At a pre-hearing conference on October 27, 2015, in Salem, Oregon, an Administrative Law Judge (ALJ) directed UM1716 parties to hold two scoping workshops to develop a strategy to show the extent of cost shifting, if any, from net metering. The parties were to collaborate and develop a scope and timeline for how to determine the extent of the cost shift, if any, from net metering. After these workshops, Staff was asked to submit a status report to the ALJ and recommend how to proceed with the docket.

Workshop #1 - Held November 16, 2015, at the Oregon Public Utility Commission (OPUC or Commission) in Salem, OR, attended by Staff, Portland General Electric (PGE), Pacific Power (PAC), The Alliance for Solar Choice (TASC), Idaho Power, Renewable Northwest (RNW), Citizens' Utility Board of Oregon (CUB), Northwest SEED (NW SEED), Oregon Department of Energy (ODOE), SolarCity, Oregonians for Renewable Energy Progress (OREP), Energy Trust of Oregon (ETO) and Interstate Renewable Energy Council, Inc. (IREC).

To begin the workshop, Staff presented an outline to show how to calculate lost revenues as a starting point. This quickly led to both PGE and Idaho Power noting that they do not have load shape data to support the full development of Staff's proposed model. The parties converged on the approach of using cost of service runs both with and without solar as a way of determining the cost shift, although Staff's orientation was more along the lines of before and after solar. The utilities agree to develop an outline of how they would determine the cost shift, showing inputs and outputs, and would present this to all parties on December 13, 2015, which is two days before the second workshop. Non-utilities parties agreed to supply a list of concerns and/or suggestions to all parties by December 13, 2015.

Outlines submitted to all parties on December 14, 2015

The following parties submitted outlines showing their suggested approaches to determining cost shifting through cost of service studies: TASC, PGE, PAC, and Idaho Power. The outlines were distributed to all parties for review one day prior to workshop #2.

Workshop #2 - Held December 15, 2015, at the OPUC in Salem, OR, attended by Staff, PGE, PAC, TASC, Idaho Power, RNW, CUB, NW SEED, ODOE, SolarCity, OREP, ETO and IREC.

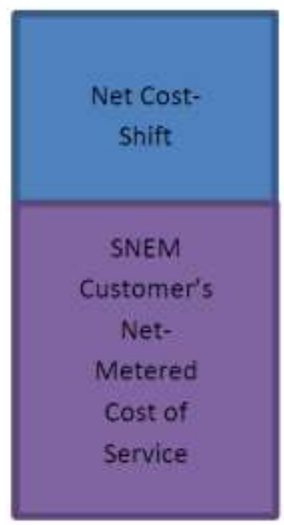
The following parties submitted their methodologies and suggestions/comments for the determination of the extent of cost shifting, if any, from net metering:

1. **PGE**

PGE proposed using the marginal cost of service (MCOS) approach to determine the cost of serving different customer classes. PGE identified two possible approaches for calculating the fixed cost shift for solar net-metering (SNEM) customers and preferred to conduct the MCOS study using the SNEM customers' full-requirements cost of service or in other words using the SNEM customers' gross load shape and then subtracting the net revenue from the SNEM customers' net-metered load shape. This value is the gross cost shift. Net cost shift is determined by subtracting the value of the SNEM customers' solar generation based on the resource value of solar (RVOS) rate from the gross cost shift.

Figure 1: SNEM Customer Gross Cost of Service

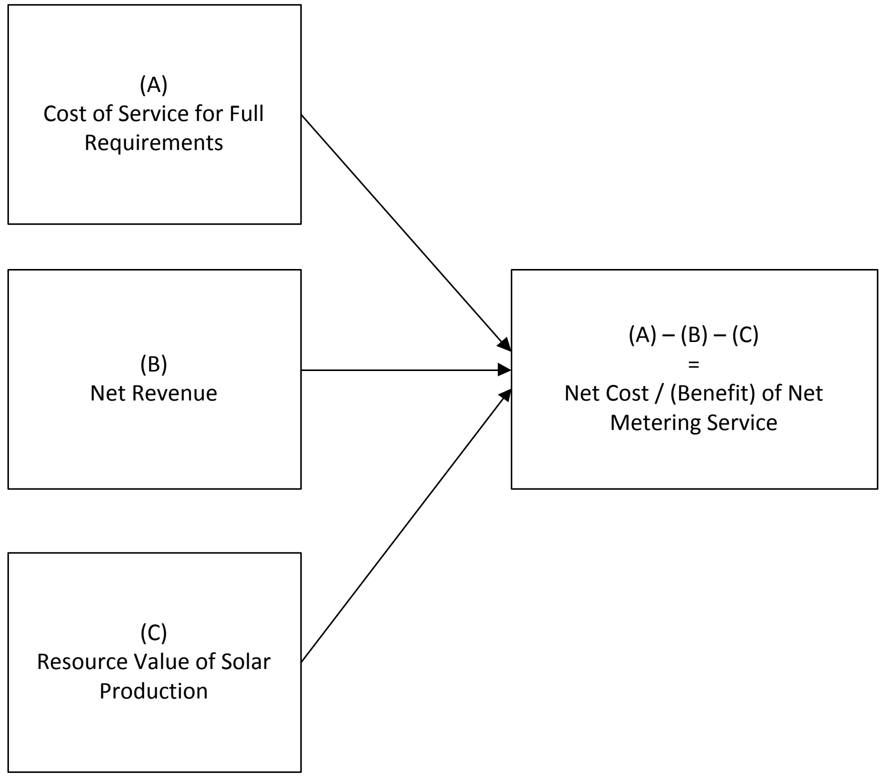
Figure 2: Non-Solar Customer Cost of Service



PGE also identified the incremental cost to serve one additional customer in a given customer class. For example, the cost of serving one additional residential customer would include the incremental cost of an extra customer bill, an extra meter, etc. For the purposes of determining the cost of serving a SNEM customer, the MCOS approach will identify the total incremental cost of serving one additional SNEM customer.

2. **PAC**

PAC also proposed a Marginal Cost of Service (MCOS) approach as seen in the diagram below:



As with PGE, the MCOS analyses would apply to (A), i.e., the full requirements load, including any new load that was induced by the availability of cheap solar power. Since a portion of (A) involves "behind the meter" consumption that does not show up on the utility's bi-directional meters, it is necessary to impute that portion of consumption by estimating the *full* output of the solar installation, not just what was sent to the utility. Estimating the full output requires knowledge of the name-plate capacity of the installation and its capacity factor, regional variances, and degradation.

3. **Idaho Power**
   Idaho Power thought their approach was not too different from the other utilities' approach and clarified that their approach created a cost of service study that separated solar customers into a separate subclass, creating a "hypothetical net metering class" different from a standard service class. Idaho Power has 80 total solar installations in Oregon, 20 of these are net metering and 60 are feed-in tariff projects. Idaho Power indicated that an average feed-in tariff or Volumetric Incentive Rates (VIR) installation is 2-3 kW larger than an average net metering installation in their data.

4. **TASC**
   TASC expressed several concerns, but also stated that they might not be far apart from the utilities' proposed methodologies. TASC stated the following at the workshop:

- Because a portion of fixed costs are volumetrically recovered in Oregon rates, high-usage customers subsidize the fixed costs of low-usage customers.
- Utilities are not entitled to revenue from any specific customer, instead they are just promised to be made whole. Thus if the utility has an excellent year, it could recover its full costs even if it receives less revenue from solar customers.
- Including behind-the-meter usage in solar customers' cost of service computations could result in outcomes similar to a fixed charge per square foot of house size, which they would not support.
- Solar NEM customers should not have to pay the volumetrically recovered portion of fixed costs on their behind-the-meter usage. (All three utilities and Staff's approach disagree with this.)
- Using revenue in the cost shifting methodologies brings in extra noise. For example, someone might sell their house and then the new owner installs solar. It might not be an accurate assumption that without solar the new homeowner would use the same kWh as the previous home owner.

5. OPUC Staff

Staff's proposed model was similar to PAC model except the marginal cost of service would apply to what the solar customers' loads had been *prior to their becoming solar customers.* Accordingly, the models are identical if taking on solar does not cause customers to increase or otherwise modify their load shapes.

Results and Proposed Next Steps

After robust discussion about cost of services, rates, revenues, and how and when the RVOS will be interwoven into the proposed cost shift models, and procedural scheduling, the parties agreed to move forward with the following approach and points of agreement, and proposed schedule:

1. Approach of the parties:
   i. With the exceptions noted above, Staff liked the models proposed by the utilities and would like the utilities to develop and run the models presented at this workshop. The DRAFT results of these models will be presented to the parties at a third workshop in early April 2016.
2. Points of agreement. At the December 15 workshop, the parties agreed to:
   i. Use the utilities' most recent cost of service study data for modeling – Staff proposed this to avoid months of delay to conduct a new cost of service study.
   ii. As needed, use VIR generation profiles to shape missing meter data for SNEM accounts.

iii. PGE and PAC will use the nameplate capacity, capacity factor, region, and degradation as filters for determining load shape profiles.
iv. Use RVOS data and insert it into the models at a later time.
v. Utilities will develop models based on the presented approaches and create DRAFT results to share with parties in late March of 2016.
vi. Staff will ask the ALJ to adopt a procedural schedule for this investigation that aligns with the procedural schedule for the investigation into RVOS.
vii. Staff will, if necessary, issue data requests to obtain data to perform its own proposed revenue approach.

3. Proposed schedule and next steps for this investigation:
    i. **March 31, 2016** - Distribute DRAFT results of models to all parties in preparation for Workshop #3.
    ii. **Thursday, April 7, 2016** - 9 am to noon, at the OPUC in Salem, OR. Workshop #3 – Parties present DRAFT results of modeling using approaches presented at workshop #2.