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MEMORANDUM

To: Utah Public Service Commission

From: Utah Division of Public Utilities
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Date: June 15, 2007

Ref: Docket No. 07-035-T14. Advice Filing 07-14 – Schedule No. 107 – Proposed Solar Incentive Program

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RECOMMENDATION (approval)

The Division of Public Utilities (Division) recommends the Commission approve the proposed (pilot project for) Schedule 107, Solar Incentive Program for the State of Utah, with the following conditions:

1. The Division requests that the Commission provide an opinion and/or guidance regarding the appropriate cost-effectiveness measures that would apply if this program were to be made permanent.
2. The Company must provide the Commission and the Division with a project overview that better defines overall project goals, identifies long-term objectives, and contains a plan of action showing how the data and information will be compiled and reported, and what actions will be taken once the program expires.

3. The Company should identify annual performance targets, and should provide an annual program review to show program results, and to justify program continuation.

ISSUE

Rocky Mountain Power submitted its proposed implementation plan to introduce a pilot Solar Photovoltaic (PV) program. The program represents a five-year pilot effort that provides incentives to induce up to 107 kW of potential PV power from both residential and small commercial participants. The program represents a partial "buydown" to help participants offset their initial capital investment for qualifying PV power systems. The proposed plan outlines how the program will be marketed, and how eligibility requirements will be established. It also defines the generation caps, and shows how incentive payments will be administered. Finally, the program defines critical project timelines.

There is concern that implementation of such a program on a "permanent" basis would not be feasible if it were required to pass the full range of Demand-Side Management cost-effectiveness tests required by the Commission. It is not clear if such tests would apply to a future, broad-based distributed PV program. While it is understood that the main purpose of the program is to evaluate impact from applying incentives for distributed PV systems, there is a lack of clarity about what happens after the program expires. This should be addressed. In addition, the filing lacks adequate information about program cost-effectiveness. It is essential that the program place more emphasis on the analysis of the economics of distributed PV systems to better address their future viability.

DISCUSSION

Program Overview

Rocky Mountain Power proposes implementation of a pilot Solar Incentive program designed to assess the viability and potential customer participation in a program that provides incentives for uptake of consumer PV systems. The project is designed to gather information about customers'

willingness to participate in the program and to further evaluate how PV power will help offset peak loads. The Company has set the following goals for the program's initial year:

- Begin gathering information on the benefits, costs, and participation rates associated with the implementation of "buydown" incentives offered under the program.
- Assess the potential of PV uptake and deployment within Utah.
- Implement program marketing efforts.
- Establish and administer program caps that include a 107 kW limit and cap between residential (57 kW) and non-residential participants (50kW), with a limit of one project per owner.
- Provide participant information that includes application forms, design guidelines, an installation contractor database, utility standards and requirements, and contact information.
- Develop application guidelines and develop a program process flow.

The program will be administered on a first come-first served basis. No projects installed prior to Commission approval of the proposed tariffs will be allowed. The deadline for initial year applicants is November 30, 2007, and all approved projects must be completed no later than January 30, 2008. In addition, the customer must be a grid-connected customer of Rocky Mountain Power within the state of Utah at the time of application, with an active and current account. In addition, an applicant must enter into a Net Metering Agreement to participate in the program.

Program Incentives and Budget

Under the program, the Company will offer a cash incentive of $2 per watt (AC). The program is limited to 107 kW per program year. All applications received after the 107 kW cap is reached will be placed on a waiting list. While participating projects can be larger than the program caps, the program limits incentives at 3 kW or $6,000 for residential PV systems, and 15 kW or $15,000 for non-residential system applicants. The program has no minimum size requirement.

Incentives will be paid to qualified applicants within 60 days of system connection to the grid. Payment is contingent upon a site inspection that confirms project conformance to required program specifications, execution of the required Net Metering Agreement, and acknowledged receipt of all required program documentation.

The filing includes a program budget with annual total program costs of $314,500 for each program year beginning in 2007 through 2011. The annual $314,500 cost is broken down as follows:

Program delivery (contracted program administration costs)	$ 79,000
Incentives paid to participants	215,500
Utility administration costs	20,000
Total annual costs:	$314,500

It is anticipated that the cap of 107 kW will be met each year over the project life. Based on these estimates, program costs over the five year period will amount to $1,572,500 for a projected cumulative total of 536 kW. The Company notes that program costs will be included in Company operating expenses and will not be funded from surcharge revenues collected under the Schedule 193 Demand Side Management (DSM) Cost Adjustment mechanism.

ANALYSIS

The Division supports the Company's effort in this filing to gather information about uptake and implementation of distributed PV systems. However, there is concern that the filing does not adequately define long term program goals and objectives, particularly with respect to future viability of distributed PV systems after the program ends.

This is of particular concern in light of the fact that overall program cost-effectiveness is questionable, particularly when net participant costs are considered. As this program is a pilot project to gather information about potential uptake of PV systems, it is understood that there is no requirement for the filing to include a detailed benefit cost analysis. However, it seems reasonable that additional information should be provided to both justify the $1.5 million program cost, and to evaluate future viability of a "permanent" program. This would be

consistent with program evaluation goals. The Division believes that a discussion of cost-effectiveness is indeed relevant, particularly if future permanent programs are identified and are required to be held to cost effectiveness standards. As the question of funding for this program will be revisited during the next rate case, program cost-effectiveness will likely be an ongoing issue. If the program fails to be cost effective, it begs the question about feasibility for uptake and expansion of similar permanent programs in the future. This program should better address these long-term issues.

Supplementary benefit-cost analysis information regarding the program was subsequently provided by the Salt Lake City Million Solar Roofs Partnership (Partnership). The Partnership's analysis evaluates program cost-effectiveness under a number of different assumptions and scenarios. The analysis shows that the program is cost-effective if total participant capital costs are not included, if avoided energy and capacity costs are included, if capacity payments are adjusted to reflect the value of PV power coincidental with peak load shape, and if a social discount rate is used.

While there may be some discussion about the analytical assumptions listed above, the Division is most concerned about the lack of a more thorough analysis of long term program cost effectiveness when total participant costs are included. The Partnership's analysis calculates the capital cost that is relevant to the Company's incentive, that is, the portion of the capital cost that the Company can ask for recovery. Assuming the average residential participant system produces 1 kW, the associated incentive of $2,000 would be considered as a utility or ratepayer cost. The residual participant costs – which could range from an additional $3,000 - $7,000 per kW – are seen as out of pocket expenditures by the customers, and are not calculated in the analysis.

It is unclear how cost-effectiveness should be measured for a similar, permanent program. If it were to be designated as a DSM program, it appears unlikely that the program would pass the Total Resource Cost Test (TRC) and the Participant Cost Test (PCT) as specified by Commission order. This is due to the fact that both these tests include participant out of pocket

expenditures necessary to fund the project, which, in this case, appear to outweigh the incentives and gross energy savings provided by the program. However, there are arguments that PV systems provide not only a reduction in power demand during peak periods, but also provide the potential to enhance system energy supply. Hence, clarification from the Commission should be made about what kind of cost-effectiveness tests would apply to a permanent, long-term program of similar composition.

The Partnership's analysis used a 4 percent discount rate as a sensitivity measure in lieu of additional external benefits. These benefits include reduction in need for SO2 and NOX emissions permits, hedge values for future prices, reduced risks for potential carbon tax regimes, and public health benefits (the Division would add state and federal tax credits, among other incentives). Inclusion of explicit estimates of these external benefits should be considered, as they may possibly help offset participant costs.

Recommendations

The Division recognizes that there are significant barriers for broad-based customer uptake of PV power systems. It further recognizes that incentives, rebates and credits must be considered to help offset the cost of renewable energy investment, particularly in a climate of low relative energy prices. Nevertheless, the cost-effectiveness constraints – particularly with respect to long-term uptake of distributed PV systems -- need to be better addressed as part of this research effort. Performance "guideposts" should be added to the program to enhance cost-effectiveness. If long-term program viability is an objective, a determination needs to be made about what cost-effectiveness standards apply. As a result, the Division developed the following recommendations.

1. The Commission should provide an opinion and/or guidance regarding the appropriate cost-effectiveness measures that would apply to this program, assuming a similar program was to be adopted on a permanent basis at the end of the 5-year research and development period.

2. Pending Commission approval, the Company should provide the Commission and the Division with an updated project overview that defines overall project goals, identifies long-term objectives, and contains a plan of action showing how the data and information will be compiled and reported, and what actions will be taken once the program expires.
3. The Company should develop an annual program review to be submitted at the end of the initial year to show program results, and to justify continuation of the program. The plan of action should include the following:
    a. Explicit program goals and performance measures for each program year. Performance measures should include efficiency targets aimed at making the program more cost-effective.
    b. A data analysis plan and annual performance report with recommendations.
    c. Long-term program objectives that define what is intended to happen after the program terminates in five years.
    d. Demonstration of how this program will meet the cost-effectiveness criterion specified by the Commission and justification showing why the program should be continued.
4. The Company should provide adequate information to ensure that all program participants and customers understand that this is a temporary research and development project that will expire five years after Commission approval.

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