BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2009 RENEWABLE ENERGY STANDARD COMPLIANCE PLAN.	))))	DOCKET NO. 08A-532E

ANSWER TESTIMONY OF
JAMES F. "RICK" GILLIAM

Introduction and Summary

Q. Please state your name and business address.

A. My name is James F. (Rick) Gilliam. My business address is 6272 W. 91st Street, Suite 2 in Westminster, Colorado.

Q. On whose behalf are you submitting this answer testimony?

A. This testimony is submitted on behalf of the Interwest Energy Alliance (IEA).

Q. By whom are you employed and in what capacity?

A. I serve as Managing Director, Policy for SunEdison, LLC (SunEdison). I oversee policy initiatives and development, and policy implementation for the Western United States related to the promotion of solar electric resources.

SunEdison is the nation's largest solar power services provider. We were the first provider to offer solar energy as a turn-key service without capital outlays, without

impact on existing services and without ongoing customer maintenance costs. Financing strategies pioneered by SunEdison and now used by many renewable energy providers have lowered the cost and simplified the installation of renewable energy systems of all types. SunEdison has approximately 200 projects in ten states totaling about 60 MW under the Solar Power Services Agreement (SPSA) model. Our Colorado projects total some 14 MW.

Q. Please describe your experience in utility regulatory matters.

A. Prior to joining SunEdison in January of 2007, my regulatory experience included twelve years at Public Service Company of Colorado (PSCo or the Company) and twelve years with Western Resource Advocates (WRA – formerly known as the Land and Water Fund of the Rockies or LAW Fund). Prior to that, I spent six years with the Federal Energy Regulatory Commission. All told, I have in excess of 30 years of experience in utility regulatory matters. A summary of my background is attached as Appendix A.

Q. Have you previously testified before the Public Utilities Commission of Colorado (Commission)?

A. Yes. I have testified before this Commission on behalf of the IEA, the Colorado Solar Energy Industries Association, SunEdison, WRA (and the LAW Fund), and PSCo.

Q. Before what other utility regulatory commissions have you testified?

A. I have testified in proceedings before the Arizona Corporation Commission, Nevada Public Utilities Commission, the New Mexico Public Regulation Commission, the Utah

Public Service Commission, the Wyoming Public Service Commission and the Federal Energy Regulatory Commission.

Q. Please summarize your testimony.

A. My testimony addresses the Company's acquisition of on-site solar renewable energy credits or SORECs. Customer-sited solar electric resources provide benefits to customers and the utility and should be available broadly throughout the Company's system. My testimony addresses broad-based participation in the program, its stability, and the structure, including costs of the Company's acquisition of SORECs. I propose a more explicit and transparent incentive structure that will lead to a more balanced program and greater penetration of customer sited solar electric resources.

Q. Please describe the regional situation regarding customer-sited solar resources.

A. Customer-sited solar resources are a reality in Colorado largely due to the Renewable Energy Standard (RES) embodied in Amendment 37 and House Bill 07-1281. The RES requires that four percent of the total RES percentage each year be derived from solar electric resources, and at least half of that amount come from solar electric resources located on-site at customers' facilities. All told, the result is approximately 160 MW of solar electric be developed with at least 80 MW located behind the customer meter, all by 2020.

The RES has made Colorado a solar leader but make no mistake, other Western states are competing to be the solar capital of the U.S. For example, New Mexico's 450 MW

program and Arizona's 1,500 MW program seek to capture the benefits of solar resources by ensuring consistent development, more rapid infrastructure improvements and lower costs more rapidly than will Colorado.

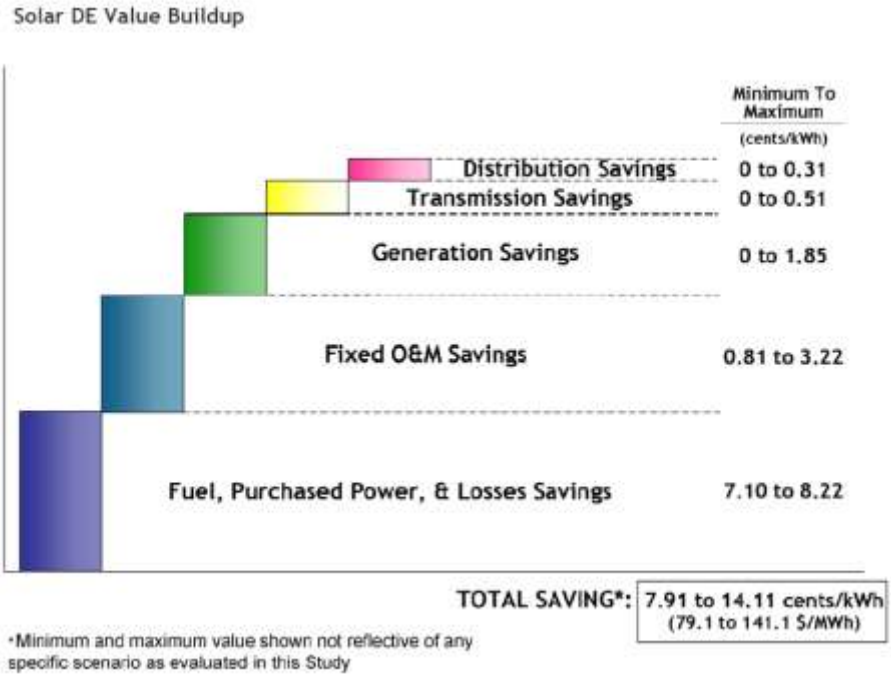
Q. What are the benefits of customer-sited solar resources?

A. The benefits of customer-sited solar resources have been described in a variety of proceedings before this Commission over the past several years thus I will attempt to only highlight key information not previously presented.

Benefits of On-site Solar Electric Resources

Customer-sited solar electric resources provide benefits to the customer through both electric bill savings, price stability and reduced carbon footprint. These resources also provide benefits to the citizens of Colorado through reduced emissions and a reduced need for transmission facilities by locating energy resources at or near the load being served. Not widely recognized however, is that customer-sited solar resources provide documented benefits to the host utility. For example, Arizona Public Service (APS) in January 2009 completed a study entitled *Distributed Renewable Energy Operating Impacts and Valuation Study*. About one year ago, APS engaged a group of consultants, led by R.W. Beck, to determine the potential value of distributed solar energy technologies for its electrical system, and to understand the likely operating impacts. The following chart summarizes the benefits to the APS system reflected in the study. As a

point of comparison, APS's standard residential "energy-only" rates range from about 8¢ to about 14.5¢.[1]



Jobs Created by Distributed Solar Electric Resources

Much has been written and debated about the jobs that result from development of solar electric resources. A recent study prepared by Navigant Consulting for the Solar Energy Research and Education Foundation (a non-profit 501(c)3 affiliated with the Solar Energy Industries Association) was released September 15, 2008,[2] and summarized the jobs resulting from PV resource development as follows:

[1] May to October - $0.08570/kWh for the first 400 kWh, 0.12175/kWh for the next 400 kWh and 0.14427/kWh for all additional kWh; and November to April - $0.08327/kWh for all usage.
[2] Source: http://www.seia.org/galleries/pdf/Navigant%20Consulting%20Report%209.15.08.pdf

Source: Navigant Consulting, Inc. estimates, June 2006.

The Navigant Study anticipates improved solar labor productivity between 2005 and 2015 and shows that each additional installed megawatt of solar has the potential to add many job-years of employment.

Relevant to near term jobs in Colorado the Navigant study shows that the jobs associated with manufacturing and assembly of PV system components are essentially the same across market segments. The differences in local job creation between the market segments are due primarily to the system integration, installation, and maintenance elements, and total approximately 4 jobs per MW.

Q. What is needed to capture these benefits for Colorado in an optimal manner?

A. A stable, consistent and viable distributed solar installation market allows solar companies to plan for the longer term by using more full-time design, engineering, procurement, and construction staff, and making longer term commitments to suppliers. Inconsistent on-again off-again solar markets require the local industry to be rebuilt multiple times, redevelopment of supplier pipelines, greater use of temporary help, and

additional and repetitive training for competent technicians. Inconsistency and instability assure that distributed solar electric resources will remain an expensive resource option far longer than necessary.

Q. Do you have any recent information related to the costs of customer-sited solar resources?

A. Yes. Lawrence Berkeley National Laboratory (LBL) released a comprehensive report earlier this month summarizing trends in the installed cost of grid-connected photovoltaic (PV) systems in the United States from 1998 through 2007.[3] This comprehensive report is based on an analysis of installed cost data from nearly 37,000 residential and non-residential PV systems, totaling 363 MW of capacity, and representing 76% of all grid-connected PV capacity installed in the U.S. through 2007. Among the report's key findings are the following:

- Among all PV systems in the dataset, average installed costs – in terms of real 2007 dollars per installed watt (DC-STC) and prior to receipt of any direct financial incentives or tax credits – declined from $10.5/W in 1998 to $7.6/W in 2007. This equates to an average annual reduction of $0.3/W, or 3.5%/yr in real dollars.
- The overall decline in installed costs over time is primarily attributable to a reduction in non-module costs, calculated as the total installed cost of each system minus a global annual average module price index. From 1998-2007, average non-module costs fell from $5.7/W to $3.6/W, representing 73% of the average decline in total installed costs over this period. This suggests that state and local PV deployment programs – which likely have a greater impact on non-module costs than on module prices – have been at least somewhat successful in spurring cost reductions.
- Average installed costs have declined since 1998 for systems <100 kW, with systems <5 kW exhibiting the largest absolute reduction, from $11.8/W in 1998 to $8.3/W in 2007. Cost reductions for systems >100 kW are less apparent, although the paucity of data for earlier years in the study period may limit the significance of this finding.

[3] http://eetd.lbl.gov/ea/ems/re-pubs.html

- The distribution of installed costs within a given system size range has narrowed significantly since 1998, with high-cost outliers becoming increasingly infrequent, indicative of a maturing market.
- Both the decline in average costs and the narrowing of cost distributions halted in 2005, with average costs and cost distributions remaining essentially unchanged from 2005-2007.
- PV installed costs exhibit significant economies of scale, with systems <2 kW completed in 2006 or 2007 averaging $9.0/W and systems >750 kW averaging $6.8/W (i.e., about 25% less than the smallest systems).
- The limited component-level cost data that are available (for systems <100 kW only) indicate that, on average, module costs represent just over 50% of total installed costs, while inverter costs represent just under 10%. Smaller residential systems are faced with higher overhead, regulatory compliance, and other costs (on a $/W basis) than are larger systems.
- State and utility cash incentives for PV declined significantly, on average, from 2002 through 2007 across all system size categories. Among systems <5 kW, for example, pretax incentives declined from 2002-2007 by an average of $1.9/W (from $4.3/W to $2.4/W).
- Although average installed costs remained flat from 2005-2007, recent developments portend a potentially dramatic shift over the next few years in the customer-economics of PV. Most industry experts anticipate an over-supply of PV modules in 2009, putting downward pressure on module prices, and presumably on total installed costs as well. In addition, the lifting of the cap on the Federal ITC for residential PV, also beginning in 2009, will further reduce net installed costs for residential installations, potentially leading to some degree of renewed emphasis on the residential market in the years ahead.

The important messages to take from these findings are (1) the cost of customer-sited solar PV has been declining and is expected to continue to decline, (2) most of the decline in costs is derived from reductions in non-module costs, and (3) significant economies of scale exist between small and large systems.

Q. What does this mean for the future of customer-sited solar resources?

A. The Department of Energy and others predict that within the next decade, the cost of electricity generated on a customer's site will be approximately the same as that available through the utility grid – a situation generally called "grid-parity."

Q. How will this affect Colorado?

A. Customer-sited solar provides benefits to those that locate it on their premises, to the local utility, and to all citizens of Colorado. While Colorado is unlikely to drive global demand or supply of PV modules, it can have an impact on the necessary infrastructure for widespread solar deployment through market consistency. Colorado needs to ensure that developers, financiers, installation crews and suppliers have ongoing work in our own state, so as to deflect attempts to attract our trained workforce to other states. The price that consumers pay for solar electric power located on-site is driven by the demand/supply balance, enhancements and efficiencies in local markets, and competition among suppliers. These are important considerations in the development of incentive policy in Colorado, so that the state can maximize its customer-sited solar resource development infrastructure in preparation for grid-parity.

Q. Please describe the Company's SOREC acquisition plan.

A. The Company has developed and implemented a successful program to promote, through the use of economic incentives, the development of solar electric generating resources located on-site at customers' facilities. As noted by Ms. Newell in her pre-filed testimony, the small (under 10 kW) program "far surpassed the Company's projections" identified in its previous plan. Indeed, the year-over-year figures indicated an increase of

65% or better in both installations and applications received through September of 2008 versus 2007. The vast majority of these were in the small category, and the surge in applications related to the incentive change announced in late October are not included.

The medium program has had minimal participation to date, however there are certain changes proposed in the Renewable Energy Standard rulemaking docket that, in my view, will have positive effects. Moreover, the lack of significant participation provides breathing room for the Company to absorb the dramatic increase in small program participation.

The large program is fulfilled through competitive acquisition and thus results in the most competitive costs for the MWs sought across the segments.

Based on its filing, it appears that the Company will be in compliance with its minimum solar requirements in 2009, and each year through 2020. The following chart depicts its pattern of projected compliance.

Q. Do you support the SOREC acquisition strategy and plan for the Company?

A. In general I support some of the broader concepts embodied in the Company's plan. For example, I support the expansion of the Renewable Energy Standard Adjustment or "RESA" to the full 2% as noted in the testimony of Company witness Ahrens. In addition, I support the Company's policies of consistent incentives, broad-based

participation, program stability, moving the industry towards self-sustainability, and accommodating customers beyond the individual residential homeowner.

It's important to note with respect to self-sustainability that in response to discovery, Company witness Pam Newell clarified:

> "Public Service cannot move the solar industry towards self-sustainability. The solar industry is National and International industry. In Colorado, Public Service only serves half the load in the state. The industry is responsible for self-sustainability.

Q. Do you have concerns about the customer-sited program?

A. Yes, I do. In the interest of continuous improvement in the program, I suggest that there are a number of practices that do not support the Company's goals for the program. These include:

- The SOREC program is not supportive of the industry efforts towards self-sustainability because it has not achieved, nor is it projected to achieve, broad-based participation nor funding stability. The program has much to do to address the needs of customers beyond the individual residential homeowner; and
- The SOREC incentives available within the various size ranges drive project development, however the incentives are not consistent. In addition, the budget available for incentive funding is limited and opaque.

Q. Please discuss your concerns regarding participation and stability of the on-site solar program.

A. The Solar Rewards program historically has revolved around individual residential homeowners within the under 10kW category. This focus has provided a consistent, viable market for that portion of the solar installation industry and the industry has responded with robust growth. However, this robust growth has come at the expense of the other segments of the market. Indeed, Ms. Newell explains the balance this way in her testimony:

> "At this time, the Company would prefer not to limit participation in the Small Program. We try to forecast the acquisitions under the small program based on historical data as well as any new market information, such as the change in the federal tax incentive. Our experience is telling us that as customers become more aware of PV applications, there are a greater number of customers willing to invest in solar. Since the program started, we have seen greater participation in the small program than we have forecasted. This may or may not continue; however, as PV systems come down in cost, we could continue to see increased levels of participation. Demand remains high, indicating customers are looking for ways to directly and personally contribute to the renewable energy effort. In fact, we continue to look for ways to accommodate customers beyond the individual residential homeowner."

This method of balancing the SOREC market, i.e. using the large segment of the market as a flexible buffer against fluctuations in the small program, prevents broad-based participation and stability for the segments of the market above 10 kW, despite the fact that about two-thirds of retail electricity sales and revenue, and funding through the RESA, derive from the non-residential customers.

Q. Has the Company performed any studies or analyses, or developed any reports or reviewed any other data to support its approach to SOREC acquisition?

A. No.[4]

Q. Is Solar*Rewards a growing program?

A. Based on Table 1 in Section 5, page 8, the program is growing dramatically for the small category, but shrinking equally dramatically for the large category.

Q. Does this acquisition strategy help the industry achieve a self-sustaining solar market?

A. Perhaps over time, but it will take longer and be more expensive in the meantime. As noted in the LBL analysis, and provided in the Company's response to OCC discovery, the cost of acquiring SORECs is highest for the small program. It's important to keep in mind that there are also differences in rate structure that impact the overall cost of the program. In addition, by limiting participation in the larger markets, customer-sited solar projects, and hence SOREC, costs will of necessity be higher than they would otherwise need to be. The result will be to slow the on-site solar cost reductions for the larger market segments, and commercial and industrial customers that may seek to install solar will pay more than they need to.

Moreover, after 2009, the Company projects a shrinking or erratic market for SORECs in each of the categories. The following chart is found on page 7 of Ms. Newell's direct testimony.

[4] Response to IEA2-12.

	Small (MW0	Medium (MW)	RFP (MW)	Total
2008	6.02	0.68	11.50	18.20
2009	8.20	3.00	6.20	17.40
2010	4.00	2.00	2.00	8.00
2011	2.00	1.00	5.00	8.00
2012	2.00	1.00	-	3.00
2013	2.00	1.00	5.00	8.00
2014	2.00	1.00	-	3.00
2015	2.00	1.00	5.00	8.00
2016	2.00	0.50	-	2.50
2017	2.00	0.50	5.00	7.50
2018	2.00	0.50	-	2.50
2019	2.00	0.50	5.00	7.50
2020	2.00	0.50	-	2.50

Q. Are there alternative strategies for accomplishing the SOREC goals set forth by the Company?

A. Yes. In an ideal world, the economic incentive provided to a group of customers would be just enough to motivate the right number of customers to install systems without providing excessive profits. The characteristics both within and among groups of customers can vary widely, and developing workable and stable incentives can be quite challenging. For example, small customers have historically been ineligible for the third party development model (or other forms of long term financing) and thus have generally required an up-front incentive (UFI) to defray the initial capital outlay. Larger customers are good candidates for the third party model and thus have typically received a performance-based incentive (PBI) payment tied to SORECS generated over time. Residential customers generally tend to include more early adopters than business customers that are more focused on their own bottom line.

The usefulness of market mechanisms varies between customer groups. Larger projects more readily lend themselves to competitive procurement, which captures the discipline

of the market through competition between suppliers. Inserting market discipline into small system SOREC acquisition has been difficult. Without a means of capturing the benefits of competition among suppliers, we are left with fixed UFIs and fixed PBIs. These are unlikely to provide the right incentive in such a dynamic market, except by coincidence.

The challenge of designing proper incentives to promote customer-sited solar is one with which a number of states have grappled. For example, California established an incentive program segregated to residential, government & non-profit, and non-residential markets under its California Solar Initiative or CSI. It designed a series of steps for each market segment with a UFI for the two former categories and PBI for the latter. It was initially designed with the concept that each incentive step would incent a certain amount of on-site solar that would take about a year to achieve. The following chart summarizes the steps for the residential and non-residential segments, and the actual time required to achieve the goals within each step.

Step[5]	Residential UFI/W	Residential MW/Step	Residential Actual Start Date	Non-Res PBI	Non-Res MW/Step	Non-Res Actual Start Date
2	$2.50	23	Jan '07	39¢	47	Jan '07
3	$2.20	33	Aug '07	34¢	67	Mar '07
4	$1.90	43	Apr '08	26¢	87	May '07
5	$1.55	53	Dec '08	22¢	107	Mar '08
6	$1.10	63		15¢	127	
7	$0.65	71		9¢	144	
8	$0.35	83		5¢	167	
9	$0.25	94		3¢	191	
10	$0.20	116		3¢	234	

[5] Note that Step 1 was deemed to be the result of all of the various solar programs that had occurred prior to 2007.

While the concept of declining incentives makes sense as the solar market grows and costs decline, the California experience demonstrates the challenges of attempting to forecast the market and provide appropriate incentives at any particular point in time. It also may provide an effective throttle that could apply to UFI-based projects.

Another example is the Uniform Credit Purchase Program (UCPP) in Arizona. While this program is just getting started, Arizona has taken a slightly different approach that harnesses market efficiencies to maximize the use of program funds. First, its program is budget-based, i.e. tied to an annual budget collected from customers through a surcharge. More importantly, while the residential program uses a traditional UFI, the non-residential program incorporates a cap into its PBI model. The program works as follows: the annual budget is divided into six equal segments to be used during six two month reservation periods. During each two-month reservation period, the utilities accept reservation requests for non-residential projects based on PBI payments that are capped by the UCPP. The caps decline 10% every other year. Projects are then ranked generally by cost, and lowest cost projects selected first. The ranking and selection process occurs within two weeks of the close of the two month cycle. This process captures market discipline and has the added advantage of spreading projects out more evenly throughout the year – further reducing costs.

In both the Arizona and California programs, a required first step is to determine the level of funding available, and how that will be used to achieve a desired outcome. This step gets directly to the second concern with the program.

Q. Please describe your second concern.

A. Colorado's developing solar market cannot function without the SOREC incentives provided by the Solar Rewards program but market participants are unable to forecast SOREC incentive budgets. The Company is now collecting the full 2% RESA, however there is no way of knowing how much of the 2% will find its way to the Solar Rewards program, and how it will be used in each category. Company witness Ahrens indicates on page 13, line 6 of his testimony that none of the RESA funds have been used for anything other than solar to date, but that this may not always be the case. Moreover, the Company was unable to break the *Modeled Incremental Costs* on Tables 6-3 and 6-4 down by resource type, so there is no way of knowing what the projected balance of impacts (net costs or net savings) among eligible resources might be, and thus how much funding might be available to the solar program. Other renewable technologies such as wind could result in net savings to the Company resulting in potential solar program budgets larger than 2% of revenue. The uncertainty associated with funding for solar incentives makes it difficult to structure a long term viable market.

Q. How does the Company address funding for the acquisition of SORECs?

A. In response to IEA2-17, the Company describes its incentive strategy as follows:

> "The Company does not try to determine the total amount of funding available for SO REC incentives within the two percent rate cap. Rather, since SO RECs are the most expensive to acquire, Public Service attempts to identify the incentive level that attracts the level necessary for compliance, allowing PSCo to use any excess funds available to acquire more cost effective renewables."

It is interesting that the Company expresses concern with the acquisition of *expensive* SORECs, yet its SOREC acquisition efforts are driven by the most expensive category of SORECs.

Q. What do you recommend?

A. Given the uncertainty, I recommend the Company establish an annual budget of 2% for the Solar program. History has shown net cost savings from wind and these savings are likely to continue in the future. Theses savings will serve to offset net costs to the utility of other Section 124 renewable resources. In addition, the rulemaking proceeding (Docket No. 08R-424E) may change certain rules including the retail rate cap determination that could have an effect on the funding available for on-site solar.

Q. You noted Section 124 resources in your last answer. Are the incremental costs of Section 123 resources recovered through the RESA?

A. To the best of my knowledge, no.

Q. How would you propose to treat the costs of the 25MW central solar facility for which the Company is currently negotiating a contract?

A. The SRECs provided by this project far exceed the amount necessary for the Company to make up the difference between the amount of on-site solar (SORECs) and the total solar requirement. Indeed, the Company projects SREC generation in 2013 at the maximum level available for the year 2020. Incremental cost funding through the RESA should be

limited to the amount necessary to make up that SREC/SOREC differential. The remainder of costs should be recovered through the general ratemaking process.

Q. Assuming a budget for incentives for the customer-sited solar program can be established, what is the next step?

A. It is important for the Commission to consider whether the goal of the program is to maximize the number of systems installed, to maximize the MWs of solar installed, or to strive for a balance of the two. Achieving the desired goals given the diverse market requires recognition of segment characteristics and a logical, fair, and transparent means for spreading available incentive funding to segments. Two basic tenets for developing a more structured incentive program are, to the extent possible, (1) all customers should have access to an on-site solar electric system, although not all customer facilities are suitable for such development, and (2) cross-subsidization of one group of customers by another should be avoided. In other words, RESA funds contributed by residential customers should be used for residential customer incentives, and RESA funds contributed by non-residential customers should be reserved for non-residential customers. This is particularly important when market segments display divergent characteristics such as economies of scale, project development time, incentive type, and rate structure.

Q. Does the company make any effort to match the source of the funding for incentives with the market segments that receive the incentives?

A. No, it does not according to the response to IEA2-16.

Q. Please elaborate on the characteristics of market segments

A. Utility customers are segregated into groups with similar characteristics as a means of simplifying the allocation of utility costs and the design of rates in a just and reasonable manner. Every customer of a utility imposes unique costs onto the utility and could, in theory, receive unique pricing. As a practical matter, the benefits of this concept are far outweighed by administrative costs. Thus, residential customers are, for the most part, grouped together as one class because their size, load factor, metering costs, voltage delivery level, and so forth are fairly homogeneous. Non-residential customers tend to be grouped in classes on similar bases. For example, commercial customers below a certain size (i.e. peak demand) are served through a traditional kWh revenue meter under a single part energy rate. Other distinctions made among class types include voltage delivery level and rate options such as time-of-use and interruptible.

These characteristics are critical for the development of establishing appropriate cost responsibility to serve and design rates for utility customers, but are less critical in the development of customer-sited solar programs. The key characteristics for subdividing candidates for on-site solar are the size of the load, the design of the customer's current utility rate (single part or two-part, and the balance between demand and energy charges in two-part rates), and the structure of the incentive. It should be noted that the structure of the incentive, i.e. UFI versus PBI, is largely related to the size of the system.

Q. Please discuss the considerations for balancing the number of solar systems installed with the amount of solar capacity installed through the incentive programs.

A. Given the assumption that a limited pool of funding for incentives is available to promote on-site solar within the Company's system, and that there are differences in cost of system and incentive mechanisms (i.e. UFI v. PBI), the Commission can strike a balance across a broad spectrum. For example, should the goal be to maximize the number of systems installed and hence the number of utility customers that can install solar on-site, then the small program (under 10 kW) should get all of the funding for incentives. Conversely, if the goal is to maximize the installed on-site solar capacity across the Company's system, or put another way – to minimize the cost per MW of customer-sited solar resources, then the incentive funding should go only to the largest systems since they have the lowest cost per watt of installed capacity.

To reach a reasonable balance of incentive funding among these two extremes, we turn back to the characteristics of the customers. These characteristics can be used to establish some level of proportionality among customer groups. As noted above, characteristics such as voltage level are less important distinctions for on-site solar than are size considerations. Thus, we suggest that the residential group (essentially the under 10 kW program group) be segregated as a group with unique characteristics, such as rate structure and the UFI. Conversely, the non-residential group generally uses a pay for performance incentive and the systems are larger with better economics. Two candidate bases for funding allocation are retail electricity sales and retail electricity revenue. For the Company, the allocations would be approximately as follows:

Proportionality[6]	Revenue Contribution	Share of Sales
Residential	37%	31%
Non-Residential	63%	69%

Q. What do you recommend?

A. Revenue contribution is the most appropriate basis for setting program budgets.[7] This method assures that funding provided by residential and non-residential customers is used to support incentives for their respective class and avoids possible cross-subsidization of segments. Although an allocation based on sales would result in a greater deployment of solar capacity, I believe it is appropriate to trade off capacity maximization for a reasonable allocation of funding consistent with ratemaking policies. Unspent incentive funds should carry forward within the associated market segment from year to year, with interest. Segregating funding in this manner also frees each market segment to be creative with incentive program design, without concern about losing funds to another segment should the new program design be less than successful.

Q. Are there other advantages to segregating the market segments in this manner?

A. Yes. Anticipated on-site solar cost changes may not be uniform across market segments. By clearly specifying a funding level within these segments, the incentive programs can be designed and adjusted to maximize the amount of capacity installed based on the segment's characteristics. For example, the Company might reduce its administrative costs associated with lengthy RFP processes by using the Arizona PBI model. In the residential segment, it is difficult to capture market efficiencies, however the California

[6] Source: EIA data, 2006.
[7] The same basis is used for the application of the RESA – see Witness Ahrens, page 16 starting at line 19.

approach of declining blocks provides an example that may serve to spur competition within the segment.

Q. How does the funding available through your proposal compare with the current funding levels?

A. As noted above, current funding levels are driven by the residential (< 10 kW) segment. The following chart depicts the amount of funding expended in the under 10 kW program by year, and the proportion of total RESA funding for that year.

Year	Incentive Expenditures for <10 kW program	Percent of Total Expenditures	Approx Portion of 2% of Retail Rev
2006	$8,171,887	98.7%	20%
2007	$18,084,031	95.1%	43%
2008	$29,829,185	82.6%	60%

This chart shows that most of the funding for incentives in the first years of the program have supported systems under 10 kW, and demonstrates how quickly the market responded to the incentives provided by the Company. The continued growth of the program in 2008, far surpassing the Company's projections (and not including the effects of the incentive change announced in late October), raises the concern that the funding may be insufficient for paying future years' PBI payments for systems larger than 10 kW. In sum, current funding for the small program exceeds the amounts that would be available under the proposed revenue allocation method.

Q. How would you propose to move from the current practice to your incentive funding proposal?

A. I would propose that the transition occur over a two year time frame – about the same period in which the Company proposes significant reductions in all market segments.

Q. Do you have other suggested improvements?

A. Yes. In addition to the increased stability in the market for larger on-site solar systems resulting from annual acquisition of large system SORECs, a more uniform construction schedule would allow for economies in workforce and equipment utilization, thus reducing overall costs. The current RFP situation requiring all projects to be online as of a date certain results in periods of very high construction activity, followed by periods of no activity. Thus, I recommend that the required in-service dates be spread throughout the year.

Recommendations

Q. Please summarize your recommendations to this Commission.

A. My recommendations to the Commission are as follows:

- Establish an explicit budget for the annual acquisition of SORECs. I recommend that the Company designate 2% of retail electric revenue as the funding available;
- Subdivide the budget: I further recommend that the annual budget be allocated into budgets for the program categories. Initially, I recommend using the proportion of residential electric revenue to total retail electric revenue as a proxy for funding the incentives in the under 10 kW category. The remainder would be available to the over 10 kW segments.

- Establish consistent acquisitions of SORECS from the large category: I recommend that the current Company proposal for a 5 MW RFP every other year be replaced with an annual program similar to the Arizona PBI process. The envisioned process would place caps on the 20 year SOREC payment stream, and applications would be taken four to six times per year. A well defined process should reduce the current administrative burden. In addition, project development would be spread out throughout the year, reducing costs.
- Incorporate market discipline into the small category: I recommend establishing MW blocks for the small category, such that when certain installation targets are reached for the small category, the UFI would automatically step down.
- Establish a transition period: While I believe that a quicker transition would be best for the program, I recommend that the new models for funding and acquisition of SORECS by fully in place by January 1, 2011, allowing two years to adjust to the new paradigms.

Q. Does this conclude your testimony?

A. Yes, it does.

James F. "Rick" Gilliam
Senior Energy Policy Advisor
Western Resource Advocates

Professional Employment

January 2007 to Present: Managing Director, Policy, SunEdison, LLC, Beltsville, MD. Directs and manages policy development for the company and implementation for the Western United States at the regulatory and legislative levels. (Promoted from *Director* Sept '07)

Dec 1994 to Jan 2007: Senior Energy Policy Advisor, Western Resource Advocates (formerly the Land and Water Fund of the Rockies), Boulder, Colorado. Develop innovative clean energy and air quality public policies within the economic and cultural framework unique to this region. Lead environmental advocate in development of Arizona Environmental Portfolio Standard, Nevada Renewable Portfolio Standard implementation rules, Colorado Renewable Energy Standard legislative proposals, and the 2003 Utah Renewable Energy Standard legislative proposal. Principal author of Colorado's Amendment 37 and lead advocate for related PUC rule development.

Jan 1983 to Dec 1994: Director of Revenue Requirements, Public Service Company of Colorado, Denver, Colorado. Primary responsibility for development of formal rate-related filings for this investor-owned utility for electric, gas, and thermal energy service in two states and the FERC. Developed and responded to a variety of proposed mechanisms to encourage the use of energy efficiency technologies, including innovative rate design approaches.

Dec 1976 to Dec 1982: Technical Witness (Engineer), Federal Energy Regulatory Commission, Washington, D.C. Testified as expert witness on behalf of the FERC in wholesale rate filings on technical, accounting, and economic issues related to rate design, pricing, and other issues.

Education

Masters, Environmental Policy and Management, University of Denver, Denver, Colorado
Bachelor of Science, Electrical Engineering, Rensselaer Polytechnic Institute, Troy, New York

Relevant Publications

Gilliam and Baker, "Green Power to the People," *Solar Today*, July/August 2006.

Dalton & Gilliam, "Walking on Sunshine: Energy Independence on the Rez," *Orion Afield*, Summer, 2002.

Gilliam, Rick, "Revisiting the Winning of the West," *Bulletin of Science, Technology & Society*, April 2002.

Blank, Gilliam, and Wellinghof, "Breaking Up Is Not So Hard To Do: A Disaggregation Proposal," *The Electricity Journal*, May 1996.

Recent Recognition

Recipient of First Annual Larson-Notari Award, Colorado Renewable Energy Society, June 2005.

Named one of Metro Denver's Top Business Newsmakers, September 2005, Denver Business Journal

Recipient of University of Colorado Wirth Chair Community Award, June 2006.

Summary of Formal Testimonies available upon request