DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF Establishing Minimum Information Requirements for NorthWestern Energy's Study of the Costs and Benefits of Customer Generation	REGULATORY DIVISION DOCKET NO. D2017.6.49

COMMENTS OF THE JOINT PARTIES
July 7, 2017

I. Introduction

The Montana Renewable Energy Association, Renewable Northwest, the Montana Environmental Information Center, NW Energy Coalition, and Vote Solar, collectively the "Joint Parties" offer the following comments.

The Montana Renewable Energy Association ("MREA") is a non-profit, membership based organization dedicated to expanding the use of renewable energy in Montana. MREA works to affect public policy in favor of renewable energy, and to educate and inform the residents of Montana of the benefits and uses of renewable energy.

Renewable Northwest is a non-profit advocacy organization that works to facilitate the development of a cost-effective, reliable, and clean energy system for the betterment of the Northwest economy and environment. We are actively engaged throughout the region in proceedings and discussions related to renewable energy. Of particular relevance to this proceeding, Renewable Northwest is working with a broad selection of stakeholders, including utilities, to quantify the benefits and costs of solar in Washington as part of the initiative Solar Plus. We are also an active stakeholder, and have provided extensive technical expertise, as part of the Oregon Public Utility Commission's current Investigation into the Resource Value of Solar.

The Montana Environmental Information Center ("MEIC") is a nonprofit environmental advocacy organization founded in 1973 by Montanans concerned with protecting and restoring Montana's natural environment. MEIC plays an active role in promoting Montana clean energy projects and policies, including advocating for the expansion of responsible, renewable energy and energy efficiency and supporting policies that insulate energy consumers from fuel price risk. At the state level, MEIC works to pass policies that help expand clean, affordable, reliable, and efficient energy solutions for Montana. MEIC has approximately 5,000 members and supporters, many of whom are in NorthWestern's Montana service territory.

The NW Energy Coalition is an alliance of about 100 environmental, civic, and human service organizations, progressive utilities, and businesses in Oregon, Washington, Idaho, Montana and British Columbia. The NW Energy Coalition promotes development of renewable energy and energy conservation, consumer protection, low-income energy assistance, and fish and wildlife restoration on the Columbia and Snake rivers.

Vote Solar is a non-profit grassroots organization working to foster economic opportunity and promote environmental benefits by bringing solar energy into the mainstream. Since 2002, Vote Solar has engaged at the state, local and federal levels of government to remove regulatory barriers and implement policies needed to bring solar to scale.

The Joint Parties thank the Public Service Commission ("Commission") for this opportunity to comment. By deciding to establish minimum information requirements for study of the costs and benefits of customer-generators, the Commission is taking an important first step to ensure a fair and transparent process for implementation of HB 219.

In our comments below, the Joint Parties respond to the Notice of Opportunity to Comment ("NOC") dated June 16, 2017. Following this introduction, the second section of these comments provides recommendations of the Joint Parties. The third section addresses each of the benefit and cost categories identified in the NOC, and the fourth section provides responses to the additional questions listed in the NOC.

II. Over-Arching Issues for Consideration

A. A Customer's Right to Self-Determination

Just as a customer has the right to grow and harvest timber on their own land to use for heating their home, a customer has the right to install distributed generation to serve their on-site energy needs. In this respect, the Joint Parties encourage the Commission to recognize that an individual customer should be free to choose the amount of energy to purchase from the grid, the amount to self-produce and consume, and the amount to save through efficiency measures that reduce consumption. This freedom includes the right to install solar generation equipment at the customer's site and to interconnect to the utility grid without discrimination. While any electrical devices connected to the grid must not compromise safety, reliability, or power quality, utilities do not have the right to restrict the decisions of customers regarding how to manage energy use on their own property. Montana's electric utilities operate under a regulatory compact that requires electric utilities to do business within the confines of the public interest to serve the needs of all customers within their territory in exchange for an exclusive monopoly franchise.

The program of net energy metering ("NEM") recognizes the customer's right to self-determination by allowing the customer-generator to avoid payments to the utility for energy generated and consumed on-site and billing the customer only for energy that is consumed from the utility. In this regard, NEM is a method for compensating the **exports** from a customer-generator, not the energy that is produced and consumed on-site. Under NEM, exported energy is "netted" against energy that is purchased from the utility, effectively valuing exported energy at the volumetric retail rate.

In addition to customers' right to self-determination, Montana law requires that the utility compensate customer-generators for the excess energy that is fed to the grid: The net metering rules state: "If electricity generated by the customer-generator exceeds the electricity supplied by the electricity supplier, the customer-generator must be [...] credited for the excess kilowatt hours generated during the billing period."[1]

[1] MT 69-8-603(3).

As the Commission undertakes the important question of evaluating the benefits and costs of customer-generators under the NEM program, the Joint Parties urge the Commission to avoid reaching "behind the meter" and to focus instead on evaluating: (1) the cost to serve customer-generators for the load that is delivered to them by the utility; and (2) the compensation for energy exported by the customer-generator.

B. Role of Benefit-Cost Study in Relation to the Rate Case

The benefit-cost study is an important tool for evaluating the impact of NEM as compensation for exported energy. Upon completion of the benefit-cost study it is the Joint Parties' hope that the Commission will have available key information regarding the impacts of current policy that can help inform future policy to be set in the rate case. The Joint Parties do not believe that it is appropriate for the Commission to make changes to NEM, nor customer-generator classification in this rulemaking, but rather to reserve those questions for the rate case where they can be appropriately evaluated.

HB 219 instructs the Commission to evaluate whether customer-generators should be served under a separate classification of service, but indicates that this finding should take place "as part of a public utility's general rate case."[2] The results of the benefit-cost study alone are insufficient to inform such a finding. In addition to examining the results of the benefit-cost study, the Commission must evaluate the cost to serve customer-generators in the context of a full cost of service study. Only with a full assessment of facts can the Commission weigh the policy considerations surrounding whether or not to place customer-generators into a separate classification of service.

Considerations should include:

1. An assessment of the cost to serve customer-generators, relative to the benefits brought to the system, and also the revenue recovery from customer-generators in relation to similar measures for standard customers;

[2] HB 219 Section 2.

2. The potential impact on customers with and without distributed generation, and whether the small size of a potential customer-generator class warrants separation; and
3. Whether the load and cost profiles of customer-generators are sufficiently different from other subclasses of customers such as multi-family residences, rural customers, or customers with electric heating so as to warrant singling out customer-generators in the rate-making process.

One of the primary challenges facing the Commission will be to gather the data on which to base its findings. In order to properly evaluate whether customer-generators should be served under a separate classification of service, the utility must gather detailed load information on its customer-generators to determine the relative cost to serve them. We encourage the Commission to instruct the utility to evaluate the cost-causing factors associated with load delivered to customer-generators in a manner consistent with how other service classes are treated in the cost of service study. The Joint Parties note that the Commission has requested that NorthWestern Energy ("NWE") provide information on the scale and scope of data that will be available in this regard, and we look forward to working with the Commission and NWE on this issue.

C. Scope of the Benefit-Cost Study

The Joint Parties note that HB 219 has authorized the Commission to establish the minimum information to be included in NWE's study of benefits and costs of customer-generators, but has not limited consideration to a single type of customer-generator. At the end of 2014 there were roughly 1,400 customer-generators in NWE's territory, nearly 1,300 of which have adopted rooftop PV generation.[3] While rooftop solar is the leading distributed energy resource ["DER"] adopted to-date, the Joint Parties encourage the Commission to consider other DERs such as net metered wind, hydro, energy storage, and electric vehicles in addition to rooftop solar PV when formulating policy in this regard.

[3] http://montanarenewables.org/maps-data/net-metering/nwe/

D. Draft Study Should be Made Available for Comment

While the Joint Parties appreciate the procedural timelines set forth in HB 219, we recommend that the Commission require NWE to submit a draft benefit-cost study for evaluation and input from interested parties. The draft should include a full description of the methodologies employed and provision of associated work-papers and source data for evaluation by interested parties. We recommend that the Commission require a public draft of the study and work-papers by February 1, 2018 and allow for interested parties to submit comments by March 1, 2018. This would provide NWE the opportunity to respond to comments in the final draft by the April 1, 2018 deadline set forth in HB 219.

Draft review prior to final submittal would provide transparency in the study. This recommendation is furthered by confusion regarding the process immediately following submittal of the study on or before April 1, 2018. HB 219 Section 1(b) states that a public utility shall "submit the study to the commission for the purpose of making determinations in accordance with a public utility's general rate case pursuant to [Section 2]." Section 2, subsection 4 states, "If a public utility files a general rate case in accordance with Title 69, Chapter 3, the general rate case must include the study required in accordance with [Section 1] and be used by the commission to meet the requirements of the review of classifications of service required in this section."

The Commission NOC, however, states, "NWE must submit the study to the Public Service Commission (PSC) as part of a general rate application." If this were true, any and all interested parties would be able to support, oppose or otherwise contest the study solely by hiring legal counsel and formally intervening in the general rate case. This presents both an undue burden on interested parties and presents significant challenges to completing the rate case in the allotted 270 days, especially considering that NWE will not have filed an electric general rate case in nearly a decade.

The Joint Parties do not interpret the statute to require a general rate case filing upon submittal of the benefit-cost study. As such, if the Commission rejects the notion of draft study evaluation prior to final submittal, we recommend that the study be reviewed by the Commission and interested parties as part of a separate docket outside of and prior to the general rate case application. This process would enable all parties to fully examine the study and provide feedback as to its merit prior to its inclusion in a rate case. Should the study be found to be of merit, the rate case, then, could focus on potential changes to rate design. Should the study be found to be delinquent, we recommend that the Commission encourage NWE not to include the study as part of a general rate application until any and all flaws are fixed.

III. Recommendations for Minimum Information Requirements

The NOC includes tables of benefit and cost categories identified for potential inclusion in a set of minimum information requirements. The section below addresses each of these categories. In evaluating appropriate categories for inclusion, the Joint Parties find that it is best to cast a broad net for the study and evaluate which categories yield useful information. If there is concern over the ability to quantify a particular benefit or cost category, it should not be excluded from the evaluation. The Joint Parties recommend that, rather than adopt a zero value for more advanced categories, the Commission identify the category and consider it qualitatively based on available evidence. In addition, we encourage the Commission to consider what information prevents the quantification of that category and consider requiring development of the necessary information to enable quantification in a future examination.

As the Commission begins this process it can be helpful to look to the experience of other states that have undertaken similar efforts. The Interstate Renewable Energy Council ("IREC") has developed a useful guidebook on calculating the costs and benefits of distributed solar generation that can inform the Commission's process.[4] The guidebook builds on experiences throughout the country to propose a standardized and reliable approach to the analysis.

The table below summarizes our comments on each benefit-cost category.

[4] IREC, *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation* (Oct. 2013), http://www.irecusa.org/publications/a-regulators-guidebook-calculating-the-benefits-and-costs-of-distributed-solar-generation/

Category	Include	Key factors for consideration
Benefits		
Avoided Energy Costs	Yes	• Use marginal costs • Account for seasonality when identifying marginal generator (DG exports vary during the year)
Avoided Capacity Costs	Yes	• Use marginal costs • Quantify based on DER contribution to capacity needs
Avoided Transmission and Distribution Capacity Costs	Yes	• Use publically available data on historical expenditures • Quantify based on DER contribution to capacity needs
Avoided System Losses	Yes	• Use marginal losses • Account for seasonality (DG exports can coincide with periods of high loading)
Avoided RPS Compliance Costs	Yes	• Use the premium NWE has paid for renewable generation
Avoided Environmental Compliance Costs	Yes	• Value both avoided particulate and carbon emissions • Include to the extent not captured in Avoided Energy or RPS Compliance costs
Market Price Suppression Effects	Yes	• Consider effects on both energy and capacity • Model as the difference between total cost paid with and without DER generation / capacity
Avoided Risk	Yes	• Quantify "risk premium" as the difference between cost of energy procured through the market and that locked-in via futures contracts
Avoided Grid Support Services	Yes	• Assume capability of current inverter technology is utilized to provide grid support services in future scenarios
Avoided Outages Costs	Yes	• Include qualitatively if data does not allow quantification
Non-Energy Benefits	Yes	• Include at least three categories – local economic benefits, reduced water usage, and public health benefits
Costs		
Reduced Revenue	No	• Exclude from analysis because utilities do not have a right to the revenue. • If the Commission includes this element, consider all DER systems including commercial and industrial, not just residential, and account for proportion of energy forfeited to utility annually under NEM arrangement
Administrative Costs	Yes	• Include costs for billing and administration • Exclude marketing, advertising and market research
Interconnection	See comments	• Most germane to expected interconnection docket
Integration	Yes	• Unlikely to result in material cost for some period of time
Production, Transmission, Distribution Cost Shifts	No	• Fully accounted for in other categories

1

A. Avoided Energy Costs

Generation from DER systems offsets energy that would otherwise have been produced by the marginal generator. Properly valuing avoided energy costs from DER thus requires (1) identifying a representative marginal generator – DER production will vary seasonally, based on the coincidence of customers' usage and solar production, as will NWE's plant stack – and then applying reasonable (2) heat rate, (3) operations and maintenance costs and (4) gas price assumptions.

B. Avoided Capacity Costs

DERs are capable of contributing a degree of firm capacity that reduces the need for new build to meet NWE's planned system capacity needs. Valuing avoided capacity costs attributable to DER requires (1) an assessment of current and forecast capacity requirements, (2) the marginal cost NWE has assessed to build new capacity and (3) a measure of the contribution of DER to NWE's capacity requirements that should be estimated using an effective load carrying capability method ("ELCC") or a recognized approximation to the ELCC that considers all hours of the year.

C. Avoided Transmission and Distribution Capacity Costs

The Joint Parties recommend quantifying the avoided cost attributable to new transmission and distribution capacity. Ideally, these avoided costs would be accomplished through marginal cost studies developed in conjunction with detailed distribution and transmission resource planning; however, it is unlikely that such data is currently available for NWE's system. Hence, the Joint Parties recommend approximating these measures through the NERA regression method whereby historical expenditures on transmission and distribution can be compared to measures of increases in demand and scaled to account for the expected contribution of DER to the factors driving transmission and distribution investment. The benefit of this approach is that it relies on publically available data and can be conducted even in the absence of detailed marginal cost information.

D. Avoided System Losses

Because DG systems offset load at the source, their production avoids line losses associated with carrying centralized generation to the point of consumption, creating greater efficiency in the system overall. The Joint Parties recommend using an assessment of marginal, rather than average, line losses, ideally accounting for seasonal differences. DG generation can be greatest during periods of high loading on the grid at which times lines losses may be considerably higher than average.

Line losses should be accounted for when calculating avoided energy, capacity, and transmission and distribution costs, as 1MW of DER capacity will be able to offset more than a MW in centralized capacity, which must be oversized to account for power lost over the transmission and distribution systems.

E. Avoided RPS Compliance Costs

Montana's Renewable Resource Standard requires investor-owned utilities to procure 15% of retail electricity sales from qualified renewable energy resources for compliance in year 2015 onward. By reducing the volume of retail sales, DER generation reduces the amount NWE is required to spend on RPS compliance. The value of avoided RPS compliance costs can be assessed based on the premium NWE has paid for qualified renewable energy contracts. A simple proxy value for this premium would be the price of any RECs NWE has put on the market for purchase. Because DER generation lessens the total amount of renewable generation NWE needs to procure and creates the ability for NWE to sell excess credits in its possession, it is appropriate to award this value regardless of NWE's overall RPS compliance position or REC procurement.

F. Avoided Environmental Compliance Costs

DER generation directly reduces the amount of criteria pollutants produced by the utility's resources, including NOx, SOx, and other particulate matter. The avoided operating expenses for the utility should be valued to the extent that these compliance costs are not captured in the Avoided Energy Cost and Avoided RPS Compliance Cost, and the volume of avoided emissions should be calculated based on the emission rate of the marginal generator identified.

In addition, a carbon avoidance value should be awarded to DER generation, consistent with precedent set in previous Commission dockets.[5]

G. Market Price Suppression Effects

DER generation reduces total system load, which can reduce the overall market price for all other purchased energy by shifting to lower-cost marginal generators. This benefit is difficult to measure directly, especially in a regulated wholesale environment, but can be modeled by first analyzing what market energy prices would have been with and without DER, and then multiplying this change in price by the volume of DER generation. A similar capacity value should also be quantified.

H. Avoided Risk

DER exports act as a fuel price hedge, reducing the utility's reliance on fuels with volatile and uncertain market prices. The benefit of removing this "risk premium" can be quantified as the cost to remove natural gas price uncertainty for the given volume of DER generation. This can be accomplished by comparing the cost to procure generation from a gas plant in which there is fuel price uncertainty, and one in which gas futures have been secured and funds invested today in risk-free securities. The resulting difference should be quantified for the duration of the DER lifetime. Due to NWE's relatively high exposure to market prices, this may be a significant value stream. As a result, we recommend that the Commission include Avoided Risk in its minimum information requirements.

I. Avoided Grid Support Services

DER capacity is able to provide support services to the grid, such as VAR regulation and voltage pass-through. However, its ability to do so largely depends on policy that requires advanced inverter standards upon interconnection, such as those put in place in states

[5] See Dockets D2013.215 and D2016.7.56.

such as Hawaii and California. The Joint Parties recommend that, in assessing avoided grid support services over the term of the study, the full functionality of currently available inverter technology is utilized by DER systems rather than limiting value to the services provided by outdated technology that may already be in place for early adopters.

J. Avoided Outages Costs

DER can increase the resiliency of the grid by reducing the risk of outages by decreasing load requirements on saturated circuits and, if behind-the-meter storage is present, allowing customers to continue to use power on-site in the case of an outage. The Joint Parties recommend quantifying this benefit to the extent NWE's data allows.

K. Non-Energy Benefits

The Joint Parties recommend quantifying at least three primary non-energy benefits of DER: (1) local economic benefits, including increased tax revenue and job creation (2) reduced water usage and (3) the public health benefits of decreased airborne pollutants.

L. Reduced Revenue

The Joint Parties recommend that the Commission does not include Reduced Revenue in the minimum information requirements for NWE's study because it is not a cost of customer-generators. HB 219 requires NWE to conduct a study of the costs and benefits of customer-generators.[6] The NOC includes Reduced Revenue as one of the cost categories for potential inclusion in the set of minimum information requirements, defining it as, "Lost utility revenue associated with reduced sales due to net metering".[7] However, the revenue that a utility does not receive from customers that reduce their load, including customer-generators, is not a cost of that customer. Indeed, a utility does not have a right to expect its customers to consume electricity at a set level. Utility customers may reduce their load as a result of several factors, including self-generators, but also energy efficiency, and should not be penalized for doing so. A study of the costs and benefits of customer-generators that includes Reduced Revenue as a cost would rely

[6] HB 219, Section 1.
[7] NOC at 3.

on the assumption that utilities have a right to their customers consuming electricity at a particular level. As a result, a study that included Reduced Revenue would offer inaccurate information on the actual costs and benefits of customer-generators.

The Joint Parties recommend the Commission does not consider Reduced Revenues when determining if customer-generators should be classified separately from other customers. Under HB 219, the Commission must determine if customer-generators should be classified separately from other customers based on the utility system benefits and the costs of serving customer-generators. However, the reduction in revenue a utility experiences as a result of customers reducing their load is not a cost of serving those customers. As a result, we recommend that the Commission does not consider Reduced Revenue when determining if customer-generators should be classified separately from other customers.

If the Commission decides to include Reduced Revenue in the minimum information requirements, or if NWE decides to use this element, the Joint Parties recommend that Reduced Revenue be calculated as the volume of exports from DER systems multiplied by the retail rate credit applied under NEM, and should not include the amount of self-generated energy consumed behind the meter. Additionally, the analysis should consider all customer classes with DER systems, including commercial and industrial, not only residential. Because commercial and industrial rates often utilize a demand charge, which cannot be offset by solar-only systems, and feature a lower volumetric energy rate relative to residential tariffs, excluding commercial and industrial classes, therefore, would overstate the average cost of exports across the DER fleet. When scaling the costs associated with reduced revenue to the benefits categories identified above, the study should incorporate the proportion of energy from customer-generators that is forfeited to the utility without compensation under the current NEM program.

M. Administrative Costs

Direct costs associated with billing and basic administration regarding DER generators are within the scope of this study. These include the one-time costs associated with setting up and verifying applications, as well as the on-going expenses of administering the program (such as manually adjusting customer bills). When forecasting, the Joint Parties recommend assuming that administrative practices and processes are automated as penetration of DER increases, thereby reducing the marginal cost of maintaining the program.

While identified in the NOC, marketing, advertising and market research costs are not direct costs required to support customer-generators. As a result, the Joint Parties do not recommend including these discretionary cost items within the scope of the study.

N. Interconnection

Interconnection costs incurred by the utility should be considered to the extent that they are incremental to any fees the DER customer pays at interconnection. Currently, NWE does not collect mandatory fees at interconnection, but is in the process of updating their interconnection agreements and is expected to file in the near future. The updated agreements may require the customer generator to cover fees for application, feasibility studies, meter upgrades and any other interconnection cost.

Pending an outcome from the interconnection docket, we encourage the Commission to ensure that interconnection costs are not double-counted in the study. It is critical that, on a forward-looking basis, the only costs considered in this study are distinct items that NWE incurs above and beyond those recovered from the DER customer.

O. Integration

Given the relatively low penetration of DER in Montana, it is unlikely that NWE will experience any costs associated with integration in the near term. Notably, a recent National Laboratory report found that rooftop solar is expected to account for far less than 0.5% of sales in Montana in 2030.[8] The Joint Parties recommend that integration costs be recognized as a potential issue in the future, but highlight that it would be premature to give the category much weight given long-term penetration forecasts.

[8] Barbose, Galen. Putting the Potential Rate Impacts of Distributed Solar into Context. Energy Analysis and Environmental Impacts Division. Lawrence Berkeley National Laboratory. LBNL-1007060. January 2017, page 11.

P. Production, Transmission, Distribution Cost Shifts

While the Joint Parties agree that the question of whether cost-shifts exist is an important issue for the Commission to consider, this issue will be fully addressed through an accounting of the benefits and costs listed above and through further analysis in the cost of service study during the rate case. As a result, this issue does not require separate quantification. Whether and to what extent a cost shift may or may not occur will depend on the balance of identified benefits and costs, and should be considered an outcome of—rather than input to—the study.

IV. Responses to Additional Questions Identified in the NOC

- **What, if any, assumptions regarding the adoption rate of solar or other net metering technologies should the Commission specify?**

The amount of DER on a utility's system can significantly impact the benefits and costs of DER, and the benefit-cost equation can therefore change as DER penetration levels increase. While it can be informative to examine the value of DER at higher levels of penetration, long-term adoption rates are highly uncertain, and the economics of DER at high penetration levels does not impact the economics of DER at current and near-term levels. Therefore, hypothetical long-term penetration levels should not influence current policy. For purposes of this analysis, the Joint Parties recommend DER benefits and costs be evaluated at penetration levels expected to occur in the next one to three years and to revisit that valuation periodically as the market grows.

- **What, if any, time frame for calculating benefits and costs should the Commission specify (e.g., 10 years, 20 years, etc.)?**

We recommend that the Commission examine the levelized costs and benefits of DERs over the economic life of the asset. For rooftop PV, this is generally considered to be twenty to thirty years. This approach is inherently distinct from cost-of-service ratemaking, which looks at a single test year, but is consistent with the methodologies used for evaluating other generation technologies such as through the Resource Procurement Plan, which looks at a 20-year period.

- **What, if any, assumptions regarding utility rates should the Commission specify (e.g., rate of increase, changes in rate design (time-of-use, other))?**

While the Joint Parties do not recommend that reduced revenue be included in the minimum information requirements, if it is included it will be necessary to make an assumption about the rate of increase in utility rates over the study period. However, we recommend that the Commission does not examine potential changes to rate design in the benefit-cost study. Rate design is a topic that should be evaluated in the context of the rate case. The purpose of the benefit-cost study is to evaluate current policy, not to weigh alternative rate designs.

- **What, if any, methodology for cost-effectiveness tests should the Commission specify (e.g., standard practice manual or the Cost Benefit Framework developed by the Electric Power Research Institute)?**

The California Standard Practice Manual ("SPM") provides the basic framework for cost-effectiveness of energy efficiency, distributed generation resources, and electric vehicles throughout the Northwest. As such, we recommend that the utility and the Commission rely on this often-used methodology as a starting point for examining cost-effectiveness. Tweaks should be considered as needed; specifically, for the purposes of this study, certain societal and environmental costs should be included in any of the cost-effectiveness tests laid out in the SPM.

- **What cost-effectiveness perspective(s) should the Commission require be evaluated (e.g., societal, utility/program administrator, ratepayer, participant)?**

Considering the debate at the legislature and the Commission on the existence of a "cost-shift," it is assumed that NorthWestern Energy would utilize the Ratepayer Impact Measure ("RIM") test. As stated by the California SPM, "The Ratepayer Impact Measure

(RIM) test measures what happens to customer bill or rates due to changes in utility revenues and operating costs caused by the program."[9]

However, as outlined in Commission's Draft Minimum Information Requirements, and in these comments, we recommend that the Commission be sure to include costs beyond those typically included in RIM as outlined by the SPM if the RIM is used. Indeed, one of the downfalls of the RIM is its lack of inputs, which can lead to inconclusive results. Jim Lazar and Ken Colburn of the Regulatory Assistance Project highlight some of the problems with RIM in discussing its use for energy efficiency programs:

> Very few, if any, states use the RIM test as the primary determinant of cost-effectiveness for their energy efficiency programs, in part because it can easily foster counterproductive outcomes. For example, a program to install **less efficient** air conditioners would increase electricity consumption, thereby reducing utility fixed costs per kWh and reducing overall rates as a result. Accordingly, such an energy **inefficiency** program would pass the RIM test.[10]

The CA SPM also notes an important weakness of the RIM: "Results of the RIM test are probably less certain than those of other tests because the test is sensitive to the differences between long-term projections of marginal costs and long-term projections of rates, two cost streams that are difficult to quantify with certainty.[11]"

As such, and in order to capture a complete picture of the costs and benefits of distributed generation, we encourage the Commission to require that each of the tests laid out in the SPM be included in the study (Total Resource Cost ("TRC")/Societal Cost Test ("SCT"), Program Administrator Cost ("PAC") [also knows and the Utility Cost Test ("UCT")], RIM, and Participant Cost Test ("PCT"). Weight should be placed on the

---

[9] *California Standard Practice Manual, Economic Analysis of Demand-Side Programs and Projects*, California Public Utilities Commission, October, 2001. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

[10] Lazar, J. and Coluburn, K. (2013) *Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits).* Regulatory Assistance Project. [Emphasis added].

[11] *California Standard Practice Manual, Economic Analysis of Demand-Side Programs and Projects*, California Public Utilities Commission, October, 2001.

TRC/SCT and the PAC/UCT, as these test most accurately capture all of the costs and benefits of a demand-side program. This approach is consistent with the use of these tests by other Northwest utilities. The Northwest Power and Conservation Council's Regional Technical Forum also follows this methodology, including each of the tests in its ProCost model for energy efficiency, while relying on the TRC to provide the most complete results.

- **Should the Commission specify the generating resource avoided by net-metered systems? If so, what generating unit should be used?**

While imperfect, we recommend that the Commission continue to use the proxy model as used in PURPA avoided cost dockets. Considering that the vast majority of net-metered systems are solar PV, providing power during NWEs heavy load hours, we encourage the Commission to specify a combined cycle natural gas turbine as the marginal energy resource. Solar PV also provides additional capacity benefits, especially during NWEs secondary peak during the summer months of July and August. As such, a natural gas internal combustion engine should provide marginal cost for these additional capacity benefits. Both of these resources were identified in NWEs 2015 Resource Procurement Plan as the marginal units for providing energy and capacity, respectively.

- **Should the Commission specify a particular locational attribute that counts as either a benefit or cost adder/subtractor?**

Because the value of DER can vary by location on the distribution system, the Joint Parties recommend that the Commission consider locational attributes. By incorporating locational attributes into the analysis, the Commission can enable DER deployment in a manner that is most efficient. Unfortunately, it appears as though NWE may lack sufficient information about its distribution system that would enable it to identify areas in which DER could be most effective in avoiding the need for infrastructure upgrades. As a result, the Joint Parties recommend that the Commission examine possible need for additional data development and potential hosting capacity analysis that can enable implementation of locational adders in the future.

- **What, if any, other compensation approaches in addition to net metering should be assessed in the study NorthWestern is required to conduct?**

The purpose of the benefit-cost study is to examine the current policy of net metering. While the result of the study may inform the need to evaluate other compensation approaches in a future proceeding, the first order of business is to develop a full understanding of the current policy. HB 219 has set time limitations on this exercise and the Joint Parties believe that increasing the scope of the study beyond current policy would water down the effectiveness of the study.

V. Closing Comments

The Joint Parties thank the Commission for their time and consideration of these comments and look forward to continuing the conversation in this rulemaking.