ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

# Solar Development Incentives:

## *Status of Colorado's Solar PV Program, Practices in Other States, and Suggestions for Next Steps*


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## Executive summary:

**Background:** In the past half decade, Colorado has instituted a set of Renewable Energy Standard ("RES") and other policies designed to move the state's electric production toward greater reliance on renewables, with specific interest in stimulating the market for solar power and other forms of distributed generation. Colorado electric utilities must achieve specific goals for renewable energy use, and offer incentives to encourage electricity customers to invest in photovoltaic ("PV") systems. These incentives have changed over time, with the intention to partially compensate customers for the above-market cost of PV equipment and installations and to gradually lower the incentives necessary to induce demand for PV applications as those costs drop. The utilities may collect the cost of these incentives (and other renewable energy resources) in rates as allowed by the Public Utilities Commission of Colorado ("Commission"), subject to a rate cap.

In a recent order approving the Settlement Agreement that allowed the restart of Public Service Company of Colorado's Solar*Rewards® program, the Commission indicated its expectation that "the upcoming proceeding concerning the Company's 2012 RES Compliance Plan will allow us to devote more time to examining the issues surrounding the on-site solar market in Colorado and to think about the costs and benefits of retail renewable distributed generation in the context of the Company's plans for longer-term compliance with the RES."[1] The Commission "desires an outcome in which the utilities structure their financial incentives for customers' adoption of on-site PV systems in order to produce the desired amount of PV deployment sustainably and within the costs constraints."[2]

In light of the challenges associated with balancing the achievement of distributed and renewable energy objectives and the provision of financial incentives within the constraint of the rate cap, the Commission engaged Analysis Group to conduct a study to assist the Commission in developing a decision-making framework for continued regulatory oversight of utilities' offering of financial incentives for customers to adopt PV systems. The project included several elements: an assessment of the current practices and trends in select states regarding the use of financial incentives to promote

[1] Colorado Public Utilities Commission, Decision No. C11-0304, Before the Utilities Commission of the State of Colorado, Docket No. 11A-135E, In the Matter of the Application of Public Service Company of Colorado for Approval of a Reduction in the Standard Rebate Offer, "Order Approving Settlement Agreement," Mailed Date: March 21, 2011; Adopted Date: March 18, 2011.

[2] Scope of Work for Project to Examine Solar Photovoltaic (PV) Market Incentives, April 11, 2011.

the PV market; guidance concerning approaches of relevance and value to Colorado's current PV market; and recommendations concerning how the Commission might proceed to examine ways to continue to foster the development of a viable commercial market demand for PV without reliance on financial incentives provided by utilities.

**Observations:** Based on a review and analysis of information and data gathered by the staff of the Commission as well as its own research, Analysis Group provides the following high-level perspectives as a backdrop for ongoing program design:

1. **The Context for Colorado's History of PV incentives**:

Colorado's experience in implementing the solar portion of the renewable energy standard since passage of the ballot initiative in 2004 reflects a series of appropriate adjustments to the rapid uptake in participation by Colorado customers, and adaptation to evolving economic and institutional circumstances. As changes have occurred quickly over the past five years in several of the factors affecting program design – including the degree of maturity of the solar industry in Colorado, the unit costs of installation, the level of tax benefits available to participants, the rate impacts associated with program expenditures, and the actual level of installed capacity relative to prevailing RES requirements – so too have the laws, regulations, Commission decisions, and company program details designed to guide program implementation. This is a program marked by dynamic changes, with evolving policy responses aimed at pushing and pulling the market as it evolves rapidly to changing conditions.

2. **Colorado's Programs Are Among the Most Advanced in the U.S.**:

Colorado has been at the front lines of solar development incentive design during this period of rapid change in the U.S. solar market. Around the country, there have been various programs that generally support renewable resources – through research and development funding, tax incentives, grants, regulatory programs, renewable portfolio standard ("RPS") requirements, market-based certificate trading programs, and others. These policies have been evolving for many years. Very-targeted programs to provide long-term financial incentives to support development of the solar PV industry are relatively new in the U.S. The history and present status of legislated and regulatory programs to promote the advancement of solar energy – through combinations of renewable standard set-asides, up-front rebates, performance incentive payments, and long-term contracts for renewable energy credits – can be characterized as still in the state of concept development, testing and evaluation.

3. **PV Policies Will Need to Continue to Adapt Nimbly Given the Pace of Change in the Solar Industry**:

The challenge of policy making with respect to solar technology deployment is complicated by the fact that the solar industry itself is going through a period of rapid change with respect to such things as: the unit costs of manufacturing panels; the proliferation of solar installers and installation approaches; the models for partnerships and financial relationships between producers, installers, customers, and utilities; the scope and scale of federal and state grant and assistance programs; and the costs of panel installation and maintenance. The combination of a rapidly changing industry and quickly-evolving portfolio requirements, incentives, and other policy mechanisms means that a nimble policy program should identify priorities and options and continuously evaluate trends in performance, rather than settle on a preferred approach.

4. **There is Wide Variation in Solar Programs and Policy Design**:

Our review of the state of solar program designs reveals a number of approaches. These tend to focus on a complicated set of goals: ways to support the continued development of the industry; carefully tracking program progress and effectiveness; and minimizing (and ideally eventually phasing out) broad-based financial support for development through utility-based solar program rate mechanisms. In our review, we outline at a high level the suite of solar policy programs in play across a subset of key states, and identify design considerations and trends where possible. Generally, policy approaches to support the development of solar electric systems exist both on a stand-alone basis (e.g., rebates, incentive programs, tax treatment), and as part of broader policy initiatives to support renewable power in general (e.g., renewable portfolio standards, net metering, "green" retail purchasing programs, information disclosure/labeling). Rarely does a state rely on just one policy mechanism to foster development of solar systems; typically there are several approaches in play at once, with important and sometimes complicated interactions between the various mechanisms.

**Recommendations for Further Attention and Review by the PUC**: Based on our review, and our understanding of the goals of PV policy evolution in Colorado, Analysis Group recommends that the Commission examine the following types of issues in any upcoming proceeding(s) to consider the status of the on-site solar market in Colorado and the continuing role and design of public, ratepayer-funded financial incentives in light of these market conditions:

1. **Clarifying the going-forward goals for solar PV incentives in Colorado**:

The legislative and regulatory record in Colorado to date has focused efforts on several outcomes. An important goal will be to test the continuing importance of the following goals for solar PV incentives in the state: (a) *increased reliance of the state's power supply on renewable energy*; (b) *balancing these goals with the costs to accomplish them*; and (c) *fostering development of a viable commercial market demand for PV without reliance on financial incentives provided by utilities*.

2. **Clarifying what success looks like, given those going-forward goals for solar PV in the state:**

We recommend that the upcoming Commission docket make inquiries into the types of indicators or metrics that would shed light on the extent to which Colorado has accomplished its goals: (a) indicators that reveal the status of market developments; and (b) indicators that could serve as triggers to allow for reducing and/or removing further financial incentives (or to restore them, in the event of changed market conditions). The purpose of data collection would be to provide information on which the Commission could evaluate the effectiveness of policies over time, relative to the goals.

3. **Identifying "best practices" for design of any incentives that remain necessary to accomplish the state's objectives**

As part of its upcoming docket, the Commission could solicit testimony and other evidence from parties to identify current best practices to support accomplishment of goals for renewable energy, and in particular for on-site solar PV. This part of the inquiry will be important, to the extent that the docket uncovers information about alternative approaches (compared to Colorado's) that accomplish goals for renewable energy at lower overall cost. These cost comparisons should focus on total costs, as well as costs to participating customers (i.e., those that install on-site solar PV systems) and costs to non-participating customers. The Commission's review could include this report's review of best practices, with the expectation that docket's parties would enhance the record on these important issues.

4. **Identifying complementary policies that are integral to sustainable accomplishment of Colorado's goals for solar PV:**

As part of its upcoming docket, the Commission should inquire about the continuing alignment (or lack thereof) of regulatory and ratemaking approaches in support of its other policies (including financial incentives), such as net metering, interconnection practices and policies, availability of other financial incentives, revenue decoupling, and others.

# Status of the Solar Market in Colorado

## Overview[3]

In the past half decade, Colorado has instituted a set of Renewable Energy Standard and other policies designed to move the state's electric production toward greater reliance on renewables, including specific interest in stimulating the market for solar power and other forms of distributed generation. Under these policies, Colorado electric utilities must achieve specific goals for renewable energy use, and offer incentives to encourage electricity customers to invest in photovoltaic systems. These incentives have changed over time, with the intention to partially compensate customers for the above-market cost of PV equipment and installations and to lower the incentives necessary to induce demand for PV applications as those costs drop over time. The utilities may collect the cost of these incentives (and other renewable energy resources) in rates as allowed by the Commission, subject to a rate cap.

Colorado's efforts to promote solar and other renewables began formally in November 2004, when the state's voters passed a ballot initiative to create a Renewable Energy Standard for Colorado's electric utilities. The ballot initiative, Amendment 37, set the requirement that the utilities initially meet a portion of their retail sales requirements through renewable energy production. Eligible renewable energy resources are: (a) solar, wind, geothermal, biomass; and (b) new hydroelectricity with a nameplate rating of 10 ten megawatts or less, and hydroelectricity in existence on January 1, 2005, with a nameplate rating of thirty megawatts or less.[4] The RES required that utilities meet the requirement through generation or purchase of eligible renewable energy resources equal to 3 percent of retail electricity sales for the years 2007 through 2010; 6 percent for 2011 through 2014; and 10 percent for 2015 and thereafter.[5]

SB 05-143 required that 4 percent of the RES amounts come from solar electric generation technologies, with at least one half of this amount from technologies located on-site at customers' facilities ("distributed generation" or "DG"). It also required that each utility make available to its customers a standard rebate offer ("SRO") of a minimum of $2.00 per watt for the installation of PV systems up to 100 kW, and required net metering for such facilities. The legislation also allowed as prudent

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[3] The main elements of this procedural background has been provided to Analysis Group by the Commission staff.

[4] Session Laws of Colorado 2005, Senate Bill 05-143.

[5] *Ibid*.

(subject to PUC jurisdiction and review) the recovery of costs associated with the PV program, including a bonus for such investments on their allowed rate of return on their PV investments, and specified that all associated contracts for the acquisition of renewable energy credits ("REC"s) for DG PV have a minimum term of 20 years. Finally, the PV program was subject to a rate impact rule, establishing a maximum retail rate impact for the program of 50 cents ($0.50) per month, or 1 percent of the total electric bill for the average residential each customer.

Since the passage of SB 05-143 there have been numerous legislative, regulatory, and program design changes to implementation of the PV programs of electric utilities in Colorado. Many changes flowed from the success of the programs implemented by the two major investor-owned utilities (Black Hills Colorado Electric, or "BHCE," and Public Service Company of Colorado, or "PSCo").

Specifically, over the course of the past five years as the popularity of the solar programs drove rapidly increasingly levels of participation by retail customers, Colorado has adopted revisions to its overall RES requirements, including such elements as the specific solar program requirements, the allowed rate impact, and the form of incentives. Over time, these changes have included:

- Increased RES requirements, and changes in the portion of RES requirements that must come from distributed retail and wholesale solar systems;
- Reduced solar incentives from the standpoint of both the up-front rebate, up-front REC payments, and as-generated (performance-based) REC payments;
- Increased collection amounts through the Renewable Energy Standard Adjustment ("RESA") tariffs;
- Changes to the terminology and classification of solar components (from specifically solar to "distributed generation");
- Addition of – and changes to incentives for – classes of solar incentives based on size of the solar installations;
- Modifications to the size requirements related to eligibility for, and provisions for payments to, solar net metering applications;
- Provisions related to the return earned by participating utilities for investments collected through the RESA tariff; and
- Proposed suspension of the solar program altogether when applications threatened to overwhelm allowed tariff amounts – a proposal that was eventually modified under a Commission-approved settlement agreement.

Implementation of the solar RES programs for BHCE and PSCo currently reflect the cumulative progression of these various changes, resulting in different tier definitions, as well as rebate and REC payment levels that are significantly lower than five years ago. The success of the RES programs in supporting development of a solar industry and installation of substantial solar PV capacity in turn reflect the rapidly changing installed cost for solar facilities, driven by changes in PV markets and changing tax incentives.

In light of these factors, discussed in more detail in the next section, over the past year both utilities and have been searching for the right combination of incentive levels and program implementation that will allow for continued development of solar PV consistent with RES requirements, within the constraints of balancing the RESA accounts, and sufficient to provide the necessary degree of financial certainty to allow continued development of the solar industry in Colorado.

On May 9, 2011, the Administrative Law Judge in Docket 10A-805E submitted a Recommended Decision to the Commission to approve a Settlement Agreement establishing the terms for continued operation of the BHCE RES program. Among other things, the revised program fundamentally changes the incentive structure by lowering the rebate levels for all customers, eliminating up-front REC payments, and creating a performance-based incentive payment structure for RECs. It also establishes maximum procurement levels and new capacity definitions by tier. And it creates a new category for small, third-party financed systems to increase participation from lower-income customers. These changes are expected to effectively addressed problems with the RESA deficit, but allow for continued growth of the solar industry in Colorado.[6]

Similarly, in March of 2011 the Commission approved a settlement agreement in Docket 11A-135E related to implementation of PSCo's RES program for 2011.[7] The proposed changes, which are proposed by PSCo as a way to continue beyond 2011 in the PSCo's 2012 RES Compliance Plan,[8] provide for the eventual elimination of the up-front rebate, and transition to (and phasing down over time of) performance-based incentive payments for RECs. It also establishes caps on procurement and spending for distributed generation (solar) installations over time. As with the BHCE proposals, PSCo cites to the success of participation in their programs, and fundamental changes (reductions) in the cost of solar installations flowing from growth of the solar industry in Colorado.

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[6] Colorado Public Utilities Commission, *Recommended Decision of Administrative Law Judge G. Harris Adams Approving Settlement and Granting Motion for Waivers,* Docket No. 10A-805E, Recommended Decision No. R11-0502, pages 9-10.

[7] Colorado Public Utilities Commission, Decision No. C11-0304, *Order Approving Settlement Agreement,* Docket No. 11A-135E, Adopted March 18, 2011.

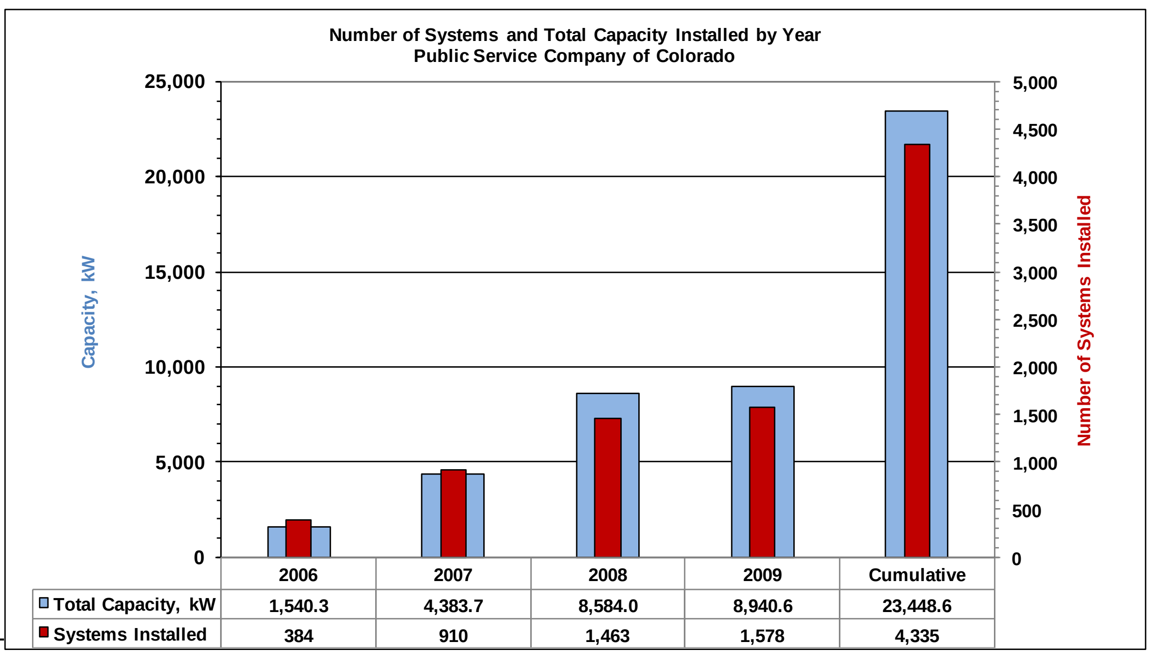
[8] Public Service Company of Colorado, *2012 Renewable Energy Standard Compliance Plan, Volume 1,* May 13, 2011.

## Program Results[9]

Implementation of the RES for solar applications has led to rapid integration of a large amount of distributed solar in the utilities service territories and the growth of a significant amount of economic activity within Colorado related to solar development, contracting and installation. In short, the state's goals for solar power (under the RES) appear to have succeeded beyond expectations from the standpoint of new solar installations and power generation, development of a solar industry, and as well as in terms of creativity in evolving policies and program elements as the program has rolled out over the past five years. Nevertheless, the pace of change has challenged the industry and its regulators with the need to address changing technology costs, growing rate impacts from the PV program, program administration surprises, and rapidly-changing economics.

As of the end of 2009, installation of capacity from small and medium solar systems had grown nine fold relative to the amount in 2005: in 2009, there were approximately 25 megawatts (MW): 23.5 MW in PSCo's service territory, 1.2 MW in BHCE's service territory). (See Figure 1.) This capacity was added in nearly 4,600 separate installations

**Figure 1**

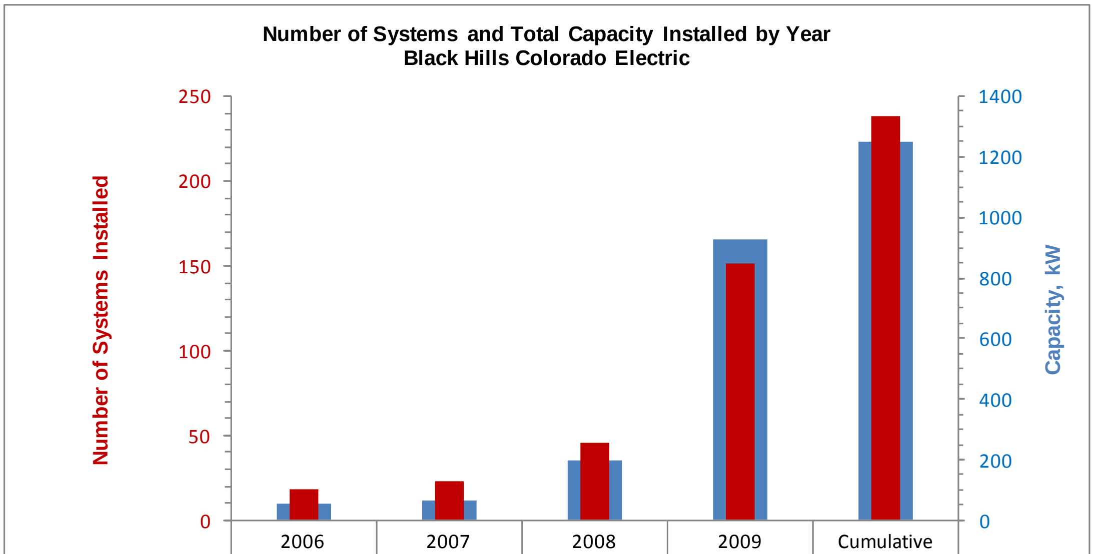



| | 2006 | 2007 | 2008 | 2009 | Cumulative |
|---|---|---|---|---|---|
| Total Capacity, kW | 1,540.3 | 4,383.7 | 8,584.0 | 8,940.6 | 23,448.6 |
| Systems Installed | 384 | 910 | 1,463 | 1,578 | 4,335 |

[9] Unless stated otherwise, the data described and portrayed in this section are extracted from an internal work product of the staff of the Colorado Public Utilities Commission, *Analysis of Solar Photovoltaic Systems Installed Under Colorado's Renewable Energy Standard Through December 2009*, December 3, 2010 ("Internal PUC Work Product"). This Internal PUC Work Product document is attached to this Report in Appendix A.

(4,335 in PSCo's service territory, 238 in BHCE's service territory).[10] (See Figure 2.) From 2006 to 2009 the average size of installed PV systems grew from 4 to 5.3 MW in PSCo's service territory, and from 3.1 to 6.1 in BHCE's.[11]

**Figure 2**




| | 2006 | 2007 | 2008 | 2009 | Cumulative |
|---|---|---|---|---|---|
| Total Capacity, kW | 56.3 | 67.4 | 198.8 | 924.9 | 1,247.5 |
| Systems Installed | 18 | 23 | 46 | 151 | 238 |

In terms of total economic activity associated with implementation of the solar RES programs in Colorado, from 2006 through 2009 there was a total of $187 million in economic activity ($179.1 million associated with installations in PSCo's service territory, and $8.3 million in BHCE's). See Figures 3 and 4. This economic activity flowed from installations involving up to 130 contractors installing systems in the PSCo service territory in 2009, and 24 in that of BHCE. The Internal PUC Work Product notes that there was very little overlap in the contractor base that worked in each service territory.[12]

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[10] Data in the Internal PUC Work Product track only small and medium sized solar installations in both BHCE's and PSCo's territory, given the lack of publicly-available data on large installations which are typically procured through company-driven competitive solicitations.

[11] The geographical distribution of installations ranged widely – for PSCo, 1,636 installations (over 9 MW) were completed in the town with the highest number of installations, to just one in the town with the least. For BHCE, 125 installations (0.68 MW) were completed in the town with the highest number of installations, to just one in the town with the least.

[12] Internal PUC Work Product, at 26.

**Figure 3**

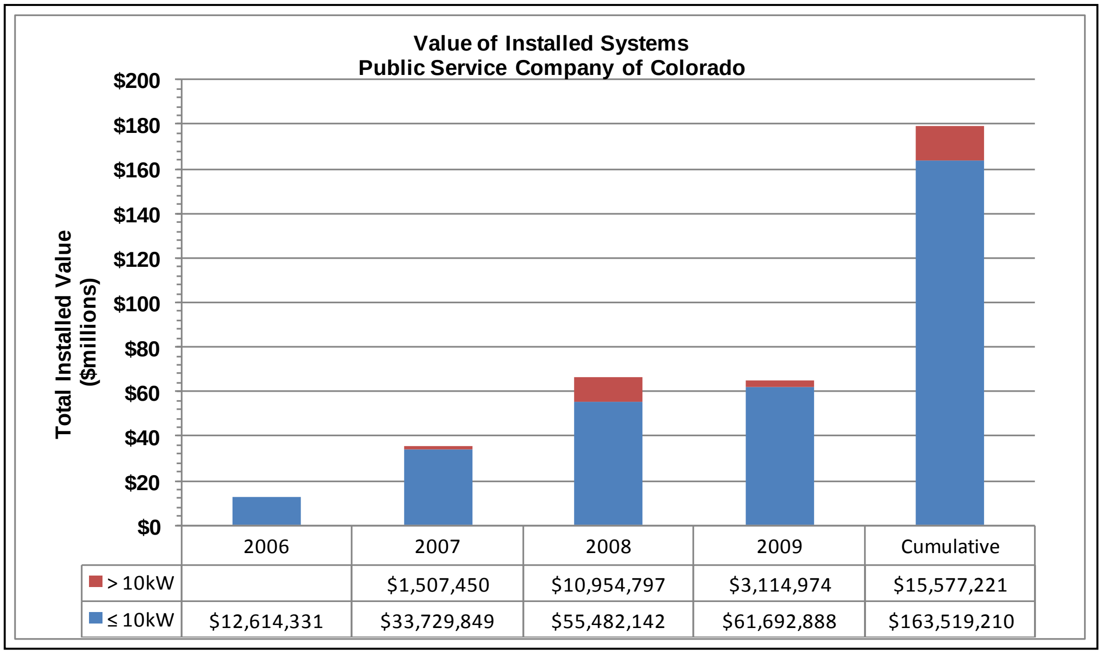
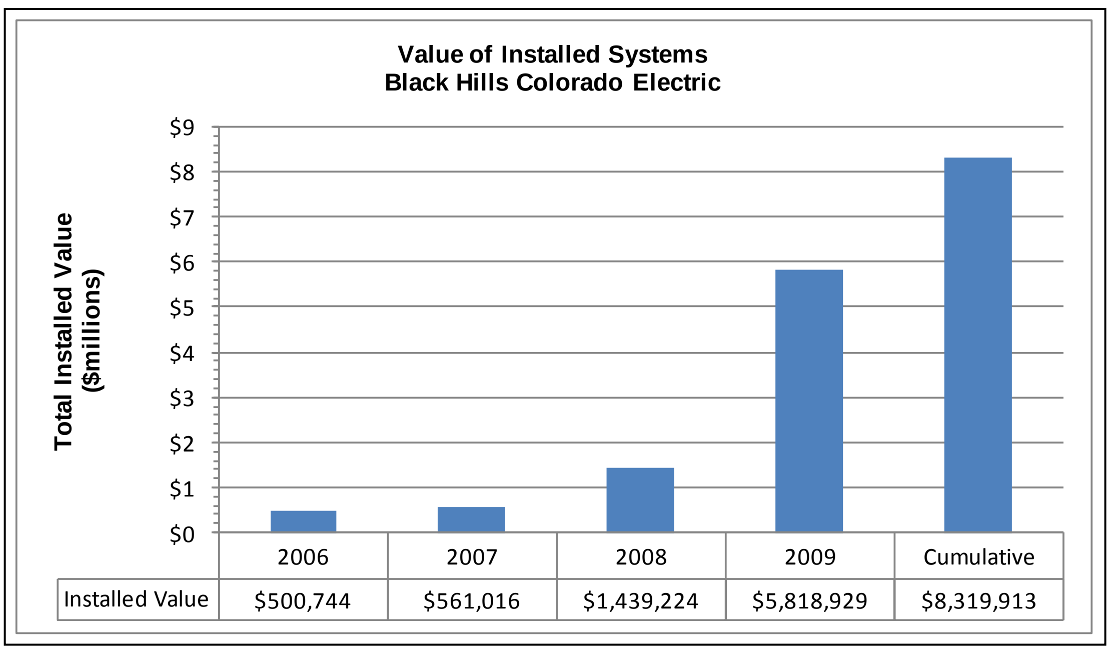


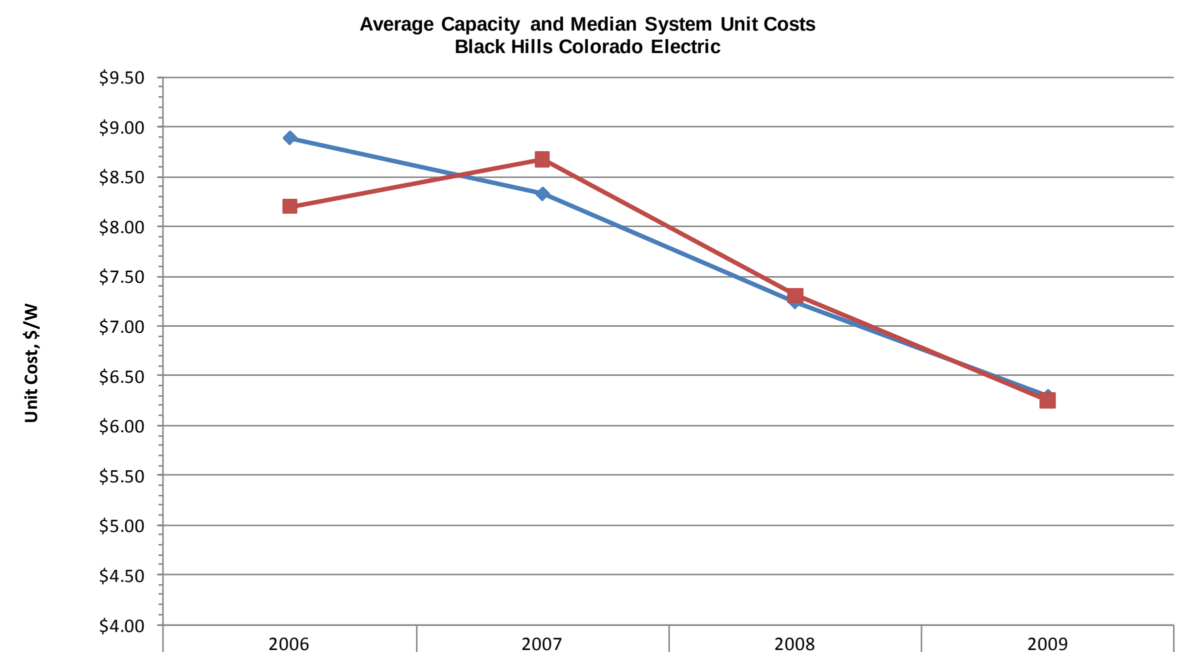

**Figure 4**



As shown in Figure 5, the data analyzed in the Internal PUC Work Product indicate a steady downward trend in the average unit cost of systems installed through 2009 (for systems below and above 10 kilowatt ("kW") in size). In PSCo's service territory the median unit cost for systems 10 kW and under decreased by 11 percent from 2006 to 2009, and by 27 percent over that same period for units above 10 kW in size. In the BHCE service territory, median costs similarly declined by approximately 24 percent.

Additional information on various aspects (installation capacity, number, location, cost and incentive payment data) of Colorado's implementation of solar RES to date can be found in Appendix A.

**Figure 5**




| | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|
| Average Cost | $8.89 | $8.32 | $7.24 | $6.29 |
| Median Cost | $8.20 | $8.68 | $7.31 | $6.25 |

## Best Practices and Benchmarking Review

Colorado's experience in implementing the solar portion of the renewable energy standard since 2004 (when the solar initiative was passed) reflects a series of adjustments in response to the rapid uptake in participation by Colorado customers, and adaptation to evolving economic and institutional circumstances. As changes occurred quickly in recent years in several factors affecting program design – including the degree of maturity of the solar industry in Colorado, the unit costs of installation, the level of tax benefits available to participants, the rate impacts associated with program expenditures, and the actual level of installed capacity relative to prevailing RES requirements – so too have the laws, regulations, Commission decisions, and company program details designed to guide program implementation.

This is not surprising, because Colorado has been one of the states at the front lines of designing policies to support solar development during a period of rapid change. Many other states have done one or another policies in general support of renewable resources – through supporting research and development funding, offering tax breaks and direct subsidies, and establishing renewable portfolio standards relying upon market-based certificate trading programs. These approaches have been evolving for many years. By contrast, very-targeted programs of long-term financial incentives to support development of the solar PV industry are relatively new in the U.S. The history status of legislated and regulatory programs to promote the advancement of solar energy – through combinations of renewable standard set-asides, up-front rebates, performance incentive payments, and long-term contracts for renewable energy credits is still being written and is still in a state of concept development, testing and evaluation.

Policy making on this issue is complicated by the fact that the solar industry itself is going through a period of rapid change, involving changes in so many factors in parallel and including: technology paths; unit costs of manufactured panels; proliferation of solar installers and installation approaches; models for partnerships and financial relationships among producers, installers, customers, and utilities; the scope and scale of federal and state grant and assistance programs; the costs of panel installation and maintenance . The combination of a rapidly changing industry and quickly-evolving portfolio requirements, incentives, and other policy mechanisms means that a best practices review should be designed more to identify options and experience and highlight trends in performance, than to select a preferred approach or metric.

With that in mind, this report provides a snapshot of the state of play in solar program design in various states around the country. It describes observations about potential best-in-class program elements for supporting the continued development of the industry. This depiction of best practices includes not only design of financial incentives but also means to carefully track program progress and effectiveness. And it looks for insights about how utility regulators may be able to minimize over time (and – ideally – eventually phase out) broad-based financial support for development through utility-based solar program rate mechanisms. Additional information on our review of programs is contained in Appendix B[13] and Appendix C.[14]

## Summary of State Policy Approaches[15]

State policies to support the development of solar electric systems exist in many forms. There are stand-alone policies such as tax incentives and rebates for individuals or companies that purchase and install solar PV equipment. These same policies are sometimes offered in the context of a broader set of policy initiatives to support renewable power more generally, including through renewable portfolio standards, net metering, "green" retail electricity products and purchasing programs, and information disclosure/labeling. Typically there are several approaches in play at once, with important and sometimes complicated interactions between the various mechanisms.

Table 1 summarizes the mechanisms used to support solar development in ten states other than Colorado. The mechanisms are broken loosely into two categories:
(i) mechanisms or requirements addressed to *utility or load-serving entities*, and
(ii) mechanisms that would provide financial incentives for *customer* installations. For each of these two categories, Table 1 outlines program elements in terms of three features – category options, key design issues, and cost mitigation strategies. Appendix C presents specific program components (e.g., incentive levels, RPS requirements) for each of the states we reviewed, and we further discuss these issues in the section below.

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[13] Appendix B is a working paper by the staff of the Colorado Public Utility Commission: "*PV Incentives: Status of Selected States,*" April 29, 2011. Hereafter, this report is called "PUC Staff PV Working Paper."

[14] Appendix C summarizes information from: (a) the PUC Staff PV Working Paper with respect to the five states (Arizona, Nevada, New Mexico, Texas, and Utah) reviewed in that paper; and (b) additional research by Analysis Group on solar programs in five other states not reviewed by Commission staff (California, New Jersey, Pennsylvania, Massachusetts, and Florida).

[15] The information in this section was taken in part from the PUC Staff PV Working Paper and Analysis Group's independent review of other states.

### Table 1: Summary of Solar Program Design Options (Based on Review of 10 States)[16]

| | Utility / Load-Serving Entity RPS or Planning/Purchase Requirements | Customer Incentives |
|---|---|---|
| **Category Options** | • Solar or distributed generation set-aside (in terms of percent or retail sales, percent of renewable portfolio standard, or minimum quantity in MW)<br>• Solar REC multipliers<br>• Utility REC long-term procurement<br>• Utility PV ownership opportunities | • Up-front rebates<br>• Up-front REC purchase/ securitization<br>• Purchases of RECs produced from on-site solar systems ('performance-based')<br>• Net metering<br>• Third-party financing/ leasing<br>• Tax exemptions, rebates, abatements |
| **Key Design Issues** | • Level of set aside (percentage, or quantity)<br>• Design of set-aside reflecting different requirements for different classes or tiers of resource types (new, existing, etc.)<br>• Design of set-aside reflecting different requirements for different customer or interconnection class (residential/ commercial; retail/wholesale)<br>• REC multiplier level<br>• Utility PV ownership quantity or procurement levels and timing<br>• Rate treatment of capital costs or contracts<br>• Phasing of or changes to set aside or ownership/procurement requirement(s) over time<br>• Utility REC contracted procurement and resale obligations | • Breakout of incentive types and/or levels by customer or PV unit size<br>• Design of rebates or performance-based incentives reflecting different levels for different classes of customer (residential/ commercial) or PV unit/installation size<br>• Minimum contract terms and conditions for REC purchases<br>• Rate treatment for incentive payment obligations<br>• Phasing of or changes to (or phasing out of) rebate and incentive levels over time<br>• Net metering size and "roll over" balance allowances<br>• Net metering aggregation and interconnection/ queuing issues<br>• REC ownership for third-party financing arrangements<br>• Levels of tax benefits |
| **Cost Mitigation Strategies** | • Total dollar expenditure limits on implementation of purchase or set-aside requirements<br>• Thresholds for maximum electricity rate or bill impact (percentage change)<br>• Cost limits or cost effectiveness evaluation on utility construction or procurement/ ownership<br>• Maximum REC price thresholds (such as 'alternative compliance mechanisms' as way to comply with RPS price caps) | • Percentage rate or bill impact thresholds (annual or on average over time)<br>• Maximum (and phased) rebate or performance incentive levels<br>• Maximum quantity participation<br>• Maximum incentive payments (annual or total) |

[16] The states are: the five states (Arizona, Nevada, New Mexico, Texas, and Utah) reviewed in the PUC Staff PV Working Paper; and the five additional states (California, New Jersey, Pennsylvania, Massachusetts, and Florida) reviewed by Analysis Group.

## Utility/Load-Serving Entity Purchase or Ownership Requirements

Broadly, programs that create obligations assigned to utilities or load-serving entities ("LSE"s) attempt to induce PV development through requiring retail electricity providers to own and/or arrange for a supply mix that contains some quantity of solar PV electric generation, or alternatively, an equivalent quantity of solar RECs. Such RPS requirements are designed to create a market for solar PV technologies and systems which presumably would not exist (in depth and/or breadth) if they had to compete with other, lower-cost renewable energy resources on price terms alone (including the value of REC prices). Since solar power has been more expensive than some other forms of renewable energy that might otherwise qualify for RPS programs in some states, a solar PV purchase requirement or carve-out is designed to stimulate a level of demand for solar PV among utility/LSE retail suppliers so as to help move the market and thereby lower the cost of PV system over time.

On the REC/portfolio standard side, programs range from the application of simple multipliers for solar RECs (e.g., a solar REC is equivalent to 1.3 times that for other REC-eligible resources), to set-asides of overall REC requirements for solar resources (that is, a certain percentage of the overall REC requirement must be met through the purchase of solar RECs). Design elements of these programs address a number of factors, including: the MW or percentage of REC or portfolio requirements that must come from solar sources; how such factors change over time; and how solar REC obligations are divided between retail, residential, or behind-the-meter applications, and wholesale or utility-scale developments.

In some states, solar programs have required (or allowed RPS compliance through) the ownership of solar renewable installations by electric utilities. (Variants include options for utilities to construct/build, and/or procure solar resources from a third party (including a customer with on-site PV energy) via a purchase power agreement. Key design features for such policies include the quantities allowed or required to be obtained (and how such amounts change over time), and the rate treatment of utility capital investment or contract payments.

One of the more important factors in the design of REC programs (and their ability to stimulate PV market development) has been the existence of a ceiling price on the amount of money that a utility/LSE buyer of renewable energy must pay for RECs. In fact, nearly all utility-based solar development policies have explicitly limited the overall impact on customers' electricity rates or bills of costs associated with RPS program implementation. A number of approaches to this have been used. One is to establish a specific limit on the total size of rate or bill impacts relative to overall rates/bills (as in Colorado's percentage-limit on the amount of total incentive payments that may be passed along to customers at any point in time, with the limit set by a maximum percentage relative to average customer bills). Other cost-containment mechanisms that may apply to RPS program implementation across the board (and may not necessarily be specific to solar PV programs) are: caps on annual or program lifetime expenditures; specific limits on procurement quantities; and effective caps on REC prices (through application of alternative compliance payments ("ACP") or penalties.

An ACP is a price cap that applies specifically to the maximum price of a REC. The ACP is a payment mechanism that the utility/LSE may make to the program administrator in lieu of buying RECs, if the price of RECs exceeds the cap (or if the utility or LSE simply does not arrange for a sufficient supply of RECs to meet its compliance obligation (in which case the alternative compliance payment is sometimes consider a penalty for failure to comply). The existence of such alternative compliance payments aims to mitigating electricity price/rate impacts on electricity customers in states with RPS. But their existence has also meant – in practice – that solar PV systems, which have required a higher REC price than other types of renewable energy in many locations have not been adopted as widely as those other forms of renewable energy.

Thus, incentive programs driven by RPS requirements for renewables generally combined with REC prices capped at levels seen in various states, have failed to induce significant solar development, especially absent (1) a specific set-aside or allocation for solar in REC program implementation, and (2) the setting of RPS targets and alternative compliance payments at a very high level (i.e., high enough to overcome the relatively higher cost of solar PV installations), Some states that have sought explicitly to stimulate solar PV markets have tended to use the set-aside approach rather than turning to a higher overall RPS target combined with a higher ACP level, as a more surgical way to induce PV market development.

## Customer Financial Incentive Mechanisms

From the standpoint of market development success, financial incentive mechanisms focused more specifically on electricity customers appear to have been more effective in leading to PV system installation, particularly at the residential or behind-the-meter level. These approaches involve targeted and specific financial incentives that lower the apparent cost to ultimate consumers of purchasing, installing, and operating solar PV systems.

Some have been in use for many years in many states, with varied success. These include various tax or payment mechanisms (e.g., income tax credits or deductions;

rebates of part of the cost to purchase and install a PV solar systems) and regulatory/ electricity-pricing approaches.

In the latter category, an effective policy is "net metering" – a ratemaking policy that operates in combination with an on-site source of generation and the ability of the DG (e.g., PV) system and interconnection equipment to send power from the system into the grid when there is more power being produced than used on site). In this way, the customer's monthly electricity bill reflects the net effect of electricity drawn from the grid less any electricity sent to the grid at times of 'excess' supply on site. Net metering provides additional economic incentive for the customer, in that he/she avoids purchasing electricity when the solar PV system provides a portion of the customer's electricity requirements in some hours, and even permits selling excess power at the full retail electricity rate when the PV system produces more power than the customer needs at any point(s) in time during the billing period. (Since 2005, Colorado has allowed power produced from certain on-site PV systems to qualify for net metering.[17])

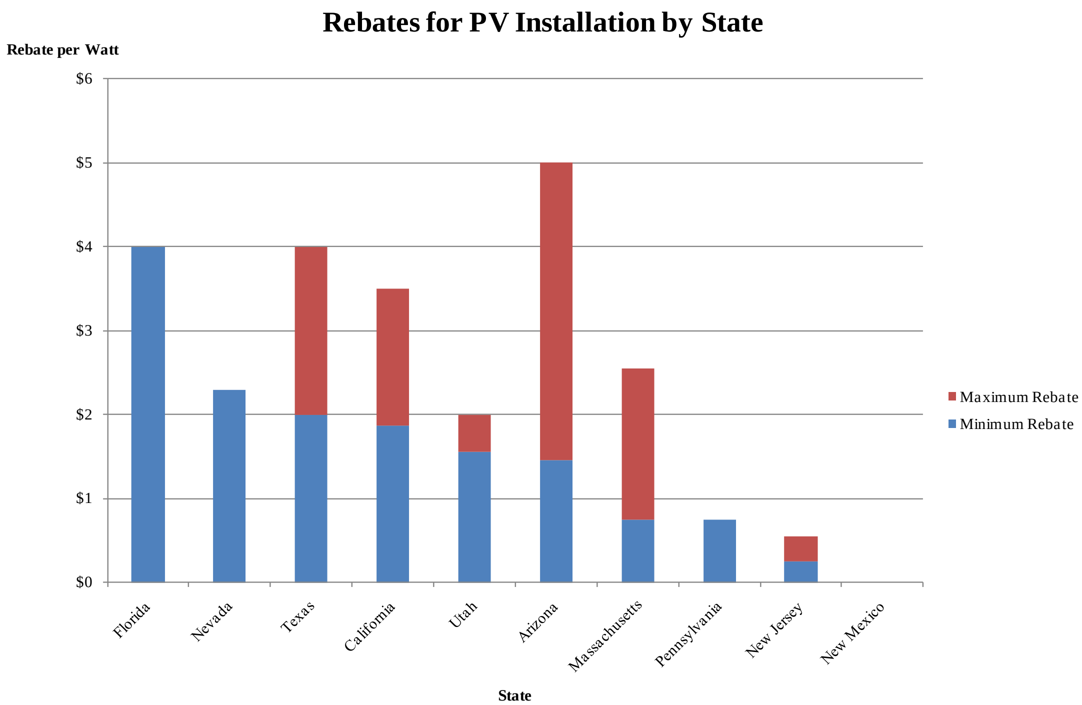
In the former category are direct and immediate financial incentive payments designed to significantly reduce up-front or lifetime solar PV costs, and induce widespread participation in the development of solar resources. (Colorado has significant experience with many of these approaches.) In most states, direct incentive programs typically include one or some combination of (1) an up-front rebate for purchase and installation of solar systems, (2) an up-front payment – or securitization – of a stream of forecast RECs produced by operation of the solar system over some period of time (e.g., 10, 15, or 20 years), and (3) the guaranteed purchase of RECs as they are earned through solar system operation over time. Numbers one and two are often referred to as "up front incentives," number three is commonly referred to as "performance-based incentives."

Figures 6 and 7 show the range of recent up-front rebates and performance-based incentives in a number of states we reviewed.

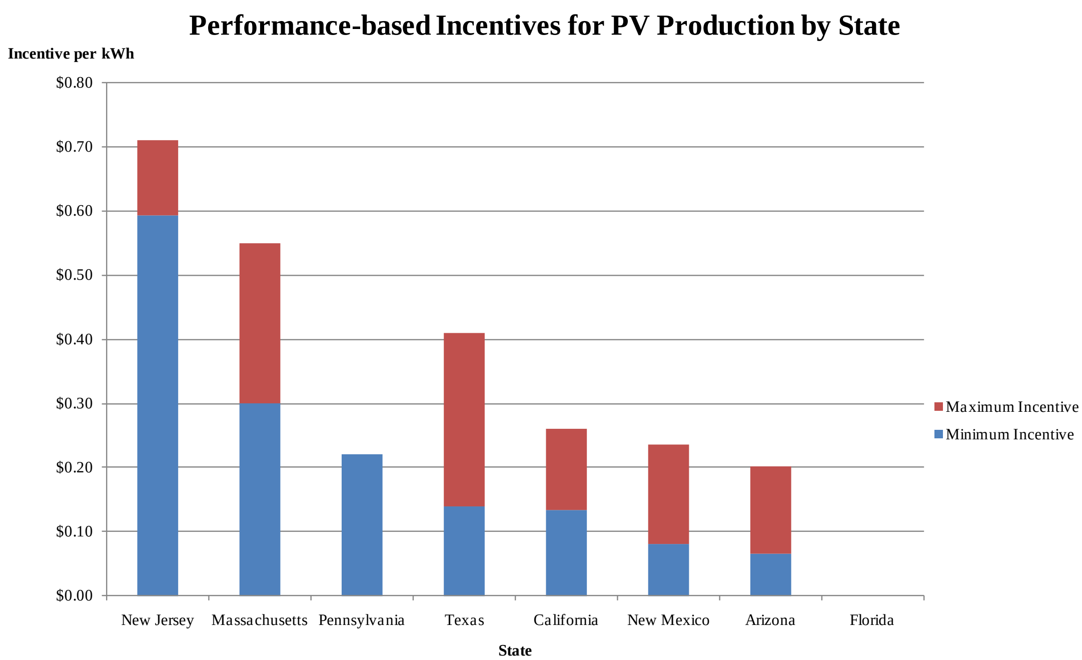
In most states a number of issues associated with the design of tax credits, net metering, third-party financing, and incentive programs have experienced multiple points at which policy decisions have had to be made: first, at the outset when the program was initially designed; and then later, when the policy has been revisited over time after program participation grew, installed costs decreased, and funding caps or limitations were reached.

[17] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CO26R

## Figures 6 and 7




Sources:
1. http://www.dsireusa.org.
2. Colorado PUC.




Sources:
1. http://www.dsireusa.org.
2. Colorado PUC.

In these rounds of program design and revision, the issues have included:

- how to set the incentive payments – either for all types of renewable resources, or for each category of eligible resource (i.e., size) or customer (retail/wholesale or residential/commercial);
- what the term of "contract" should there be for the utility's (LSE's) purchase of RECs – whether in one lump sum at the start, or over time as RECs are generated;
- what should be the phasing over time of rebate or incentive levels as programs grow or pre-set limits begin to be saturated;
- what rate treatment should be afforded utilities through which revenues are collected from customers for funding of the incentive mechanisms;
- how net metering programs should be designed with respect to customer-sited installation size thresholds, ability to carry positive balances from one month to the next, and how to "queue" proposed projects for net metering eligibility as caps or limitations on solar program funding or net metering tariff applicability are approached; and
- how to determine REC ownership when installation and/or maintenance are funded by a third party lender or solar installation and maintenance company, potentially involving a leasing arrangement or contract for the sale of power and/or RECs between the parties.

A special case for program design regarding financial incentive aimed at customers applies in some states where the customer is a public, non-profit or otherwise tax-exempt entity for whom certain financial incentives have little value. For example, New Jersey has provided higher rebates per watt for PV installations adopted by public and non-profit sector entities as compared to private-sector (or individual) customer rebates per watt of PV, in order to encourage public and non-profit entities to implement PV systems.[18]

[18] The amounts of rebates for each group (private sector and public/non-private sector) declined in value over time from 2005, with amounts in that year in some cases up to 30-80 percent higher than the amounts available starting in September 1, 2007, when the rebates were as follows:

| Size of PV system | Private sector and PPA [purchase power agreement] customers rebate per Watt | Public and Non-Profit Sector Rebate per Watt |
|---|---|---|
| 0 – 10,000 watts | $3.50 | $4.10 |
| 10,001 – 40,000 watts | $2.50 | $3.15 |
| 40, 001 – 100,000 watts | $2.25 | $2.50 |
| 100, 001 – 500,000 watts | $2.00 | $2.30 |
| 500,001 – 700,000 watts | $1.75 | $1.85 |

As with utility/LSE-focused programs, most customer-focused financial incentive programs have explicitly limited the impact on rates or bills of utility customers associated with program implementation. A number of approaches to this have been used, and typically involve either an explicit cap or another mechanism that limits the total amount of expenditures on incentives that may be supported by the program. These cost-containment mechanisms include specific limits on rate or bill impacts relative to overall rates/bills (as in Colorado) associated with expenditures on incentives, either up-front or on a performance basis; caps on annual or program lifetime expenditures; specific limits on quantities of solar that may be induced through the incentives.

## Phasing Down/Out of Solar Incentive Programs

Several states have modified their solar programs' incentive levels in recent years to balance out responding to aggressive customers participation levels and/or challenges associated with available funding, on the one hand, while also trying to phase out programs over time as the need for incentives declined, on the other. Energy Trust of Oregon, for example, responded to increased demand for PV rebates by reducing incentive levels for commercial, industrial, non-profit, government and residential systems in order to keep the program open. Such actions can extend the duration of programs and provide greater market certainty by ensuring that incentives are more consistently available.

In addition, a number of incentive programs operate on a declining-block structure, in which incentive levels are designed to decrease when the aggregate capacity installed under the program reaches certain benchmarks. Incentive programs at the state or

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In New Jersey, at "the core of the new solar policy was CORE [Customer On-Site Renewable Energy]. To overcome the up-front cost barrier of PV system construction, the program initially provided rebates of up to 70% of the installed cost or $5.50 per watt. Over time the rate was stepped back, so that by the end of 2006, the highest subsidy in the program had declined about 30%, to about 50% of the installed cost or $3.80 per watt. (Installed costs remained flat through this period at around $8 per watt for small systems.) CORE subsidies varied according to the owner and size of the system. This design was intended to roughly level final costs across the various categories. Larger systems received lower rebates per watt, because costs per watt decline as systems get larger. Public schools and other public projects received higher rebates than private projects at every system size, since their owners were unable to access federal tax incentives that supplemented the state rebate for private PV system owners….The state encouraged commercial and public agency participation in the program by allowing relatively large systems to be net-metered, which was not the case in many other states." David M. Hart, "Making, Breaking, and (Partially) Remaking Markets: State Regulation and Photovoltaic Electricity in New Jersey," MIT-IPC-Energy Innovation Working Paper 09-005 [also MIT-IPC-09-004], Industrial Performance Center, Massachusetts Institute of Technology. July 2009, page 15.

utility level in Arizona, California, Colorado, Nevada, New York, Pennsylvania and Vermont employ step-downs. Programs in Arizona, Colorado, New York and Vermont implemented this structure for the first time this year. In most (but not all) cases, the step-down paths are predictable and transparent so that it is clear to market participants when reductions in incentive levels will occur. The California Solar Initiative and the Pennsylvania Sunshine Solar Program employ such an approach. Both programs have online tracking systems, allowing stakeholders to monitor the status of rebate levels and anticipate step-downs. More detail on phasing programs is provided in Appendix C.

## Recommendations: Issues to Examine in Upcoming Proceedings

To date, Colorado's policies to support the on-site solar market in the state have produced significant PV capacity and installations, with costs borne by those participating in the program as well as the customers of Colorado's utilities. Installations of solar PV systems on customer premises have supported the state's goals of generating more of its electrical demand from renewable (and distributed generation/solar) energy, consistent with the Colorado RES. And Colorado's policy to date has supported development of a solar industry in the state.

Looking ahead, the Commission seeks to understand how different financial-incentive and regulatory approaches in the future might affect costs and benefits for customers' adoption of PV systems and for the development of the state's solar installation market. In the upcoming proceeding to review these issues, we recommend that the Commission focus its docket on the following issues:

1. **Clarifying the going-forward goals for solar PV incentives in Colorado**:

The legislative and regulatory record in Colorado to date has focused efforts on several outcomes. An important goal will be to test the continuing importance of the following goals for solar PV incentives in the state:

First, *increased reliance of the state's power supply on renewable energy*. The starting point for this goal is the statement of intent adopted by people of Colorado when they voted to approve Amendment 37 in 2004:

> Energy is critically important to Colorado's welfare and development, and its use has a profound impact on the economy and environment. Growth of the state's population and economic base will continue to create a need for new energy resources, and Colorado's renewable energy resources are currently underutilized.
>
> Therefore, in order to save consumers and businesses money, attract new businesses and jobs, promote development of rural economies, minimize water use for electricity generation, diversify Colorado's energy resources, reduce the impact of volatile fuel prices, and improve the natural environment of the state, it is in the best interests of the citizens of Colorado to develop and utilize renewable energy resources to the maximum practicable extent.

Second, *balancing these goals with the costs to accomplish them*: Colorado's solar policies aim to balance other goals – use of indigenous renewable resources in the state, economical energy supply, economic development (including in rural areas), mitigation of fuel price volatility, water use and environmental impacts – with others (acceptable levels of rate impacts for electricity customers as they reimburse utilities for the costs of financial incentives needed to encourage installation of on-site renewable energy; and encouraging utility participation through financial incentives and other ratemaking policies).

Third, *fostering development of a viable commercial market demand for PV without reliance on financial incentives provided by utilities*. Over time, Colorado's policies aim to support the ultimate objective of accomplishing the goals of greater reliance on solar PV resources without the need to provide financial carrots paid for by all electricity customers in the state.

The Commission is charged with implementing the statutes relating to renewable energy, and on-site solar PV in particular, while also assuring that rates charged to customers are just and reasonable. Clarifying the appropriate balance across the many objectives of solar PV policy should be an important foundational issue in the upcoming docket.

2. **Clarifying what success looks like, given those going-forward goals for solar PV in the state:**

We recommend that the upcoming docket make inquiries into the types of indicators or metrics that would shed light on the extent to which Colorado has accomplished its goals (such as those articulated above). Two types of metrics seem important to consider:

indicators that reveal the status of market developments; and

indicators that could serve as triggers to allow for reducing and/or removing further financial incentives (or to restore them, in the event of changed market conditions).

Based on our research, we suggest that the following set of metrics would shed light on the solar PV market conditions that exist as of the time of the Commission's docket. The inquiry could test the relevance/usefulness/value of these indicators, along with the current availability of data on each variable as well as the benefits/costs of collecting new information about other variables.

The purpose of data collection would be to provide information on which the Commission could evaluate the effectiveness of policies over time, relative to the goals. Metrics on which data should be collected include:

- Relative cost of on-site solar PV versus other renewable resources on a common unit basis (e.g., installed kW)

- Trends in value (prices) of renewable energy credits as produced by:
    - On-site solar PV located in Colorado on a stand-alone basis
    - Relative to other resources (e.g., from generation from Colorado-based renewable energy versus other renewable energy)
- Trends in customers' adoption of on-site solar PV:
    - Trends in absolute numbers of installations
    - Trends in absolute numbers of MW installed in Colorado
    - Trends in installations/customer (or installations/capita) in Colorado versus in other states with policies promoting adoption of solar resources (and/or renewable resources more generally)
    - Trends in MW of installed on-site solar PV as percentage of total contribution to annual Colorado renewable energy standard goals
- Trends in payback period (and/or Net Present Value) to the customer for customer installation of on-site solar PV, in light of information about the following, with information varying by customer segment (e.g., residential, commercial)
    - Prices of renewable energy credits
    - Prices of retail electricity (including the influences of natural gas prices on such overall price trends)
    - Prices of installed PV systems
    - Capacity factors of PV systems
    - Level(s) and type(s) of financial and other incentive(s) provided by the local utility (through its customers' rates) –
        - Upfront incentive ($/watt)
        - Performance-based incentives (cents/kwh produced)
        - Other
    - Availability of other financial incentives (specifically identified, but such as: federal production tax credits; federal installation tax credits; loans; mechanisms to support financing of investment in on-site PV systems; other mechanisms)
    - Literature on elasticity of demand for on-site solar PV given payback periods, prices of electricity, ease of installation, etc.

- Trends in electricity customers' interest in adoption of on-site solar PV (e.g., in the form of polling data, consumer preference surveys) – and on various factors affecting their willingness to invest in/install systems on their premises
- Trends in costs to provide financial incentives for the adoption of on-site solar PV:
  - Costs recovered from utility customer base
  - Costs unrecovered from utility customer base
  - Size of unrecovered costs relative to utility revenue base
  - Number of years needed to recover unrecovered amounts, if recoveries set at the maximum rate cap
  - Size of incentive (total cost) in relationship to installed on-site solar PV
- Trends in the development of the solar industry in Colorado, such as:
  - Numbers of companies
  - Numbers of employees
  - Contribution to gross state product
  - Installed product prices
  - Time to install after request for installation
- Trend in the amount of incentive provided by the utility (through its customers' rates) relative to the size of the NPV of net benefits to participating customers

Additionally, our research suggests that an important focus of the Commission's review should be to identify triggers for potential reduction or and/or removal of financial incentives for the adoption of on-site solar PV. These triggers might focus on the relationship of the costs of incentives to the level of installed on-site solar PV capacity and to the cost of installed PV systems.

Over time, if Colorado seeks to accomplish its goal of fostering development of a viable commercial market demand for PV without reliance on financial incentives provided by utilities, it will be important to understand when it is possible if not optimal to remove the financial incentive without undermining the development of the solar PV market. This phenomenon, sometimes called "learning by doing," is tied to policies (such as Colorado's on-site solar PV program) that are intended to "promote fledgling energy technologies that promise to reduce our reliance on fossil fuels"[19] (among other things). Typically, policies in place to kick-start a market are designed to correct market failures (such as regulatory barriers to entry, or environmental externalities, or public goods) or the problems associated with first-movers of new technologies.

We recommend that the Commission solicit comments on this "learning-by-doing" issue, with the goal of discovery whether current market conditions warrant removal of financial incentives, and if not, to identify triggers or other indicators that would inform the Commission in the future about market development that warrants such removal.

3. **Identifying "best practices" for design of any incentives that remain necessary to accomplish the state's objectives**

As part of its upcoming docket, the Commission could solicit comments from parties to identify current best practices to support accomplishment of goals for renewable energy, and in particular for on-site solar PV. This part of the inquiry will be important, to the extent that the docket uncovers information about alternative approaches (compared to Colorado's) that accomplish goals for renewable energy at lower overall cost. These cost comparisons should focus on total costs, as well as costs to participating customers (i.e., those that install on-site solar PV systems) and costs to non-participating customers.

Our review of best practices identifies a number of issues that are relevant for the design of policies, including:

- The relative effectiveness of policies focus on set-asides (e.g., a specific MW target or percentage of renewable targets provided by solar) versus credit multipliers (e.g., the relative value of a renewable energy credit generated by a solar project relative to another renewable resource or technology)
- The relative effectiveness of subsides to lower the initial technology investment/installation cost versus the availability of subsidies that flow over the life and performance of the project/technology.
    - The effectiveness with respect to ability to finance the initial investment/installation
    - The effectiveness with respect to level of interest (demand) by potentially and actually participating customers.

[19] See, for example, Arthur van Benthem, Kenneth Gillingham, and James Sweeney, "Learning-by-doing and the optimal solar policy in California," *The Energy Journal*, July, 2008, http://www.entrepreneur.com/tradejournals/article/181856442.html.

- The relative effectiveness of the presence of an alternative compliance payment ("ACP") mechanisms in accomplishing the outcome of installed MW of on-site solar PV for the expenditures by utility customers
    - The effectiveness of an ACP in mitigating rate impacts
    - The effectiveness of an ACP in leading to installed MW (total payments per MW installed)

The Commission's docket could include our review of best practices, with the expectation that commenting parties would enhance the record on these important issues.

4. **Identifying complementary policies that are integral to sustainable accomplishment of Colorado's goals for solar PV**

As part of its upcoming docket, the Commission should inquire about the continuing alignment (or lack thereof) of other regulatory and ratemaking policies in support of its other policies (including financial incentives), such as:

- Net metering
- Interconnection practices for on-site solar PV systems
- Availability of financial incentives for utility participation
- Security of the regulatory asset associated with uncollected costs to provide financial incentives
- Availability of Property Assessed Clean Energy ("PACE") incentives
- Availability and design of revenue decoupling
- Other policies

# APPENDICES

# APPENDIX A

## Staff working paper of the Colorado Public Utilities Commission, "Analysis of Solar Photovoltaic Systems Installed Under Colorado's Renewable Energy Standards Through December 2009," December 3, 2010

("Internal PUC Work Product")

Dora
Department of Regulatory Agencies

# Analysis of Solar Photovoltaic Systems Installed Under Colorado's Renewable Energy Standard Through December 2009

Staff Working Paper
December 3, 2010

Colorado Public Utilities Commission
Suite 250
1560 Broadway
Denver, CO  80202

Consumer Protection

## Preface

In November 2004, Colorado voters passed Amendment 37 which created the Renewable Energy Standard (RES) for Colorado electric utilities. An important component of the RES for Colorado's investor owned utilities (IOUs) was a requirement that they acquire a small percentage of their renewable energy from solar systems. As part of that solar set-aside, the IOUs were also required to establish standard offer programs to encourage IOU customers to invest in solar systems and help compensate them for the above market costs of solar electric generation. Colorado's two investor owned utilities, Public Service Company of Colorado (PSCo dba Xcel Energy) and Black Hills Colorado Electric (BHCE), initiated their standard offer programs in March and September of 2006, respectively.

Initially, the standard offer programs compensated customers at the rate of $4.50 per installed $Watt_{dc}$ which, in most cases, covered more than 50 percent of the installed cost. To minimize the actual investment that would be required by the IOUs for compliance with the RES, the utilities were granted up-front cost recovery via a rate rider known as a Renewable Energy Standard Adjustment (RESA). Thus, the real investment in these solar energy systems has been provided not by the utilities, but by the customers who install them and by the ratepayers via the RESA surcharge applied to their monthly bill.

The goal of the solar set-aside and the standard offer was to provide support for a nascent solar industry that would not be viable without the public subsidy. And, while the utilities have been required to file annual compliance reports that demonstrate their compliance with the RES, these reports have provided only sparse data about the PV incentive programs. Similarly, the monthly RESA reports required by the settlement agreements that allowed the utilities to begin collecting a RESA rider also do not offer sufficient granularity to assess the unit costs or the geographic distribution of PV installations. Those settlement agreements, however, do require the utilities to submit system level data to the PUC, but this data has heretofore not been subjected to a rigorous evaluation. Thus, this study was undertaken to provide the first comprehensive report to the public concerning the success of its investment in the creation of a solar industry in Colorado. Based on data provided by the two IOUs, we report on the installed capacity, costs, and the state of the industry that has resulted from the public's investment in small (up to 10 kW) and medium scale (up to 100kW) solar energy systems from 2006 through 2009.

In this report, we occasionally refer to the Commission's policy on distributed generation incentives developed in response to House Bill 07-1228 (codified as *§40-2-109.5, C.R.S*). This DG policy was founded on a Staff report entitled *Distributed Generation Incentives for Colorado Consumers* dated 17 December 2007.[1]

This analysis of photovoltaic systems developed under the Colorado RES is based partly on information filed in the PSCo docket that created its RESA (06S-016E) and the BHCE compliance plan docket that first required reporting of its RESA expenditures (08A-470E).

[1] Both the distributed generation report and the Commission's letter of transmittal to the General Assembly (dated 25 January 2008) may be found on the PUC website under Docket No. 07M-230E.

# Table of Contents

# 1.0 Introduction

The Colorado Renewable Energy Standard (RES) – codified as 40-2-124, *C.R.S.* – requires Colorado's two investor owned utilities (IOUs), Public Service Company of Colorado (PSCo) and Black Hills/Colorado Electric Utility Company (BHCE), to generate four percent of their annual RES obligation from solar electric technologies. Of this amount, half must come from customer sited facilities.[2] Virtually all of the customer sited photovoltaic (PV) systems up to 100 $kW_{dc}$ installed in these utility service territories have resulted from standard rebate offer (SRO) programs offered by the utilities. This report presents an analysis of the system costs, capacity, and geographic distribution of the systems installed under these programs based on data obtained from the utilities through December 2009.[3] For ease of analysis and discussion, we consider the two utility programs separately.

## 1.1 Background

Colorado's renewable energy standard began in November 2004 with the passage of ballot initiative Amendment 37, which established the RES in Colorado. As noted above, the statute requires Colorado's two IOUs to obtain a minimum of four percent of their annual RES obligation from solar electric technologies and half of that amount from customer sited facilities. The principal mechanism for incentivizing these customer sited systems has been the SRO consisting of a combined rebate and renewable energy credit (REC) payment that offsets customers' up-front costs of installation. These SRO programs provide a statutorily mandated rebate of $2.00 per DC Watt of capacity for the first 100 $kW_{dc}$ plus a payment for the purchase of 20 years of future RECs from the installations. For "residential" systems up to 10 $kW_{dc,}$ the REC payment consists of an up-front payment based on the estimated generation from the system over the 20 year period.[4]

[2] HB10–1001, enacted in the 2010 legislative session, replaced this solar carve-out with a distributed generation set aside. Rules to implement the new legislation are presently being promulgated by the Colorado Public Utilities Commission.

[3] This report updates an earlier preliminary analysis that considered data through May 2009.

[4] Although commonly referred to as *residential* systems, these maximum 10kW systems may be deployed by commercial customers as well.

For systems larger than 10 $kW_{dc}$, the RECs are purchased at an established rate on a pay for production basis; this has certain similarities to a feed-in tariff, an incentive mechanism that has been widely implemented in Europe and been the subject of widespread debate recently in the U.S. Initially, both utilities established an up-front payment of $2.50 per Watt for the REC purchase. In October 2009, PSCo lowered that amount to $1.50/W and has recently implemented a degression schedule for further reductions in the price paid for solar RECs.

### 1.2 Solar Program Analysis Overview

For this analysis, PV systems are classified according to the same categories used in the utility incentive programs and are broken down according to the following criteria: small systems (0.5 kW-10 kW), medium systems (10.1 kW-100.0 kW), and large systems (100.1 kW-2 MW).

Most of the large systems have been built by third-party developers who bid the systems into competitive solicitations run by the utilities. Typically, the customer-hosts of these systems acquire the energy from them via a Purchase Power Agreement (PPA) with the developer and a net metering arrangement with the utility. The PPA energy price paid by the host represents the first revenue stream to the developer while the utility REC payment constitutes the second and most important revenue stream to the developer. The REC prices under these competitive solicitations have been protected as confidential by the utilities and the PPA energy prices have been similarly protected by the developers. In addition, the installed costs for systems funded under these PPA arrangements are not reported to the utilities, thus we have no data with which to report to the public on the cost effectiveness of the large systems or with which to analyze trends in installed costs. Because of the unavailability of large system data, this report will present our analysis of only small and medium sized systems.

PSCo began its solar rebate program in March 2006, shortly after the Commission approved the company’s first Renewable Energy Standard Adjustment (RESA) rider, which was then 0.6 percent of a customer’s total electric bill. BHCE (then Aquila) introduced its solar incentive program in September 2006. Given that the RESA is calculated on top of all other rate adjustments, it is often referred to as a *super rider*. With nearly four years of data, this report examines the trends and results of these programs through the end of 2009. One of the key questions that will hopefully be answered from this analysis is whether the solar incentive programs are achieving their principal goal of reducing the costs of solar energy over time. We also sought to discern whether there is equity in the penetration of these systems geographically and, where possible, across customer segments. Third, we sought data on the growth of the nascent solar industry in Colorado: its key players and the revenue garnered from the program. Metrics employed included the average cost per DC watt installed, average system size and geographic distribution, the distribution of the system capacity and total kW per installer, and the number of systems installed per capita in the counties served by the two IOU programs.

# 2.0 Review of Public Service Company of Colorado (Xcel Energy) Solar Rewards Program

## 2.1 Introduction to PSCo Solar Rewards

As noted above, PSCo's solar incentive program was initiated in March 2006 and was funded by an initial RESA of 0.6 percent.[5] For the most recent systems included in this analysis, incentive payment rebates for small systems consisted of a $2.00/W_{dc}$ rebate plus an additional $1.50/W_{dc}$ REC payment. Medium systems received $2.00/W_{dc}$ plus $115/MWh of energy produced. Net metering is also provided for all installations.

## 2.2 Total Installations and Installed Capacity – PSCo

Evaluating the total growth of installed solar capacity is key to assessing the performance of a program that is intended to bring more solar-generated electricity online. Through December 2009, the total installed capacity in small and medium systems in PSCo territory was approximately 23.5 $MW_{dc}$.[6] The annual capacity additions shown in figure 1 demonstrates robust growth over the first three years of the program. Although 2009 had the most systems installed, the growth rate did level off that year.

[5] The initial RESA tariff of 0.6 percent was arrived at in a settlement agreement between PSCo, PUC Staff, and interested parties in docket 06S-016E. It has since been increased twice and is presently at 2.0 percent.

[6] As discussed later, BHCE added an additional 1.2 $MW_{dc}$ in its service territory for a combined total of 24.7 $MW_{dc}$. However, we remind the reader that this total represents only the small and medium systems installed under PSCo's and BHCE's incentive programs and is roughly half of the total installed capacity of 59 MW in Colorado reported by the Solar Energy Industries Association in its 2009 US Solar Industry Year in Review, 15 April 2010, p. 5.

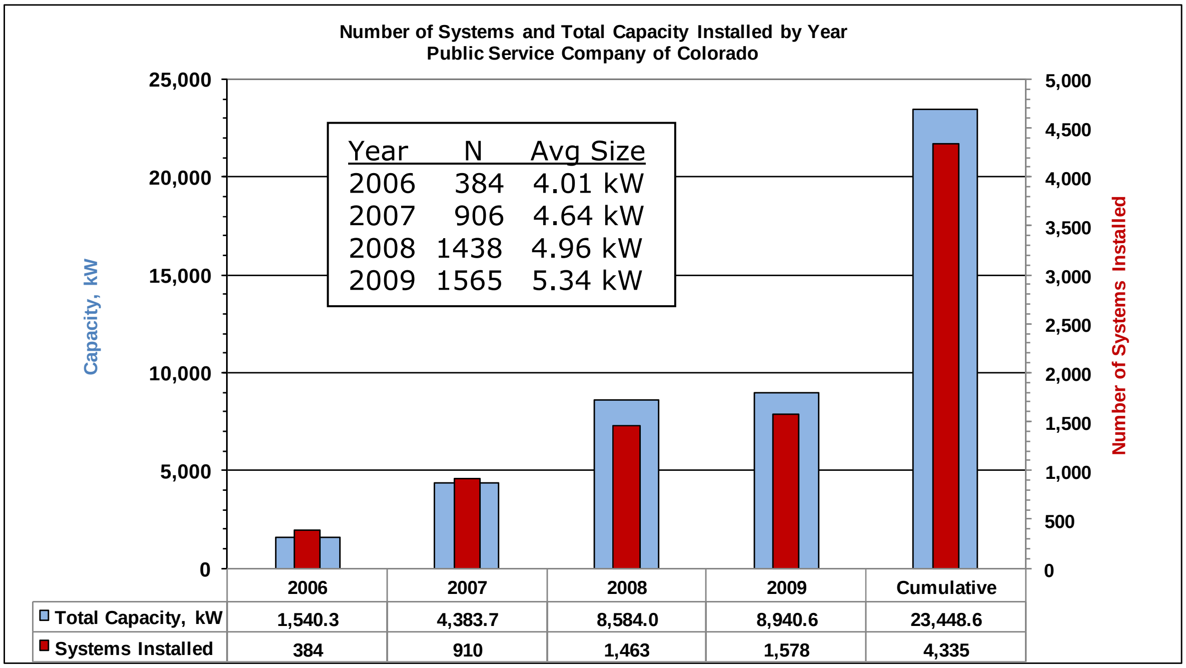



Figure 1 - Annual capacity and system additions for Public Service Company of Colorado.

As shown in the text box within figure 1, when the ≤10 kW systems are isolated, there is also a steady growth in average system size from 4.01 kW in 2006 to 5.34 kW in 2009. For the four years covered by this analysis, the histogram in figure 2 indicates that approximately 65 percent of the 4,335 systems installed in PSCo's service territory range from 2 to 6 kW in capacity. A significant minority, approximately 11 percent, are from 9 kW to 10 kW. Recall that projects through 10 kW in size benefit from receiving both the rebate and REC payment as an up front lump sum while larger projects receive their REC payments on a production basis. The database used for this analysis contained only 42 projects greater than 10 kW and up to 100 kW.

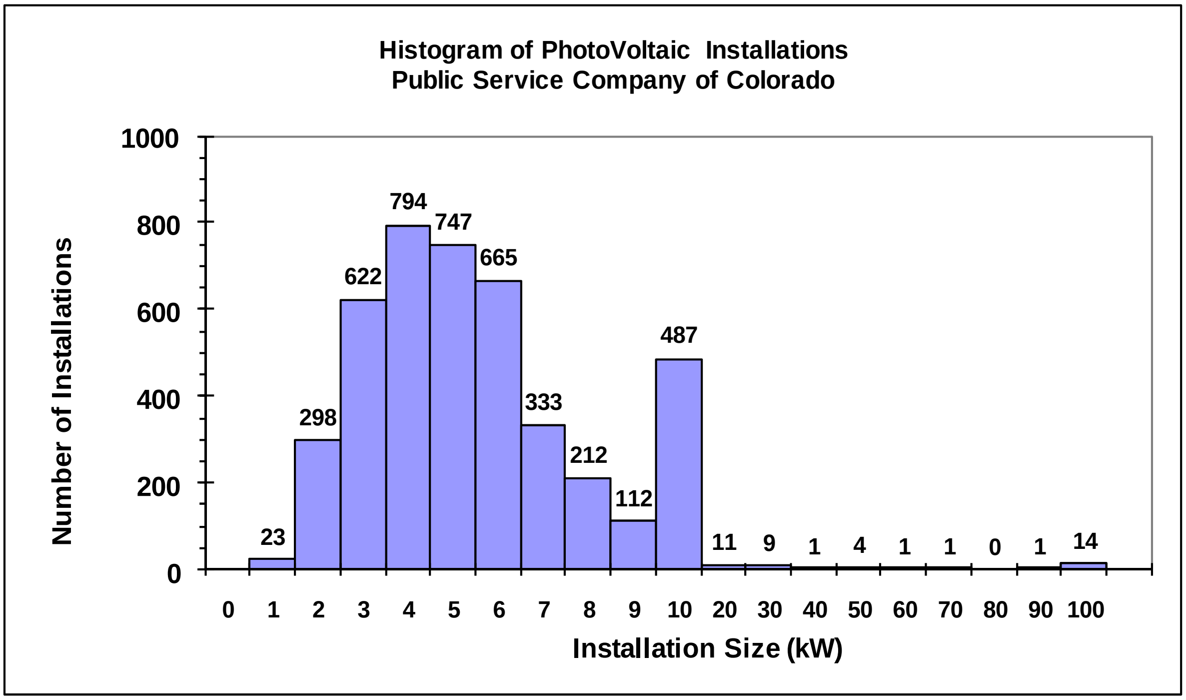
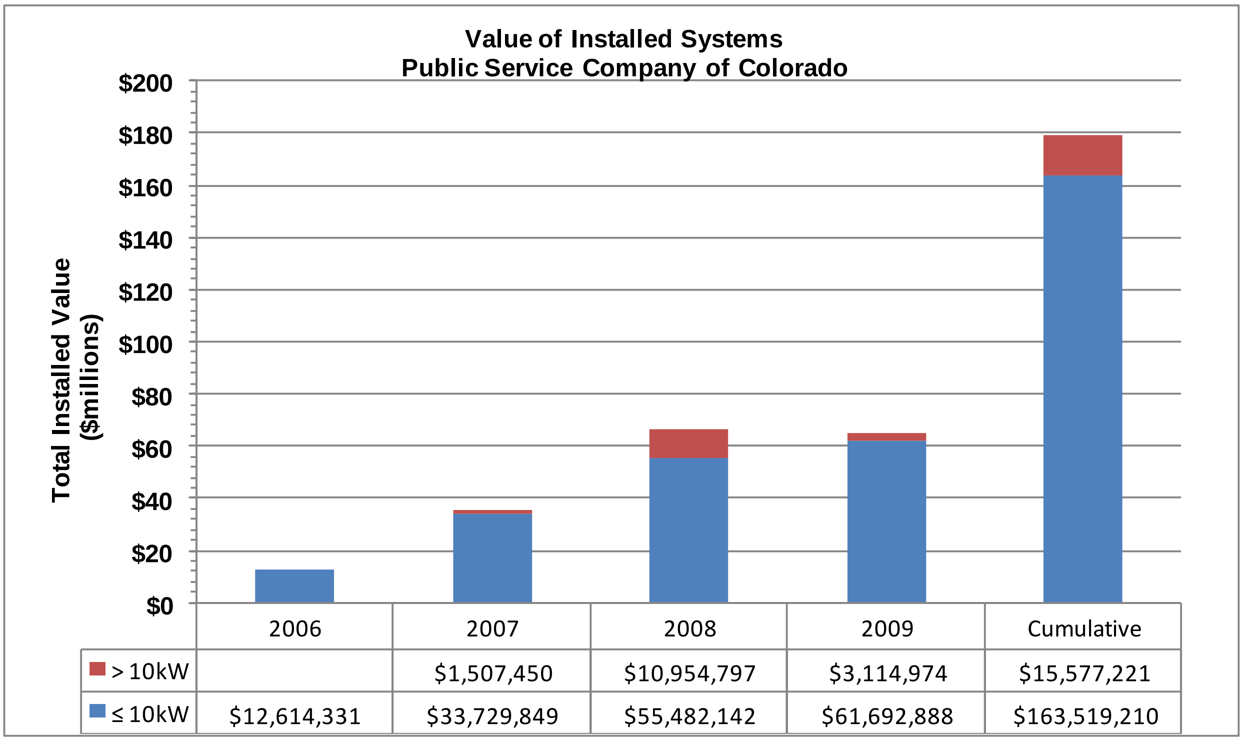



Figure 2 - This chart presents a histogram showing the size distribution of all PSCo installations. The bulk of the systems are between 2 kW and 6 kW but there are a significant number of 9 kW to 10 kW systems. Further analysis revealed that nearly half of the 9 kW to 10 kW systems are small commercial rather than residential, per se.

Figure 3 shows the total value of the economic activity created by the solar program in PSCo's territory as a result of the incentive program (again, this considers only small and medium systems acquired through the SRO). As shown in the chart, these systems are responsible for creating a small solar industry that has grossed over $179 million between 2006 and 2009.




| | 2006 | 2007 | 2008 | 2009 | Cumulative |
|---|---|---|---|---|---|
| > 10kW | | $1,507,450 | $10,954,797 | $3,114,974 | $15,577,221 |
| ≤ 10kW | $12,614,331 | $33,729,849 | $55,482,142 | $61,692,888 | $163,519,210 |

Figure 3 - Economic activity created by PSCo's small and medium solar program from 2006 through 2009.

## 2.3 County Analysis – PSCo

The distribution of capacity and installations by county (figure 4) illustrates which portions of the state have been able to take advantage of the PV incentive programs required by the RES. With 1,636 completed projects, Boulder has by far the most installations of counties within PSCo's territory. Denver, Jefferson, Mesa, and Arapahoe finish up the top five with total of 1,946 completed projects among them. On a capacity basis, the same top five counties lead the analysis with only Denver and Jefferson counties switching places.

Boulder County also leads the capacity rankings with just over 9 MW of installed capacity – more than twice that of second place Jefferson County.

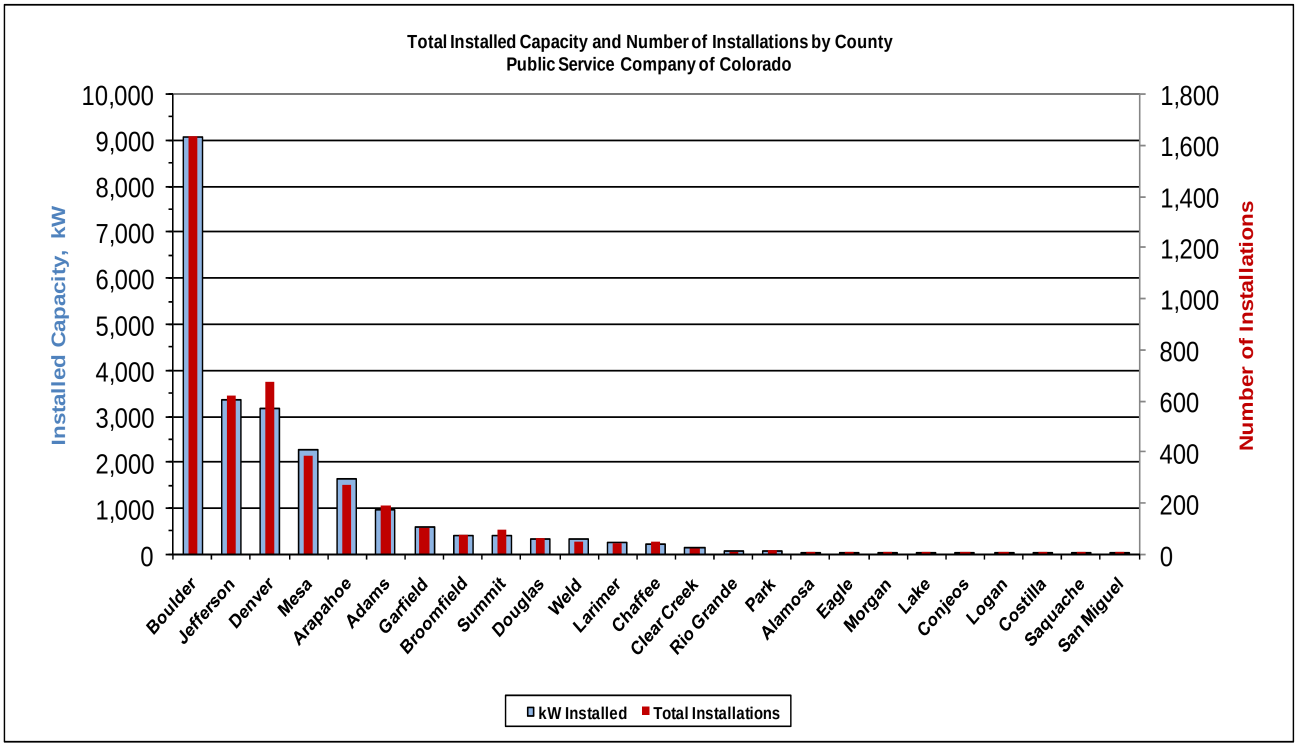



Figure 4 - Total installed capacity and total installations by county in PSCo territory.

Since the population of each county is not equal it may be illustrative to view that same data on a per capita basis. As shown in figure 5, Boulder County still leads the county rankings by a wide margin, but the next few show some surprises with several rural counties coming in ahead of the metropolitan Denver counties. Of course, this does not tell the entire story either and it could prove interesting to add to this analysis a breakdown according to per capita income within each county.

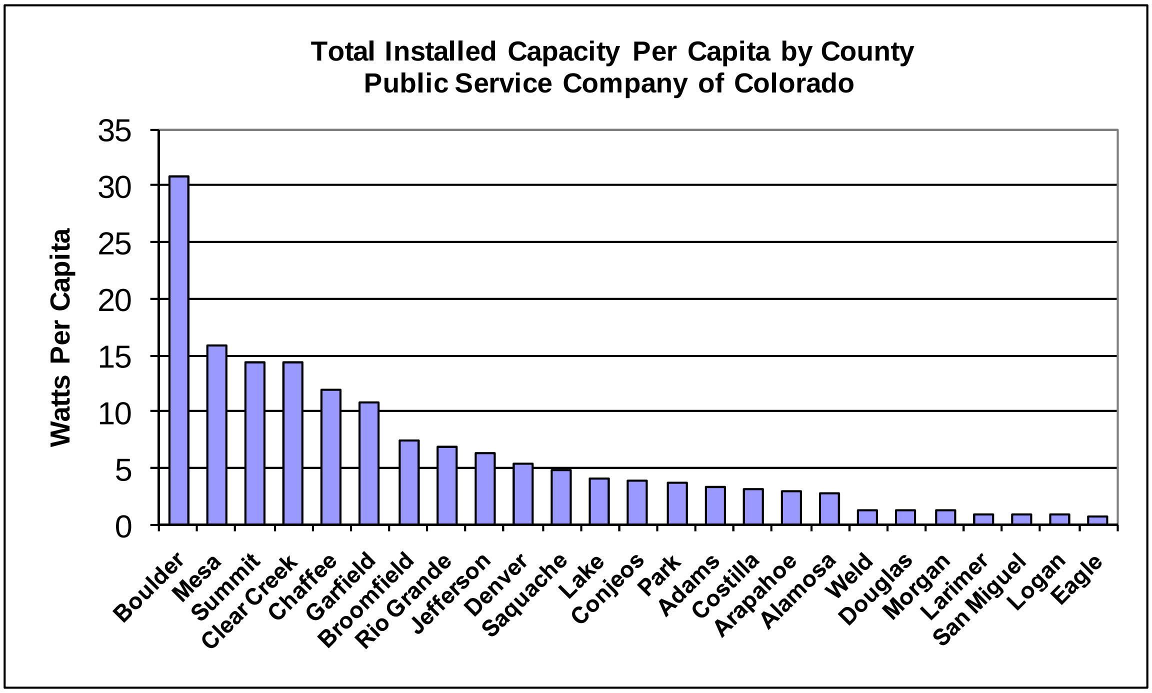



Figure 5 - Total installed PV capacity per capita by county in PSCo territory.

Perhaps a better feel for the geographical distribution of PV systems in the IOU service territories can be obtained from the maps shown in Figures 6a and 6b. These figures, based on data for installations through May 2009 illustrate visually the concentration of PV installations in Boulder and a few other communities.

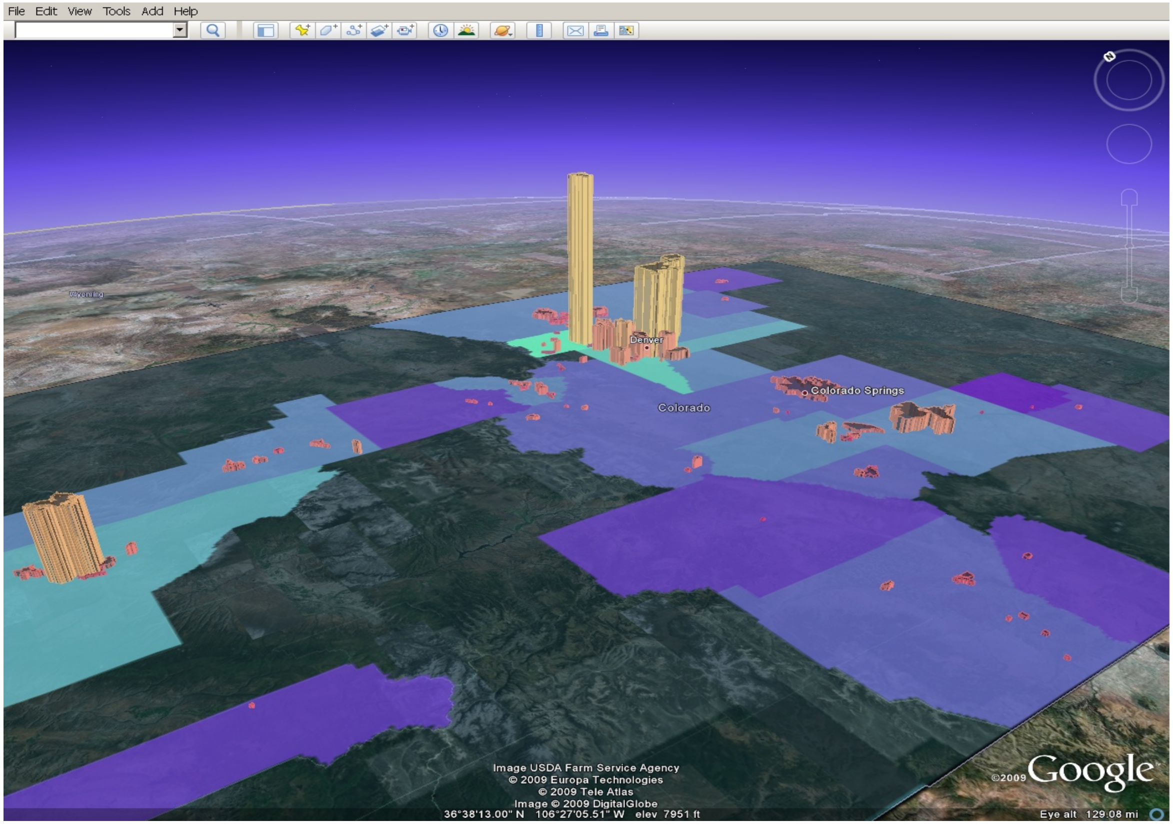



Figure 6a – Composite map showing installed PV capacity by city and county based on May 2009 data. For the county overlay the lighter teal indicates more capacity while the darker purple indicates less. For the incorporated areas, a higher elevation and lighter color indicate greater capacity.

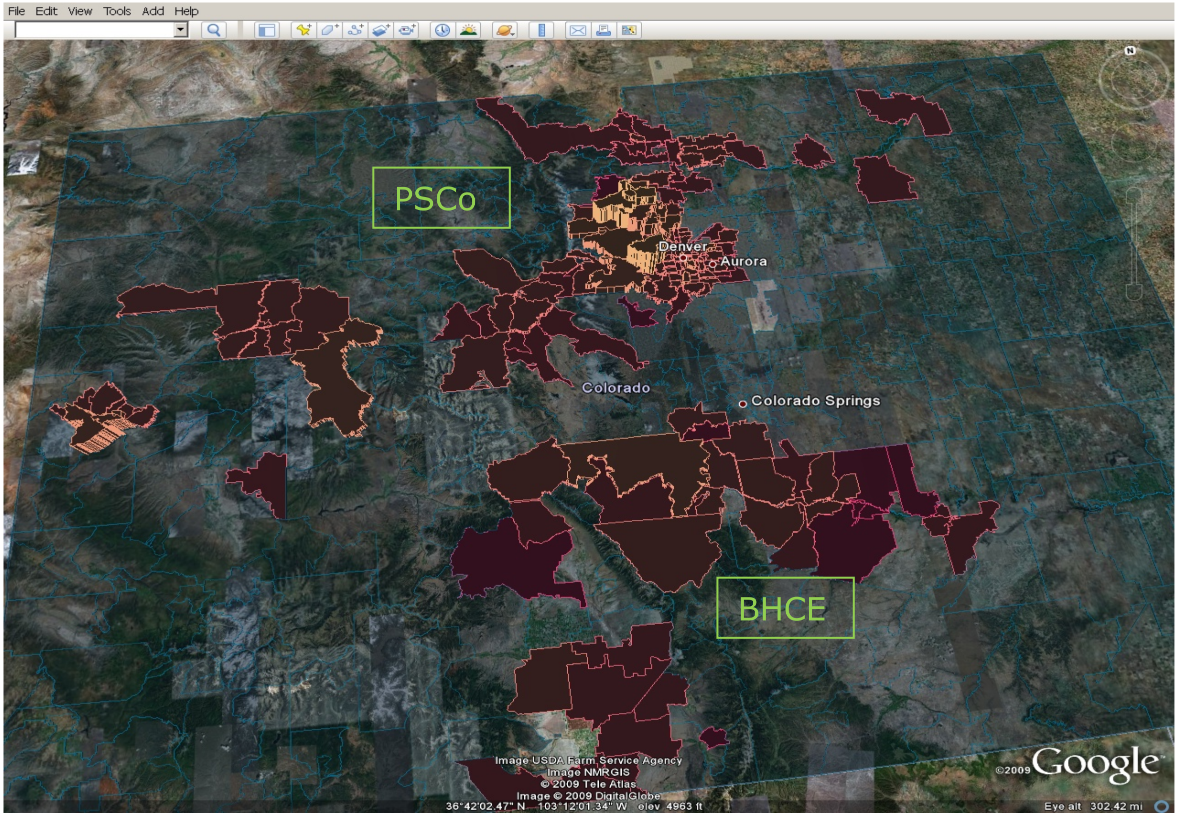



Figure 6b – Map of Colorado showing installed PV capacity by zip code based on May 2009 data. Higher capacity values for individual zip codes are indicated by lighter colors and greater elevations.

One additional item of county-level data illustrates the uneven distribution of benefits from the RES incentive programs. As noted earlier, the PV rebates are set at a statutorily mandated $2.00 per Watt and PSCo's up front REC payment started at $2.50 per Watt and declined to $1.50 per Watt in October 2008. However, the funds for these incentive payments come from the RESA rider paid by all PSCo customers. Figures 7 and 8, respectively, show the total and per capita incentive payments received by residents of each of the counties in PSCo's territory. Given that the incentives are capacity based, it is not surprising to find that Boulder again leads the rankings in terms of both total incentive payments received from PSCo ratepayers and per capita incentive payments received. From this, it is clear that some communities receive economic benefits from RES-mandated programs disproportionately to their contributions to the RESA fund.[7]

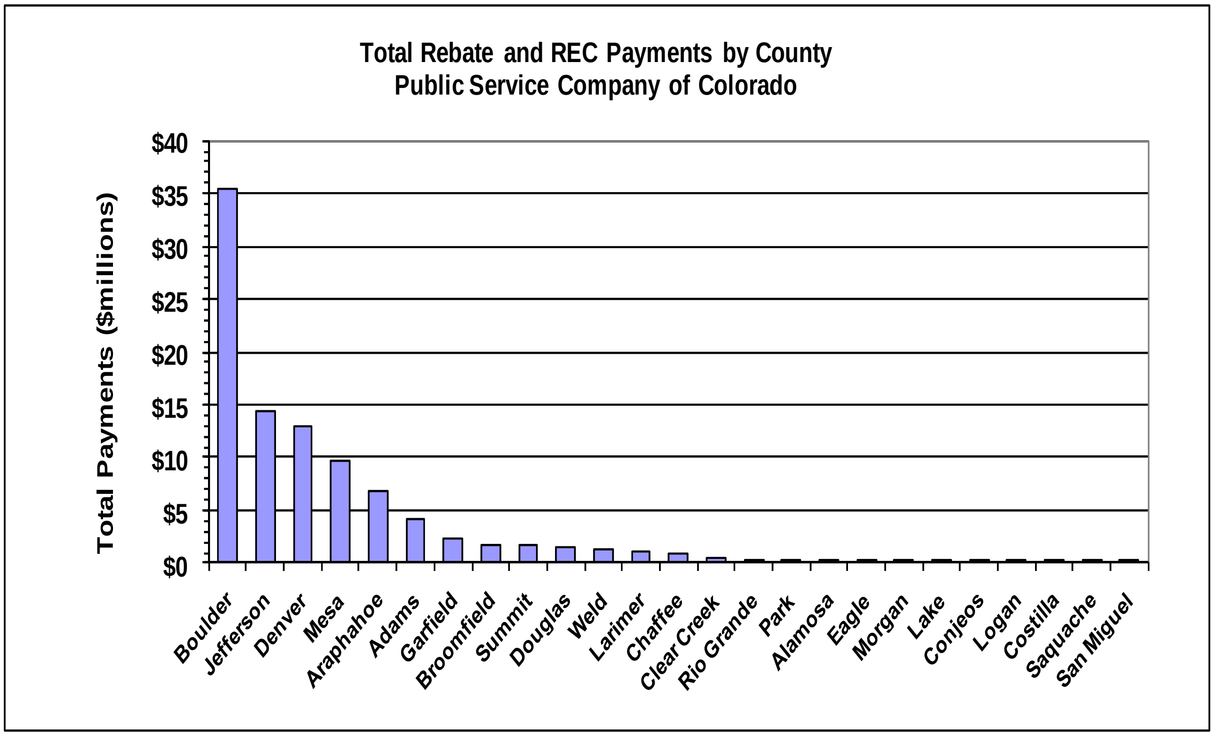



Figure 7 - Total incentive payments received by residents of the counties in PSCo territory.

[7] The Commission policy on distributed generation incentives developed in response to House Bill 07-1228 was founded on eight guiding principles. The second and third of these principles, respectively, state that 2) responsibility for compliance with the RES should be borne equally by all consumers and companies, and 3) there should be congruence between the population that pays for incentive programs and the population that benefits from them.

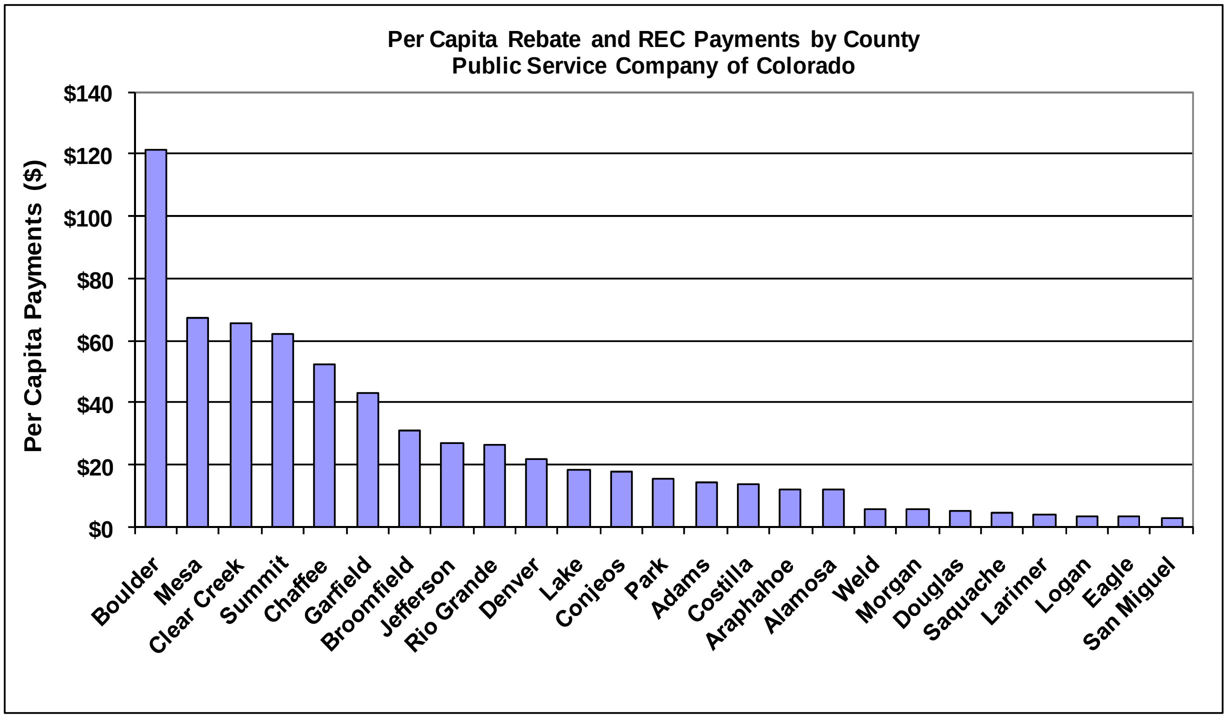



Figure 8 - Per capita incentive payments received by residents of the counties in PSCo territory.

## 2.4 Contractor Analysis – PSCo

One of the motivations for the solar PV incentive program was to stimulate economic activity and help grow Colorado's nascent solar industry. The utility databases analyzed for this report include, for each system, the identity of the installer and the invoiced cost for each of the systems funded by ratepayer provided incentives. To preserve the confidentiality of each individual customer and transaction, we present this data only in aggregate or summary form. In the next two sections, we first analyze the state of the small solar installer industry as represented by the systems in the database. In the following section, we then analyze the cost of these systems.

Figure 9 shows the growth in solar installers as represented by those erecting systems for PSCo customers. In 2006, the first year of the solar incentive program, only 36 installers were responsible for the 384 systems installed that year. By 2009, 130 installers were responsible for the 4,335 systems installed.

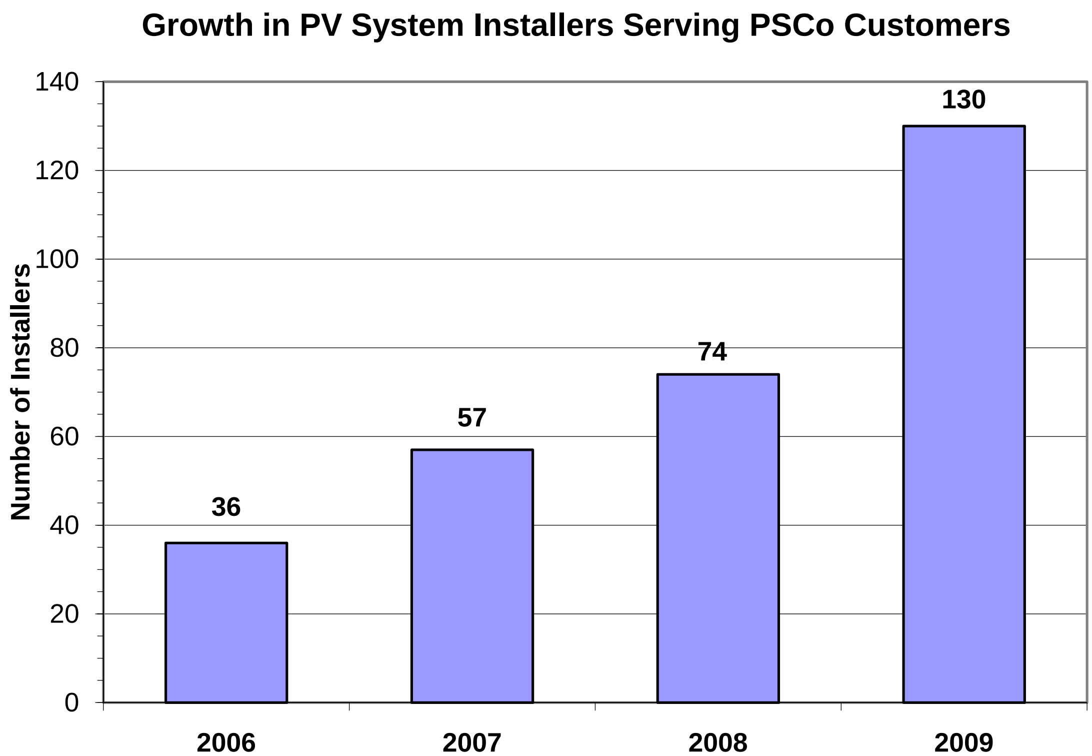



Figure 9 - Chart showing the number of installers represented in the PSCo database.

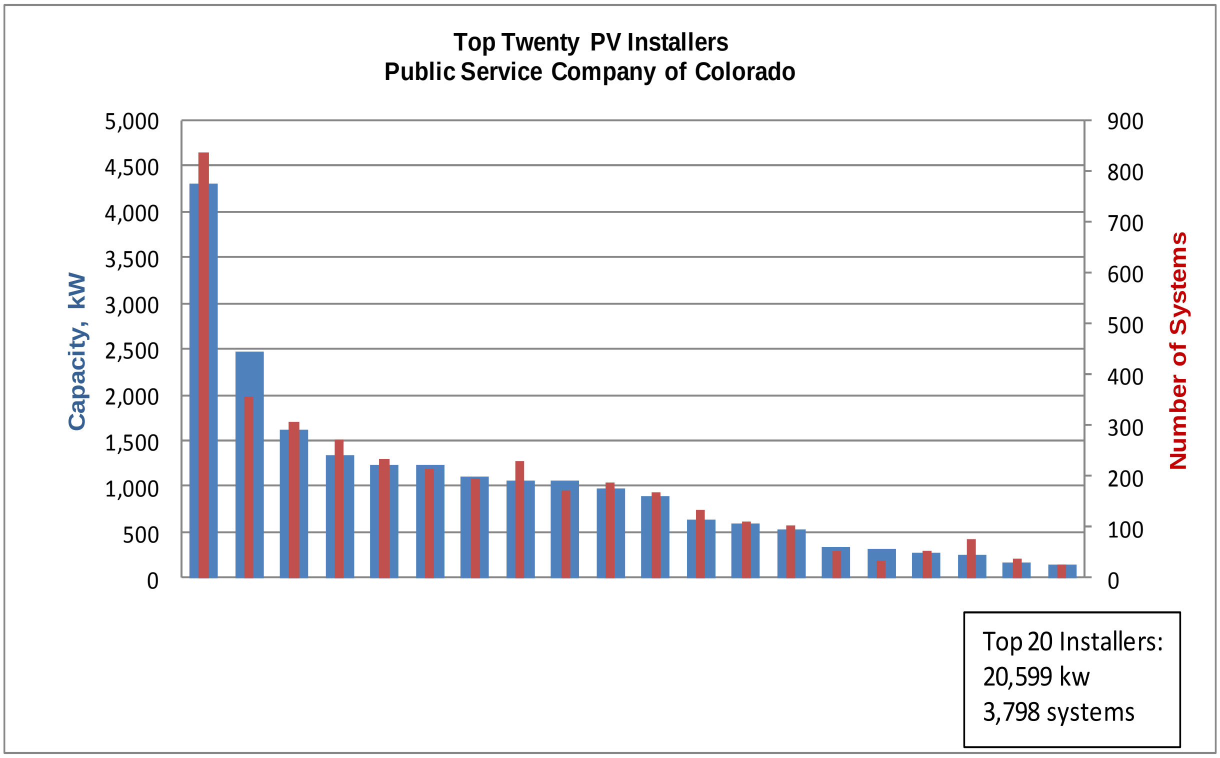



Figure 10 - Top 20 installers in PSCo database.

Figure 10 shows the top 20 installers by capacity in the PSCo database (also shown on the right hand axis are the number of systems installed). This chart illustrates the concentration in the industry. Although there were 130 installers listed in the database, the top 20 accounted for nearly 88 percent of the total installed capacity from 2006 through 2009 while the top 5 accounted for nearly 47 percent. The market leader held an 18.3 percent market share as measured by installed capacity. Moreover, each of the top nine installers had installed at least 1 MW of capacity over this time period.

The same data from figure 10 was also used to calculate the average system size installed by each of the top 20 contractors (figure 11). The horizontal axis lists the same top 20 installers but there is no apparent relationship between installed capacity and average system size.

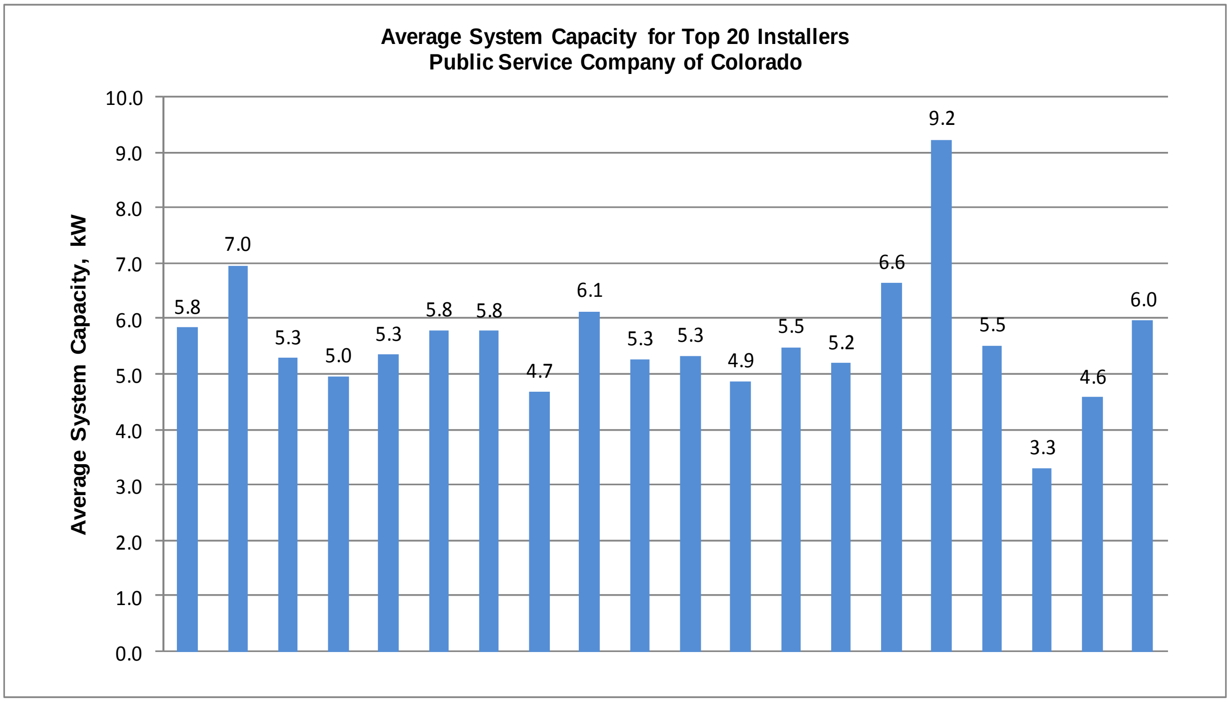



Figure 11 - Average system capacity for the top 20 installers in the PSCo database.

## 2.5 Cost Analysis – PSCo

The data analyzed for this report included the installed cost for the system as reported by the party entering the data into PSCo's database (generally, this is done by the installer). This amount represents the price to the customer before any rebates or other incentive payments. Figures 12 and 13, respectively, show the trend in unit costs for under 10 kW and over 10 kW systems. Although there is a great deal of dispersion in the data, these charts indicate a mild downward trend in the unit cost of systems installed under the SRO over time. We surmise that the wide range of installed unit costs may likely be due to the wide variety of roof types and other installation conditions encountered by the installers.

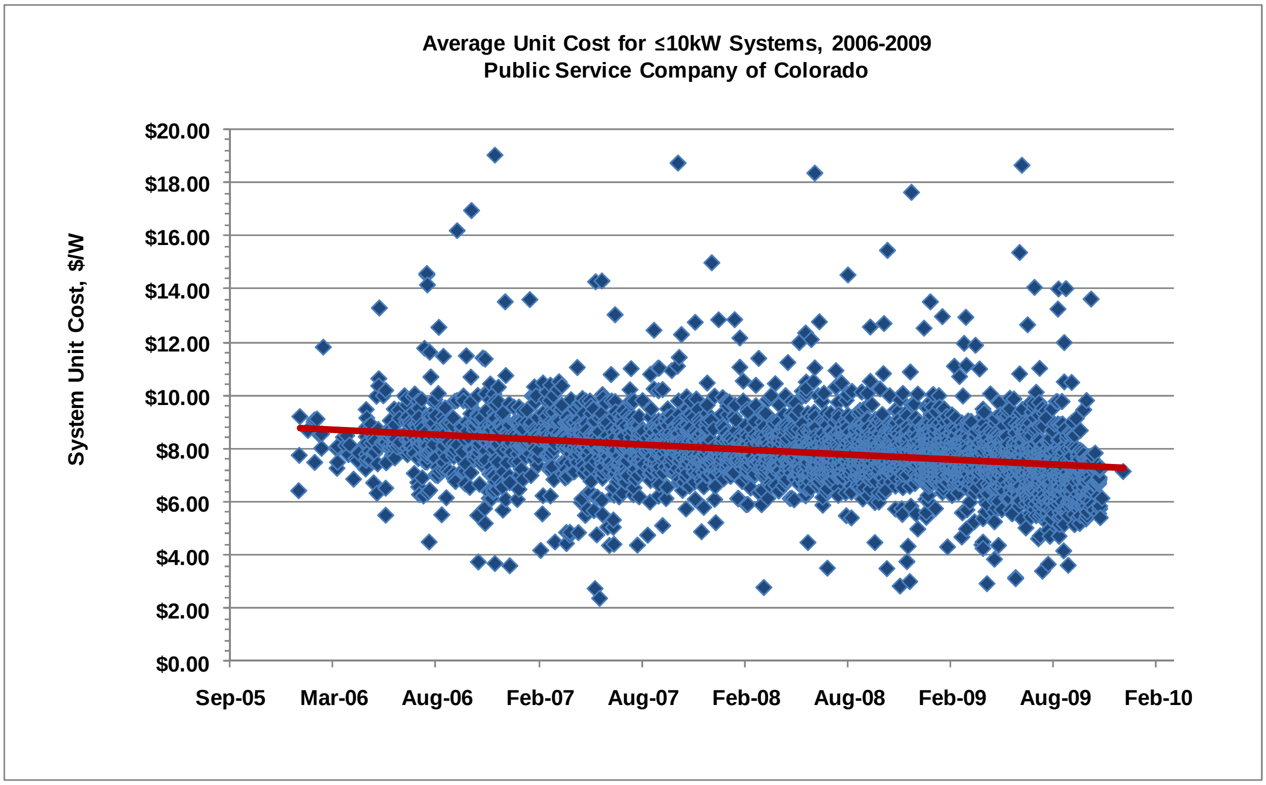



Figure 12 – Trend in system unit costs for PSCo's 10 kW and under SRO.

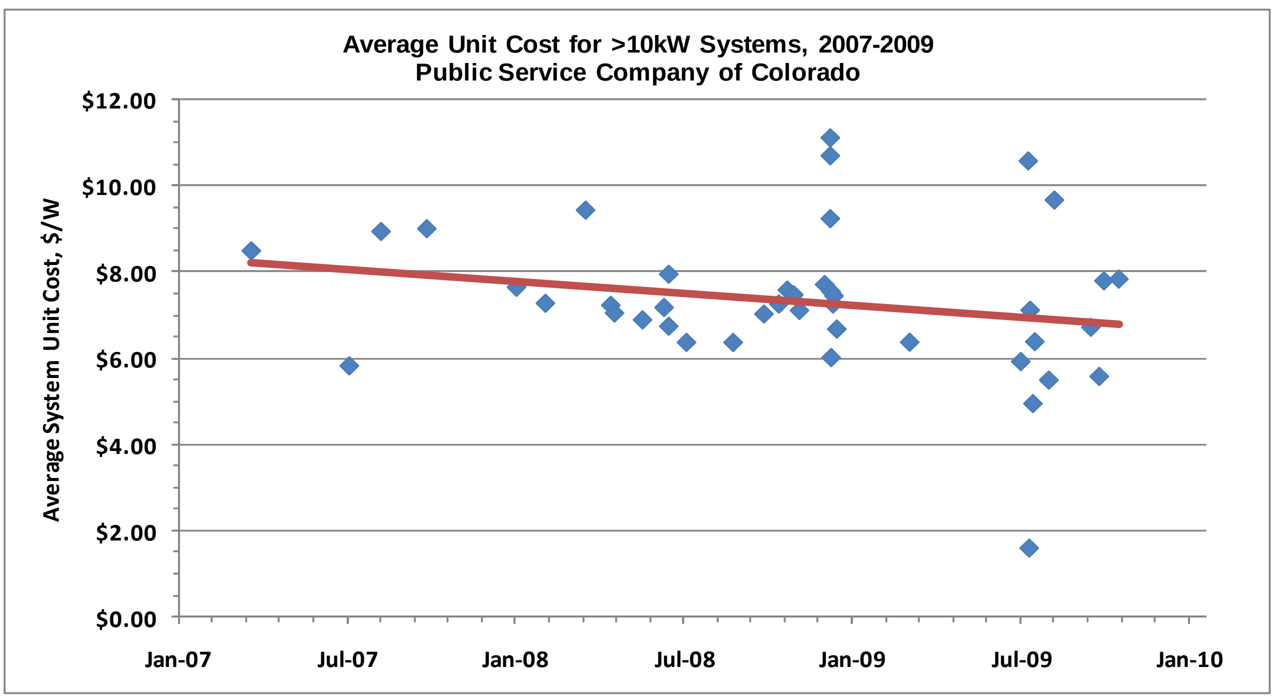
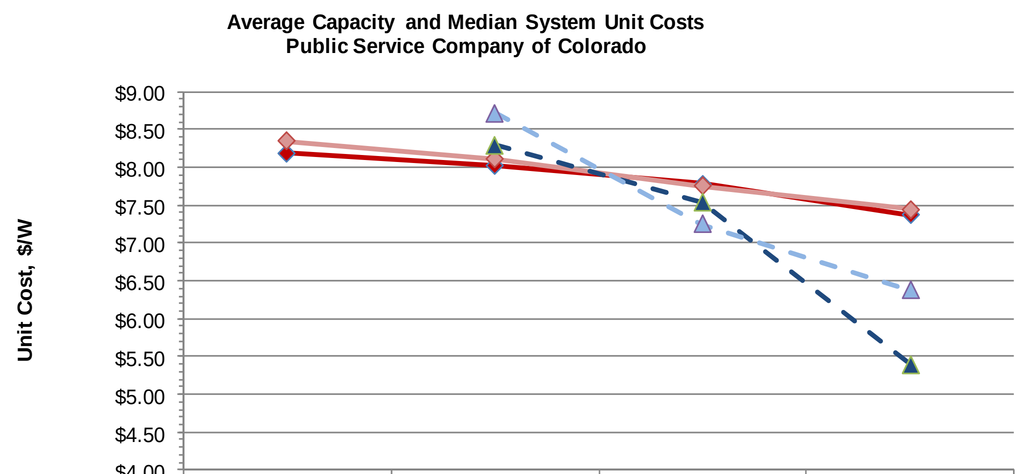



Figure 13 – Trend in system unit costs for PSCo's over 10 kW SRO.

When segmented by year, the cost reduction over time is more easily discernable. As shown by figure 14, the median unit cost for 10 kW and under systems declined by only $0.90 per Watt (11 percent) from 2006 through 2009. In contrast, the median unit cost of larger systems declined by nearly 27 percent, from $8.71 per Watt to $6.37 per Watt, in only three years. This data seems to support the generally held assumption that larger systems are more cost effective than the smaller residential systems, likely due to economies of scale in panel prices and amortization of fixed costs over greater capacity.




| | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|
| Under 10kW, Avg Cost | $8.19 | $8.03 | $7.78 | $7.38 |
| Under 10kW, Median Cost | $8.34 | $8.11 | $7.75 | $7.44 |
| Over 10kW, Avg Cost | | $8.29 | $7.54 | $5.40 |
| Over 10kW, Median Cost | | $8.71 | $7.25 | $6.37 |

Figure 14 – Annual trends in average capacity and median system unit costs under PSCo's SRO.

Similar to the weak trend shown in figures 12 and 13, there also appears to be a mild but discernable relationship between unit cost and system size for 10 kW and under systems. Figure 15 shows only a slight decrease in unit cost with increasing system capacity indicating that customers receive only a modest benefit due to economies of scale. Although not shown, the relationship between unit cost and system size is similarly weak for 10 kW to 100 kW systems.

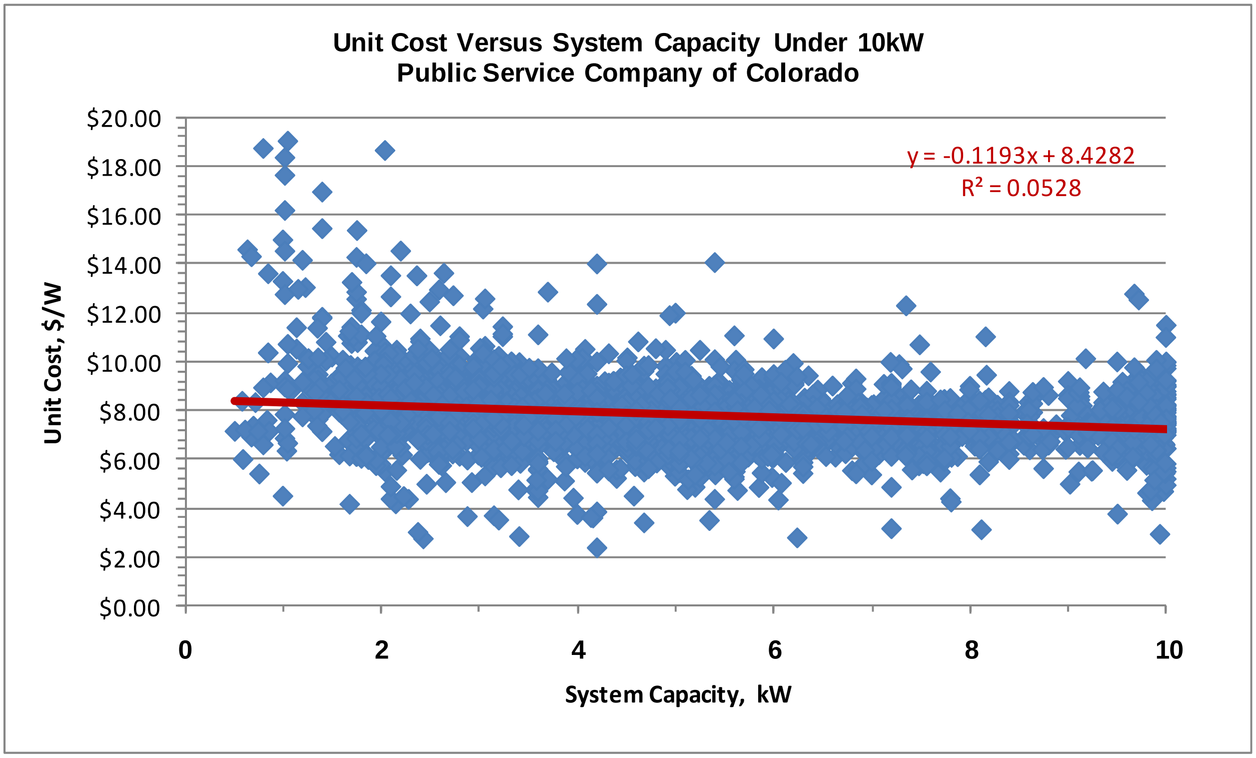



Figure 15 – Relationship between unit cost and system capacity for PSCo's 10 kW and under SRO program.

In a competitive market, one would expect all suppliers to be offering customers pricing within a relatively narrow band. Figure 16 shows the range and median pricing for the top 20 installers in PSCo's database. As shown by this chart, the average median unit cost for the top 20 installers was $7.80 per Watt with a standard deviation of $0.44 per Watt. Stated differently, the median unit cost offered by the top 20 installers varied from the norm by roughly 11 percent on the high side and 6.5 percent on the low side. And, as one would expect to see in a competitive market, the median price offered by the top 20 installers does not appear to be related to the volume of business done by those installers.

Although the median unit cost across installers is relatively uniform, it is apparent that some installers exhibit a far wider range in unit costs than others. Unfortunately, the database provided to us does not contain sufficient detail on each system to explain this disparity.

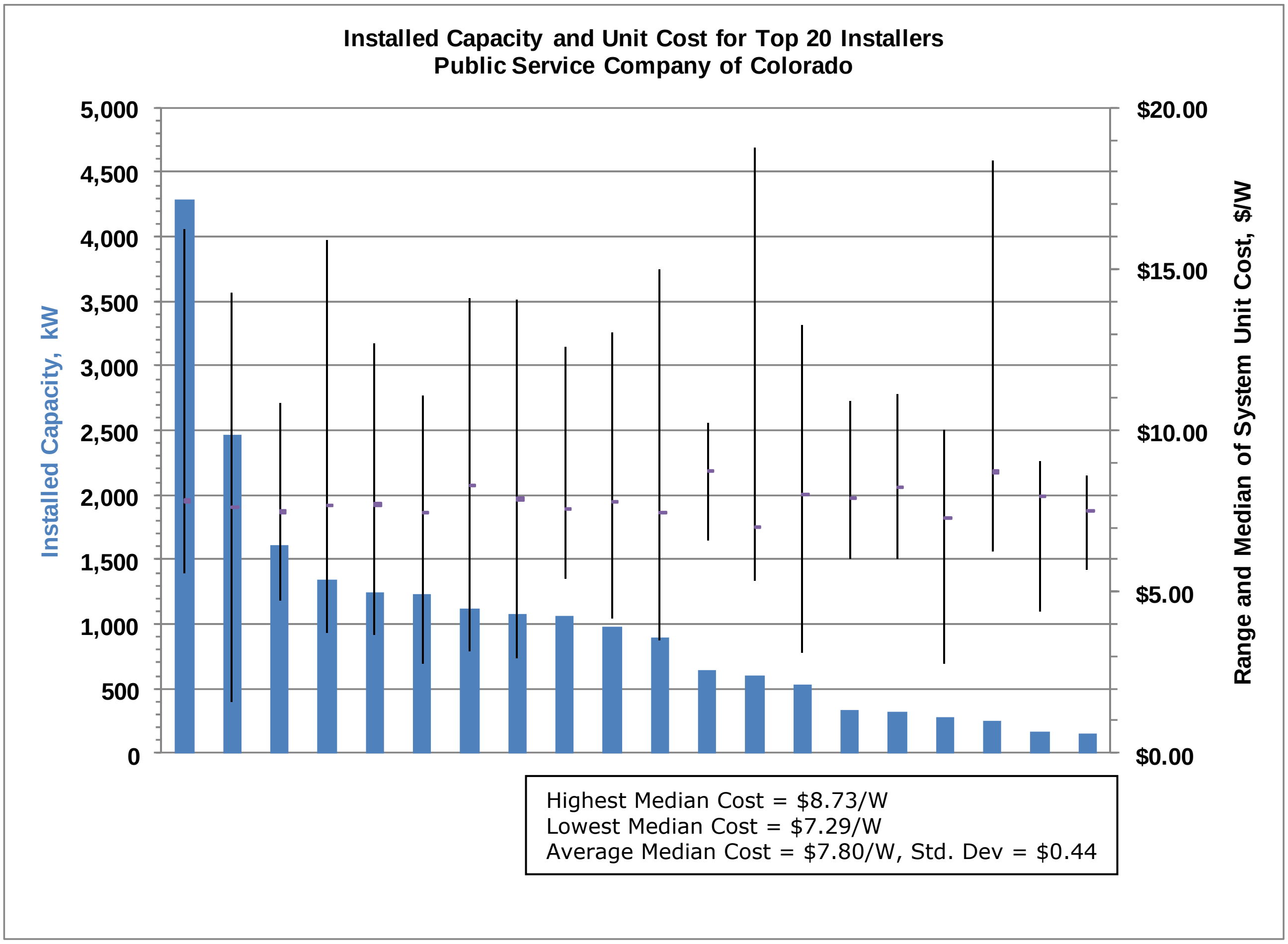



Figure 16 – Installed capacity and unit cost for PSCo's top 20 installers.

Last, a common tool for evaluating the effectiveness of increasing penetration of a product or technology in reducing costs is a learning or experience curve. In learning curve theory, the unit cost decreases by a constant percentage with each doubling of production. The learning rate, p, is 1 minus the percentage reduction for each doubling of production. For example, in an 80 percent learning curve, the cost (or time) of the 1,000$^{th}$ unit is only 80 percent of that of the 500$^{th}$ unit. A company or industry that follows a steeper learning curve reduces costs faster than one on a flatter trajectory.

One of the arguments often made for subsidizing the rollout of an emerging technology is that, with greater production, the industry will travel down the learning curve faster with a resulting diminution in costs. But, this assumes a relatively self contained system, free from exogenous influences, which is not the case with the PV industry in Colorado. Figure 17 shows the learning curve for the four years of data in the PSCo database. Note the relatively flat trajectory of the cost reduction which, in this case, is on the order of only 2.4 percent with each doubling of production. This apparently shallow learning rate is likely due to three causes:

1. Approximately half of the unit cost of a system is the cost of the panels which is set in a larger market beyond the influence of Colorado's industry,

2. The collective installer experience in Colorado is founded on earlier experience gained in the broader national market, and

3. The initial systems installed in Colorado, due to item 2 above, probably do not represent the true beginning of the experience curve. The mathematical artifact of this would be an artificially high (slower) learning rate.

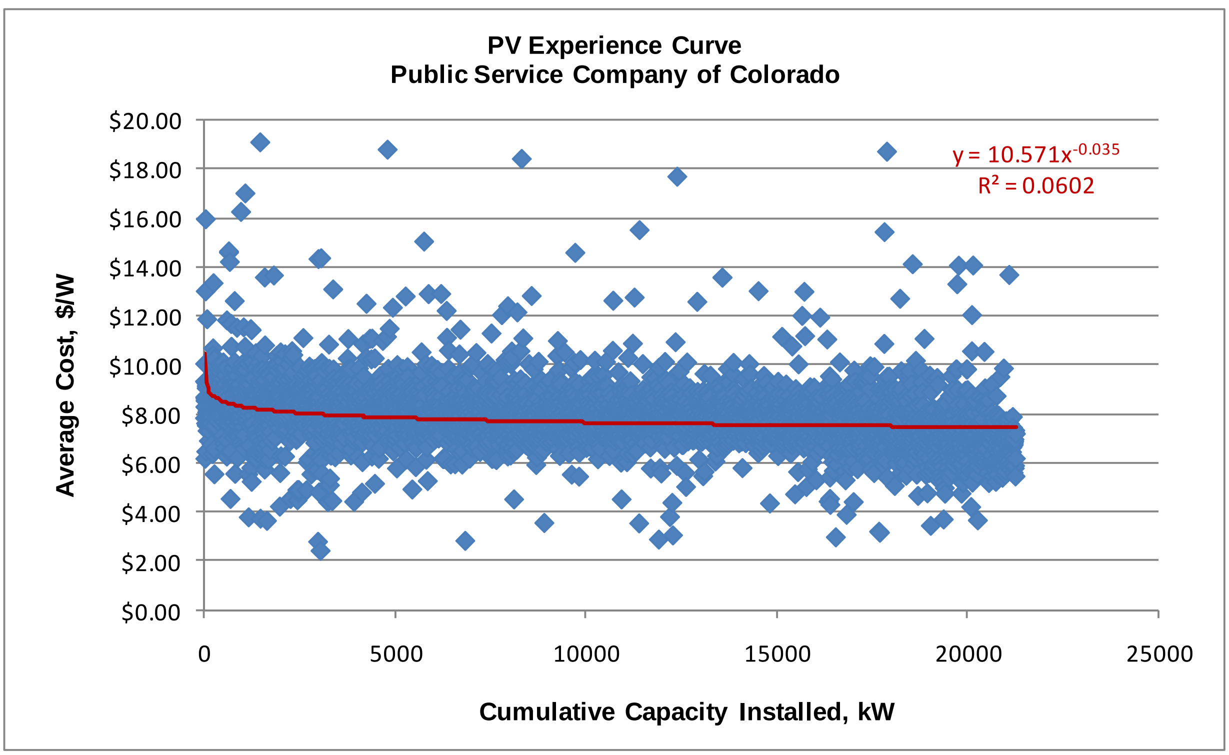



Figure 17 – PV experience curve for all 10 kW and under systems installed in PSCo territory from 2006 through 2009.

The above discussion notwithstanding, it is disappointing that the reduction in unit costs for the smaller systems, as shown earlier in figure 14, lags the more favorable cost reduction for the larger systems. But, as suggested earlier, this is likely due to the inability to capitalize on the economies of scale enjoyed by larger systems and installers with a higher volume of business.

# 3.0 Review of Black Hills Colorado Electric Solar Program

## 3.1 Introduction to Black Hills Colorado Electric Solar Program

Black Hills Colorado Electric (BHCE) began its PV incentive program in September 2006 under the prior ownership of Aquila Networks following the approval of Aquila's RESA tariff by the PUC.[8] Because of differences in the way the two utilities acquire and store data on their solar programs, the analysis for BHCE is slightly different from that conducted for PSCo. However, for the most part, the analysis here tracks that conducted using the PSCo data. The most notable difference is that because BHCE is a much smaller utility, the data set which is comprised of just over 300 installations is sparser than that analyzed for PSCo. Hence, for some charts and where data was available, we carry the analysis out to May 2010 rather than stopping at the end of 2009.

## 3.2 Total Installations and Installed Capacity – BHCE

Figure 18 shows the annual capacity additions for BHCE from 2006 through the end of 2009 (note that the program only existed for four months in 2006). Even more noticeable than with the PSCo data, the average system size for BHCE installations increased during the course of the program, with a substantial increase between 2008 and 2009. As before, we have no information that enables us to explain this trend.

[8] This occurred prior to the acquisition of Aquila, Inc by Great Plains Energy and the subsequent sale of Aquila's Colorado operations to Black Hills Energy Corporation.

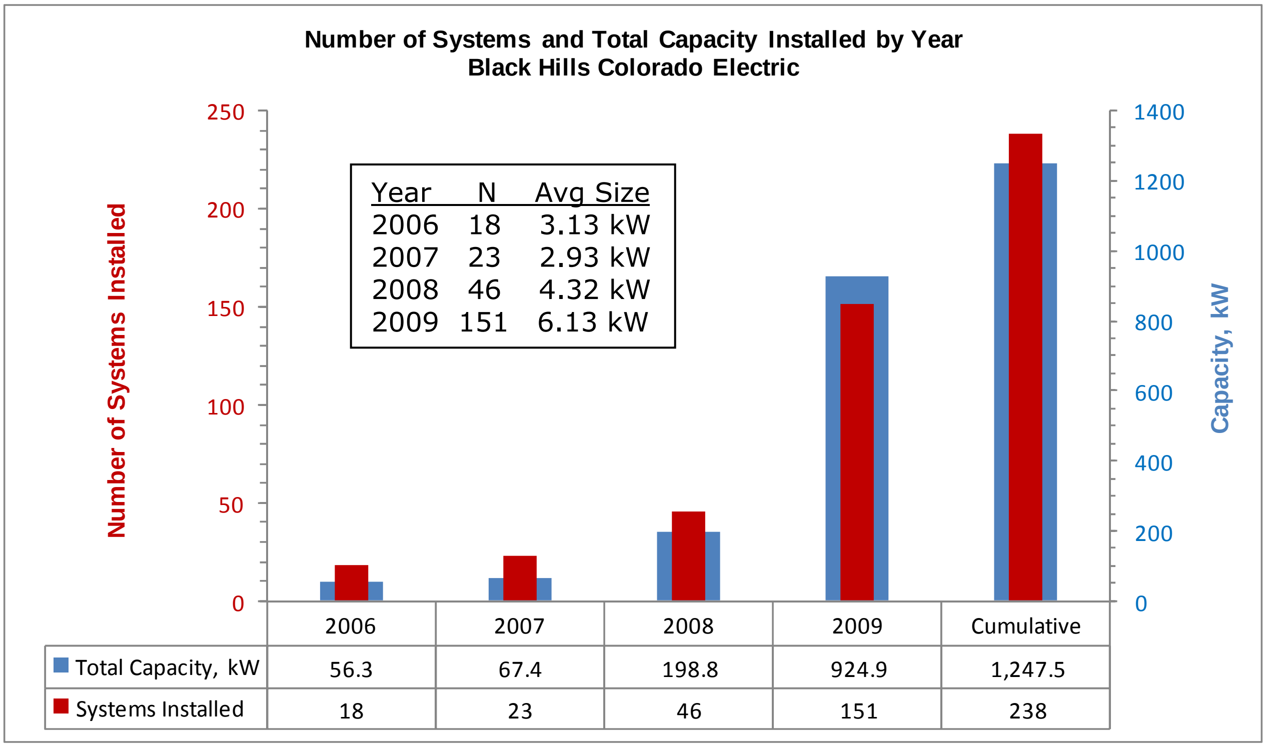



Figure 18 - Annual capacity and system additions for Black Hills Colorado Electric through 2009.

Figure 19 presents a histogram of the BHCE installations. As with the PSCo installations, the distribution is bimodal with spikes at 4 kW and 10 kW.

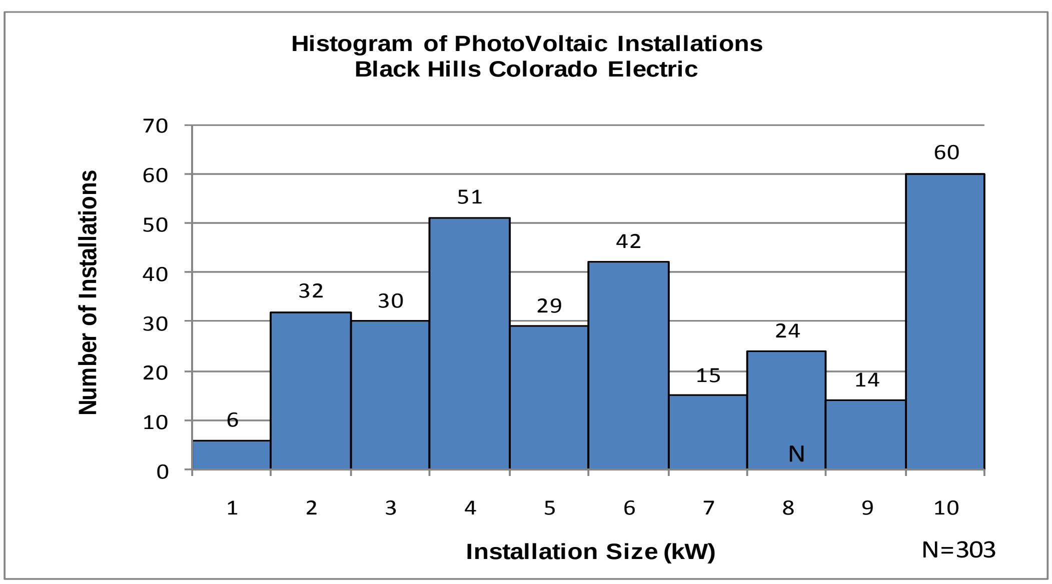
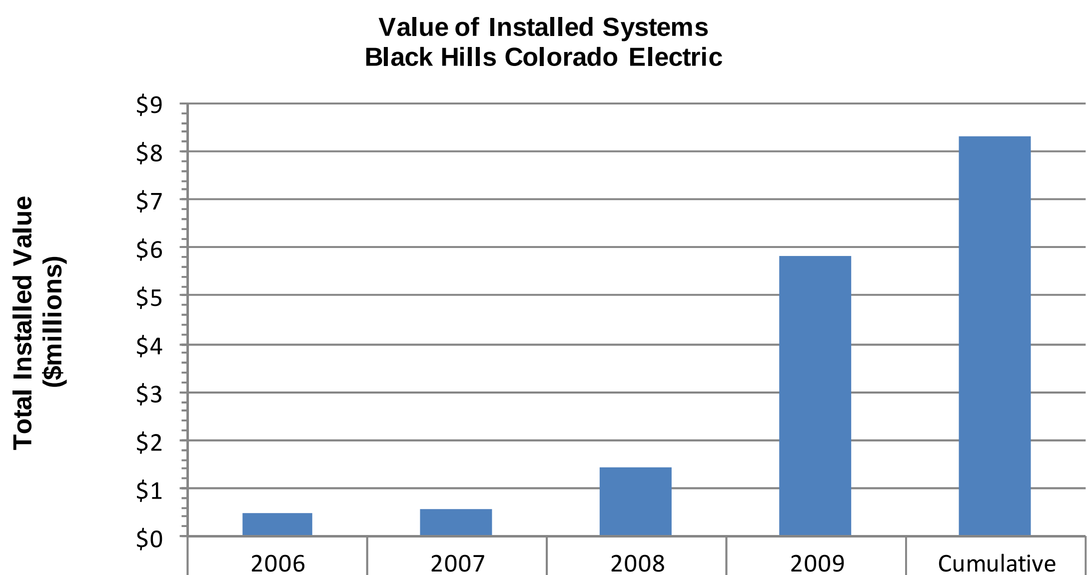



Figure 19 - Histogram showing the size distribution of all BHCE installations.

Figure 20 shows the total value of the economic activity created by the solar program in BHCE's service territory as a result of its incentive program. For the 3-1/3 years represented on this chart, the solar industry grossed approximately $8.3 million. Not shown on this chart is an additional $2.1 million for the first five months of 2010 bringing the total to approximately $10.5 million through May 2010.

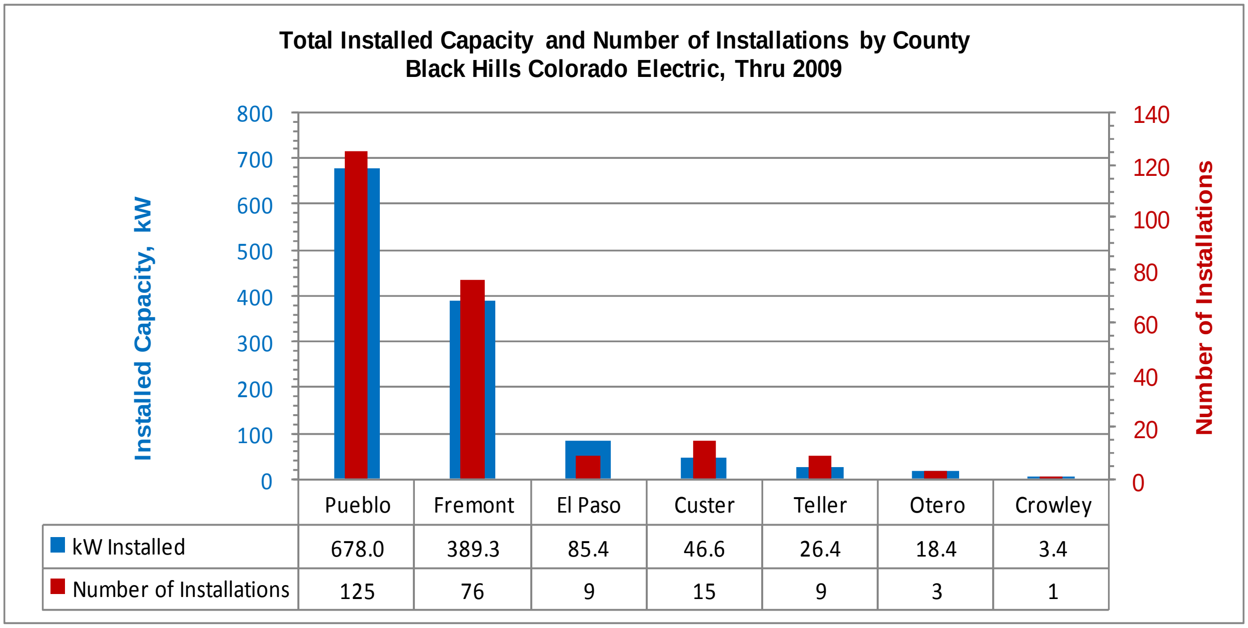



| | 2006 | 2007 | 2008 | 2009 | Cumulative |
|---|---|---|---|---|---|
| Installed Value | $500,744 | $561,016 | $1,439,224 | $5,818,929 | $8,319,913 |

Figure 20 - Economic activity created by BHCE's small solar program from 2006 through 2009.

### 3.3 County Analysis – BHCE

As noted previously, BHCE's service territory is far smaller than PSCo's and portions of only seven counties are included in its solar PV database (figure 21). Caution in viewing this data is advised since not all of each county listed is covered by BHCE. For instance, El Paso County is the most populous county in southern Colorado but its largest population center is covered by Colorado Springs Utilities and therefore not included in this analysis. For a more visual representation, return to the composite maps in figures 6a and 6b which also include the installations in BHCE service territory.




| | Pueblo | Fremont | El Paso | Custer | Teller | Otero | Crowley |
|---|---|---|---|---|---|---|---|
| kW Installed | 678.0 | 389.3 | 85.4 | 46.6 | 26.4 | 18.4 | 3.4 |
| Number of Installations | 125 | 76 | 9 | 15 | 9 | 3 | 1 |

Figure 21 - Total installed capacity and total installations by county in BHCE territory.

## 3.4 Contractor Analysis – BHCE

Figure 22 shows the growth in the installer base serving BHCE. Interestingly, there was very little overlap in the contractor base that served PSCo service territory and that which served BHCE territory.

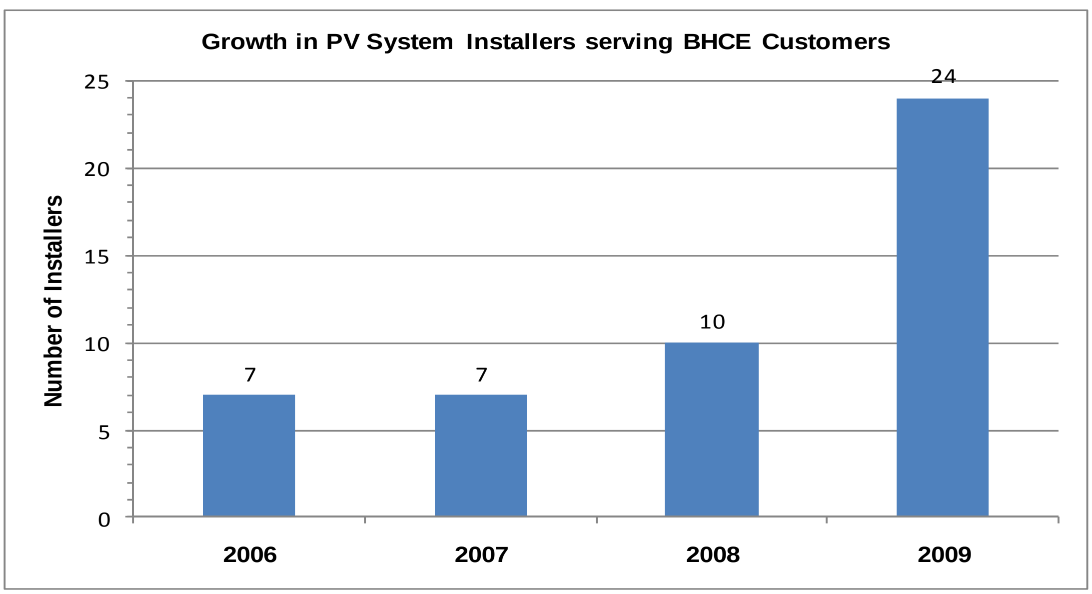



Figure 22 - Chart showing the number of installers represented in the BHCE database.

In addition to the growth in the installer community being similar for the two utilities (at about 3.5x over the four years), there was a similar concentration of business among the top few installers. Figure 23 shows the top 15 installers in BHCE territory. Using data through May 2010, the top five installers accounted for 57 percent of the business volume (as measured by installed capacity) with the top 15 accounting for nearly 90 percent of the installed capacity. In BHCE territory, market leader Power House Solar & Wind accounted for 19.6 percent of the installed capacity.

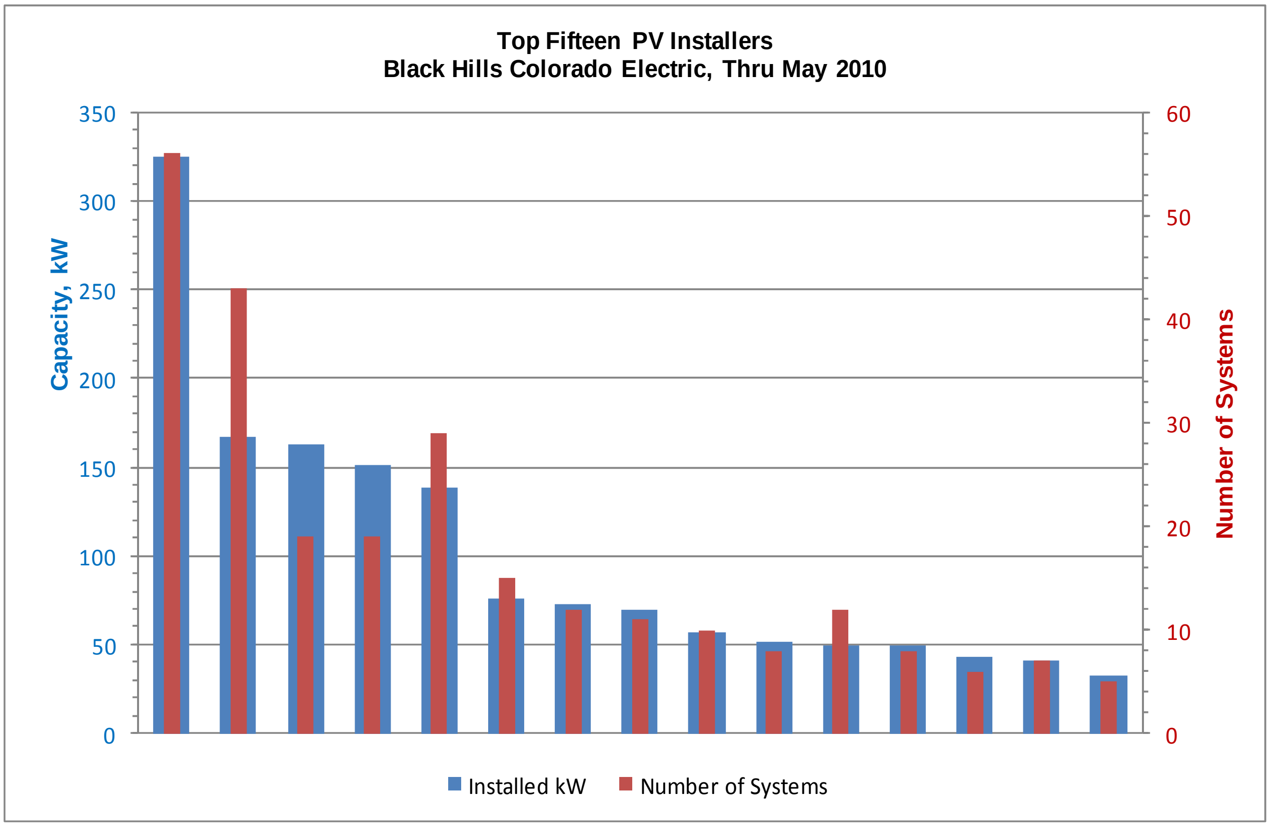



Figure 23 - Top 15 installers in BHCE database.

Figure 24, shown below, shows the average system size constructed by each of the top 15 installers. As with the PSCo data, the installers are ordered according to installed capacity and there appears to be no relationship between an installer’s total business volume and the average size of the systems it constructs.

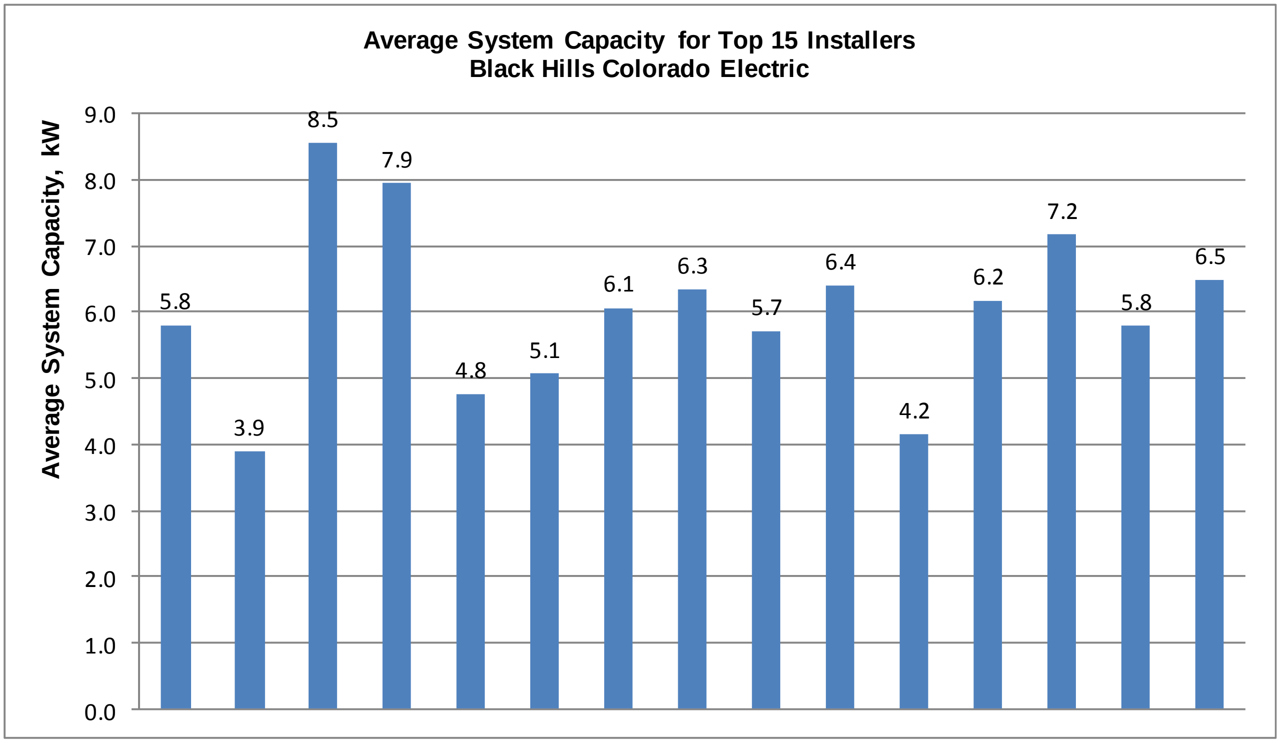
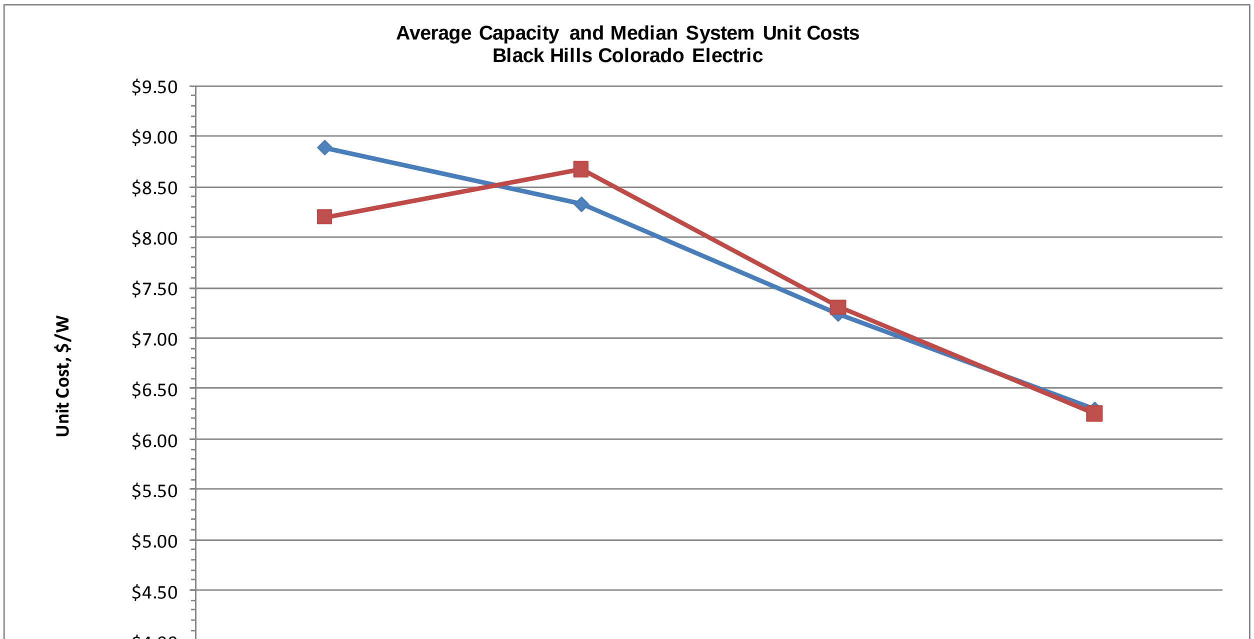



Figure 24 - Average system capacity for the top 15 installers in the BHCE database.

### 3.5 Cost Analysis – BHCE

Figure 25 shows the annual reduction in average and median unit costs for the PV systems installed under BHCE's incentive program. Although the unit costs in the two utility service territories started at comparable levels in 2006, the unit costs in BHCE territory fell more than in PSCo territory, concluding 2009 at a median cost of $6.25 per Watt versus $7.44 per Watt for PSCo. Not shown in the chart is a further reduction to $5.17 per Watt for the first 5 months of 2010. While the market dynamics that resulted in the greater cost reduction in BHCE territory are far from clear, it appears that BHCE ratepayers acquired more solar for their RESA dollar than did PSCo ratepayers.




| | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|
| Average Cost | $8.89 | $8.32 | $7.24 | $6.29 |
| Median Cost | $8.20 | $8.68 | $7.31 | $6.25 |

Figure 25 - Annual trends in average and median unit costs under BHCE's SRO.

Unlike the PSCo database, the data provided by BHCE included only systems up to 10 kW. Therefore, we were unable to identify a clear difference in costs between the smaller residential systems and the medium commercial systems up to 100 kW. Nonetheless, even for systems up to 10 kW, the BHCE data shown in figure 26 does indicate a decrease in unit costs with increasing system capacity up to 10 kW. Not only does there appear to be some economy of scale at play but the range appears to narrow as one gets away from the smallest systems.

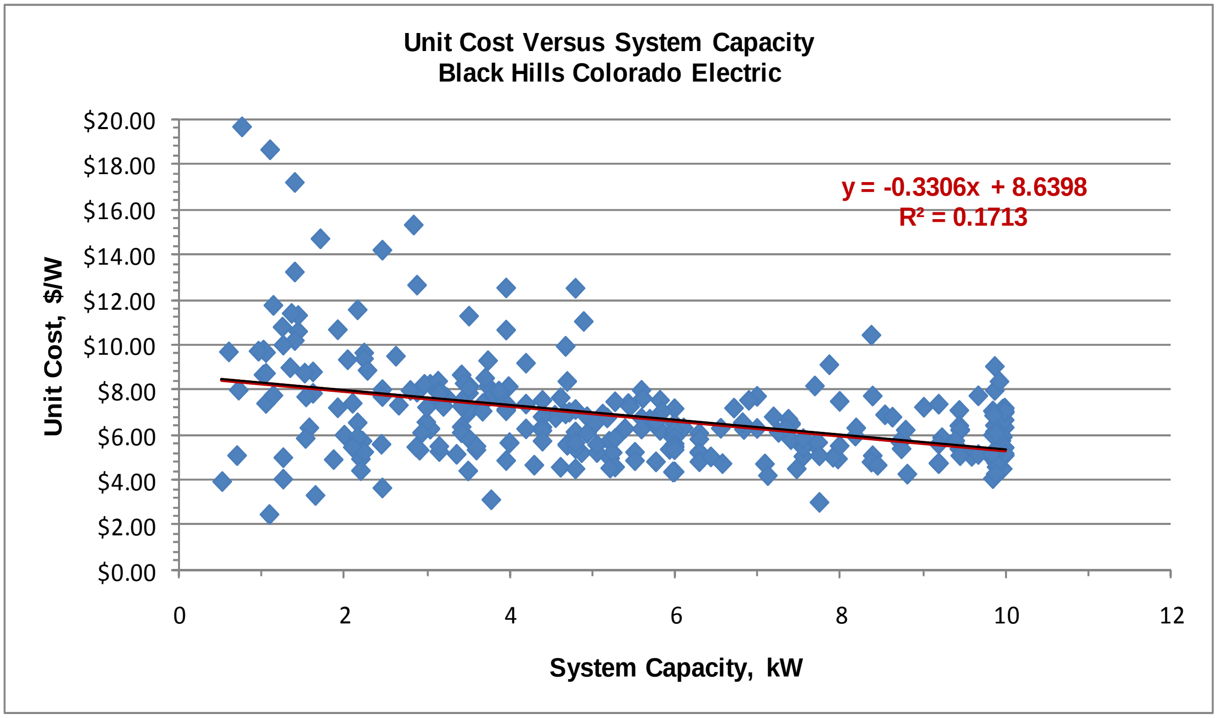



Figure 26 - Relationship between unit cost and system capacity for BHCE's SRO program.

As noted in the discussion of PSCo's program, one would expect all suppliers in a competitive market to be offering prices within a relatively narrow band. Figure 27 shows the range and median pricing for the top 15 installers in BHCE's database. In BHCE territory, the average median cost for the top 15 installers was $6.06 per Watt versus PSCo's $7.80 per Watt. Once again, the reason for this discrepancy is not clear. Possible explanations could include any or all of the following:

- The pricing in PSCo territory may reflect a more affluent customer base,
- Installers in PSCo territory may have higher labor costs that are reflected in their pricing, and/or
- Installers in PSCo territory seek higher profit margins which results in them passing along less of the cost reduction in hardware prices to their customers.

A considerable amount of further study would be required to adequately distinguish between these or other possible explanations.

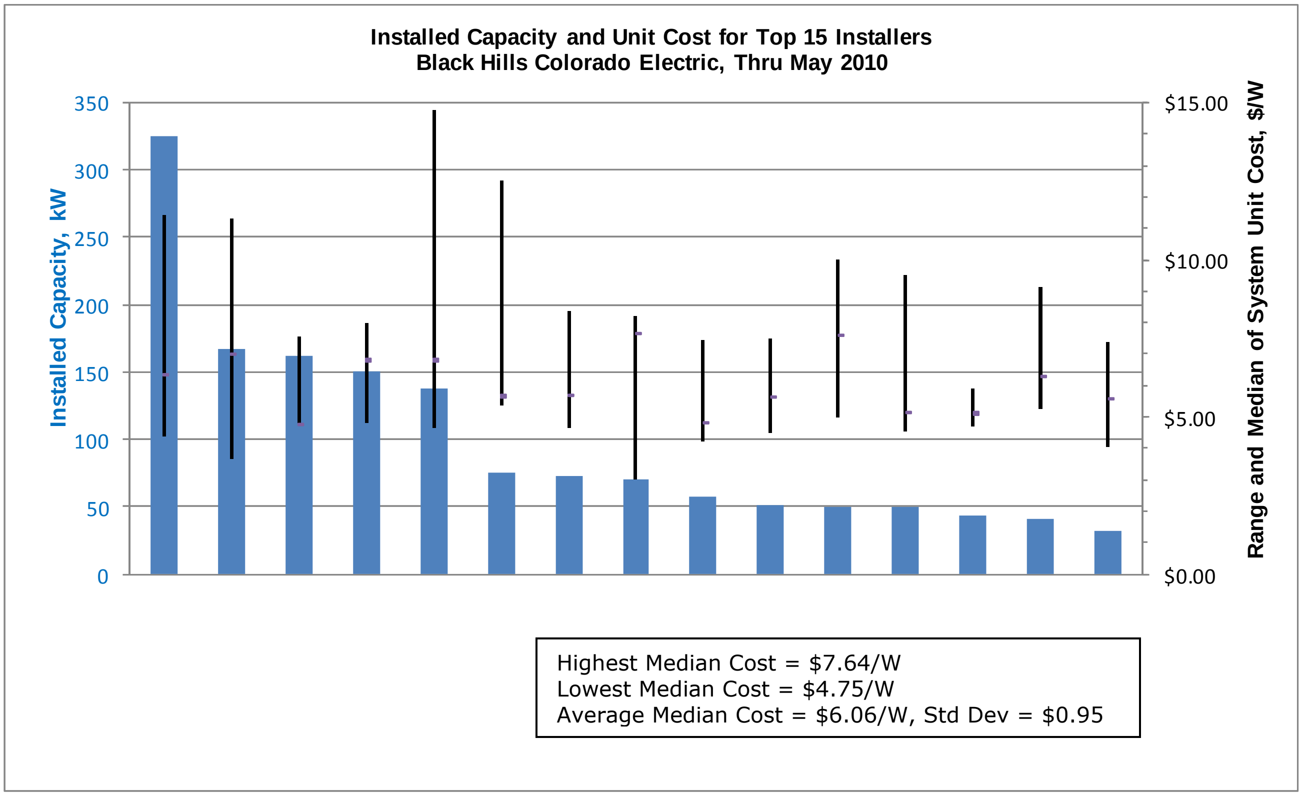



Figure 27 - Installed capacity and unit cost for BHCE's top 15 PV installers.

To conclude the analysis, as with the PSCo data, we developed an experience curve to provide an alternative tool for evaluating the reduction in PV system prices over time in BHCE territory (figure 28). Interestingly, the BHCE curve reflects an 8.7 percent cost reduction with each doubling of installed capacity (compare to the 2.4 percent in PSCo territory).

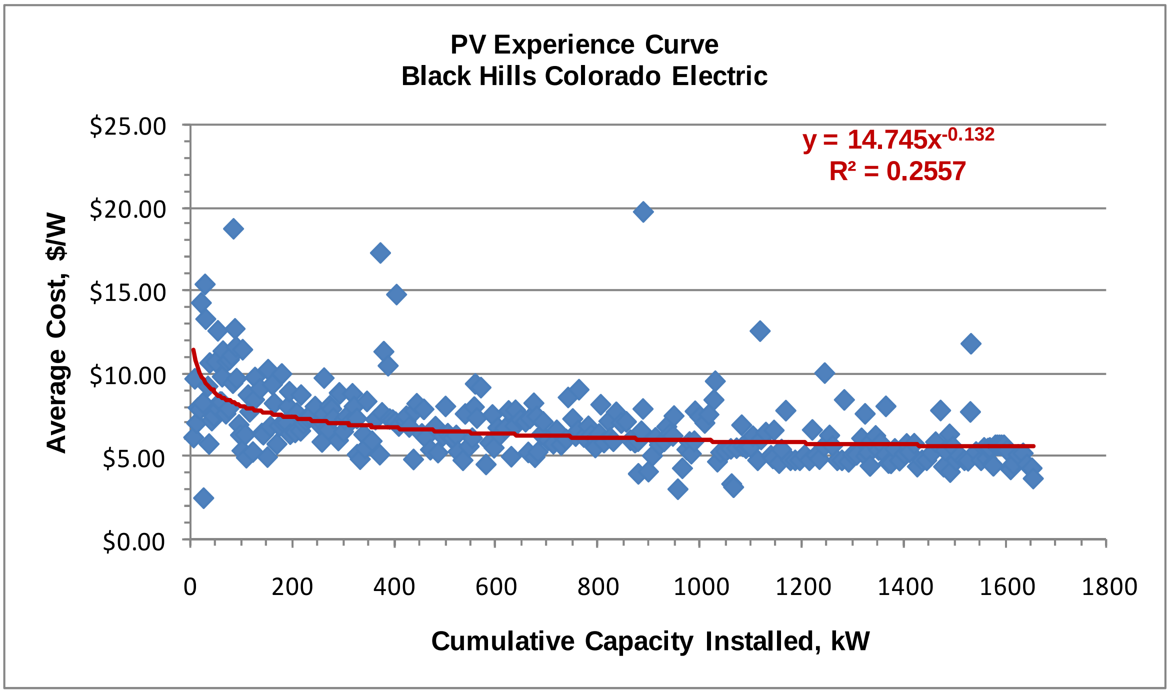



Figure 28 - Experience curve for BHCE installers reflecting a learning rate of 91.3 percent.

# APPENDIX B

**Staff working paper of the Colorado Public Utility Commission:**
**"PV Incentives: Status of Selected States," April 29, 2011.**

# PV Incentives: Status of Selected States

## INTRODUCTION

The following information outlines the status and history of PV incentives as being used in selected states. The information was gathered with the objective of understanding the following:

- How the state is using financial incentives to encourage PV installations;
- The context and motivation behind the financial incentives;
- The type and magnitude of the financial incentives in use;
- How the financial incentives have changed over time, and if possible, why; and
- The plans/projections for phasing out financial incentives.

Five states are presented in the information contained herein. These states were selected because of their physical proximity and situational relevance to Colorado. As such, these states are relatively more likely to contain in their stories lessons and insights of value to Colorado.

The following states were included in this overview:

- Arizona
- Nevada
- New Mexico
- Texas
- Utah

# ARIZONA

## I. AZ Statutory/Regulatory Parameters

***Historical:*** Renewable Energy standards in AZ have been established under the authority of the Arizona Corporation Commission (ACC) rather than by statute. The earliest renewable energy requirement was a 1996 solar portfolio standard (solar energy) goal of 0.2% in 1999 and 1% in 2003. This was superseded by an Environmental Portfolio Standard (EPS) that was established in 2001 and required 0.4% renewable energy in 2002 (50% from solar electric), increasing to 1.1% for 2007 to 2012 (60% from solar electric starting in 2004).

***Current:*** The current requirements were put in place in November, 2006 when the ACC issued final Renewable Energy Standard (RES) Rules as follows:

| Year | % of Retail Sales[1, 2, 4] | % DR[3] |
|---|---|---|
| 2006 | 1.25 | |
| 2007 | 1.50 | 5 |
| 2008 | 1.75 | 10 |
| 2009 | 2.00 | 15 |
| 2010 | 2.50 | 20 |
| 2011 | 3.00 | 25 |
| 2012 | 3.50 | 30 |
| 2013 | 4.00 | 30 |
| 2014 | 4.50 | 30 |
| 2015 | 5.00 | 30 |
| 2016 | 6.00 | 30 |
| 2017 | 7.00 | 30 |
| 2018 | 8.00 | 30 |
| 2019 | 9.00 | 30 |
| 2020 | 10.00 | 30 |
| 2021 | 11.00 | 30 |
| 2022 | 12.00 | 30 |
| 2023 | 13.00 | 30 |
| 2024 | 14.00 | 30 |
| 2025 | 15.00 | 30 |

1. The RES rules apply to IOUs and Cooperatives.
2. Salt River Project, a quasi-municipal utility that is not regulated by the Commission, voluntarily adopted the 15% standard by 2025.
3. Distributed Renewable (DR) is to come from half from residential and half from non-residential.
4. Per a 2009 settlement agreement, Arizona Public Service (APS) is required to install additional renewable energy above the RES requirements, essentially doubling the percentage requirements through 2015.

See http://www.azsos.gov/PUBLIC_SERVICES/Title_14/14-02.htm#ARTICLE_18

Affected utilities submit annual compliance reports and implementation plans to the ACC. They propose a 5-year plan with annual budgets for supporting RE investments and incentives and a RES tariff for recovering those costs. The RES tariff follows a sample structure provided in the rules and consists of a per kWh charge with monthly cost caps for each rate class. The ACC approves or modifies those proposals each year.

## *II. AZ Renewable Energy Credits*

One REC equals one kWh RES or one kWh of conventional energy resources displaced by DG.

REC trading is permitted and utilities may meet the distributed renewable energy requirement through REC purchases. However, according to the RES rules (R14-2-1805),

> *An Affected Utility may satisfy no more than 10 percent of its annual Distributed Renewable Energy Requirement from Renewable Energy Credits derived from distributed Renewable Energy Resources that are non-utility owned generators that sell electricity at wholesale to Affected Utilities. This Wholesale Distributed Generation Component shall qualify for the non-residential portion of the Distributed Renewable Energy Requirement.*

## *III. AZ Utility Incentives*

Twelve AZ utilities have established incentive programs for distributed renewable (DR) energy sources. All require the transfer of RECs to the sponsoring utility. Most programs support a variety of DR technologies, but almost all of the funding has gone to solar PV and, to a lesser extent, solar hot water.

The four largest utility programs are as follows, in descending order:

- Arizona Public Service Company (APS),
- Tucson Electric Power (TEP),
- Salt River Project (SRP) and
- UniSource Energy Services (UNP).

A matrix of individual utility incentives is provided in a separate Excel workbook. Details about utility programs and systems installed by zip code are also available at the Commission-sponsored and utility collaborative ***Arizona Goes Solar*** website, which was launched in October 2010: http://www.arizonagoessolar.org/

The following are items of note related to current incentive programs in AZ.

Up-Front Incentives (UFI):

- All 12 utilities offer some type of UFI, which is based on an assumed production level for a 20 year contract.
- Incentives range from a high of $5/watt to a low of $1.45/watt.
- Programs limit the UFI to between 30 and 60% of the total system cost (varies by utility). Some also require that the purchaser pay at least 15% after <u>all</u> incentives.
- UFIs are generally only applicable to "small" systems, with cutoffs ranging from 10 to 100 kW, with some programs also applying dollar limits.

Performance-Based Incentives (PBI):

- Four of the eight small utilities do not offer any PBI program.
- PBIs generally apply to larger systems (> 10, 50 or 100 kW).
- Payments range from 6.5 to 20.2 cents/kWh depending on the utility, the length of the REC payment term (10, 15 or 20 years), the size of the system, and whether it is on or off-grid.
- Most of the PBI programs set a maximum PBI payment and then use a competitive process for selecting projects.

Of the 12 programs, two are currently suspended pending additional funding and/or Commission approval of proposed incentive changes. The two utilities with suspended programs are Salt River Project and Sulphur Springs Valley Electric Cooperative.

Arizona Public Service (APS) represents by far the largest program and thus serves as the best example for a more detailed explanation of an incentive program in AZ.

<u>APS Incentive Program</u>

APS offers UFI payments for residential systems and small (up to 30kW) non-residential systems, and PBI incentives for non-residential systems over $75,000. All non-residential payments are awarded on a competitive basis.

*<u>APS Residential UFIs - 2008 to Current:</u>* The implementation plan for 2008 called for a very conservative reduction in incentive amounts through 2013, but was changed over time as follows:

APS Residential Rebates $/Watt

| Year | Proposed in 2008 | Actual as of 2011 |
|---|---|---|
| 2008 | $3.00 | |
| 2009 | $3.00 | |
| 2010 | $2.70 | $2.15[1]$1.95[2] $1.75[3] |
| 2011 | $2.70 | $1.60[4] $1.45[5] |
| 2012 | $2.30 | |
| 2013 | $2.30 | |

1. First quarter of 2010 applications were much higher than anticipated, so APS filed to lower the residential UFI from $3.00 per watt to $2.15 per watt.
2. April 2, 2010, the ACC ordered APS to further reduce the incentive to $1.95 per watt once the Company reserved 3 MW of capacity within the residential program (TEP reported a very similar issue in early 2010 and also was approved to lower incentive levels.). As of 2010, incentives paid out totaled almost $50 million. An additional $20 million was committed in reservations.
3. September 21, 2010 to January 16, 2011
4. January 17, 2011 to March 25, 2011
5. March 26, 2011 for reservations that would apply to 3rd quarter 2011

APS sets an annual budget (subject to Commission approval) and divides it into calendar quarters. Rebate amounts step down once the target budget for that step has been reached. Once a quarter's budget is allocated, reservations are accepted for the following quarter at the new lower rebate amount.

| APS | 4Q 2010 | 1Q 2011 | 2Q 2011 | 3Q 2011 | 4Q2011 | Totals |
|---|---|---|---|---|---|---|
| Budget | $8,015,000 | $6,264,434 | $7,341,309 | $6,802,872 | $4,302,872[2] | $32,726,486 |
| Applications | 594 | 484 | 599 | 500[1] | 0[3] | 1677/500 |
| Capacity | 4.1 MW | 3.6 MW | 4.2 MW | 3.6 MW | 0 MW | 15.5 MW |
| Requested | $8,015,000 | $6,401,000 | $13,520,000 | $19,043,000 | $19,043,000 | $27,058,000 |

1. Estimated no. of applications available 135
2. Remaining budget before next step down $5,668,486
3. Estimated no. of applications available 558

On April 1, 2011, APS has also instituted a new "Rapid Reservations" award system that provides a $1/watt incentive to anyone willing to accept the lower amount in lieu of being waitlisted for a future quarter. A total of $2.5 million has been allocated to the Rapid Reservations program. As of this writing, no applications have been received for this program. http://www.aps.com/main/green/choice/solar/funding.html

*APS Non-Residential UFIs - 2008 to Current:* The UFI incentives for small non-residential systems also were reduced more quickly than envisioned in 2008:

APS Non-Residential Rebates $/Watt (maximum values)

| Year | Proposed in 2008 | Actual as of 2011 |
|---|---|---|
| 2008 | $2.50 | $2.50 |
| 2009 | $2.50 | $2.50 |
| 2010 | $2.25 | $2.25 |
| 2011 | $2.25 | $1.75 |
| 2012 | $1.91 | |
| 2013 | $1.91 | |

Non-residential incentives are competitively awarded. Values listed are maximum incentives. Incentive amounts cannot exceed 50% of the total projects costs.

| Non-Residential | Up-Front Incentive[1,2] Up to $75,000 | Production-Based Incentive[3,4] Over $75,000 | | |
|---|---|---|---|---|
| REC agreement | 20 year | 10 year | 15 year | 20 year |
| Grid tied | $1.75/watt | $0.14/kWh | $0.13/kWh | $0.125/kWh |
| Off grid | $1.35/watt | $0.109/kWh | $0.101/kWh | $0.065/kWh |

Notes: Maximum incentive levels: the incentive may be adjusted if the expected performance of the system is lowered due to shading of the PV panels of installation of the panels at a less than optimal direction or angle.
In 2010,

1. $8.7 million was paid out
2. An additional $21 million was committed in reservations
3. $4.9 million was paid out
4. Accepted 159 reservations totaling approximately $9.8 million in annual commitments

http://www.aps.com/main/green/choice/choice_67.html

*APS Historical - Through 2008:* APS hired R.W. Beck to study the costs and benefits to the APS system of adding distributed renewable energy. Their January 2009 report provides some summary information about APS's solar PV resources acquired through 2008. The following two tables are from that report, which is available here:
http://www.solarfuturearizona.com/Resources/Documents/Solar%20DE%20Study.pdf

Table 2-1

**Cost of Residential PV Systems Installed under the APS PV Incentive Program**

| Year | # of Systems | Total installed Capacity (kW DC) | Average System Size (kW DC) | Total Installed Cost ($) | Average Installed Cost per System ($) |
|---|---|---|---|---|---|
| 2002 | 2 | 4.9 | 2.5 | $36,952 | $18,476 |
| 2003 | 8 | 54.2 | 6.8 | $274,665 | $34,333 |
| 2004 | 42 | 154.1 | 3.7 | $1,144,337 | $27,246 |
| 2005 | 59 | 236.6 | 4.0 | $1,541,550 | $26,128 |
| 2006 | 175 | 798.5 | 4.6 | $5,865,557 | $33,517 |
| 2007 | 208 | 1089.6 | 5.2 | $7,725,983 | $37,144 |
| 2008 | 87 | 481.3 | 5.5 | $3,303,396 | $37,970 |
| **Total** | **581** | **2819.3** | | **$19,892,440** | |
| **Average** | | | **4.9** | | **$34,238** |

Table 2-2

**Cost of Commercial PV Systems Installed under the APS PV Incentive Program**

| Year | # of Systems | Total installed Capacity (kW DC) | Average System Size (kW DC) | Total Installed Cost ($) | Average Installed Cost per System ($) |
|---|---|---|---|---|---|
| 2002 | 2 | 4.0 | 2.0 | $29,200 | $14,600 |
| 2003 | 1 | 2.3 | 2.3 | $38,051 | $38,051 |
| 2004 | 1 | 25.3 | 25.3 | $148,096 | $148,096 |
| 2005 | 14 | 162.5 | 11.6 | $1,614,241 | $115,303 |
| 2006 | 8 | 258.5 | 32.3 | $2,082,548 | $260,319 |
| 2007 | 11 | 357.6 | 32.5 | $3,197,715 | $290,701 |
| 2008 | 1 | 11.3 | 11.3 | $93,379 | $93,379 |
| **Total** | **38** | **821.5** | | **$7,203,230** | |
| **Average** | | | **21.6** | | **$189,558** |

According to APS's annual RES compliance reports for 2009 and 2010, their acquisition of distributed solar PV accelerated rapidly after 2008. (RES compliance reports are available from the ACC website: http://www.cc.state.az.us/divisions/utilities/electric/environmental.asp)

APS Distributed PV Deployment:

| Year | Residential | | Non-Residential | | | Total MW |
|---|---|---|---|---|---|---|
| | # Systems | MW | # Systems | UFI MW | PBI MW | |
| Thru 2009 | 1396 | 13.25 | 52 | 2.86 | 4.98 | 21.09 |
| Thru 2010 | 2860 | 31.6 | 83 | 6.9 | 19.8 | 58.30 |

As shown by the table below from APS's 2010 RES Compliance Report, they finally achieved compliance with the residential DR requirement and came close to compliance with the non-residential DR requirement:

**Table 6:**
**2010 Distributed Energy Target Detail (in MWh)**

| | Targets | Actuals[1] | % Achievement of DE Target (Actuals Only) | Actuals with Reservations[2] | % Achievement of DE Target (w/Reservations) |
|---|---|---|---|---|---|
| **2009:** | | | | | |
| Residential | 42,260 | 31,227 | 74% | 40,974 | 97% |
| Non-residential | 42,260 | 18,158 | 43% | 110,672 | 262% |
| *Total* | *84,520* | *49,385* | 58% | *151,646* | 179% |
| **2010:** | | | | | |
| Residential | **69,274** | **70,969** | **102%** | 81,544 | 118% |
| Non-residential | **69,273** | **60,444** | **87%** | 302,301 | 436% |
| *Total* | ***138,547*** | ***131,413*** | ***95%*** | *383,845* | 277% |
| **Year over Year Incremental:** | | | | | |
| Residential | 27,014 | 39,742 | 147% | 40,570 | 150% |
| Non-residential | 27,013 | 42,286 | 157% | 191,629 | 709% |
| *Total* | *54,027* | *82,028* | 152% | *232,199* | 430% |

*Notes to Table 6:*
[1] Actual installations completed through December 31, 2010.
[2] Actual installations completed and funding issued through December 31, 2010.

This trend is statewide, as PV installations across Arizona have increased rapidly in the last 2 years. According to IREC's annual Solar Market Trend reports (http://irecusa.org/irec-programs/publications-reports/), and (for 2010), the SEIA Solar Market Insight report (http://www.seia.org/cs/research/SolarInsight) AZ statewide total grid-connected PV installations by year are as follows:

| Year | Grid-Connected PV Installations in AZ |
|---|---|
| Thru 2006: | 16.0 MW |
| 2007 | 2.8 MW |
| 2008 | 6.2 MW |
| 2009 | 21.1 MW |
| 2010 | 54.0 MW |
| Total thru 2010 | 100.0 MW |

Other market indicators reported by APS in their 2009 and 2010 RES Compliance Reports:

- In 2006, 27 PV installers participated in the Company's REIP. In 2009, the number of PV installers present within APS's territory increased to 197. In 2010, the number of PV installers present within APS's territory increased to 248.
- APS initially began to offer incentives to customers for the installation of residential PV systems in 2002. At that time, the average grid-tied PV system was 2.5 kWdc. Since then, APS has seen the average installed PV system size increase incrementally each year to an average system size of 6 kWdc in 2009 and 7.1 kWdc in 2010.
- In 2007, it was not uncommon for systems to be installed at costs near $9 per installed watt. Market research demonstrates that at the end of 2009, the average installed cost of residential solar electric systems is currently below an average of $6 per installed watt. This is a result of a general decrease in the cost of both the solar equipment and installation of the equipment as installers gain greater experience. APS also believes that the 50 percent cap on incentive contribution has caused the PV market to remain artificially high. In 2010, system price declines moderated from the strong downward trends reported in 2009. The average installed cost of residential solar electric systems continues to decline from the $6.00 per watt level of 2009. APS witnessed a gradual decrease in cost per watt concurrent with each incentive decrease.
- In 2010, APS saw a significant increase in the number of applications under a lease or retail PPA (also known as a Solar Service Agreement (SSA)). Residential leased systems often leverage the non-residential economics and remove up-front barriers for some customers. On average, these leased systems result in a higher installed cost per watt than the average customer-owned system.
- APS began 2009 with a lifetime PBI authorization of $77 million; however, due to an overwhelming interest in the program, APS filed a request with the Commission and was authorized to increase the lifetime PBI authorization to $220 million.
- APS has seen the average lifetime cost per kWh of distributed PV projects drop from $0.148/REC to $0.114/REC during 2009. APS believes this drop in cost can be attributed to both the competitive allocation process and the declining cost in PV modules.

*Other APS PV Incentive or Enabling Programs:*

In 2009, APS instituted an incentive program for schools by transferring unused residential incentive funding. During the limited 2009 Schools Program, APS approved about $16 million of up-front schools reservations. In 2010, this program became the Schools and Government Program, under which APS reserved approximately 3.75 MW of capacity, installed approximately 670 kW and committed the entire $15 million budget. The current PBI for the schools program offers $0.17/kWh for 15 years or $0.155/kWh for 20 years.

In 2010, APS started the Community Power Project - Flagstaff Pilot which resulted in 31 residential installations totaling 108 kW and applications from eight non-residential customers, including a park and a school.

APS also participates in a collaborative project to support financing of residential solar PV. The Solar Phoenix program was announced in November 2009 and also involves the city of Phoenix, National Bank of Arizona and SolarCity. This program is advertised as the "Nation's Largest City-Sponsored Residential Solar Financing Program." It was expected to allow up to 1,000 Phoenix homeowners to adopt solar power by the end of 2010.

In 2010, the ACC began considering establishing a feed-in tariff (FiT) program for solar PV. APS proposed a pilot FiT program in their 2011 RES Implementation plan, but it was modified by the Commission such that any energy obtained would count as utility-scale rather than distributed renewable energy. It appears that the FiT program has not yet been established.

## *IV. AZ Other State Incentives*

Credit for Solar Energy Devices: Arizona offers a personal state tax credit of 25% of the system cost, up to a maximum credit of $1000.
http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=AZ01F&re=1&ee=1

Commercial/Industrial Solar Energy Tax Credit Program: A business tax credit is available for commercial/industrial facilities that install solar. "The tax credit is equal to 10% of the installed cost of the solar energy device not to exceed $25,000 in credits for one building in a single tax year and $50,000 total credits per business per tax year. Tax credits can be used to offset Arizona income tax liability; any unused credit amounts can be carried forward for a five-year period."
http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=AZ18F&re=1&ee=1

Renewable Energy Production Tax Credit: Owners of renewable energy systems that are 5 MW or larger and installed on or after 12/31/2010 can apply for this production tax credit program, which is capped at $20 million in total annual credits and $2 million per applicant. The tax credit for PV and solar thermal electric systems declines according to the following schedule:

Years 1-2: $0.04 per kWh
Years 3-4: $0.035 per kWh
Years 5-6: $0.03 per kWh
Years 7-8: $0.02 per kWh
Year 9: $0.015 per kWh
Year 10: $0.01 per kWh
http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=AZ48F&re=1&ee=1

Energy Equipment Property Tax Exemption: For property tax assessment purposes, solar energy devices are considered to add no value to the property.
http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=AZ20F&re=1&ee=1

Solar and Wind Equipment Sales Tax Exemption: A sales tax exemption also applies to solar PV systems.
http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=AZ08F&state=AZ&CurrentPageID=1&RE=1&EE=1

Tax Incentive Program for Manufactures: To promote renewable energy industries, the state also offers a tax incentive program for manufacturers.
http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=AZ41F&re=1&ee=1

# NEVADA

## I. NV Statutory/Regulatory Parameters

A Renewable Portfolio Standard (RPS) was established in Nevada in 1997. Under the standard, NV Energy was directed to use eligible renewable energy resources to supply a minimum percentage of the total electricity it sells. In 2001, the minimum requirement was increased by 2% every two years. In 2009, the renewable portfolio requirement was revised and now stands as follows:

| Year | Percent (%) of Retail Sales |
|---|---|
| 2005-2006 | 6 |
| 2007-2008 | 9 |
| 2009-2010 | 12 |
| 2011-2012 | 15 |
| 2013-2014 | 18 |
| 2015-2019 | 20 |
| 2020-2024 | 22 |
| 2025 and thereafter | 25 |

Solar Technology Minimum: 5% of annual requirement through 2015 (1.2% of sales in 2015) and 6% for 2016-2025 (1.5% of sales in 2025)

## II. NV Renewable Energy Credit

Portfolio Energy Credits (PEC) generated from renewable energy installations can be used to satisfy the Renewable Portfolio Standard where:

- one kilowatt-hour of solar generation equates to 2.4 PEC and
- one kilowatt-hour of customer-sited solar distributed generation equates to 2.45 PEC.

http://www.leg.state.nv.us/register/2005Register/R167-05RA.pdf

## III. NV Utility Incentives

NV Rebates:

The RenewableGenerations program began with the creation of SolarGenerations, an incentive program created to encourage NV Energy customers to install approved solar photovoltaic systems and help offset installation costs.

The program began in 2004 as a demonstration program by the Nevada State Legislature and is now regulated by the Public Utility Commission of Nevada. SolarGenerations was extended in 2005 and made permanent in 2007. The program is defined in the Nevada Revised Statutes 701B and amendments made to it in subsequent Bills.

Incentive amounts are determined by the size of systems installed. Maximum incentive levels are as follows:

| | |
|---|---|
| Residential | 10 kW |
| Small Business | 50 kW |
| Public Building | 100 kW |
| Schools | 50 kW |

Schools can build more than 50 kW with prior Commission approval.

Applications are accepted on a first-come, first-serve basis and reservations are issued from available incentive steps. The steps correspond to program years and have declining incentive values as follows:

| | | Private Residential Property and Small Business Property | | School Property | | Public and Other Property | | Total kW |
|---|---|---|---|---|---|---|---|---|
| Step | Year | Kilowatt Capacity | Rebate Per Watt | Kilowatt Capacity | Rebate Per Watt | Kilowatt Capacity | Rebate Per Watt | |
| Base | 2009-2010 | 1,000 | $2.50 | 2,000 | $5.00 | 760 | $5.00 | 3,760 |
| 1 | 2010-2011 | 1,090 | $2.30 | 2,180 | $5.00 | 828 | $5.00 | 4,098 |
| 2 | 2011-2012 | 1,188 | $2.10 | 2,376 | $4.90 | 903 | $4.90 | 4,467 |
| 3 | 2012-2013 | 1,295 | $1.90 | 2,590 | $4.80 | 984 | $4.80 | 4,869 |
| 4 | 2013-2014 | 1,412 | $1.70 | 2,823 | $4.70 | 1,073 | $4.70 | 5,308 |
| 5 | | 1,539 | $1.50 | 3,077 | $4.60 | 1,169 | $4.60 | 5,785 |

For example, the available capacity for the residential category for Step 2 is 1,090 kW. The incentive amount for Step 2 is $2.30 per watt installed. If a residential customer applies for an incentive that is approved for Step 2 incentive amounts and installs a 10 kW system, the residential customer would be eligible to receive a $23,000 rebate.

Once the capacity in a step is fully reserved, subsequent reservations will be made from the next step. Although reservations may be made from future steps, incentives for a step may only be claimed after the program year that the step corresponds to begins. Program years begin on July 1 and end on June 30. For example, if a solar application is submitted and the reservation comes from the capacity in the following step, the project must be built within 12 months of the date of approval. However, the incentive will only be claimed after the following incentive year.

In other words, the rebate program in Nevada is based on a step process where the duration of each step will depend on when the utility reaches a specified total number of kilowatts of confirmed reservations. If the maximum kW capacity for a given step year is reached before the end of that year, the utility shall suspend the payment of incentives for capacity beyond the capacity authorized but may continue to issue reservations at an incentive level up to two steps ahead.

Currently, the program has reached capacity beyond two steps ahead and is now oversubscribed. The program has been closed to new applications and is currently being reviewed by the Public Utility Commission of Nevada under Docket No. 11-02001. The PUCN, per Docket 11-02001, has a Staff and Intervener Direct Testimony scheduled for Thursday May 5, 2011 at 2 P.M. PST. It is anticipated that the Order rebate level will be reduced when the program opens again to new applications on August 1st. [1]

1. Email correspondence with Mark Harris, P.E. of the Public Utility Commission of Nevada on 04/14/11.

Concurrently, there is also discussion in the Legislature for reducing the rebate for third-party ownership from $5 per watt to $3.30 per watt where a school or public building is the site for a renewable energy system where the third-party would realize a tax benefit unlike a school or public building owner. The outcome of these discussions is expected by the first week of June.[2]

2. Telephone correspondence with Mark Harris, P.E. of the Public Utility Commission of Nevada on 04/29/11.

http://www.nvenergy.com/renewablesenvironment/renewablegenerations/solargen/

According to NV Energy, at least 4MW have been installed to date.

<u>NV Performance-based Credits:</u>

There was also discussion in the Legislature about performance-based incentives for small wind turbines instead of an up-front rebate program. Any legislative bills resulting from these discussions are expected to be approved by the first week of June.[3]

3. Email correspondence with Mark Harris, P.E. of the Public Utility Commission of Nevada on 04/19/11.

## IV. NV Other State Incentives

Renewable Energy Sales and Use Tax Abatement: New and expanded businesses may apply for a sales-and-use tax abatement for qualifying renewable energy technologies. A purchaser of a renewable energy technology up to 10 MW is required to pay sales and use taxes imposed at the following rate structure:

| Year | Sales and Use Tax |
|---|---|
| Through June 30, 2011 | 2.60 |
| July 1, 2011 – June 30, 2049 | 2.25 |

Several job creation and job quality requirements must be met for a project to receive a tax abatement.

http://leg.state.nv.us/NRS/NRS-701A.html#NRS701ASec360

Renewable Energy Property Tax Exemption: Any value added by a qualified renewable energy system shall be subtracted from the assessed value of any residential, commercial or industrial property for property tax purposes. The exemption will apply in perpetuity.

http://www.leg.state.nv.us/NRS/NRS-701A.html#NRS701ASec200

# NEW MEXICO

## I. NM Statutory/Regulatory Parameters

In 2006, the New Mexico Legislature directed investor-owned utilities to generate a percentage of total retail sales from renewable energy resources. The Renewable Portfolio Standard also established a standard for rural electric cooperatives to generate 10% of their total retail sales from renewable energy sources by 2020.

| | Percentage of Retail Sales | |
|---|---|---|
| | Investor-Owned Utility | Rural Electric Cooperative |
| 2006 | 5 | |
| 2007-2010 | 6 | |
| 2011 | 10 | |
| 2015 | 15 | 5 |
| 2016 | | 6 |
| 2017 | | 7 |
| 2018 | | 8 |
| 2019 | | 9 |
| 2020 | 20 | 10 |

NM Investor-Owned Utilities

In 2007, the New Mexico Public Regulation Commission began requiring investor-owned utilities to meet the Renewable Portfolio Standard through a "fully diversified renewable energy portfolio". The renewable portfolio requirement is to be met as follows:

| Renewable Resource | Percentage of Portfolio | |
|---|---|---|
| Solar | 20 | |
| Wind | 20 | |
| Other Renewables | 10 | |
| Distributed Generation: | | Year |
| | 1.5 | 2011-2014 |
| | 3 | 2015 and beyond |

A Reasonable Cost Threshold was established by the commission in an effort to control costs. A Reasonable Cost Threshold means the cost above which a public utility shall not be required to add renewable energy to its electric energy supply portfolio pursuant to the Renewable Portfolio Standard.

Reasonable Cost Threshold

| Year | Percent of Electric Charges[1] |
|---|---|
| 2006 | 1.00 |
| 2007 | 1.20 |
| 2008 | 1.40 |
| 2009 | 1.60 |
| 2010 | 1.80 |
| 2011 | 2.00 |
| 2012 | 2.25 |
| 2013 | 2.50 |
| 2014 | 2.75 |
| 2015 | 3.00 |

1. Percent of all customers' aggregated overall annual electric charges

As changing circumstances warrant, and after notice and hearing, the Commission may modify the Reasonable Cost Threshold to new contracts, but not to existing contracts. In modifying the Reasonable Cost Threshold, the Commission will take the following into account:

1) the price of renewable energy at the point of sale to the public utility;
2) transmission and interconnection costs required for the delivery of renewable energy to retail customers;
3) the impact of the cost for renewable energy on retail customer rates;
4) overall diversity, reliability, availability, dispatch flexibility, cost per kilowatt-hour and life cycle cost on a net present value basis of renewable energy resources available from suppliers; and
5) other factors, including public benefits, that the Commission deems relevant.

http://www.nmcpr.state.nm.us/NMAC/parts/title17/17.009.0572.htm

## *II. NM Renewable Energy Credit*

Utilities are to document compliance with the RPS through the use of renewable energy credits (REC). One REC equates to one kilowatt-hour of renewable energy generation.

http://www.nmprc.state.nm.us/renewable.htm

## *III. NM Utility Incentives*

El Paso Electric

In 2010, El Paso Electric began a performance based incentive system for renewable energy. Effective on January 1, 2010 El Paso Electric purchases renewable energy credits (RECs) from customers that install photovoltaic systems as follows:

| System Size | Capacity | Price per kilowatt-hour |
|---|---|---|
| Small | Up to 10 kW | $0.120 |
| Medium | 10 kW to 100 kW | $0.155 |

REC payments will be made for a period of 12 years. REC payments to medium systems are limited to the on-site consumption portion.

PNM

On August 31, 2010, the New Mexico Public Regulation Commission made several changes to the performance based solar incentive program. The REC price paid for systems will step down over time accordingly.

| | Step | REC Price per kWh |
|---|---|---|
| Up to 10 kW | 1 | $0.12 |
| | 2 | $0.11 |
| | 3 | $0.10 |
| | 4 | $0.09 |
| | 5 | $0.08 |
| | 6 | $0.07 |
| | 7 | $0.06 |
| 10 kW to 100 kW | | |
| | 1 | $0.14 |
| | 2 | $0.13 |
| | 3 | $0.12 |
| | 4 | $0.11 |
| | 5 | $0.10 |
| | 6 | $0.09 |
| | 7 | $0.08 |
| | 8 | $0.07 |
| | 9 | $0.06 |
| 100 kW to 250 kW | | |
| | 1 | $0.13 |
| | 2 | $0.12 |
| | 3 | $0.11 |
| | 4 | $0.10 |

| | | |
|---|---|---|
| | 5 | $0.09 |
| | 6 | $0.08 |
| | 7 | $0.07 |
| | 8 | $0.06 |
| 250 kW to 1 MW | | |
| | 1 | $0.12 |
| | 2 | $0.10 |
| | 3 | $0.08 |
| | 4 | $0.06 |
| 1 MW to 8 MW | | |
| | 1 | $0.11 |
| | 2 | $0.09 |
| | 3 | $0.07 |
| | 4 | $0.05 |

The REC rate is available for 12 years of the system's operation.

Xcel Energy

Xcel Energy purchases renewable energy credits (RECs) through the Solar*Rewards Program from customers who install photovoltaic systems. Currently, there are two incentive levels as follows:

| System Size | REC price per kWh | Capacity | kW Confirmed | kW Remaining |
|---|---|---|---|---|
| 0.5 kW to 10.0 kW[1] | | | | |
| | $0.13 | 100 | 3 | 97 |
| | $0.10 | 100 | | 100 |
| | $0.08 | 100 | | 100 |
| 10.1 kW to 100 kW[2] | | | | |
| | $0.13 | 500 | 595 | 0 |
| | $0.10 | 500 | 498 | 0 |
| | $0.08 | 500 | 15 | 485 |
| 100.1 to 2 MW | RFP | RFP | | |

Notes:
Information current as of 04/20/2011
1. Small Group contracts extend 12 years
2. Medium Group contracts extend 10 years

## *IV. NM Other State Incentives*

Personal Income Tax Credit: The Solar Market Development Tax Credit provides a 10% personal income tax credit (up to $9,000) for residents and businesses (non-corporate) that purchase and install photovoltaic systems. Credits are capped annually at $3 million for photovoltaic systems and are set to expire on December 31, 2016.

http://www.emnrd.state.nm.us/ECMD/CleanEnergyTaxIncentives/solartaxcredit.htm

Property Tax Exemption: Solar systems are not to be treated as physical improvements to the property until it is sold.

http://www.conwaygreene.com/nmsu/lpext.dll/nmsa1978/9a1/4c31/6983/6a1b?f=templates&fn=document-frame.htm&2.0#JD_7-36-212

Solar Energy Gross Receipts Tax Deduction: Revenue generated by the sale and installation of solar systems used to produce electricity to the property on which it is installed may be deducted from gross receipts before gross receipts tax is calculated.

http://www.emnrd.state.nm.us/ECMD/CleanEnergyTaxIncentives/grossreceiptstaxexemption.htm

# TEXAS

## I. TX Statutory/Regulatory Parameters

The TX legislature created the first RPS in 1999, as part of their electric market restructuring bill. Based on that legislation, in 1999 the TX PUC established the RPS rules.

| Enacted | | RPS | Non-wind |
|---|---|---|---|
| 1999 | By 2009 | 2,000 MW | |
| 2005 | By 2015[1] | 5,000 MW | |
| | By 2025[2] | 10,000 MW | 500 |

1. RPS met in 2008
2. RPS met in 2009

To implement the non-wind RE directive, the PUC awarded a "compliance premium" for other renewable energy sources such that each non-wind REC would equal two wind RECs. This element of the PUC rules is part of a current rulemaking effort: http://www.puc.state.tx.us/rules/rulemake/35792/35792.cfm

The RPS requirements apply to all Investor-Owned Utilities. Municipalities can voluntarily adopt their own requirements.

The DSIRE website offers the following summary of how the TX RPS functions: (http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=TX03R&re=1&ee=1)

*"Each retailer in Texas is allocated a share of the mandate based on that retailer's pro rata share of statewide retail energy sales. The program administrator maintains a REC account for program participants to track the production, sale, transfer, purchase, and retirement of RECs. Credits can be banked for three years, and all renewable additions have a minimum of 10 years of credits to recover over-market costs. An administrative penalty of $50 per MWh has been established for providers that do not meet the RPS requirements.*

*In 2004, the PUCT amended the RPS regulations to change the formula for calculating final REC purchase requirements, add a mechanism to account for corrections to retail sales data, and allow the program administrator of the REC-trading program to petition for deadline changes under certain circumstances.*

*The PUCT has the authority to cap the price of RECs and may suspend the standard if necessary to protect the reliability and operation of the grid. For more information on RECs, including* *annual compliance reports, visit the ERCOT Renewable Energy Credit Trading Program website.*

*In 2007 H.B. 1090 clarified that RECs retired for other purposes (e.g. sold through a voluntary green power program) could not be counted toward the RPS requirements. The law also permits large utility customers served by transmission voltage to opt out of the RPS requirements. Finally, H.B. 1090 empowers the PUCT to establish alternative compliance payments (ACP) for the RPS and for the non-wind target. To date, the PUCT has declined to set an ACP for either portion, although as noted above, an administrative penalty exists for providers that do not meet the general renewable energy obligation. The non-wind portion remains effectively voluntary without a penalty or an ACP.*

*Regulations for the "opt-out" provision were adopted by the PUCT effective January 2, 2009. The 2009 RPS report issued by ERCOT indicates that a total of 90 transmission voltage customers (unique meter IDs) elected to opt-out during 2009. Data such as the customer name and load (MWh) associated with these opt-outs remains confidential"*

Austin Energy (Municipal) established its own RPS requirement in 1999 and revised it through City Council resolutions in 2003 and again in 2007. The current RPS calls for 30% by 2020, with 100 MW from solar (with an interim goal of 15 MW solar by 2007).
http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=TX11R&re=1&ee=1

San Antonio's CPS Energy (Municipal) in 2003 established a Strategic Energy Plan goal for renewable energy to meet 15% of peak demand by 2020. They increased that target in June 2008 to 20% by 2020 with 100 megawatts (MW) from non-wind RE sources. As of June 2010, the utility had obtained 41 MW of solar electricity.
http://www.dsireusa.org/solar/incentives/incentive.cfm?Incentive_Code=TX15R&re=1&ee=1

## *II. TX Renewable Energy Credits*

As described above, ERCOT administers the Renewable Energy Credit Trading Program and provides an annual report on statewide compliance with the RPS.

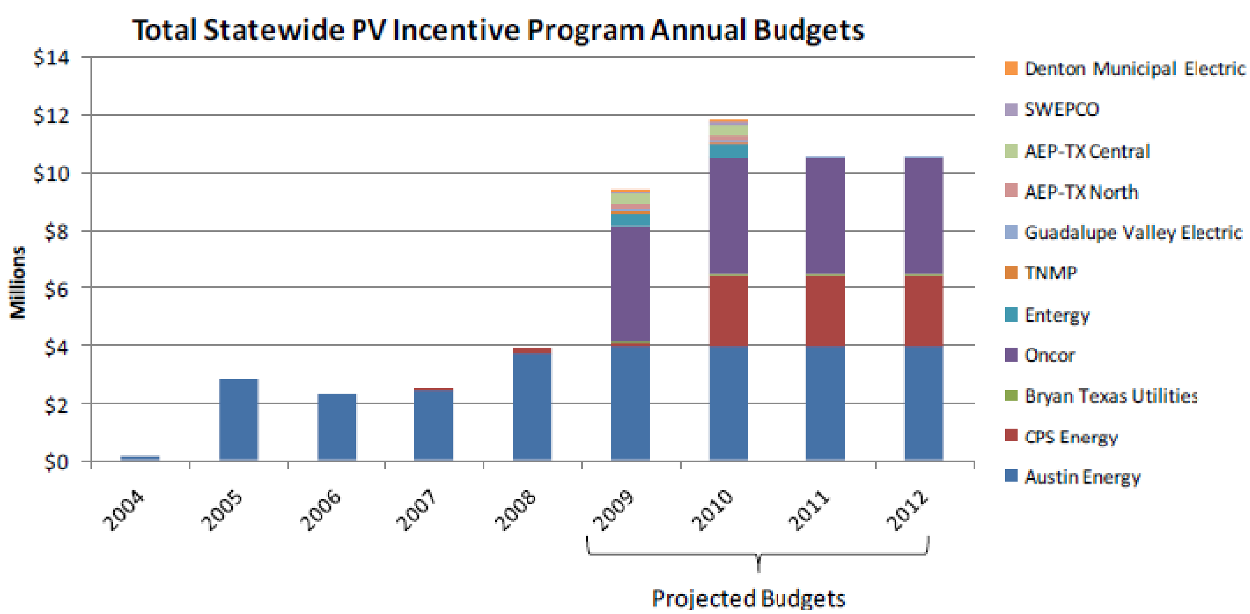
According to their reports, registered solar energy generators produced 4,492 MWh in 2009 and 14,449 MWh in 2010.

## *III. TX Utility Incentives:*

TX Solar PV programs are utility specific, but the types of incentives offered are generally similar. Most programs offer only up-front incentives rather than performance based payments.
History of PV Incentives in TX

Clean Energy Associates reviewed the status of solar PV incentives and installations in mid-2009 and produced a report summarizing their findings (http://www.txreincentives.com/opv/documents/TALOTSPV.ppt). According to their analysis, municipal utilities (Austin Energy and CPS Energy of San Antonio) began providing incentives as early as 2004, but IOUs did not begin offering incentives until 2009.

The report provides the following summary graphic of incentive budgets:




As illustrated, Oncor Electric Delivery (which had budgeted $16 million for a four year program) was projected to provide the largest share of IOU incentives. However, as of June 26, 2010 all funding had been expended, no new funding was allocated for 2011 and thus this program has been closed to new applications. http://www.txreincentives.com/opv/status.php

The report also lists the incentive levels offered in mid-2009:

| Utility* | Incentive per Watt | | 2010 Budget | Res'l Limit | Com'l Limit |
|---|---|---|---|---|---|
| BTU | $4.00 | AC | Unknown | $12,000 | $12,000 |
| AE** | $3.75 | AC | $4,000,000 | $50,000 | $100,000 |
| CPS | $3.00 | AC | $2,500,000 | $30,000 | $100,000 |
| DME*** | $3.00 | AC | $80,000 | $15,000 | $15,000 |
| TNMP | $2.50 | DC | $90,000 | $25,000 | $25,000 |
| Entergy | $2.50 | DC | $450,000 | $25,000 | $125,000 |
| Oncor | $2.46 | DC | $4,780,000 | $24,600 | $246,000 |
| GVEC | $2.00 | AC | unknown | $8,000 | $8,000 |
| AEP-TNC | $2.50 | DC | $180,000 | $25,000 | $90,000 |
| AEP-TCC | $2.50 | DC | $360,000 | $25,000 | $180,000 |
| SWEPCO | $2.50 | DC | $180,000 | $25,000 | $90,000 |
| | **Total** | | **$12,620,000** | | |

* BTU – Bryan Texas Utilities; AE = Austin Energy; CPS = CPS Energy; DME = Denton Municipal Electric; TNMP= Texas New Mexico Power Company; Entergy = Entergy Texas; Oncor = Oncor Electric Delivery; GVEC = Guadalupe Valley Electric Cooperative; AEP-TNC = AEP Texas North Company; AEP TCC = AEP Texas Central Company; SWEPCO – Southwestern Electric Power Company.
** Austin Energy's 2010 budget is not yet approved, but this figure represents what Austin Energy expects to grant.
*** DME's 2010 budget reflects 50% of estimated 2010 budget for all energy efficiency rebate programs.

Current Programs: Investor-owned utilities.

The TX IOUs have combined forces to document their information through one website: http://www.cleanenergyassociates.com/resources/texas-distributed-renewable-generation-incentive-programs/

That site provides the following graphic summarizing incentive levels and limits. (The incentive levels listed are still in place as of April 25, 2011, but AEP-TCC appears to be out of funds for 2011 reservations.)

## 2011 Texas IOU PV Incentive Programs Summary

| | AEP-TCC | AEP-TNC | El Paso | Entergy | SWEPCO | TNMP |
|---|---|---|---|---|---|---|
| **2011 Funding Available** | | | | | | |
| Residential | $180,000 | $90,000 | $450,000 | $225,000 | $121,500 | |
| Non-Residential | $180,000 | $90,000 | $450,000 | $225,000 | $121,500 | |
| Flexible | - | - | $450,000 | - | - | $108,000 |
| **Total $ Available** | **$360,000** | **$180,000** | **$1,350,000** | **$450,000** | **$243,000** | **$108,000** |
| **Incentive Level ($/w dc-stc)** | | | | | | |
| **Residential** | $2.00 | $2.25 | $2.00 | $2.00 | $2.00 | $2.00 |
| **Non-residential** | $1.75 | $2.00 | $1.75 | $1.75 | $1.75 | $2.00 |
| **Program Limits** | | | | | | |
| **Per Project** | | | | | | |
| Residential | $20,000 | $22,500 | $20,000 | $20,000 | $20,000 | $20,000 |
| Non-Residential | $87,500 | $40,000 | $43,750 | $87,500 | $17,500 | $20,000 |
| **Per Customer (multiple projects)** | | | | | | |
| Residential | $20,000 | $22,500 | $90,000 | $20,000 | $20,000 | $20,000 |
| Non-Residential | $87,500 | $40,000 | $90,000 | $87,500 | $17,500 | $20,000 |
| **Per Service Provider/Owner** | | | | | | |
| Residential | $90,000 | $45,000 | $180,000 | $225,000 | $60,750 | - |
| Non-residential | $90,000 | $45,000 | $180,000 | $225,000 | $60,750 | - |
| Flexible | - | - | $180,000 | - | - | $54,000 |
| **All Categories** | **$180,000** | **$90,000** | **$540,000** | **$225,000** | **$121,500** | **$54,000** |
| **Treatment of RECs (RECS belong to)** | Customer | Customer | Utility | Utility | Customer | Customer |
| **Program Website** | | | | | | |
| www.txreincentives.com | /apv | /apv | /elpasopv | /epv | /apv | /tpv |

**updated 12/30/2010**

The utility-specific web pages provide 2009 and 2010 budget information, as follows.

| 2009 Results | AEP-TCC | AEP-TNC | El Paso | Entergy | SWEPCO | TNMP |
|---|---|---|---|---|---|---|
| Final Budget | $360,000 | $180,000 | NA | $350,000 | $90,000 | $90,000 |
| Paid | $192,950 | $12,960 | NA | $82,937 | $27,600 | $88,464 |
| Paid as % of Budget | 54% | 7% | NA | 24% | 31% | 98% |
| kW-dc Installed | 110.480 | 5.180 | NA | 33.175 | 11.040 | 35.530 |
| Avg $/watt | 1.75 | 2.50 | NA | 2.50 | 2.50 | 2.49 |

| 2010 Results | AEP-TCC | AEP-TNC | El Paso | Entergy | SWEPCO | TNMP |
|---|---|---|---|---|---|---|
| Final Budget | $527,050 | $347,040 | $231,300 | $452,025 | $287,400 | $108,000 |
| Paid | $296,675 | $346,563 | $207,325 | $452,025 | $207,475 | $101,088 |
| Paid as % of Budget | 56% | 100% | 90% | 100% | 72% | 94% |
| kW-dc Installed | 121.472 | 184.960 | 83.470 | 183.715 | 132.690 | 42.135 |
| Avg $/watt | $2.44 | $1.87 | $2.48 | 2.46 | $1.56 | $2.40 |

Austin Energy - Residential Solar PV Rebate Program

According to their website (http://www.austinenergy.com/Energy%20Efficiency/Programs/Rebates/Solar%20Rebates/index.htm?wwparam=1303754737): "As of March 2010 Austin Energy supports more than 1,050 customer-owned solar energy systems, 70 commercial projects, 24 municipal projects, 28 school installations, and 6 libraries. Together, these produce more than 4 megawatts of generation capacity. In addition, more than 35 new solar installation companies have developed in Austin, creating approximately 300 green jobs."

This program was approved and funded by City Council in 2004. The FY 2011 budget is $4 million. Some portion of prior year budgets has been allocated to installing solar PV on municipal buildings. Current incentives are:

| Residential | Commercial |
|---|---|
| $2.50/watt | $0.14/kWh for systems up to 20 kW |
| limited to $15,000 per site per year up to a maximum rebate of $50,000<br><br>Home must meet specific energy efficiency requirements | Qualifying equipment at least sixty percent manufactured or assembled in AE's electric service area may qualify for a PBI at a rate not to exceed $0.175 per kWh. (does not include installation of the system) |

CPS Energy Solar Initiative Rebate Program (San Antonio's municipal utility) (http://www.cpsenergy.com/Residential/Rebates/Solar_Rebates/Solar_Photovoltaic/)

| Tier 1 (Private and Public School Campuses, CPS certified local contractor) | Tier 2 (Residential & Commercial, CPS certified local contractor) | Tier 3 (Residential & Commercial, not a CPS certified local contractor) |
|---|---|---|
| $3.00/watt AC for first 25kW<br>$1.65/ watt AC for remaining | $2.50/watt AC for first 25 kW<br>$1.65/ watt AC for remaining | $1.65/watt AC |
| Maximum rebate $200,000 | Maximum rebate $200,000 | Maximum rebate $200,000 |

- Tiers 1 and 2 must have system installed "by a CPS Energy certified contractor with local (CPS Energy service territory) presence. Local presence defined by a facility in the name of the solar contractor's business with an associated CPS Energy electric account for that location."
- All 3 Tiers are subject to this limitation: "This solar rebate offering is not available for client leased equipment installations or other financing options that remove the client's

upfront investment in order to own the PV array. The client's investment amount required is at least the invoice cost of the PV system less the CPS Energy rebate. Solar PV array installations funded via federal or state grants obtained by the customer are exempt from this requirement."

- Customers have 120 days from date of CPS Energy approval to complete the installation of the system. Systems completed after 120 days, unless granted an extension, will be disqualified for the rebate.

Bryan Texas Utilities (BTU)

Residential systems:

- The standard rebate level for qualifying equipment is $2.00/watt (AC). IRS designated Non-Profits are also eligible for the $2.00 per watt rebate level. The maximum rebate is for a 3 kW system.
- The maximum rebate per customer is capped at 80% of invoice cost or $6,000 "per fiscal year" (October – September) for each customer site.

Commercial Systems:

- The standard rebate level is $2.25/watt (AC), available for up to 9 kW.

Guadalupe Valley Electric Cooperative

GVEC offers a rebate of $2.50/watt up to a maximum of $10,000. Systems must not exceed 20 kW.

Xcel Energy - Residential and Hard-to-Reach Standard Offer Program

This is primarily an energy efficiency program. Each year, Xcel Energy TX selects "Project Sponsors" who are eligible to receive incentives for installing energy efficiency or renewable energy measures. The primary goal is providing comprehensive energy efficiency retrofits for single-and multi-family customers who meet the income guidelines of the program.

As illustrated by the 2011 budgets, this is a small program.

| **Program** | **2011 Residential SOP** | | **2011 Hard-to-Reach SOP** | |
|---|---|---|---|---|
| | Large Projects | Small Projects | Large Projects | Small Projects |
| **Funding** | $517,255 | $50,000 | $200,549 | $50,000 |

To determine incentive amounts, the kW rating (DC) is used to infer energy and demand savings according to these formulas:

- Deemed Energy Savings (kWh) = 1.6 * watts DCSTC installed
- Deemed Demand Savings (kW) = 0.83 * kW DCSTC installed

Incentive rates for Residential and Hard-to-Reach projects are based on a percent of the avoided cost benefit. Demand (kW) payment is based on Peak Demand Savings.

| Units | Residential | Hard-to-Reach |
|---|---|---|
| kW | $245 | $400 |
| kWh | $0.07 | $0.11 |

http://www.xcelefficiency.com/TX/RES_HTR/index.html

## *IV. TX Other State Incentives*

Solar Energy Devices Franchise Tax Deduction: "In calculating its business franchise tax, a corporation or other entity subject to the state franchise tax may deduct from the tax base the cost of a solar energy device. An entity may deduct 10 percent of the amortized cost of the system." http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=TX04F&re=1&ee=1

Solar Energy Devices Business Franchise Tax Exemption: "Texas also offers a franchise tax exemption to companies in Texas engaged solely in the business of manufacturing, selling, or installing solar energy devices. This exemption has no ceiling, so it is a substantial incentive for solar manufacturers."
http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=TX02F&state=TX&CurrentPageID=1&RE=1&EE=1

Renewable Energy Systems Property Tax Exemption: "Texas voters in 1978 adopted a constitutional amendment authorizing the Legislature to exempt solar or wind-powered energy devices from property taxes. The Tax Code allows an exemption from the appraised value of the property equal to the amount that arises from the installation or construction of a solar energy device primarily for on-site use."
http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=TX03F&re=1&ee=1

In 1975, the Legislature exempted solar energy devices from the sales and use tax, but the exemption was repealed in 1987.

Department of Rural Affairs - Renewable Energy Demonstration Pilot Program: Non-tax incentives in Texas include a program offered by the Texas Department of Rural Affairs, to provide grants to qualifying cities with fewer than 50,000 residents and counties with fewer than 200,000 residents for installing renewable energy projects.
http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=TX89F&re=1&ee=1

LoanSTAR Program: A revolving loan program through SECO under the Comptroller's Office, offers low-interest loans to all public entities, including state, public school, college, university, and non-profit hospital facilities, for enacting measures to reduce energy costs. On-site renewable energy options, such as solar water heating, photovoltaic panels, and small wind turbines, are encouraged in the analysis of potential projects.
http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=TX12F&re=1&ee=1

Also, HB 2961 "relating to the creation of a program for the development of solar energy industry in this state" has been proposed in the current legislative session and is pending in committee. It would establish a surcharge on electric bills to fund incentives for wholesale and distributed solar generation.

# UTAH

## I. UT Statutory/Regulatory Parameters

In 2008, Utah passed what is more accurately described as a Renewable Portfolio Goal (RPG). Specifically, utilities need to pursue renewable energy to the extent that it is "cost effective" to do so. The guidelines for determining the cost effectiveness of acquiring a renewable energy source include several considerations as follows:

- an assessment of whether the acquisition of the renewable resource will result in the delivery of electricity at the lowest reasonable cost,
- an assessment of long-term and short-term impacts,
- risks,
- reliability,
- financial impact on the affected utility, and
- other factors as determined by the Utah Public Service Commission.

To the extent that it is cost effective to do so, investor-owned utilities, municipal utilities, and cooperative utilities must use eligible renewable sources to account for 20% of their adjusted retail sales by 2025. While states that have enacted RPSs have interim targets that increase over time, Utah has no interim targets for the goal.

http://le.utah.gov/~code/TITLE10/10_19.htm

## II. UT Renewable Energy Credits

Utilities may meet the Renewable Portfolio Goal by producing electricity with a renewable energy source or by purchasing renewable energy credits.

## III. UT Utility Incentives

UT Rebates:

Rocky Mountain Power
Its program began in the fall of 2007 as a 5-year pilot program that was eligible to all customer classes to install solar photovoltaic systems. Each year the program is limited to paying incentives for 50 kW of non-residential and 57 kW of residential PV. Until this year, 2011, the incentive had been $2.00 per watt. For program year 2011, the financial incentive is now $1.55 per watt. There is no minimum system size but there is a maximum system size of 25 kW.

Residential systems are capped at 2 kW ($3,100) and commercial systems at 15 kW ($23,250). With the exception of the late start in 2007, the remaining years have fully subscribed allocation within minutes of the designated application start date/time. The program was set to sunset at the end of December 31st of 2011.

On February 24, 2011 Rocky Mountain Power proposed, under Docket No. 11-035-T02, to move the program's last annual deadline from December 31, 2011 to June 30, 2012 to allow sufficient time for projects awarded funding in 2011 to be completed by the program deadline. Stating that extending the program deadline would provide additional time to the Company to meet the objective of fully subscribing the program capacity over the five year pilot term.

On April 4, 2011, the Commission approved the request to extend the annual deadline to June 30, 2012 in Docket No. 11-035-T02. In addition, the Commission inserted in the last paragraph of the tariff sheet 107.3 the following: *Unless otherwise extended by the Company after approval by the Utah Public Service Commission, this program is of limited duration and funding. All equipment must be installed by the annual deadline to be eligible to receive a program incentive. The last annual deadline will be no later than June 30, 2012.*

http://www.psc.state.ut.us/utilities/electric/elecindx/2011/11035T02indx.html

City of St. George

Beginning in 2005, the City of St. George began offering rebates for solar photovoltaic systems. Currently, the City offers $2 per watt for both residential and commercial customers. The rebate limits are 3 kW ($6,000) for residential and 10 kW ($20,000) for commercial customers. Minimum system size that is eligible for a rebate is 1 kW and the maximum is 25 kW.

Washington City

Washington City offers a $2 per watt rebate to customers that install solar photovoltaic systems. The rebate limits are 3 kW ($6,000) for residential and 10 kW ($20,000) for commercial customers. Eligible system size is 10 kW. Rebates are administered through a 50% electrical account credit and 50% direct payment.

UT Performance-based credits:

Utah has yet to consider a performance-based credit.

## *IV. UT Other State Incentives*

Renewable Energy Systems Tax Credit: Utah provides a State Tax Credit of 25% up to a maximum of $2,000 for individuals and a 10% tax credit up to a maximum of $50,000 for commercial solar photovoltaic systems.

http://le.utah.gov/~code/TITLE59/htm/59_10_110600.htm

Renewable Energy Sales Tax Exemption: State sales tax is exempt from the purchase of equipment used to generate electricity from renewable resources in Utah. Eligible purchases must be made for or by a renewable energy production facility before June 30, 2019. This applies to leases as well and all leases must be made for at least seven years.

Installations must have a minimum capacity of 20 kW. An existing facility that is expanded by one or more megawatt (MW) as a result of installation of equipment or machinery may also be eligible for the exemption.

http://le.utah.gov/~code/TITLE59/htm/59_12_010400.htm

# APPENDIX C

## Data on Solar Program Initiatives in Ten States:

**Arizona**
**California**
**Florida**
**Massachusetts**
**Nevada**
**New Jersey**
**New Mexico**
**Pennsylvania**
**Texas**
**Utah**

| | Renewable Portfolio Standard for Investor-owned Utilities | | | | | Solar-specific Incentives | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| State | Date of First RPS Agreement | Initial Requirement | Current Peak Requirement | Distributed Generation Carveout | Solar Carveout | Rebates | Performance-based Incentives | Income Tax Incentives | Sales Tax Incentives | Property Tax Incentives | Total MW of PV Currently Installed | Total MW of Planned PV | Current Plan for Phase Out of Incentives |
| Arizona | 1996 | 1.25% by 2006 | 15% by 2025 and each following year | 4.5% by 2025, half from residential installations | Initially half of renewables (0.2% overall in 2002), increased to 60% of renewables (0.66% overall in 2007-2012); currently no solar-specific requirement | Rebate varies by utility, approximately $1.35-$2.00/Watt up to 40-60% of cost or $6,750-75,000 for both commercial and residential (according to DSIRE) and from $1.45-$5.00/Watt up to 30 to 60% of total cost (according to CO PUC) | REC payment of 6.5 to 20.2 cents/kWh depending on utility (some utilities do not offer any performance-based incentives), length of REC payment term (10, 15, or 20 years), size of system, and whether it is on/off grid (does not specify residential or commercial) | Residential income tax credit 25% of cost of installation of solar up to $1,000 | 100% of sales tax of equipment (commercial and residential) | Property tax exemption: all value added by renewable energy system is subtracted from value for property tax purposes (commercial and residential) | 29.5 | 96.8 | Unknown |
| Nevada | 1997 | 6% by 2005 | 25% by 2025 and each following year | N/A | Initially 5% subset of renewables through 2015 (1.25% overall in 2015) and 6% subset of renewables from 2016-2025 (1.5% overall in 2025) | Rebate of $2.30/Watt (residential and small business), $5.00/Watt (Schools, public and other property including non-profits and churches), maximum of 1 MW | PV earns 2.4-2.45 PECs per kWh of generation, while other renewables earn only 1 PEC per kWh (commercial and residential) | | Sales tax abatement to 2.25% for qualifying technologies (commercial only) | Property tax exemption: all value added by renewable energy system is subtracted from value for property tax purposes (commercial and residential) | 79.9 | 20.0 | Rebate scheduled to decline gradually from current rate of $2.30/Watt to $1.50/Watt in 2015 |
| New Mexico | December 2002 | 5% by 2006 | 20% by 2020 (unclear thereafter), although not required if cost of renewable energy is above "Reasonable Cost Threshold" | 1.5% by 2011, 3% by 2015 | 20% subset of renewables (4% overall in 2020) | | REC payment varies by utility and is 8 to 15.5 cents (commercial and residential) | Income tax credit of 10% of purchase and installation costs up to $9,000 for minimum 100 W PV (commercial and residential), additional $0.015-0.04/kWh produced for commercial systems of at least 1 MW capacity | 100% of sales tax of equipment (commercial and residential) | For the purposes of determining property taxes, cap on property value increase due to solar installation by more than 3-6.1% (residential only) | 33.9 | 75.0 | REC payments made for only 12 years and REC rate declines over the 12 year period; income tax credits expire at end of 2016 |
| Texas | 1999 | 2,280 MW by 1/1/2007 | 10,000 MW by 2025 (unclear thereafter); Austin: 30% by 1/1/2020; San Antonio: 20% by 2020 | N/A | Austin: at least 100 MW subset by 2020; San Antonio: at least 100 MW subset by 2020 | Rebate varies by utility, approximately $2.00-2.50/Watt for residential systems with various maximum amounts and generally lower rebates for commercial (according to DSIRE) and from $2.00-4.00/Watt (according to CO PUC) | REC payment varies from 14-27 cents per kWh, and each non-wind REC is equal to two wind RECs (commercial and residential) | Deduction of 10% of amortized cost from corporate tax | | Property tax exemption: all value added by renewable energy system is subtracted from value for property tax purposes (commercial and residential) | 16.9 | 30.0 | REC payments for 10-20 years |
| Utah | March 2008 | | Goal of 20% of adjusted retail electric sales (total sales reduced by sales attributable to nuclear power, demand-side management measures, and fossil fuel power plants that sequester their carbon emissions), although only if renewable energy is "cost effective" | N/A | N/A | Rocky Mountain Power initially offered $2/Watt, but in 2011 this was reduced to $1.55/Watt; City of St. George and Washington City offer $2/Watt (commercial and residential) | Each kWh of electricity produced using solar counts as 2.4 kWh for the purposes of meeting the goal (does not specify residential or commercial) | 25% of purchase and installation costs up to $2,000 for residential, 10% for commercial up to $50,000 | 100% of sales tax of equipment if capacity is at least 20 kW (commercial only) | | 0.3 | 0.1 | Unknown |

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| California | 2002 | 20% by December 31, 2013 | 33% by 2020 and each following year | N/A | N/A | Varies by utility; began at $2.50/Watt for systems under 30 kW with performance-based incentives instead if system is over 30 kW; Currently approximately $1.87-3.50/Watt for systems up to a certain size (10-50 kW); also varies by commercial/residential | Began at $0.39/kWh for systems over 30 kW for the first 5 years; decreases as aggregate PV capacity increases; Currently approximately $0.133-0.26/kWh for systems over a certain size (10-50 kW) for the first 5 years (residential and commercial) | | 100% of sales tax of equipment (industrial only) | Property tax exemption: all value added by renewable energy system is subtracted from value for property tax purposes; if equipment is used to carry both solar and energy from other sources only 75% exemption (commercial and residential) | 220.5 | 119.0 | Performance-based incentive decreases as aggregate PV capacity increases |
| New Jersey | 1999 | 4.0% Class I and 2.5% Class II by 2012 | 17.88% Class I and 2.5% Class II renewables by 2020-2021 and equal to or greater than this in each following year | N/A | Currently 5,316 incremental GWh of any solar by 2025-2026 and each year thereafter; initially a subset of 0.01% from solar by 2005 increasing to 2.12% by 2021, but revised in January 2010 to have increasing incremental carve outs from 306 GWh in 2011 up to 5,316 GWh in 2026 | $0.25/Watt for eligible photovoltaic panels, $0.15/Watt for eligible inverters, $0.15/Watt for eligible racking systems, each up to 10 kW for residential systems (lower for commercial) | 15 years of performance-based incentives, with a decreasing maximum cost per solar REC each year, starting at $711/MWh in 2008-2009 and decreasing to $594/MWh in 2015-2016; the weighted average price for 2010-2011 was approximately $600/MWh (residential and commercial) | | 100% of sales tax of equipment (commercial and residential) | Property tax exemption: all value added by renewable energy system is subtracted from value for property tax purposes (commercial and residential) | 73.5 | 47.1 | 15 years of performance-based incentives, with a decreasing maximum cost per solar REC each year |
| Pennsylvania | November 2004 | 1.5% Tier I and 4.2% Tier II by 2006-2007 | 8% Tier I and 10% Tier II by 2020-2021; 10% Tier II in each following year; Tier I will be reviewed in 2021 and may be modified | N/A | Initially 0.0013% subset for PV by 2007 increasing to 0.5% subset for PV by 2021 and each following year | $0.75/Watt, 35% of installed cost for low income; overall maximum is lesser of $7,500 or 35% of installed cost; minimum system size 1 kW; rebates have declined based on steps of installed capacity, where each step is 10 MW; initial rebate was $2.25/Watt and has declined by $0.50 at each step so far (residential); $0.50-0.75/Watt for commercial with maximum of lesser of $52,500 or 35% of installed cost | Varies based on market conditions; as of April 2011 the market price was approximately $0.22/kWh (commercial and residential) | | | | 12.0 | 6.5 | Rebates have declined based on steps of installed capacity, where each step is 10 MW; initial rebate was $2.25/Watt and has declined by $0.50 at each step so far |
| Massachusetts | April 2002 | 1% by 12/31/2003 | 15% Tier I by 12/31/2020 and an additional 1% each year thereafter; 7.1% Tier II (existing resources) in 2009 and each following year (3.6% renewables and 3.5% waste-to-energy) | N/A | 30 MW PV subset of overall Tier I in 2010 (equivalent to 0.0679%), increasing to 69 MW in 2011, with eventual target of 400 MW; no date has been set for the 400 MW target, but once 400 MW have been installed, no additional solar facilities qualify for the solar carveout | Varies by utility: Commonwealth Solar II (including NSTAR and National Grid) base incentive of $0.75/Watt (residential and commercial), with additional $0.10/Watt for Massachusetts company components (residential and commercial), $0.85/Watt for moderate home value (residential only), and $0.85/Watt for moderate income (residential only); others range from $0.625-$2.50/Watt | Price for SRECs determined by market, but price floor of $300/MWh and price ceiling of $550/MWh (commercial and residential) | 15% credit up to $1,000 against state income tax for net expenditure of a renewable energy system including installation costs (residential); 100% deduction off net income for commercial | 100% of sales tax of equipment (residential) | Property tax exemption: all value added by renewable energy system is subtracted from value for property tax purposes for 20 years (commercial and residential) | 7.0 | 6.2 | Once 400 MW of PV have been installed, no additional solar facilities qualify for SRECs; property tax incentive expires after 20 years |
| Florida | No state RPS; JEA, Jacksonville's municipal utility: November 1999 | JEA: 7.5% by 2015 | JEA: 7.5% by 2015 | N/A | N/A | $4/Watt up to $20,000 (residential) and up to $100,000 (commercial) | None state-wide; Orlando: $0.05/kWh for the first 600 kW installed; Gainesville: fixed rate of $0.19-$0.32/kWh declines with later year of contract (commercial and residential) | | 100% of sales tax of equipment (commercial and residential) | | 54.3 | 506.5 | Gainesville: fixed rate of $0.19-$0.32/kWh declines with later year of contract |