Attachment A:

RESPONSE OF KEYES & FOX LLP TO THE DIVISION OF PUBLIC UTILITIES' NOVEMBER 8, 2011 REPORT ON THE SOLAR INCENTIVE PROGRAM

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To: Jason Coughlin, National Renewable Energy Laboratory
and submitted in Utah PSC Docket No. 07-035-T14.
From: Thadeus B. Culley, Jason B. Keyes
Re: Cost-Effectiveness of Expanding Rocky Mountain Power's Solar Incentive Program
Date: 11/22/11

Objective

The National Renewable Energy Laboratory asked us to examine the cost-effectiveness of Rocky Mountain Power's ("RMP's") pilot Solar Incentive Program ("SIP") and to make recommendations on how cost-effectiveness could be improved in an expanded program. This memorandum is based on sources in the public record of Utah Public Service Commission ("Commission") dockets related to the SIP and on external sources on policy design and cost-effectiveness of solar programs.

Executive Summary

This memorandum reviews the Solar Incentive Report issued by the Division of Public Utilities ("Division") on November 8, 2011, and will be submitted to the Division. According to the Division's report, the SIP, with minor adjustments, would become cost-effective in year five based on the Utility Cost Test, a result due in large part to the Commission's reduction in the SIP incentive to $1.55 per Watt. With the SIP in its fifth and final year, the Division recommends a one-year extension at the $1.55 per Watt rate, a doubling of the current program size to 214 kilowatts ("kW"), elimination of metering requirements, and a cap on administrative costs at 15% of program costs. As well, the Division recommends workshops ending in March 2012 to redesign the SIP for future years, while stating that the SIP should not extend past the expiration of the federal Investment Tax Credit in 2016.

The Division's report followed a series of discussions with stakeholders in which Keyes & Fox participated to assist Utah Clean Energy in its analysis of the SIP. While the Division had hoped to develop a report representing a consensus of the stakeholders, the report states the Division's position and stakeholders have been invited to comment. Utah Clean Energy and others intend to file comments. The intent of this memorandum is to review the Division's analysis and recommendations, without taking a position on what should be done with the SIP. Most importantly, we question why the Division limited its recommendation for program size for the next year to 214 kW given that the program has been shown to be cost-effective. As well, we recommend that the correlation between program size and administrative costs be recognized; with the potential for administrative costs being less than 15% of program costs if the program were significantly enlarged. Finally, we review and concur in the recommendation to drop metering requirements and to hold workshops in early 2012 to redesign the SIP, but question the Division's recommendation to tie the SIP to the availability of federal incentives for solar energy.

I. Background

In 2007, Rocky Mountain Power proposed and instituted a pilot solar photovoltaic ("PV") program to provide incentives encouraging residential and commercial customers to install 107 kW of solar PV per year for a period of five years. The incentive program consists of a per watt rebate that assists participating customers in paying for on-site solar PV systems, offsetting the initial outlay of capital required to finance a project. The initial purpose of the pilot program was to "assess the viability and potential customer participation in a program that provides incentives for uptake of consumer PV systems."[1] The pilot's 107 kW annual program capacity allocates 57 kW to residential systems and 50 kW to commercial systems and has been fully subscribed over the course of the program.[2]

Rocky Mountain Power estimated an annual budget of $314,500 for the pilot program for each year from 2007 through 2011 in its original tariff filing.[3] This proposed budget consisted of $79,000 for "program delivery" (including contracted program administration costs), $215,500 for incentives paid to participants, and $20,000 for utility administration costs. Adding the program delivery and utility administrative costs together, total administrative costs were budgeted at 31.5%. Cumulatively, the program would cost $1,572,500 and result in total program capacity of 535 kW.

Assessing the "viability and potential customer participation" of the SIP implies two different tests. Viability relates to whether the program is cost-effective for the utility, by comparison with other options at the utility's disposal. The Utility Cost test is appropriate for this analysis. "Potential customer participation" relates to whether customers will be motivated by the SIP to install solar facilities. The Participant Cost test is appropriate for this analysis, though the fact that there has always been a waiting list makes this analysis somewhat unnecessary. According to RMP's annual reports, the program was not cost-effective for the first four years, but was trending toward cost-effectiveness, per the Commission's prescribed methodology.

In 2010, RMP proposed to cancel the pilot and, in its place, launch a pilot program for energy storage devices using the existing SIP budget. The Division opposed closing the pilot, insisting that the program would be cost-effective in its final year, 2011. The Division instead supported

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1 *See* Division's June 15, 2007 Memorandum of Recommendations on the Proposed Solar Incentive Program at p. 2, Docket No. 07-035-T14.

2 *See* RMP's 2010 Annual Report for the SIP at p. 4.

3 *See* August 3, 2007 Order (Approving Tariff with Certain Conditions) ("August 3, 2007 Order") at p. 3, Docket No. 07-035-T14.

the idea of providing funding, separately, for the specific power storage pilot. The Division believed that those programs could prove to be complimentary, given the potential benefits of pairing energy storage devices with solar PV systems.

To continue the solar incentive program, the Division is now proposing that the Commission double the total annual program capacity in 2012 and hold workshops to consider a redesign of the SIP, with the caveat that the program not extend past 2016. The Commission will consider the Division's proposal, and the comments and proposals of other parties to determine whether and to what extent to continue the SIP.

II. Determining Program Cost-Effectiveness

At the most basic level, the cost-effectiveness of a utility program depends on whether the measurable benefits outweigh the measurable costs. Thus, the meaning of a test is highly related to whether the benefits and costs being measured are relevant to the proposed program. There are a variety of applicable tests that have been utilized to assess the cost-effectiveness of renewable energy, energy efficiency and demand-side management ("DSM") programs, but the decision of which methodology to employ varies depending on the vantage that is sought.

The traditional cost-effectiveness measures used by utility commissions to evaluate program cost-effectiveness, have been the Ratepayer Impact ("RIM") test, the Total Resource Cost ("TRC") test, the Utility Cost ("UC") test, and the Participant Cost ("PC") test.[4] Each methodology has its place, but ultimately it is the UC test that is most determinative of whether and to what extent programs are to be implemented in Utah.[5]

The Commission's DSM Order generally followed the recommendations of a report filed by RMP, the Division and the DSM Advisory Committee. That group's 2009 report ("2009 DSM Report") concluded that utilities should assess the cost-effectiveness of small-scale renewable programs in the same manner used for DSM programs, using five tests, but that it was not necessary for the program to pass all five tests if, in the balance, the program proved to be in the public interest.[6] The five tests are the UC test, two variations of the TRC test (one with and one without a conservation adder), the RIM test, and the PC test, which looks at cost-effectiveness from the customer-generator's perspective. While the 2009 DSM Report recommended that all of these tests be considered, it concluded that the UC test should be established as "the threshold test for cost-effectiveness in the assessment of program prudence."[7] The Commission agreed that a program for small-scale renewable resources should pass the UC test, at a minimum.

4 *See* October 7, 2009 Commission Order ("DSM Order") at p. 5, Docket No. 09-035-27.
5 *Id.* at pp. 9 & 15.
6 *Id.* at p. 4.
7 *Id.* at p. 5.

III. Analysis of the Division's Report on the Solar Incentive Program

A. The Division does not emphasize the SIP's performance in the fifth year.

In the Division's November 8, 2011 report on the SIP ("Division's 2011 Report"), there is unusual emphasis on the SIP's failure to achieve cost-effectiveness under the UC test during the program's first four years.[8] Importantly, the results of these tests were based on the pilot's incentive being set at $2 per watt, a level that was reduced for the fifth year of the program to $1.55 per watt by Commission Order.[9]

With its emphasis on the first four years of the SIP, the Division's 2011 Report leaves an impression that the SIP is typically uneconomic, though it clarifies that it appears likely that it will be cost-effective in its last year. Moreover, the cost-benefit analyses conducted as part of the solar workgroup efforts showed the program to be cost-effective with only slight modifications to the incentive levels and administrative costs. Given that, the more important message to convey is that the SIP has undoubtedly become cost-effective and that with certain improvements, it will be even more cost-effective. Utah Clean Energy reported the results of analysis of the program at the $1.55 per Watt incentive level and made the connection that the program was cost-effective at this level. The Division notes that RMP's resource selection model would select all of the available solar energy at this level, without clarifying that this is due to the fact that it has achieved cost-effectiveness.[10] There is no indication that the SIP will become uneconomic in future years, leading to the conclusion that the program should be continued and expanded. While the Division reaches this conclusion, a modest critique of the Division's 2011 Report is that it could better support the conclusion by deemphasizing results from years when higher incentive rates were in use, since there is no intent to return to those rates.

B. The Division's recommendation to increase the programmatic size in the coming year is supported, but the recommended size is not supported.

A primary recommendation of the Division's 2011 Report is a doubling of the SIP's size to 214 kW in 2012, but there is no explanation regarding why this level was chosen. We are not aware of a major utility anywhere in the country with such a modest program. As discussed below, administrative costs alone are a valid reason to set program size at a higher level. The fact that the SIP has only supported 107 kW per year is not a basis for setting the program at a multiple of that amount in the coming year, and we expect that the Commission will seek some other basis for setting the program level.

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[8] The Division's 2011 Report looks back to the conclusions of the Division's November 30, 2010 Memorandum (on the three year assessment of the Solar Incentive Program) ("2010 Memorandum") at p. 5, Docket No. 07-035-T14.

[9] *See* February 10, 2011 Order (lowering rebate to $1.55 per watt) at p. 7, Docket No. 07-035-T14.

[10] Division's 2011 Report at p. 4, footnote 10.

A possible explanation for the Division's decision to use a programmatic doubling is that a greater expansion might entail such rapid expansion that there would be inherent inefficiencies. This is not well founded. PacifiCorp's 2011 Integrated Resource Plan reports that as of year-end 2010, the company's customers had installed over 10,000 kW of net-metered systems, 92% of which are solar energy facilities.[11] PacifiCorp averaged 68 new net-metered customers *per month* in 2010, a 50% increase over 2009.[12] A one MW SIP with residential and commercial components and a total of 100 new customers per year would be a modest expansion in the program that PacifiCorp is already managing. Even so, a one MW program is very modest and there does not appear to be any reason to limit the SIP to that level. Accordingly, there does not appear to be a basis for limiting the program expansion to 214 kW as the Division proposes.

C. The Division appropriately recognizes that additional metering requirements are not be necessary given the performance of pilot program solar systems.

The Commission, in its Order approving RMP's tariff for the pilot program, recognized the importance of actual system production and performance, noting that "the Program clearly has the potential to be cost-effective depending on how cost-effective is defined and depending on the actual performance of solar projects relative to system costs."[13] The case for cost-effectiveness should be bolstered, then, by evidence indicating that the average of actual production from installed solar PV systems exceeds estimates.

Given the fact that the performance of the systems has closely matched projected output, as estimated using the National Renewable Energy Laboratory's PV Watts calculator, there may be good cause to eliminate the additional meter requirement. Currently, the RMP requires a meter socket be made available so that RMP can install a meter to accurately measure the production intervals of the systems. As reported in its Annual Reports, the cost of the meter upgrade for residential customers was approximate $125 per site. However, the 2009 Annual Report, the first year in which production interval meters were utilized, notes that there were seven generation meters installed at a cost of $1,800 per site. In 2009 and 2010, the Annual Reports note that significant telecommunications charges applied to these generation meters as well, ranging from $98 in 2009 to $1,680 in 2010.[14] Nearly $16,000 in metering costs were incurred in 2009 alone, although some of those costs were not charged to the program until 2010.[15] These meter costs represent a significant part of the utility's costs and necessarily impact the cost-effectiveness of the program.

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11 PacifiCorp 2011 IRP, p. 88. Available at http://www.pacificpower.net/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf

12 *Id.*

13 *See* August 3, 2007 Order at p. 7.

14 *See, e.g.*,RMP's 2009 Annual Report at p.5; RMP's 2010 Annual Report at p. 5.

15 RMP's 2009 Annual Report at p.5.

If the actual production and performance of solar projects can be reliably forecast by software like PV Watts, then the meter sockets, the interval meters provided by the utility and the related telecommunications costs may represent unnecessary and redundant costs. As reported in the 2010 Annual Report, from a report that studied the correlation of meter output data to PV Watts forecast, the "overall weighted average realization rate was computed to be 108%," with individual variations in the range of 82% of production to 120% of production.[16]

From a pilot program perspective, the production meters may have been necessary to verify that software estimates accurately represent actual production, a correlation strongly suggested in the Cadmus report in RMP's 2010 Annual Report. In reality, the solar facilities outperformed estimates by creating 8% more production than expected. Perhaps this means that PV Watts provides conservative estimates for Utah, or perhaps this could be explained by an annual variation in solar insolation, which would indicate that even a marginally lower year of production would still come very close to meeting the estimated production. The conclusion to be drawn here is that solar facilities generally perform as predicted, and expensive metering is not necessary to confirm this fact. Accordingly, removing the costs of metering from the cost-benefit analysis is reasonable.

As a practical matter, RMP can use available data at a much lower cost if it wants data. Program participants everywhere want to know how their facilities are performing and they typically have data from their inverter to find out. Many net metered customers upload this data to the internet; the leading monitoring company has thousands of sites listed publicly and many more monitored without public listing and charges less than $100 per year for the service.[17] RMP could offer to pay for half of the cost to have customers upload their data to a website to verify output remotely. Inverter data is slightly less accurate than revenue-grade metering, but it is perfectly adequate to assure that power is being generated near expected levels. This further bolsters the Division's point that metering costs under the SIP are unnecessary and should be eliminated.

An argument against eliminating production metering is that one of the objectives of the program was to evaluate the ability of solar PV to impact system peaks, requiring 15 minute output data. RMP suggests that the actual measured solar PV output did not create any meaningful value in this regard. As the Division notes in its 2010 Memorandum, however, one reason for the less than optimum peak correlation was that most systems were south-facing, an orientation that reaches peak generation much earlier in the day than RMP's system peak, but also an orientation that generates the largest number of kilowatt-hours ("kWh") for net metering customers. The Division argued that it was premature to come to the conclusion that solar PV would not create meaningful peak shaving benefits because there was an insufficient sampling of southwest-facing systems, which would be expected to reach its peak generation later in the day, closer to RMP's system peak.

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16 RMP's 2010 Annual Report at p. 24, Appendix 2, ("Cadmus Report").

17 Fat Spaniel monitoring, recently acquired by Power-One, with sites listed at http://www.fatspaniel.com/fat-spaniel-in-action/live-sites/.

While analysis of peak-shaving effects is important, production metering is not necessary for the analysis. PV Watts provides predicted output with the ability to adjust orientation and tilt to accommodate and create later peak generation. As well, remote metering programs based on inverter data can report 15 minute interval data. Individual system variations due to intermittent cloud cover are lost in the process of aggregating production from all systems. In any event, removing the meter costs would positively impact the cost-effectiveness assessment. As the Division suggests, achieving the goal of coincidence with RMP's peak load could be done by program design by incentivizing southwest facing systems with a slightly higher rebate payment.[18]

As the Division noted in its 2010 Memorandum, reducing incentive levels to $1.55 makes the solar incentive program 99.6% cost-effective, even with all other aspects of the program at the status quo.[19] The Division also recommended in 2010 that the Commission require additional cost analysis that examined the cost-effectiveness without generation meters and with caps on administrative costs.[20] The Division is now proposing those adjustments to the program. For further analysis, Utah Clean Energy has illustrated the positive impact of removing the metering requirement would have on cost-effectiveness.[21]

D. Program administration of the pilot is a substantial portion of the annual budget

Currently, 38% of the annual program budget is spent on administrative costs. As the Division notes, this is a high percentage for administration of other similar demand-side management programs. A few recent examples demonstrate that a more reasonable percentage of administrative costs to the overall incentive budget would be within the range of 10-15%. In 2011, the California Public Utilities Commission approved a solar PV rebate incentive budget for PacifiCorp in which the administrative costs would amount to approximately 15% of the total incentive budget.[22] Note that PacifiCorp has just over 45,000 customers in California, or 5.7% of the number of customers its RMP subsidiary has in Utah.[23] If PacifiCorp can achieve 15% administrative costs in California, it should be able to do at least as well in Utah. Elsewhere, Colorado sets a 10% administrative cost cap on implementation of programs related to its renewable energy standards, which includes programs for rebates.[24] The District of Columbia set a 10% administrative cost cap for certain weatherization and renewable energy demonstration programs.[25] In 2010, the Florida Public Service Commission set a 9.8% cap for administrative

18 Division's 2010 Memorandum at p. 6.
19 *Id.* at p. 5.
20 *Id.* at p. 7
21 June 9, 2011 Comments of Utah Clean Energy at p. 6.
22 *See* California Public Utilities Commission Decision 11-03-007 (March 10, 2011).
23 PacifiCorp "Company Quick Facts" at http://www.pacificorp.com/about/co/cqf.html on Nov. 18, 2011 (45,148 CA customers, 787,550 Utah customers).
24 *See* 4 CCR 723-3, Rule 3661(d).
25 *See* District of Columbia Order Public Service Commission No. 12971 (2003).

cost for a solar pilot program.[26] This list is far from exhaustive, but illustrates the Division's assertion that administrative costs of 38% of the program budget far exceeds the norm.

Moving forward, there are several methods to lower the percentage of administrative costs for the annual program budget. The most obvious method, which is discussed further below, would be to expand the size of the annual budget. In theory, much of the administrative costs would involve fixed costs that would not change much, if at all, with increased program volumes. In this way, increasing the program spreads the administrative costs among a greater number of installed kW, lowering the impact of administration on cost-effectiveness.

Another way to lower the administrative costs is to simply cap the amount of recovery RMP can seek for the administrative portion each year. Setting a reasonable limit will give RMP incentive to find efficiencies in the process beyond what has already been identified. This appears to be the Division's approach, but a program that penalizes RMP is not as viable as a program that is likely to allow RMP to recover its costs. While we concur with the Division that 38% is far too high for administrative costs, we believe that the easiest way to bring those costs down is to expand the program by more than the Division is proposing.

E. The various benefits of solar PV should be considered in determining cost-effectiveness

A head to head examination of the benefits of distributed solar PV against the cost may reveal significant net benefits, but it is difficult to know exactly what benefits and values RMP input into its cost-effectiveness tests. As the Division and Utah Clean Energy noted in comments, much of the data related to the calculation of the cost-benefit analysis is confidential and a thorough explanation of the inputs and assumptions is not provided.[27] Without a clear understanding of those inputs and assumptions, we cannot know if RMP considered the comprehensive list of values associated with solar PV and distributed solar PV.

The value of distributed solar PV will vary according to each utility's system and its customer load profiles, but solar PV is associated with many generally recognized benefits. In a study of the cost-effectiveness of net metering systems, Austin Energy based its analysis on a report from the National Renewable Energy Laboratory and considered a broad spectrum of benefits: the value of solar energy production, generation capacity value, transmission and distribution deferrals, reduced transformer and line losses, environmental benefits, natural gas price hedge, disaster recovery, blackout prevention and emergency utility dispatch, managing load uncertainty, retail price hedge, and reactive power control.[28] Based on a comprehensive consideration of all but the last four of these benefits to Austin Energy's system, the report

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26 *See* Florida Public Service Commission Order No. PSC-10-0605-PAA-EG (October 4, 2010).

27 *See, e.g.*, June 9, 2011 Comments of Utah Clean Energy at p. 12, fn 38, Docket No. 07-035-T14; Division's 2010 Memorandum at p. 7, ¶ 4.

28 Hoff, T.E., Perez, R., Braun, G., Kuhn, M., & Norris, B. (2006). *The value of distributed photovoltaics to Austin Energy and the city of Austin*, p. 12.

concluded that solar PV had average values of $3,139 per kilowatt and $0.16 per kilowatt-hour (in 2008 dollars).[29] Ensuring that RMP is accounting for the many benefits of solar PV may also contribute to even more positive outcomes for the solar incentive program under the various cost-effectiveness tests.

F. There is no reason that an expanded program cannot continue beyond 2016 or the expiration of federal investment tax credits

The Division's report recommends that the solar incentive program should not be extended beyond 2016, when the Federal investment tax credit ("ITC") expires. The Division's report does not provide any further explanation of why the term of the program should be tied to the sunsetting of the federal incentives. It might be logical to tie the solar incentive program to the expiration of the ITC if the ITC had been shown to be a fundamental assumption in the cost-effectiveness analysis. Neither the report nor the public record support that proposition. With declining installation costs, it is possible that a modest solar incentive rebate would still be cost-effective from the utility's standpoint and would still make investment in on-site solar PV worthwhile from a customer's standpoint. Because there are many variables that affect the cost-effectiveness of the program, and there has been no discussion of the extent to which the ITC impacts the viability of the program, the suggestion that the program should not outlive the federal ITC appears unfounded. A more prudent approach would be for the Commission to reassess the viability of the program in 2016, when stakeholders and the Commission will have a better understanding of the whether the ITC will be renewed and whether the installation costs of solar have dropped to a level where the ITC is not critical.

IV. The program's solar resources would be a preferred resource in Integrated Resource Plan ("IRP") models

The Commission's October 7, 2009 Order in Docket No. 09-035-27, adopting some of the RMP's, Division's, and DSM Advisory Group's recommendations on programmatic cost-effectiveness evaluation, directs the RMP to "include in its application for program approval… a demonstration of the program's contribution to the IRP annual planned acquisition of DSM load reductions."[30] The IRP is additionally relevant as a measure of cost-effectiveness where the program's cost is in line with IRP avoided costs.[31]

The solar incentive program appears to be an economic resource in terms of resource planning. Utah Clean Energy's June 2011 comments highlight the fact that PacifiCorp's modeling indicates that a utility solar rebate program is an economic resource.[32] According to Utah Clean Energy, PacifiCorp's model was designed in a way that limited its maximum procurement of distributed solar resources to 1.2 MW each year between 2011 and 2028. In that model, solar was an economic resource and all 1.2 MW was selected each year of the program. Moreover, as

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29 *Id.*

30 DSM Order at p. 12.

31 *Id.*

32 *See* June 9, 2011 Comments of Utah Clean Energy at p. 3.

Utah Clean Energy notes, the IRP model selected solar resources with both the $2.00 and a $1.50 per watt rebate incentive level. The current rebate level of $1.55 per watt, which is proposed to be the level in an expanded program by the Division and others, will certainly conform to the characteristics that PacifiCorp's IRP model found to be economic. [33]

V. Public Interest in the Solar Incentive Program

The solar incentive program must be in the public interest to gain Commission approval, since it does not pass all five iterations of cost-effectiveness required by the Commission, at least as those tests are currently calculated. The fact that it does now pass the UC test should be given significant weight, and failure to pass other tests should be taken in context of what those tests measure and the appropriateness of those tests to measure the cost-effectiveness of a program meant to encourage private actors to install solar PV systems. Accordingly, the Commission will look to the significance of the solar market to Utah's public policy generally, the importance of distributed PV (i.e., customer-sited systems) to state energy goals particularly, and consider any other societal benefits, such as job creation in Utah and increased economic activity.

Utah has already developed extensive policy preferences for renewable energy sources, including distributed PV. Utah's Renewable Portfolio Goal strives to meet 20% of all retail sales of electricity by 2025 with renewable generation, including solar PV. Utah's net metering program, which also promotes PV, boasts one of the most progressive aggregate capacity caps in the nation, with the cap set at 20% of peak demand for Rocky Mountain Power. Utah also features a successful state rebate program, a majority of which has been used to install solar PV systems. Overall, there is a broad range of programs that support and favor the use of solar PV as a zero-emissions generation resource.

The development of the solar PV market, which is furthered by each of these policies, has spillover benefits that inure to the citizens of Utah. Development and installation of solar PV systems requires trained professionals and potentially creates jobs in the state. Additionally, distributed solar PV brings significant grid benefits. Distributed PV, which generally correlates with system peaks, can help reduce peak demand, reduce line losses, and help defer upgrades or additional capacity for transmission and distribution systems. Taken together, all of these benefits present a strong argument that promoting PV is a substantial public policy aim in Utah. This range of public interest support might convince the Commission that the program is in the public interest, despite failing several of the cost-effectiveness measuring sticks.

VI. Additional Considerations of an Expanded SIP's Cost-Effectiveness

Based on the Division's comments and analysis of the pilot program's cost-effectiveness, an expanded program would be both cost-effective and in the public interest, satisfying the Commission's standard for program. An optimally designed expanded program will maximize cost-effectiveness, while taking measured steps. The program does not have to be overhauled in order to be cost-effective, it merely needs to be brought to a sufficient scale. Expanding on the

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33 *Id.* at p. 4.

existing program will create continuity and capture the learned efficiencies within the existing process. Expanding the annual program capacity will optimize cost-effectiveness by lowering the per watt administrative costs. Expanding the individual rebate caps for residential and commercial customers will, similarly, create greater economies of scale and contribute to the accelerating the declining per Watt installation costs of solar PV.

A. Program Continuity

If creating an uptake in customer installations of solar PV through cost-effective means is the goal, there are several reasons to favor expanding the existing pilot program over developing an alternate path to that goal. First, RMP has engaged in outreach and marketing to make customers aware of its limited program. The fact that there is currently a waiting list indicates the success and popularity of the existing program. Thus, there is an existing awareness of the pilot program due to these efforts that will make reaching the capacity limits in an expanded program highly likely without the need for significant new marketing efforts.

Second, RMP and its contractors have gained important experience and institutional knowledge by administering the pilot. If the Commission were to abandon the pilot program at this time, it may prove difficult and costly to design a new program or resume a form of the pilot program at a later time when the processes and institutional experience with program administration have been dormant. Thus, from an efficiency standpoint, there is a real benefit in maintaining continuity between pilot administration and any expanded program. RMP personnel and contractors who have developed administrative efficiencies with the program will be shifted to other tasks if the program expires, leaving a question of whether the institutional knowledge could benefit a new program or a delayed resumption of the rebates.

Third, expansion of the program, based on its success and cost-effectiveness, creates public goodwill and a positive perception that RMP is actively looking for ways to "green" its grid. On the other hand, terminating a successful and cost-effective program could result in a negative perception of both RMP's commitment to greater use of clean sources of generation and the viability of solar PV as a grid resource.

B. Expanding program size brings program administration costs within levels experienced by other programs

An exceptionally high percentage of the existing program budget (38%) is dedicated to program administration. Many similar programs around the country have hard caps on what percentage of the annual budget can be spent on administration, ranging from 5% on the lowest end to 15%. As the Division and other parties have shown, reducing the percentage of administrative costs to 10% would make the program's benefits far exceed its costs under the all-important UC test.

Expanding the annual program size to at least 500 kW would be a modest step for RMP, but would deliver measurable benefits by increasing the cost-effectiveness of the program. Even with a 500 kW annual program cap, the program would still be small compared to other utility rebate programs for solar PV. Many state and utility rebate programs exceed 1 MW of capacity per year, and we do not know of any major utilities with a program below 500 kW.

Additionally, expanding the annual program size would work in concert with state rebates for renewable energy to help lower the per Watt installed cost of solar PV in Utah, providing even further enhancement to the cost-effectiveness from the customer's perspective.

C. Increasing individual rebate caps for residential and commercial customers will encourage larger installations and lead to economies of scale

As it stands, residential customers may only seek a rebate for the first 3 kW of a system and commercial customers are limited to collecting rebates for the first 15 kW. These caps limit a significant portion of the existing residential and commercial market, meaning that many potential participants might be unable to offset enough of their usage to make investment in a system that fits under those caps economically viable. Because a customer will typically size a system based on on-site load, in an effort to limit utility purchases to the maximum extent, these program caps limit the higher usage customers—who are typically the most eager to invest in solar PV—from participating in the program and installing PV.

Additionally, larger systems typically benefit from increasing economies of scale. Capping the system size at such a low level may discourage customers from optimally sizing a system to meet load and may result in higher installation costs per watt.

CONCLUSION

Rocky Mountain Power's Solar Incentive Program is cost-effective under the recently-approved lower incentive rebate payment of $1.55 per watt, based on the Utility Cost test. We agree that metering costs can be eliminated and administrative costs per Watt reduced, which will both result in higher performance under the Utility Cost test, and we suggest that the simplest way to assure lower administrative costs is a significant programmatic expansion.