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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program	Docket No. 14-035-114 **SIERRA CLUB INITIAL COMMENTS ON ANALYTICAL FRAMEWORK**

Sierra Club appreciates the opportunity to submit these comments regarding the appropriate analytical framework for investigating the costs and benefits of net metering in Utah. The Commission's decision to reject the net metering facilities charge proposed by Rocky Mountain Power in its 2014 general rate case properly recognized that further analysis and evidence, conducted within a coherent framework, is necessary to compare the costs and benefits of net metering as required by the Utah Legislature. Specifically, the Commission has invited comment on the following questions:[1]

- "Whether the traditional costs and benefits test equations (e.g., the utility cost test, the total resource cost test, the ratepayer impact measure test, and the participant test) and metrics (e.g., benefit to cost ratio) used to evaluate utility-sponsored demand side management programs can and should be applied to examining the costs and benefits of PacifiCorp's net metering program."

[1] Docket No. 14-035-114, *Notices of Comment Period and Scheduling Conference*, issued Nov. 21, 2014 at 3-4.

- "Description of any other type of analysis" for examining the costs and benefits of PacifiCorp's net metering program.
- Comment on the consistency of any proposed analysis with the statutory definition or requirements of the net metering program.
- Comment on whether the types of analyses to be used will vary depending on whether the analysis examines residential or non-residential net-metering customers.

Sierra Club believes that it is critical for the Commission to undertake a thorough and unrushed analysis of the cost-benefit question, and the subsequent determination of a "just and reasonable" rate structure in light of those costs and benefits. While the Utah Legislature requires utilities to offer a net metering program, the decision that the Commission makes regarding how net metering should be implemented has the potential to boost or derail a fledgling industry that gives Utah's utility customers greater choice, reduces system costs for all customers, and puts Utah on a path to cleaner air and compliance with forthcoming carbon regulations. It is critical that any changes to the current tariff structure reflect the best possible analysis of the costs and benefits of net metering, rather than unfounded assumptions. The Commission has the benefit of learning from the analytical approaches employed other states who have conducted cost-benefit analyses of distributed generation in the last few years.

Sierra Club makes the following recommendations for the analytical framework to be approved by the Commission:

- Cost-effectiveness tests developed in the context of demand-side management programs can be applied to an analysis of the costs and benefits of net metering. While most of these tests will supply valuable insight on the cost-benefit question, Sierra Club believes that the RIM test is of limited analytical value, and should not be used as part of the analytical framework. Lost revenues should be considered as a “cost” to the utility and ratepayers only in specific, limited circumstances.

- To understand more specifically how the costs and benefits of net metering should be reflected in a “just and reasonable rate structure” the Commission should require a study of the cost of serving net metering customers, and a distinct rate and bill impact analysis.
- Utah Code Ann. § 54-15-105.1 requires a holistic analysis of the utility’s net metering program, including all affected customer classes, rather than an isolated analysis of the residential net metering program. The type of analysis appropriate for commercial net metering is not fundamentally different from the type of analysis appropriate for residential net metering, although certain key variables will differ based on the different rate structures for the two classes.
- The Commission should consider inviting an independent consultant to conduct a cost-benefit study as part of a broader collaborative stakeholder process—the course chosen by commissions in Nevada, California, and Mississippi. At a minimum, we recommend that a neutral, experienced moderator guide discussion during the scheduled technical conferences.

I. <u>Background on Net Metering in Utah</u>

Utah statute requires each “electrical corporation” to make available to its customers a net metering program, which is defined as “a program . . . whereby a customer with a customer generation system may: (a) generate electricity primarily for the customer’s own use; (b) supply customer-generated electricity to the electrical corporation; and (c) if net metering results in excess customer-generated electricity during a billing period, receive a credit as provided in Section 54-15-104."[2] The credits to be provided should be "at least avoided cost, or as determined by the governing authority."[3]

This Commission determined, in Docket No. 08-035-78, that the credit for residential and small commercial NEM customers should be the retail rate, while the credit for other NEM customers is based on one of several different methods of calculating the utility's avoided cost rate, which is greater than the retail energy rate for those customers.[4]

In April 2014, the Utah Legislature amended the Net Metering Code to require the Commission to:

> (1) determine, after appropriate notice and opportunity for public comment, whether costs that the electrical corporation or other customers will incur from a net metering program will exceed the benefits of the net metering program, or whether the benefits of the net metering program will exceed the costs; and
> (2) determine a just and reasonable charge, credit, or ratemaking structure, including new or existing tariffs, in light of the costs and benefits.[5]

The Commission endeavored to make the required determination in the context of Rocky Mountain Power's ongoing general rate case, which sought to impose a $4.65 monthly charge on all residential net metering customers. However, the Commission found that it lacked the evidence needed to compare the costs and benefits of net metering and understand the cost of serving residential net metering customers. The Commission correctly interpreted this statute to require that a determination as to whether the costs of the net metering program exceed the benefits, or vice versa, must precede the

[2] Utah Code Ann. § 54-15-102(12).
[3] *Id.* § 104(3)(a)(i)
[4] *See* Docket No. 08-35-78, Order dated February 12, 2009, at 19-22.
[5] Utah Code Ann. §54-15-105.1 (amended by Senate Bill 208).

determination of a just and reasonable charge under subsection (2) of the newly enacted section.[6]

Specifically, the Commission's order recognized the need for further evidence regarding the following:

- How the cost of serving net metering customers compares to non-net metering customers in the same class. *Id.* at 61-62. Relatedly, the Commission noted the absence of "load characteristic data for residential net metered customers," and explained that "information identifying and explaining the differences in load characteristics is critical to our understanding of the costs net metered customers uniquely cause." *Id.* at 62-63.
- Evaluation of net metering program impacts on all cost categories (e.g., generation versus transmission). *Id.* at 66.
- Comprehensive view of all the programs costs and cost savings that are appropriate to considering in making the S.B. 208 determinations." *Id.*
- To justify a facilities charge or new rate design for net metered customers, the Commission stated that it "must understand the usage characteristics, e.g., the load profile, load factor, and contribution to relevant peak demand, of the net metered subgroup of residential customers, [and] have evidence showing the impact this demand profile has on the cost to serve them." *Id.* at 68.

The Commission therefore opened this docket to examine the costs and benefits of PacifiCorp's net metering program. In our view, the purposes of this docket are to make

[6] Docket No. 13-035-184, PacifiCorp dba Rocky Mountain Power General Rate Case, Report and Order issued August 29, 2014, at 58 (hereinafter "GRC Order").

clear how the costs and benefits should be compared, how the cost of service for NEM customers should be determined, and what should be contained in the utility's next rate case filing to enable these analyses to be completed.

II. Analytical Framework for the Costs and Benefits of Net Metering

As the Commission recognized in its order on the general rate case, the Company's evidence to support its proposed net metering charge was inadequate to resolve the question posed by S.B. 208, and also failed to meet the Commission's standard of proof for ratemaking. To resolve the issues identified by the Commission, several related but distinct types of analysis are required.

The first stage is a cost-benefit analysis that examines in detail the different categories of costs and benefits of net metering, using the well-known cost-effectiveness tests already applied to PacifiCorp's demand side management programs. These tests allow the Commission to consider the costs and benefits from a variety of perspectives, and directly respond to the Legislature's first mandate to the Commission. The Commission should not focus exclusively on the cost-benefit ratios produced by these tests but rather consider the results more holistically as part of the second phase of its determination. The second stage should use the information about costs and benefits to evaluate the cost of serving net metered customers, and the rate and bill impacts of the current net metering policy. Both of these analyses are critical to the Commission's determination of a just and reasonable net metering tariff, and are discussed further below in Section III.

A. Use of the Demand-Side Management Cost-Effectiveness Tests

The Legislature did not specify a method for the required cost-benefit analysis, but left that decision to the Commission. In deciding how to implement the S.B. 208 mandate, this

Commission can look to studies done on behalf of other utility regulatory bodies seeking to implement similar statutes or investigate related questions. All of these studies used some form of the demand-side management cost-effectiveness tests as part of their analysis:

- The Public Service Commission of Mississippi commissioned a study in 2014 as part of a docket to investigate establishing and implementing net metering and interconnection standards for the state. The study, completed by Synapse Energy Economics, Inc., evaluated the costs and benefits of a net metering program using several standard and modified cost-effectiveness tests that were already used to evaluate demand-side management programs in the state.[7]
- The Nevada Public Utilities Commission commissioned a study of the impacts of net metering in response to state legislation requiring the commission to "open an investigatory docket to examine the comprehensive costs of and benefits from net metering in this State, including, without limitation, the costs and benefits to: (a) The State of Nevada; (b) Customer-generators who participate in net metering; (c) Customers of a utility who do not participate in net metering; and (d) Each utility which offers net metering."[8] The study, conducted by Energy & Environmental Economics (E3) and completed in July 2014, evaluated the program using three analyses: a cost-benefit analysis, a study of macroeconomic impacts, and a demographic study of NEM and non-NEM customers. For the cost-benefit analysis, E3 employed five standard cost-effectiveness tests.[9]

[7] Stanton et al., Synapse Energy Economics, Inc., *Net Metering in Mississippi*, Prepared for the Public Service Commission of Mississippi (Sept. 19, 2014), available at http://synapse-energy.com/project/mississippi-net-metering-study.
[8] Nevada Assembly Bill No. 428, Sec. 26.5. (2013 – 77th session).
[9] Energy & Environmental Economics (E3), *Nevada Net Energy Metering Impacts Evaluations*, prepared for State of Nevada Public Utilities Commission (July 2014), available at

- In 2013, the California PUC commissioned a study by E3 to evaluate the ratepayer impacts of the California net energy metering (NEM) program and fulfill the requirements of Assembly Bill (AB) 2514 and Commission Decision 12-05-036 to determine "who benefits, and who bears the economic burden, if any, of the net energy metering program." The study used both the traditional cost-effectiveness ratepayer impact test and a full cost of service assessment that compared the utility cost of serving NEM customers with their actual bill payments.[10]

The Commission has previously considered the application of demand-side management cost-effectiveness tests to distributed generation. In 2007, the Commission reviewed procedures for demand-side management programs and noted that the cost-effectiveness tests typically applied to demand-side management programs were appropriate for evaluating small-scale renewable resources.[11] The Commission again addressed this issue when considering an extension of RMP's Solar Incentive Program, which had originally been approved as a pilot program in 2007.[12] In 2012, the Commission approved an extension of the Solar Incentive Program, based in part on evidence that the incentive program was cost-effective.[13] In particular, the Commission noted that an analysis by the Cadmus Group showed that the program's benefit

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http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.

[10] Energy and Environmental Economics, Inc. (E3), *California Net Energy Metering Ratepayer Impacts Evaluation*, prepared for California Public Utilities Commission (2013), available at http://www.cpuc.ca.gov/NR/rdonlyres/D74C5457-B6D9-40F4-8584-60D4AB756211/0/NEMReportwithAppendices.pdf.

[11] In the Matter of the Proposed Revisions to the Utah Demand Side Resource Program Performance Standards, 2009 Order, at pages 4-6, 15.

[12] *See* Docket No. 07-035-T14 (order dated Aug. 3, 2007).

[13] Docket No. 11-035-104 (Report and Order dated Oct. 1, 2012).

to cost ratio under the Utility Cost Test was 1.75—that is, the benefits exceeded the costs by 75%.[14]

Consistent with these previous determinations by the Commission, we believe the DSM cost-effectiveness tests are an important part of a comprehensive analysis of the costs and benefits of net metering, though some modifications to those tests are needed for the distributed generation context.

i. Utility Cost Test (Program Administrator Cost Test

In Utah, the Utility Cost Test is the primary test used to screen energy efficiency measures for cost-effectiveness.[15] The Utility Cost Test (UCT) compares the costs directly incurred by the utility, such as program administration costs, with the benefits experienced by the utility. One reason the UCT is preferred in Utah is that it allows easy comparison to supply-side options available to the utility.[16] Thus, calculating the cost-effectiveness of net metering from the utility's perspective facilitates direct comparison of net metered resources to other resources considered as part of integrated resource planning processes. By comparing directly to other supply-side resources, the UCT is designed to answer the question of whether the utility's revenue requirement will increase or decrease.

To apply the Utility Cost Test to net metering, the costs to the utility would include additional metering or customer service costs, and any costs to integrate distributed generation that exceed interconnection fees paid by the customer.[17] Under this test, costs to the utility do

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[14] *Id.*
[15] *See* Docket No. 07-035-T14 (order dated Aug. 3, 2007), at 9.
[16] *Id.*
[17] Sierra Club notes that PacifiCorp's witness, Douglas Marx conceded at the July 2014 general rate case hearing that the Company currently incurs no integration costs for rooftop solar due to the low penetration, and does not even know when such costs might arise. Docket No. 14-035-184, Transcript, Vol. 1 at 105:13-17.

not include lost revenues, only administrative costs and in the case of demand-side management, program incentives.[18] Lost revenues do not affect the revenue requirement, which is the focus of the UCT test.[19] The benefits counted under this test include avoided energy, capacity, line losses, transmission and distribution, ancillary service, and regulatory compliance costs, among others discussed in Section A.2.b, below.

ii. Ratepayer Impact Measure

While the impact of net metering on energy rates is a key question to be investigated in this proceeding, we believe that the Ratepayer Impact Measure test (RIM) is not helpful in making this assessment. The key difference between the UCT and RIM tests is that the latter includes the utility's lost revenues as a cost, to reflect that those revenues may be collected from all ratepayers through higher energy charges. The error in this approach is that the lost revenues are not a *new* system cost created by net metering (i.e., they do not increase the revenue requirement). These lost revenues represent an existing or "sunk" cost that must be collected regardless of whether net metering exists or in what form. A basic economic tenet is that future resource decisions should not be driven by the need to recover sunk costs.[20]

If the RIM test returns a benefit-cost ratio of less than one, the implication is that the program generates negative net benefits. But this is often not the case, as the net metering program could

[18] *See* Docket No. 09-035-27, In the Matter of the Proposed Revisions to the Utah Demand Side Resource Program Performance Standards, Guidelines Revisions Report, April 27, 2009, Exhibit A, at 14 ("The costs for the utility test are the administrative costs of the program and any incentive paid to participants.").
[19] In the Mississippi net metering study cited above, Synapse Energy Economics uses an alternative the UCT that calculates a "revenue requirement savings-to-cost ratio," which this Commission could consider as well. *See Net Metering in Mississippi*, *supra*, at 42.
[20] *See* Synapse Energy Economics, Inc., *Benefit-Cost Analysis for Distributed Energy Resources*, prepared for the Advanced Energy Economy Institute (Sept. 22, 2014), at 15-17 (submitted to the New York Public Service Commission's Reforming the Energy Vision (REV) proceeding).

actually be reducing the revenue requirement, and it is only the inclusion of sunk cost recovery that makes net metering appear to be a bad deal for ratepayers.[21]

The RIM test also does not provide useful information about the scale of impact to rates, nor to overall customer bills. An unfavorable RIM result indicates that rates will go up, but does not tell the regulator whether that increase is negligible or substantial.[22] The degree of increase is intrinsically determined by utility cost allocation and rate design. For example, whether rates will increase depends in part on the exact residential rate tiers employed by Rocky Mountain Power and whether NEM customers are avoiding energy consumption in the middle or high tiers. Because the RIM test is so sensitive to factors *extrinsic* to the net metering program itself, it has limited utility in answering the question or whether the benefits exceed the costs or vice versa.

In other words, rate and bill impacts should be evaluated separately from the cost-effectiveness analysis, rather than conflating the two concepts as the RIM test does. This separate analysis of rate impacts should include all factors related to net metering that affect rates. For example, all utility savings or factors that affect allocation of costs among PacifiCorp subsidiaries and assignment to Rocky Mountain Power's different rate classes should be incorporated. Thus, if net metered distributed generation reduces the contribution of the residential class to the system peak, then reduced generation and T&D capacity costs would be assigned to the residential class, and that reduction should be reflected alongside any shifting of costs *within* the residential class. A long-term view of avoided marginal costs is necessary to accurately capture the ratepayer impact, as certain costs like avoided transmission and generation

[21] *Id.*
[22] *Id.*

investment, and environmental compliance costs, are not experienced in the short-run, but are experienced well within the lifetime of installed solar systems.[23]

A final point regarding the RIM test is that while it purports to reflect the perspective of non-NEM customers, it takes a narrow view of their concerns and benefits. When distributed generation displaces fossil-fuel based generation, all ratepayers benefit from the resulting cleaner air and conserved water, as residents of the state of Utah. Installation and maintenance of distributed generation increases local employment and spending at local gas stations, restaurants, and other retail establishments. In other words, the RIM test does not reflect the portion of non-energy benefits that accrue to non-NEM customers.[24] Sierra Club contends that the Legislature's mandate to the Commission calls for this broader assessment of the benefits to Utah residents, rather than a strict focus on PacifiCorp customers as ratepayers only.

iii. Total Resource Cost and Societal Cost Test

Utah utilities use several forms of the Total Resource Cost test to evaluate demand-side management measures. In general, the total resource cost (TRC) test compares the costs incurred by both the program administrator and the program participant related to a measure, with the avoided costs (benefits) of that measure. In Utah, three forms of the TRC test are employed—one that considers only the energy benefits, another that includes a 10% adder to the benefits to account for non-energy benefits (the "PacifiCorp TRC"), and the Societal TRC that includes additional environmental and societal benefits.[25]

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[23] *See* Carl Linvill, John Shenot, and Jim Lazar, Regulatory Assistance Project, *Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition* (Nov. 2013), at 27.
[24] *Id.* at 24.
[25] *See* 2009 Utah Demand Side Management and Other Resources Benefit and Cost Analysis Guidelines and Recommendations, *supra*, at 15 n.10.

These tests are highly informative as applied to net metering, because they provide a more comprehensive sense of the costs and benefits of net metering than considering only the benefits and costs to the utility. In particular, the Societal Cost Test, which factors in environmental and economic benefits experienced by society as a whole, is critical to understanding how net metering affects the larger public interest.

The text and legislative history of Section 54-15-105.1 do not limit the types of costs and benefits that can be considered, and suggest that a wide range of values should be considered. First, Section 54-15-105.1 incorporates the state's "just and reasonable" standard, which considers "the cost of providing service to each category of customer, economic impact of charges on each category of customer, and on the well-being of the state of Utah; methods of reducing wide periodic variations in demand of such products, commodities or services, and means of encouraging conservation of resources and energy."[26] Thus, a just and reasonable rate may take into consideration the well-being of the state of Utah, which would include the type of public health and economic development benefits addressed by the Societal Cost Test. A just and reasonable rate should also reflect the values of "conservation of resources and energy," hence the statute permits this Commission to consider both the load reduction and fossil fuel conservation benefits of distributed solar as part of determining whether a charge on net metering customers is just and reasonable. If the Commission does not have in hand the results of a Societal Cost Test, it will not be able to fully consider these aspects of the just and reasonable standard.

The results of the TRC and SCT tests should be considered alongside the other tests discussed here, as each test contributes something different to the Commission's analysis, and

[26] Utah Code Ann. § 54-3-1.

has its own limitations. For example, a family or small business installing rooftop solar in Utah is solely responsible for the substantial upfront cost of installation. This substantial investment, far greater than that associated with most DSM measures, will be included in the cost side of the TRC. Thus, if net metering appears not to be cost-effective under the TRC, the Commission should keep in mind that the majority of the costs are borne by individual ratepayers not the utility or its other customers.

iv. Participant Cost Test

The Participant Cost Test looks at the costs and benefits of net metering from the perspective of the net metering customer (or a customer deciding whether to install a solar system). While this is a narrow perspective on the question of costs and benefits, it is important for understanding how customers' incentive to install solar systems would be affected by changes in the tariff structure. During the recent general rate case, there was discussion about whether the imposition of a $4.65 monthly charge would be a deterrent to further distributed generation. The participant cost test is designed specifically to answer this question, by evaluating whether the benefits exceed the costs from the potential net metering customer's perspective. This test should look at the benefits and costs over the lifetime of the solar system, and reflect changes in the cost to the NEM customer that are likely or under consideration (such as changes in the customer fixed charge, imposition of net metering facilities charges, or reduction in the rate paid for excess generation).

v. How the Cost-Effectiveness Results Should be Used

The Commission also seeks comment on whether the metrics used to evaluate DSM programs, such as cost-to-benefit ratios, are appropriate for the net metering program. While the cost-to-benefit ratio provides valuable information, whether net metering has favorable cost-to-benefit ratio on any particular test should not be determinative of the fate of the net metering program. For example, as noted above, the results of the Participant Cost Test and Total Resource Cost test answer specific questions, but don't in themselves provide a comprehensive answer to the question posed in Section 54-15-105.1(a). And the RIM test can be highly misleading if its limitations are not considered.

More fundamentally, the use of cost-effectiveness tests in the demand-side management context is part of an effort to procure the least-cost resources as part of the state's integrated resource planning process. Thus, a DSM measure or program that does not have a favorable cost-benefit ratio is presumed not to be in the public interest. By contrast, the net metering program does not emerge from an IRP process, but rather a statutory mandate. If evaluation of the current net metering program produces a cost-to-benefit ratio greater than 1.0, the utility or Commission cannot simply reject the resource. Rather, further analysis must be done to determine what, if any, changes to the net metering tariff structure are just and reasonable in light of that cost-benefit result and related cost-of-service studies. In short, none of the cost-benefit results should be viewed as conclusive—the other "just and reasonable" factors[27] must also be balanced by the Commission. This is especially the case where key benefits associated with distributed generation, such as reduced regulatory risk, fuel hedge value, and increased grid resiliency may not be quantified as part of the cost-benefit analysis. The Commission should be provided with a thorough qualitative analysis of those benefits so that they can be weighed in determining a just and reasonable rate.

[27] Utah Code Ann. § 54-3-1.

A. Key Costs and Benefits

The Commission must address, as part of this docket, what specific costs and benefits should be quantified or otherwise investigated as part of the analysis. Most of these cost and benefit categories will be used in both the cost-effectiveness analysis and a cost-of-service analysis. This may be an area of significant disagreement among the parties and to the extent these issues can be developed and resolved during this docket, rather than in a follow-up rate case where time will be more limited, the Commission's analysis will be stronger and more defensible.

i. <u>Costs</u>

As noted above, the utility's cost of administering the net metering program is easily quantifiable and should be included in all cost-effectiveness analyses except the participant cost test. However, the utility must demonstrate that its administrative costs are reasonable and reflect efforts to streamline administrative processes.[28] In addition, over the longer time period appropriate for this study, administrative costs per NEM customer should decline as the utility implements streamlined billing systems and process automation.

The cost of incentives under the Solar Incentive Program should not be included as a utility cost in this analysis, since that program is distinct from the net metering program. If the Commission desires information relating to the combined cost-effectiveness of net metering and the Solar Incentive Program, it could be evaluated as a sensitivity, which should also include

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[28] In a study involving three California utilities, the self-reported administrative costs put forward by one utility were five times those of the other two utilities, showing the need for caution regarding how program costs are identified. *See* Solar America Board for Codes and Standards, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering* (Version 1.0 undated), at 17 (discussing the 2010 E3 study).

other benefits received by the utility in exchange for the incentive payments, such as renewable energy credits.

To the extent that lost revenues are considered part of the utility's costs in a rate impact analysis, only lost revenues necessary to recover fixed costs should be included.[29] Furthermore, estimates of lost revenues should reflect the likely, rather than theoretical, impact on rates according to the state's ratemaking standards and practices.[30] That means that where state ratemaking practices reflect principles of gradualism and lags occur due to gaps between rate cases that in reality limit the utility's recovery of the full revenue requirement, those practical limitations should be factored into an assessment of the *actual* rate impact.

ii. Benefits

In the general rate case, evidence was entered by intervening parties regarding the benefits of net metered generation, including avoided energy, avoided generation capacity, avoided transmission and distribution, avoided ancillary services, avoided environmental cost, and fuel price guarantee value.[31] All of these values have been considered in many other distributed generation cost-benefit studies and value of solar studies. In 2013, the Rocky Mountain Institute compiled a very useful meta-analysis of sixteen studies of the value of distributed solar resources.[32] While several more studies have been completed in the intervening years, this meta-analysis remains a valuable starting point.

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[29] Synapse Energy Economics, *Benefit-Cost Analysis for Distributed Energy Resources*, *supra*, at 18.
[30] *Id.*
[31] *See* Docket 13-035-184, Direct and Surrebuttal Testimony of Dustin Mulvaney on behalf of the Sierra Club; Clean Power Research, Value of Solar in Utah (Jan. 7, 2014), Exhibit 2.1 to Direct Testimony of Sarah Wright on behalf of Utah Clean Energy.
[32] *See* Electricity Innovation Lab, Rocky Mountain Institute, *A Review of Solar PV Benefit and Cost Studies* (2nd ed. Sept. 2013), available at www.rmi.org/elab_emPower. Attached as Exhibit 1.

By contrast, PacifiCorp argued in the general rate case that the benefits of net metered generation should be limited to the payments made to qualifying facilities under the Public Utilities Regulatory Policy Act (PURPA). The Commission should not limit the scope of the benefits analysis for net metered facilities to those already quantified under PURPA, for the reasons described in the general rate case post-hearing briefs filed by the Sierra Club and The Alliance for Solar Choice.[33] Likewise, the Commission need not limit itself, in making this determination, to the set of benefits and costs that are considered in integrated resource planning and CPCN dockets, since those resource procurement dockets are dominated by least-cost considerations, whereas the just and reasonable ratemaking standard requires the Commission to consider a wider range of factors.

Several excellent reports are available on the topic of how to calculate the costs and benefits of distributed generation. These include:

- Interstate Renewable Energy Council, Inc., A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation (Oct. 2013) (Attached as Exhibit 2).
- Denholm et al., National Renewable Energy Laboratory, Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System (Sept. 2014), NREL/TP-6A20-62447.
- Carl Linvill, John Shenot, and Jim Lazar, Regulatory Assistance Project, Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition (Nov. 2013).

[33] Docket 13-035-184, filings dated Aug. 8, 2014.

Sierra Club does not necessarily agree with every recommendations stated in each of these reports, or others cited in these comments, but offers them as helpful resources for the Commission's consideration in laying out the scope for this proceeding.

Sierra Club recommends that the following benefits be included in any analysis, though this list is not comprehensive. When there is uncertainty about the value of these benefits, a range of reasonable values should be tested through sensitivity analysis, so that the Commission can understand how differing assumptions would affect the result.[34] If a benefit cannot be quantified with a reasonable degree of certainty, it should still be described thoroughly so that it can be considered qualitatively alongside the calculated study results.

- *Avoided energy.* This benefit is based on the cost of generating electricity from the marginal generating unit on Rocky Mountain Power's system, including the variable operations and maintenance (O&M) costs and the fuel costs. Variable O&M costs include the variable costs of environmental compliance at the unit, such as the cost of pollution control sorbents, parasitic load, and waste disposal costs, among others.

  Because the study must reflect the life of the net metered system, it is critical that avoided energy cost be viewed dynamically, including considerations such as how fuel and variable O&M will change, and that the marginal unit itself may change over that time period. At some point in time, market purchases may also be avoided, rather than generation at one of the utility's own units. Due to the very high likelihood that greenhouse gas emissions from electric generating units will be

[34] Key variables on which sensitivity analysis should be conducted include: regulatory price of carbon, natural gas prices, and retail rate escalation.

regulated in the next five years,[35] this analysis must include a regulatory price of carbon in the base case, or at the very least, as a sensitivity.

- *Avoided line losses.* Because net metered generation is sited at or close to load, the losses associated with transporting power over great distances are avoided. Line losses average about 7%, but can be higher during heavy load periods due to increased resistance on the lines.[36] The Commission may also consider requiring marginal line losses to be used in the analysis to reflect differences in those losses based on load, ambient temperature, and other factors.

- *Avoided generation capacity.* There are two basic methodologies to determine avoided generation capacity credit. The first relies upon the market value of the avoided capacity resource, while the second estimates the marginal costs (both capital and O&M) of the existing marginal generator. Because distributed generation is installed incrementally, while capacity investments are lumpy, distributed generation's capacity contribution is often overlooked. However, it is critical that the ability of distributed generation to defer generation capacity investments be included in any cost-benefit analysis, especially one with the long time horizon appropriate here. For example, based in part on the forecasts for significant solar distributed

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[35] U.S. EPA, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule, 79 Fed. Reg. 34,830 (June 18, 2014) ("Clean Power Plan") (requiring states to limit carbon dioxide emissions from the utility sector beginning in 2020).
[36] *See* Interstate Renewable Energy Council, Inc., *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation* (Oct. 2013), at 23.

generation to come online, the California PUC recently denied an application to construct a new natural gas-fired power plant, the Chula Vista project.[37]

In quantifying the avoided capacity credit for distributed solar, the effects of cloud cover should be considered. However, it would be inaccurate to base distributed solar's capacity value on the intermittency of a single system, because the geographic diversity of solar systems has a smoothing effect. One 2006 study showed that the collective output of twenty distributed systems has almost no variability on a partly cloudy day, despite the variability of each individual system.[38] Researchers at the National Renewable Energy Laboratories showed that over a 15-minute period, the aggregate variability of a dispersed set of PV systems is only one-sixth that of a single system.[39]

- *Avoided transmission and distribution capacity*. This benefit received considerable discussion during the general rate case. Generating electricity close to load reduces the need to build the transmission and distribution system to meet the higher loads that would be present absent the distributed generation. It also reduces wear and tear on the system and therefore avoids or defers O&M costs. Finally, distributed generation reduces congestion, which both extends the life of distribution system

[37] Solar America Board for Codes and Standards, *Generalized Approach*, *supra*, at 13.
[38] Perez, R. et al., *Integration of PV in demand response programs* (2006), available at http://www.asrc.cestm.albany.edu/perez/directory/LoadMatch.html.
[39] Mills A. & Wiser, R. *Implications of wide-area geographic diversity for short-term variability of solar power* (LBNL-3884-E) (2010), available at http://emp.lbl.gov/publications/implications-wide-area-geographic-diversity-short-term-variability-solar-power.

components and reduces line losses. The basic inquiry to be made is: what is the value of any avoided maintenance or deferred capacity upgrades?[40] Calculating this value requires current information on the utility's system planning activities, and on how the utility makes decisions about when repairs and upgrades are needed. Accurate determination also requires hourly data on load and solar resource generation profiles. While some of this information can be provided by the load research study that Rocky Mountain Power is beginning, we strongly recommend these data be supplemented by modeled generation from distributed generation on the system, which will serve as a benchmark for the data RMP is collecting from a more limited number of systems. In addition, Synapse Energy Economics maintains a clearinghouse of public reports on avoided transmission and distribution costs, which includes studies for Utah.[41] These studies may be a useful starting point for the analysis required here.

- *Avoided grid support (ancillary) services.* The ability of distributed generation to provide grid support services is currently limited by electrical codes that have not yet been updated to allow the use of advanced inverters that would provide additional functionality. Such advanced inverters are in common use elsewhere in the world, and at the end of 2014, the California Public Utility Commission revised its interconnection standards to require the use of advanced inverters in the next several

[40] *See Regulator's Guidebook*, *supra*, at 26-29 for a more detailed discussion of the various methodologies for calculating this benefit.
[41] *See Net Metering in Mississippi*, *supra*, at 28.

years.[42] SolarCity and Hawaiian Electric Company have initiated a test of advanced inverter capabilities at NREL's Energy Systems Integration Facility, which will demonstrate the ability of these inverters to respond to grid voltage fluctuations, and absorb or release reactive power, among other grid stabilizing functions.[43]

Due to the likelihood that advanced inverters will be available and part of the standard installation package in Utah within a few years, it would be appropriate to include ancillary service values as part of a long-term study of distributed generation value.[44] Even in the immediate term, by reducing peak demand, distributed generation reduces the quantity of ancillary services that the utility must purchase or provide.

- *Fuel price hedge.* Distributed generation reduces the utility's reliance on volatile fuel sources, offering the kind of hedge that utilities often pursue to reduce their financial risk and that benefits customers substantially. This benefit has been quantified in at least five studies to date.[45]
- *Environmental benefits.* In addition to the avoided costs of compliance with environmental regulations, distributed generation reduces the adverse environmental and public health consequences of fossil-fuel generation. As the Commission will

[42] Cal. Pub. Utils. Comm., D. 14-12-035 (December 18, 2014), available at http://www.clean-coalition.org/site/wp-content/uploads/2014/12/Av-Inv-FD-Dec-2014.docx; see also Clean Coalition News Release, California adopts nation's first advanced inverter standards (Jan. 6, 2015), at http://www.utilitydive.com/press-release/20150106-california-adopts-nations-first-advanced-inverter-standards/.
[43] *See* Jeff St. John, HECO and SolarCity to Put Smart Solar Inverters Through Real-World Testing, Greentech Media (Dec. 8, 2014), at http://www.greentechmedia.com/articles/read/HECO-and-SolarCity-to-Put-Smart-Solar-Inverters-Through-Real-World-Testing.
[44] *See Regulator's Guidebook*, *supra*, at 29-30.
[45] *See* Electricity Innovation Lab, Rocky Mountain Institute, *A Review of Solar PV Benefit and Cost Studies* (2nd ed. Sept. 2013), at 35, available at www.rmi.org/elab_emPower.

recall, members of the public who spoke at the July 29, 2014 public meeting following the general rate case hearing emphasized that the poor air quality on the Wasatch Front was a significant concern to them and deterred businesses from locating in the area.[46] The benefits of distributed generation must be considered quantitatively as part of the Societal Cost Test and should be evaluated in a qualitative sense as part of any determination by the Commission as to the costs and benefits of net metering. These benefits have been quantified in numerous studies, perhaps most comprehensively in the Minnesota Value of Solar Study conducted by Clean Power Research on behalf of the Minnesota Department of Commerce.[47]

- *Economic Development Benefits.* Installation of distributed generation, and the roofing upgrades that sometimes accompany installation, generate local employment, which in turn stimulates local spending and additional tax revenue at the state and local level. This is in stark contrast to the operation of fossil-fuel plants which often involves sending money out of state for fuel purchases. Several studies have quantified these benefits or at least considered them in a qualitative manner.[48] These benefits must be considered quantitatively as part of the Societal Cost Test and should be evaluated in a qualitative sense as part of any determination by the Commission as to the costs and benefits of net metering.

[46] *See also, e.g.*, GRC Order at 56.
[47] *See* Clean Power Research, *Minnesota Value of Solar*: Methodology Prepared for Minnesota Department of Commerce, Division of Energy Resources (Jan. 30, 2014), at 39-40, available at http://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf; *see also* RMI, *A Review of Solar PV Benefit and Cost Studies*, at 38-41.
[48] RMI, *A Review of Solar PV Benefit and Cost Studies*, at 42.

B. Additional Considerations

i. How should analysis differ for commercial NEM customers?

The analytical approach for net metering by commercial customers is fundamentally the same as for residential customers, though the results of the analysis would likely be different for several reasons. First, small and large non-residential customers are compensated differently under Schedule 135. Small non-residential (commercial) customers are compensated identically to residential net metering customers – excess customer generated electricity at the end of each month is credited at the retail rate. By contrast, large non-residential customers have a choice of three different compensation levels: (1) an average energy price that reflects a weighted average of the winter and summer on- and off-peak prices on Schedule 37; (2) a seasonally differentiated energy price based on Schedule 37; or (3) an average retail rate based on data reported on the previous year's FERC Form 1.[49] Because these large commercial customers can choose their compensation method, and change it once per year, the calculation of how much the utility pays for excess customer-generated electricity is more complicated and requires forecasting of the underlying prices and customers' selection among them.

Another key difference in the cost-benefit analysis for large commercial customers is the presence of a demand charge. Evaluating the costs and benefits from both the customer's and utility's perspective includes an analysis of how much the customer is able to reduce its demand charge by supplying some of its own electricity needs through on-site generation. PacifiCorp has asserted that cost-shifting is not a concern for commercial customers because the demand charge ensures recovery of demand-related costs even when there is net excess customer-generated

[49] Schedule 135, Original Sheet No. 135.3, Special Conditions, 2(B) (effective Sept. 1, 2014).

electricity.[50] However, the analysis required by S.B. 208 is not limited to protecting the utility against under-recovery of costs, but rather to ensure that rates are just and reasonable in light of the costs and benefits of net metering. It may very well be that commercial net metering customers are being undercompensated for the value they provide to the grid. Therefore, the Commission should require PacifiCorp to conduct the same cost-benefit analysis for commercial customers as for residential customers.

ii. Timeframe for the Study

Because distributed generation systems installed today are typically warrantied for 25 years and likely to continue producing power for even longer, it is appropriate for the study of costs and benefits to look at an equivalent timeframe. The initial costs incurred by both the utility and the NEM customer should be spread out over the lifetime of the system, not averaged over the first year or even decade.[51]

iii. Appropriate Discount Rate

Because the costs and benefits will be experienced over the lifetime of the distributed generation system, the choice of discount rate to be applied can make a significant difference in the overall results. The utility's cost of capital is often used as the discount rate in other planning analyses where utility procurement options are being considered. However, because distributed generation is a customer investment and not a utility one, it would be reasonable to discount

[50] *See, e.g.*, Rocky Mountain Power, Docket No. 14-035-114, Reply Comments To Comments Filed By Sierra Club, The Alliance For Solar Choice, Utah Clean Energy And Utah Citizens Advocating Renewable Energy (Dec. 19, 2014), at 4.
[51] IREC, *Regulator's Guidebook*, *supra*, at 16.

future benefits and costs at a rate closer to that of inflation, rather than the utility's cost of capital.[52]

iv. Level of market penetration

It is important to have accurate information and reasonable forecasts about the level of distributed generation during each year of the study period. PacifiCorp offered estimates of the short-term rate of distributed generation growth during the general rate case,[53] but additional information will be needed about the likely rate of increase over the next several decades. These forecasts should account for the declining costs of solar systems and retail rate escalation, among other factors. The costs and benefits of distribution generation increase with the level of DG market penetration, but not all of the costs and benefits do so at the same rate. For example, as noted earlier, the administrative costs of the net metering program should not increase linearly with the number of NEM customers, but rather increase more slowly as the utility streamlines its processes.

v. Analysis of total generation versus excess customer generation

The Commission has requested comment on the consistency of any proposed analysis with the statutory definition or requirements of the net metering program. The statute defines a "net metering program" as "a program administered by an electrical corporation whereby a customer with a customer generation system may: (a) generate electricity primarily for the customer's own use; (b) supply customer-generated electricity to the electrical corporation; and

[52] IREC, *Regulator's Guidebook*, *supra*, at 15; *see also* Synapse Energy Economics, Inc., *Benefit-Cost Analysis for Distributed Energy Resources*, *supra*, at 54-55 (recommending societal discount rate of less than three percent).
[53] See Direct Testimony of Joelle Steward Direct, at 22:480-90 (noting a 30 percent rate of growth in recent years).

(c) if net metering results in excess customer-generated electricity during a billing period, receive a credit as provided in Section 54-15-104."[54]

As the Commission recently noted, "the Net Metering Code excludes the amount of the net metered customers' production and consumption behind the meter in the definition of electricity eligible for credit."[55] This factor is highly relevant to the assessment of the costs of the net metering program, as those costs will vary depending whether the analysis considers total generation by customer-owned systems, or only the excess customer-generated electricity that is credited against consumption.[56]

The Commission should clarify whether this analysis is to evaluate only the exported energy or all generation. Evaluating only exported energy is consistent with the Net Metering Code, since only that portion of the generation is eligible for retail credit. In addition, there are very limited data on the amount of total generation from NEM systems, since the standard meters track only monthly billed consumption. Rocky Mountain Power's load research study will, at best, gather data from around 60 production meters that are not necessarily representative of the installed systems.[57] Those data will be collected over less than a year by the time Rocky Mountain Power begins its analysis for the rate case. If total generation will be used for any part of this analysis, we believe that an estimate of the total production based on information about installed systems and SolarAnywhere irradiance data should be used alongside data from the load research study.

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[54] Utah Code Ann. § 54-15-102(12).

[55] GRC Order at 64.

[56] *Id.*

[57] *See generally* Joint Comments of Utah Clean Energy, Sierra Club, TASC, and UCAR, on PacifiCorp's Load Research Study (submitted Dec. 10, 2014).

III. <u>Cost of Service Study</u>

The Commission has asked for comment on whether analysis other than cost-effectiveness should be conducted. Sierra Club believes that while S.B. 208 specifically calls for only an evaluation of the costs and benefits, the second part of the mandate to the Commission, to impose just and reasonable rates in light of these costs and benefits, requires additional analysis. As the Commission noted in its order on PacifiCorp's general rate case, a key piece of information is whether the cost of serving net metered customers differs from serving other customers in the same class.[58]

The Legislature's phrase, "in light of the costs and benefits," does not mean that the NEM tariff must be modified in order to equalize costs and benefits. In referring to the Commission's standard for ratemaking, and using general language such as "in light of," the Legislature intended for the Commission to consider the costs and benefits in a qualitative, holistic way, as one factor among many relevant to the just and reasonable determination.

Likewise, cost of service is an important piece of information, but is not determinative in ratemaking. The cost of serving customers within a single class varies significantly, but the Commission's objective is not to ensure that each customer pays exactly its fair share, but rather to adopt rates that balance the many ratemaking principles. Nevertheless, there is value in undertaking a cost of service analysis for net metered customers, including residential, commercial, and industrial, as part of better understanding how net metering affects the utility and other customers.

[58] GRC Order at 61-68.

Sierra Club also recommends that a rate and bill impact analysis be conducted, separately from the cost-benefit analysis. A cost-benefit analysis only tells the Commission whether a resource is cost-effective from the perspective of a NEM customer, the utility, or society as a whole (depending on the test). It does not, alone, provide the kind of detailed information about how net metering affects customer bills that the Commission needs to determine whether the particular net metering tariff is just and reasonable. This analysis considers net metering not only as an intra-class distributional issue, but places it in the context of the broader cost of service analysis. Distributed generation affects the utility's revenue requirement, including how that requirement is allocated across PacifiCorp's different geographic territories. It also affects apportionment of costs to different classes served by PacifiCorp. All of these factors can affect the rates and bills of residential customers, not just how net metering may shift costs within the class. These broader effects are also why it is so important for the Commission to undertake a holistic analysis of the entire net metering program (including commercial and industrial net metering), rather than engaging in single-issue ratemaking, such as considering a residential NEM fee in isolation.

IV. Process Recommendations

The Commission has initiated this docket to determine the appropriate analytical framework for evaluating the costs and benefits. As evident from these comments and those filed by other parties, the analytical framework is unavoidably complex, and will require the Commission to make numerous policy decisions. In the last general rate case, the Commission's ability to fully evaluate the issues was hamstrung by the time constraints imposed on rate cases. The

Commission noted in its order that because "the distribution and customer intra-class cost shift asserted by PacifiCorp and supported by the Division and the Office is very small . . . we conclude that under these circumstances the better course is for PacifiCorp and interested parties to gather and analyze the necessary data."[59] Sierra Club is not aware that the situation has become any more pressing in the six months since the Commission entered its order. Therefore, the Commission should not short-circuit the very important process underway in this docket, but take all the time that it feels is necessary to fully deliberate the issues and collect the data. If this process is rushed, the Commission may very well find the next rate case mired in similar disagreements about the appropriate analytical framework.

The Commission's November 2014 notice indicated that the Commission would undertake its examination of the costs and benefits based on this analytical framework, as needed to make the determination required by Utah Code Ann. §54-15-105.1(2), "[i]n a further phase of this docket, a general rate case or other appropriate proceeding."[60] However, it now appears that the Commission has settled on an approach wherein the analytical framework developed in this docket will be applied in the context of the next rate case filed by Rocky Mountain Power. Sierra Club believes that conducting this analysis in the context of a rate case is not ideal for generating the most robust results. Any analysis done as part of a rate case will likely focus only on the questions most directly relevant to the tariff change that the company is seeking, which will not provide the Commission with the full picture. Moreover, the time constraints and adversarial nature of a rate case will not allow for the kind of iterative and collaborative process that would yield a study reflecting the best information.

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[59] GRC Order at 67.
[60] *Id.*

To ensure that this proceeding to determine the analytical framework is as productive as possible, Sierra Club recommends that the Commission and staff make full use of the scheduled technical conferences. No topics have been established for these conferences due to disagreement among the parties as to the purpose of those conferences. While Sierra Club recognizes that the Commission's record in this matter will be limited to the prefiled testimony and matters presented at the October 2015 hearing, technical conferences have significant value in allowing the parties to consider the experience of other states and national experts, promoting open discussion of contentious issue and thereby narrowing the scope of disagreement among the parties.

Technical conferences have the most value when led by an experienced and neutral moderator, and when the perspectives of the presenters are balanced and focused on expertise rather than ideology. For example, one helpful topic for the Commission might be how distributed generation affects the transmission and distribution system, including (a) how DG should be incorporated into system planning, (b) how higher levels of DG can be successfully integrated into the distribution system, and (c) how advanced inverter technology will affect integration and value of DG systems in avoiding T&D costs. The presenters on this panel could include distribution system planners at Rocky Mountain Power and other utilities that face high or growing levels of distributed generation, and experts at the National Renewable Energy Laboratories on emerging inverter technologies and distribution best practices. The Commission and parties might also find it helpful to hear from regulators from other states, other utilities' rate division personnel, and an independent expert from the Regulatory Assistance Project about how to properly determine the cost of serving net metered customers.

Looking ahead to the testimony to be filed this summer, Sierra Club believes the parties would benefit from guidance as to the specific factual issues to be addressed. Any legal issues that are not fact-dependent should be resolved prior to the filing of testimony, if at all possible, so as to further define the scope of the factual disputes at issue.

V. <u>Conclusion</u>

Sierra Club appreciates the complexity of the process facing this Commission. Developing a cost-benefit analytical framework and determining what net metering tariff structure is just and reasonable involves challenging questions of policy and fact. Therefore, Sierra Club urges the Commission to create a structured collaborative process leading up to the formal litigation phase of this proceeding that will allow all involved to learn from the experiences of other state regulators and utilities, and refine the issues that require resolution during the October evidentiary hearing.

Net metering has, to date, provided an important incentive for the development of distributed generation in Utah. However, the amount of distributed generation on Rocky Mountain Power's system is still incredibly small, and therefore is not yet causing any integration costs for the utility. The Commission's consideration of whether this small amount of distributed generation is shifting costs to other ratepayers in an unjustified fashion must reflect the full suite of benefits provided by distributed generation, despite the challenges of quantifying many of these benefits. The Commission's process should allow for distinct analysis of the costs and benefits, the rate and bill impact, and the cost of serving net metered customers, rather than attempting to shorten the process by compressing all of these analyses into a single step.

We thank the Commission for the opportunity to submit these comments and look forward to fully engaging in the forthcoming conferences and other proceedings.

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Respectfully submitted,

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