proceeding was precipitated by the enormous infrastructure needs of the utility. APS projects it will be spending a billion dollars each year on infrastructure.

Moreover, as noted above, the REST requires that the Affected Utility's tariff filing provide data to demonstrate that the affected utility's proposed tariff is designed to recover only the costs in excess of the Market Cost of Comparable Conventional Generation. To the extent that customers must seek higher payments through the UCPP to cover the additional costs associated with this rate, then clearly the Utility's tariff would be recovering more than the incremental cost.

Finally, the effects of local and system-wide growth have not been considered. Growth may require additional distribution investment, however development of distributed generation on certain distribution line sections can have the effect of *reducing* the investment cost burden. Similarly, system-wide growth may require additional transmision investment, however development of distributed generation across the system can reduce these investments. Growth, by itself, may also reduce costs through a wider spread on more billing units if additional transmission and distribution investments are not needed. The proposed E-57 standby rate has not taken any of these potential effects into consideration.

Effects on Economic Development in Arizona

Re-positioning our economies with cleaner, greener alternatives is a major endeavor. The approach taken in the U.S. is to enlist the power of markets to allocate, value, and distribute, making the job a little less painful and more efficient. Penalizing customer-generators when they are shouldering more than the non-generator customer's share of the system capital requirements and risks does not make very much sense. It violates the principle of market based incentives, decreases efficiencies and increases bias and unfairness in the system.

That renewable energy sources offer reduced and/or eliminated fossil fuel generation impacts such as diminished air and water quality, and destructive land use, is commonly accepted. However, renewable energy can offer many other benefits to the larger community from which all rate-payers can benefit, not just customer-generators.

Many studies have forecasted the economic development benefits of distributed renewable energy deployment. Those forecasts have ranged from 32-100 person year jobs per 1MW of PV deployed. Actual experience has shown that the job impacts have been realized at the lower end of the range. The jobs produced are primarily higher level construction jobs, with a smaller number of engineering, management, and business professionals. In a state like Arizona that depends so heavily on construction for jobs and regional personal income, an industry that can build on that core capacity and add value (and income) offers a productive regional strategy. Given the current downturn in traditional construction, a major PV development initiative could provide some relief and soften the blow of the present credit crunch.

In addition, PV deployment offers advantages of security, reliability, and sustainability. Locally available renewable feedstock, at dispersed sites and with the ability to interact or not with the larger power delivery system, offers flexibility and options independent of severe weather impacts and/or intentional sabotage.

Impacts on Public Policy efforts in Arizona

Renewable Energy Standard and Tariff: In a nutshell, any additional costs imposed on distributed generation will result in higher implementation costs for the REST. This may take the form of higher costs through the UCPP to cover the additional costs of the standby rate, or in fewer customers interested in developing distributed generation on their premises – again resulting in higher costs necessary to attract sufficient customer interest.

Net metering: What many states have determined, through intensive system specific studies (like the Austin Energy analysis discussed above), is that there are indeed net positive benefits from distributed generation, especially PV generation (we are not suggesting that other renewables do not deliver benefits, but here focus on PV).

These benefits appear to at least off-set the reduction in fixed cost contribution from the customer-generators energy displacement. There is a theoretical mismatch in costs and benefits with a possible reduction in fixed cost contribution by customers with PV[5] in the near term, and infrastructure savings over a somewhat longer term. However, this is no different than the addition of new generating capacity (or transmission capacity) that is oversized for current load and sales, but looks to accommodate the future growth. Over time, the near term costs paid by retail customers will be offset by the additional capacity and the utility's ability to meet new growth (and receive new revenue). Renewable energy distributed generators can provide major efficiencies, additional flexibility and cost deferrals that benefit the whole system. Effective assessment of projects and productive deployment of distributed renewable resources would be hampered by additional charges and tariffs. Those losses would be borne by all rate-payers.

[5] This impact is greatly reduced for rates that include a demand charge.

Other states have faced a similar uncertainty as they have launched their renewable energy economies. The best practice for addressing this uncertainty is to offer true net metering up to two megawatts, without any additional charges placed on renewable energy generation.

Recommendation

The Commission should view its options in this proceeding in the context of other matters that are pending before it – namely the rulemakings associated with net metering and the uniform credit purchase program. The outcome of those rulemaking proceedings will directly impact any sort of standby rates applied to distributed PV generation. Moreover, there would be extremely limited applicability of the E-57 rate to existing systems at this time, thus no urgent cost recovery issues present themselves.

In addition, the Commission should consider the following factors:

- There are real benefits in terms of avoided present and future costs that have not been taken into account in this rate;
- There has been no cost justification for the proposed E-57 rate filed unilaterally by APS;
- The language in the proposed E-57 rate is confusing and needs serious redrafting in any event;
- There are significant impacts of the proposed rate on the policy goals established by the REST; and
- APS will file a rate case every two years that will keep APS whole within the bounds of normal regulatory lag; and the additional revenue related to E-57 is relatively small in the near term.

We recommend the Commission postpone consideration and implementation of the E-57 rate until completion of the net metering and uniform credit purchase program rulemakings, and resolution of APS's REST filing. There would be little revenue collected through the E-57 rate in the near term – prior to completion of these dockets. If, at that time, APS continues to believe it must implement a rate such as E-57, it may file to do so at that time.

Respectfully submitted this 7th day of September, 2007

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