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July 21, 2016

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UM 1716 – In the Matter of
PUBLIC UTILITY COMMISSION OF OREGON,
Investigation to Determine the Resource Value of Solar.

Enclosed for filing in UM 1716 are the following documents:

UM 1716 Exhibit 300 Dolezel
UM 1716 Exhibit 400 Olson and
UM 1716 Exhibit 401 Olson

/s/ Kay Barnes
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CASE: UM 1716
WITNESS: CINDY DOLEZEL

PUBLIC UTILITY COMMISSION
OF
OREGON

Staff Exhibit 300

Cross Responsive Testimony

July 21, 2016

1. INTRODUCTION AND OVERVIEW OF TESTIMONY

Q. Please state your name, title, and business affiliation.

A. My name is Cindy Dolezel, I am a Senior Renewable Energy Analyst for the Public Utility Commission of Oregon (OPUC or Commission), located at 201 High Street SE, Suite 100, Salem, OR, 97301.

Q. Are you the same Cindy Dolezel that filed testimony previously in this proceeding?

A. Yes, I previously filed testimony in this proceeding, marked as Exhibit Staff/100. My qualifications were previously provided in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to discuss this phase of the resource value of solar (RVOS) investigation, Staff's proposed RVOS methodology provided by E3, the elements of solar generation valued in the methodology, and respond to some of the issues raised by intervenors in testimony filed on June 30, 2016. I also outline a future process to obtain inputs for the proposed model to determine the RVOS.

Q. Please give a brief background as to what has preceeded the submittal of this reply testimony.

A. On June 1, 2016, I submitted direct testimony discussing the procedural history of this investigation into the RVOS in Oregon and recommended the Commission adopt the methodology for determining RVOS be developed and presented by Staff's consultant Energy and Environment Economics (E3). My testimony was accompanied by testimony of E3 partner, Arne Olson, who presented and explained the recommended methodology.

On June 30, 2016, the following intervenors submitted testimony and comments on the proposed RVOS methodology and accompanying model: Portland General Electric Company (PGE), PacifiCorp, Idaho Power Company (Idaho Power), the Citizens' Utility Board of Oregon (CUB), the Oregon Department of Energy (ODOE),The Alliance for Solar Choice (TASC), Renewable Northwest (RNW), Oregon Solar Energy Industries Association (OSEIA), NW Energy Coalition (NWEC), and Northwest Sustainable Energy for Economic Development (NW SEED).[1]

Q. Did Staff explain the model to stakeholders?

A. Yes. Staff held a phone in, informational workshop for all stakeholders on July 11, 2016. At this workshop, E3 explained the model's inner parts and the expected inputs for the model. Over 40 stakeholders participated in this workshop. E3 and staff answered questions pertaining to how the model worked and its underlying algebraic formulas and assumptions.

Q. What is the purpose of this phase of this investigation into RVOS?

A. To determine what elements of solar generation should be included in the RVOS and a methodology to value them. The Commission has stated that it does not intend to pre-judge how the RVOS methodology will be used,[2] and so

[1] Michael O'Brien testified on behalf of RNW, NWEC, NW SEED, and OSEIA. These parties will be referred to as "the Joint Parties."
[2] Order No. 15-296 at 1.

my testimony does not address potential policies for how the RVOS will be used in Oregon.

Q. What elements of solar generation are valued in the Staff-proposed RVOS methodology?

A. The elements valued are:

1. Energy
2. Generation Capacity
3. Line Loses
4. Transmission & Distribution Capacity
5. RPS Compliance
6. Integration
7. Administration
8. Market Price Response
9. Hedging Costs
10. Environmental Compliance

This list of ten elements is based on the Commission's direction in Order No. 15-296 to value only "elements that could directly impact the cost of service to utility customers."[3]

Mr. Olson identified one additional element that could directly impact the cost of service to utility customers, but that is not included in the list of elements to be valued. Mr. Olson testified that resiliency, reliability, and security were potential benefits of solar generation that could have value to ratepayers when the generation is in a microgrid that would allow the solar photovoltaic (PV) system to provide electric service to utility ratepayers that do not have solar PV systems.[4] Mr. Olson testified that in absence of microgrid applications in

[3] Order No. 15-296 at 2.
[4] Staff/200, Olson/25.

Oregon, E3 did not include security, resiliency, and reliability in the calculation of RVOS. [5]

Q. Do intervenors object to Staff's determination of the elements that should be valued?

A. With some exceptions, the intevenors do not oppose the list of elements subject to valuation in the E3 methodology. The exceptions are that TASC, the Joint Parties, and ODOE urge the Commission to include reliability, resiliency, and security provided by solar generation in the list of elements valued by the methodology. The Joint Parties recommend splitting "integration" into two elements, "integration" and "interconnection."[6] Finally, TASC recommends creating a placeholder for valuation of certain societal benefits.[7]

Although there are few objections to the list of elements subject to valuation, all intervenors raise concerns about how one or more of the inputs for the elements will be determined.

Q. Does Staff continue to believe that it is not yet appropriate to include resiliency, security, and reliability in the list of elements valued in the RVOS methodology?

A. Yes. Staff believes that the RVOS should be generally applicable to mass market solar systems installed in Oregon. These systems are generally not installed with the capabilities, hardware, or software necessary to provide

[5] Staff/200, Olson/25-26.
[6] Joint Parties/100, O'Brien/7-8.
[7] TASC/100, Gilfenbaum/4-5.

resiliency, security, or reliability benefits to non-participating utility ratepayers. Therefore, Staff continues to believe it is not yet appropriate to include these elements as a benefit in the RVOS.

Q. Does Staff agree that the element labeled "integration" should be split into two elements – "integration" and "interconnection?"

A. No. Staff agrees with the premise underlying the Joint Parties' proposal, which is that solar generation may be used to provide ancillary services, which would be an integration benefit, and that this benefit is not currently captured in the element of integration/interconnection valued in the RVOS methodology. However, as explained in Mr. Olson's testimony, the model calculates an RVOS that is meant to be generally applicable to a solar system installed by a retail, mass market customer. Currently, the distribution systems of Oregon utilities are not capable of extracting ancillary services such as "frequency response, voltage support or peak shaving" [8] from distributed generation solar PV systems. It is therefore inappropriate at this time to create a valuation method to ascertain such benefits.

Q. What is Staff's position on TASC's proposal to include a placeholder method for valuing "potential societal benefits"?

A. Staff disagrees with TASC's proposal. TASC points to what it believes to be "specific requirements" in the statute governing net metering (ORS 757.300) that may "necessitate modification to the methodology contemplated in this

[8] See Joint Testimony/100, O'Brien/8 (noting these potential ancillary services can be provided by solar).

proceeding if it is to be used in the future to assess NEM successor tariffs."[9] However, the statutory subsection relied on by TASC allows the Commission to consider "environmental and other public policy benefits of net metering systems" when deciding whether to limit an investor-owned utility's statutory obligation to allow net metering once a particular capacity threshold has been reached. The statute does not impact the Commission's decision in Order No. 15-296 to exclude societal benefits from the RVOS methodology.

Q. How does Staff respond to the intervenors' concerns that they are unclear as to how certain inputs will be determined.

A. Staff acknowledges that there is more work to be done to clarify and determine what inputs will be used for the elements valued in the proposed RVOS methodology. However, that work is scheduled for the second phase of a two-phase process. In Order No. 15-296, the Commission "envisioned a two-phase process. The first phase will examine elements and methodologies. The second phase will examine values for each utility using those adopted methodologies."[10]

Staff believes the second phase of the process will culminate with determinations on what inputs are appropriate for the RVOS methodology.

Q. What is Staff's recommendation for the second phase of this investigation into RVOS?

[9] TASC/100, Gilfenbaum/4-5.
[10] Order No. 15-296 at 2.

A. Staff recommends the second phase begin with collaborative workshops to discuss and clarify inputs and timelines for each utility. To the extent it is necessary, the Commission could allow a contested case process to establish the appropriate inputs to the methodology.

Q. Mr. Brian Dickman of PacifiCorp and Mr. Michael Youngblood of Idaho Power state that their companies currently incur no monetary cost of carbon for environmental compliance, and that this element therefore should either be excluded or set to zero.[11] Do you agree with this point?

A. This phase of the investigation is not intended to fully resolve all issues related to the appropriate inputs into the methodology. The determination of the value included in the RVOS model for cost of compliance with environmental regulation, and for other inputs, will be addressed in a subsequent phase of this investigation.

Q. The RVOS model is designed to calculate RVOS based on hourly data. What does Staff propose if the utilities do not have hourly data for some of the elements?

A. Staff anticipates that utilities will not have hourly data for all the elements subject to valuation under the proposed RVOS. Mr. Olson has testified that proxy values can be used when hourly data is not available. To the extent parties are concerned about the integrity of proxy values, Staff notes that there will be additional proceedings in this investigation to address and refine them.

[11] PAC/100, Dickman/15; Idaho Power/100, Youngblood/14.

Q. Do any intervenors object to the calculations proposed by E3 for calculating RVOS?

A. No party objected to the algebraic formula E3 proposed for determining RVOS. However, as already discussed, all intervenors raise concerns about how the inputs into the algebraic formula are determined. Staff anticipates addressing these concerns in the second phase of this proceeding.

Mr. Olson testifies on potential resolutions to some of the input issues raised by intervenors in his reply testimony.

Q. Does this conclude your testimony?

A. Yes, this concludes my testimony.

CASE: UM 1716
WITNESS: ARNE OLSON

PUBLIC UTILITY COMMISSION
OF
OREGON

Testimony of Arne Olson

On behalf of

Oregon Public Utility Commission

Cross Responsive Testimony

July 21, 2016

Contents

1. INTRODUCTION AND OVERVIEW OF CROSS RESPONSE TESTIMONY

Q. Please state your name, title, and business affiliation.

A. My name is Arne Olson. I am a Partner at Energy and Environmental Economics, Inc. (E3), located at 101 Montgomery Street, Suite 1600, San Francisco, California, 94104.

Q. Are you the same Arne Olson that filed testimony previously in this proceeding?

A. Yes, I previously filed testimony in this proceeding, marked as Exhibit Staff/200. My background, qualifications, and experience can be found in my direct testimony.

Q. What is the purpose of your cross response testimony?

A. This testimony addresses many of the questions, comments, assertions, and concerns raised by intervenors through this process.

Q. Please give a brief background as to what has preceeded the submittal of this cross response testimony.

A. On June 1, 2016, I submitted direct testimony outlining, explaining, and endorsing a calculation methodology for the resource value of solar (RVOS) in Oregon. Accompanying this testimony was a Microsoft Excel based model that demonstrated these calculations using illustrative data.

On July 30, 2016, various intervenors submitted testimony and comments on the proposed RVOS methodology and accompanying model. Intervenors used this opportunity to raise questions, comments, and concerns about various calculation methodologies, data inputs, and the inclusion or exclusion of specific benefit or cost elements from the RVOS.

Q. Were there any broad themes raised by intervenors?

A. Yes, there were several broad themes raised by intervenors along with many comments that did not fit within a general broad theme. I have structured my cross response testimony to walk through each broad theme and then address any lingering issues or comments that do not fit neatly into these categories.

Q. What are the broad themes you will address?

A. I first make a general clarification about the solar installations that are assumed to be valued with the methodology. This, in turn, shapes the applicability of the methodology. I then address the broad themes of:

- Data inputs
- Inclusion or exclusion of specific cost or benefit elements
- RVOS calculation methodology

At the end, I will address several comments raised by intervenors that do not fit neatly into a broad theme.

2. CLARIFICATION: WHAT IS THE METHODOLOGY VALUING?

Q. What type of solar installation is the RVOS methodology valuing?

A. In asset valuation, it is important to be specific about the characteristics of the asset that is being valued, e.g., where is it located, what type of asset is it, how old is it, what are its specific operating characteristics, how many years is the valuation covering, etc. Because the specific application of the RVOS methodology is not yet determined, I have made some assumptions about the specific solar installations that are being valued. Namely, I have developed the RVOS methodology to produce a *25 year marginal, levelized value for a generic, small-scale solar resource installed in 2016*. This choice of a specific solar asset for valuation has a number of implications and some limitations that were pointed out by various intervenors.

Q. What are the implications of this choice of a solar installation for generation capacity deferral value?

A. The marginal capacity value of solar varies depending on penetration, if using the Effective Load Carrying Capability (ELCC) method. In calculating capacity value, this means that the utilities should use the marginal ELCC for 2016, based on solar penetration levels during that year.

In addition, the generation capacity deferral value depends on the utility's resource-balance year (RBY). In calculating the financial savings from capacity deferral, utilities should use their actual, expected RBY as of 2016.

If the Commission elects to use the RVOS methodology to value a different set of solar installations, different choices about data inputs would be appropriate. For example, if the RVOS methodology were used to value all solar resources installed prior to 2020, an average ELCC value would be more appropriate. Also, for the selection of a resource-balance year, it would be appropriate to consider the average number of years of expected capacity surplus over time, rather than the specific circumstances of 2016.

Q. In years before the utility reaches resource-balance, what should be used as the value of capacity?

A. In years before the utility reaches resource-balance, the short run marginal cost of fixed operations and maintenance (fixed O&M) should be used. This is currently how the RVOS spreadsheet methodology values this component. In my direct testimony, I incorrectly stated that this value should be equal to zero in years before resource-balance,[1] while it should have said that this value should be equal to fixed O&M.

Q. What are the implications of this choice of a solar installation for potential additional values of solar?

A. The model calculates an RVOS that is meant to be generally applicable to a solar system installed by a retail, mass market customer. In turn, specialized solar capabilities that can be provided by advanced and uncommon infrastructure are not included in this generic RVOS. There are two examples raised in intervenor testimony where such uncommon capabilities are assumed or implicit.

[1] Staff 200, Olson/30.

1. Ancillary services. I do not account for the ability of solar to provide ancillary services such as regulation or load following by interacting with the electric system operator. If a specific solar installation were capable and willing to provide these services, it would be appropriate for these additional services to be valued under a separate methodology. Further, any system offering these services would necessarily have a different production profile than a system that did not offer these services so other elements of the RVOS such as energy value would be affected as well.
2. Microgrid or islanding capability. I do not account for the ability of solar to provide microgrid services such as the ability to disconnect from the broader electrical system and continue to provide energy to surrounding homes and businesses. The types of controls and hardware necessary to provide this functionality are not commonly installed with the mass-market solar package and often require significant additional investment and coordination from adjacent homes and businesses. Because the RVOS is intended to be generally applicable to a mass market solar generator, I do not include these benefits. If a specific solar installation were capable and willing to provide these services, it would be appropriate for these additional services to be valued under a separate methodology.

While the specific application of the RVOS methodology is not yet determined, I will consider the case where the RVOS is used to determine compensation for customer-owned solar installations. In this instance, it would be inappropriate to include these additional values in the general RVOS methodology. Instead, I recommend that the value of these additional services be calculated separately and established in a utility tariff and rate schedule, applicable only to those installations that provide them according to the terms and conditions of the tariff.

3. DATA INPUTS

Q. Please describe more specifically issues raised by intervenors about input data into the model.

A. Several parties raised concerns about the protocols to follow when data was not available in the structure required for input into the model. In several instances, utilities asserted that data was not available at all for some of the required inputs. For example:

- PGE states that hourly usage data by feeder is "not currently available";[2]
- PacifiCorp states that "several of the proposed elements are not" … "available on an hourly basis";[3] and
- Idaho Power states that "the model assumes the input of certain hourly data that may not be currently available to Idaho Power, nor easily collected and provided".[4]

Q. Is it surprising that the utilities do not presently have hourly data for each of the proposed elements at a variety of locations on their systems?

A. No, it is not surprising that hourly, location-specific data is not available for every element. Many utilities do not routinely develop hourly, location-specific values for transmission and distribution deferral value. In California, the utilities have undertaken specific new analysis through the Distribution Resource Plans (DRPs) in an attempt to more accurately characterize these potential

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[2] PGE/100, Brown-Murtaugh/11.
[3] PAC/100, Dickman/16.
[4] Idaho Power/100, Youngblood/9.

benefits/costs; however this is a relatively recent effort and it has not yet been duplicated universally. I have designed the RVOS methodology to be as robust as possible if all of the desired data were available. My hope is that this will allow the methodology to continue to provide a solid foundation for valuation of customer-owned solar installations in the future when more data is available.

Q. If the data is not available at the desired level of granularity, would it be appropriate for the utilities to simply assume the values are zero?

A. No, it would not be appropriate for the utilities to assume the values are zero, unless they have firm evidence that no solar installations can provide this value. Rather, they should be assigned a proxy value or a value based on a broader geography. For example:

- If a utility does not currently have location-specific distribution deferral estimates, it should use a system-wide average based on the utility marginal cost of service study (MCOSS).
- If a utility does not have an estimate of the costs of potentially deferrable distribution system investments, it should use an average of all growth-related distribution system investments.
- A utility should use a zero value for distribution system deferral value only if it presents evidence based on a detailed study that there are no distribution system investments that could be deferred with sufficient customer-owned solar.

As a general rule, the utilities should calculate the RVOS values so that the total compensation to customer solar owners would be equal to the total value provided by those systems, at each level of granularity. This means that if a portion of the solar installations are providing the value, the RVOS for all installations should reflect an average of those systems providing the value and those that do not.

4. RVOS ELEMENTS

Q. Ms. Diane Broad from the Oregon Department of Energy and Mr. Michael O'Brien,representing several parties, state that the "Security, Reliability, and Resiliency" element should be included.[5] What is your response?

A. As I discuss above in the "Clarification" section, the RVOS methodology is intended to apply broadly to all customer-owned solar installed in 2016. Since very few (if any) systems are providing this value today, it would be inappropriate for the RVOS methodology to treat them as if they were. I recommend instead that these very specific types of benefits be valued separately for the few solar installations that may provide them.

Q. Mr. O'Brien states that "the colocation of electricity storage and modern inverters with solar offers the possibility of increasing the solar resource value in various categories."[6] Do you agree with this statement?

A. Yes, I agree that solar coupled with storage could provide significant additional value beyond what is captured in the RVOS methodology as proposed. In addition to the values listed by Mr. O'Brien, solar coupled with storage provides a much more reliable resource for T&D deferral as well as potential additional T&D benefits such as voltage control.

[5] ODOE/100, Broad/2; RNW, OSEIA, NWEC, NW SEED/100, O'Brien/4.
[6] RNW, OSEIA, NWEC, NW SEED/100, O'Brien/5.

Q. Ms. Broad and Mr. O'Brien discuss the potential value of solar coupled with storage.[7] Should storage be included in the RVOS methodology?

A. Solar installations with storage have fundamentally different characteristics than systems without storage. As I discuss above in the "Clarification" section, the RVOS methodology is intended to apply broadly to all customer-owned solar installed in 2016. It is not designed to address storage, with or without solar. While many of the same techniques can be applied to storage facilities, different choices must be made with respect to data inputs in a number of areas (e.g., generation capacity value, T&D capacity value, ancillary services). Since very few solar installations are coupled with storage today, it is appropriate for the RVOS methodology to exclude the additional value that could be provided by storage. However, the Commission may wish to explore this potential value in a future proceeding.

Q. Mr. O'Brien states that "Solar could provide power to customers safely during a power outage, whether that is a private residence, hospital, school emergency shelter or other public building." Do you agree that this value should be included in the RVOS?

A. No, I do not. The value of power provided by solar during an outage accrues to the solar owner, not to the utility ratepayer as a whole. Per Commission direction, the RVOS methodology calculates values that accrue to all utility ratepayers.

[7] ODOE/100, Broad/2; RNW, OSEIA, NWEC, NW SEED/100, O'Brien/8.

Q. Stefan Brown and Darren Murtaugh of PGE state that the RPS value "would apply only if the RPS compliance is truly avoided and PGE gets the RECs from the solar production."[8] Does the utility have to receive the REC in order for the RPS value to be positive?

A. No, customer-owned solar provides an RPS compliance value if it reduces the utility's retail sales, e.g., through net energy metering. The reduction in RPS compliance is the applicable RPS percentage in any given year (e.g., 25% in 2025) multiplied by the solar production. If the utility receives the REC, then an additional value would be provided by the solar equal to the full RPS value. This value would be in addition to the value provided by the reduction in retail sales.

Q. Mr. Michael Youngblood of Idaho Power states that "The State of Idaho does not have an RPS requirement and, while Idaho Power is subject to the Oregon RPS, its obligations under that statute are not applicable until 2025. Therefore, Idaho Power would value an RPS component to distributed generation at zero."[9] Is this an appropriate interpretation of the RPS value element?

A. No, it is not. The RVOS methodology estimates a 25-year levelized value of a resource installed in 2016. Starting in 2025, a customer-owned resource would reduce retail sales on Idaho Power's system, and therefore reduce its RPS compliance obligation. Therefore, Idaho Power should include an RPS compliance value beginning in 2025.

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[8] PGE/100, Brown-Murtaugh/5.
[9] Idaho Power/100, Youngblood/12.

Q. Mr. Brian Dickman of PacifiCorp states that "to the extent the RVOS methodology takes into account deferred transmission and distribution investments, a symmetrical component of the calculation should be included: costs associated with accelerated transmission and distribution investments."[10] Is this component included in the RVOS methodology?

A. Yes, the Administration element includes "the cost of interconnecting solar generators and any ongoing administrative costs such as billing." Any incremental distribution system investments caused by customer-owned solar should be included in the Administration costs.

[10] PAC/100, Dickman/14.

5. CALCULATION METHODOLOGY

Q. Mr. Eliah Gilfenbaum of The Alliance for Solar Choice (TASC) states that "By looking at an integrated portfolio which includes both demand and supply side resources, a utility may determine that new resources are not needed until further in the future. Including only supply side resources (or only resources that are owned or contracted by the utility) will lead to a smaller portfolio and a larger net short position in earlier years."[11] Do you agree with this assertion?

A. Yes, I agree that the inclusion or exclusion of demand side resources, specifically behind-the-meter solar, in the load forecast can have a significant impact on determining the first year of resource deficiency, otherwise known as the resource balance year. If solar resources are included in the load forecast, this will push the resource balance year further into the future which will in turn decrease the generation capacity element of the RVOS. I discuss the circularity problem that this creates in my response to the TASC Data Request.[12]

To avoid this circularity, I agree with Mr. Gilfenbaum that any solar resources whose compensation is tied to the RVOS should be excluded from the utility's forecast of the resource-balance year. Any other resources whose compensation is not tied to the RVOS, whether demand-side or supply-side, should be included in the resource-balance year calculation based on the utility's best available forecast.

[11] TASC/100, Gilfenbaum/7.
[12] See Exhibit Staff/401.

Q. Messrs. Brown and Murtaugh of PGE state that PGE does not currently calculate a hedge value.[13] Does this mean that the hedge value should be zero for PGE?

A. If the cost of hedging is embedded in PGE's calculation of the energy value, then it may be appropriate to zero out the separate hedge value component. The important point is that the RVOS reflect PGE's full cost of energy purchases, including any premium paid for forward purchases.

Q. Mr. Bob Jenks and Ms. Nadine Hanhan with the Citizens' Utility Board of Oregon state that the future values for energy should reflect the potential for non-normalized conditions such as a low hydro year that would result in higher than average energy prices.[14] Do you agree with this position?

A. Yes, I agree that the values input for future energy prices should reflect a distribution of potential hydro conditions, including both low and high hydro years. To the extent that market data is used, I would expect these market-based expectations to be embedded in the prices. To the extent that utilities are developing internal forecasts that do not rely on market data, the modeling should incorporate the effect of a distribution of hydro years on energy values, rather than just an average hydro year.

[13] PGE/100, Brown-Murtaugh/5.
[14] CUB/100, Jenks-Hanhan/4.

6. GENERAL RESPONSES

Q. Mr. O'Brien raises concerns that the utility scale solar proxy option could be used to attempt to make the case that utility-scale solar is somehow 'better' than distributed solar.[15] Is this a valid concern?

A. No, I believe this concern is misplaced. The utility scale solar proxy specifically incorporates additional values—T&D deferral value and loss reduction—that are assumed to be provided by distributed solar and not utility scale solar. Thus, under the RVOS methodology, the value of distributed solar would always be greater than or equal to the value of utility scale solar.

Q. Messrs. Brown and Murtaugh of PGE state that the RVOS methodology could be applied to utility scale solar on a case-by-case basis.[16] Do you agree that the RVOS could be applied to utility-scale solar?

A. Yes, I agree that the methodology is suitable for application to utility-scale solar. In my direct testimony, I recommended that the RVOS not be used to replace solar valuation methodologies already used in the utility Integrated Resource Planning and procurement processes, and in developing rate schedules under the Public Utility Regulatory Policies Act.

Q. Mr. Dickman of PacifiCorp asserts that "locking in fixed prices for private solar sold under net metering based on long-term forecasts risks compensating one class of customers at the expense of others."[17] Do you agree with this assertion?

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[15] RNW, OSEIA, NWEC, NW SEED/100, O'Brien/11.
[16] PGE/100, Brown-Murtaugh/12.
[17] PAC/100, Dickman/8.

A. No, I do not. Long-term, fixed-price contracts result in a known future price, which provides a value to consumers. For example, many homeowners prefer the certainty of a fixed interest rate over the course of a 30-year mortgage to the risk of interest rates that vary depending on economic conditions. In addition, consumers annually spend billions of dollars insuring their health, property, and lives. In making these transactions, they willingly pay much more than they expect to receive in benefits. In other words, they prefer the certainty of a somewhat higher initial cost to the risk of a much higher potential future cost.

While there is always the risk that changing market conditions will result make a prior hedging decision look poor, I do not see how this applies differently to customer-owned solar installations than to other decisions that utilities routinely make. I therefore recommend that the length of valuation period in the RVOS methodology, and any compensation that may be tied to it, be commensurate with that of other utility decisions such as power purchase agreements with utility-scale renewable resources and depreciation schedules for utility-owned, rate-based assets, in addition to the PURPA contract lengths cited by Mr. Dickman.

Q. Mr. Youngblood of Idaho Power states that the company "has concerns regarding the model's applicability to net metering service."[18] Specifically, he states that "This concern arises from the use of multiple modeling components that may be appropriate from a long-

[18] Idaho Power/100, Youngblood/15.

term levelized cost perspective, but not from an embedded ratemaking perspective." Do you agree with this position?

A. I agree in part. As I discuss above in the "Clarification" section, the RVOS methodology is intended to apply to *marginal* customer-owned solar installed in 2016. As such, not all elements are appropriate for estimating the *average* value of *all* solar installations, as would be required for estimating the cost shift associated with existing systems. For example, the marginal ELCC value for new systems installed in 2016 is likely to be lower than an average ELCC value calculated for all solar installations.

However, the same elements would be included in an RVOS methodology designed for calculating cost shifts from existing solar installations. The difference would lie in the development of specific data inputs.

Q. Mr. O'Brien raises a concern about your statement that "a reduction in utility revenue is a cost to non-participating customers whose rates must increase." He asks the Commission to "encourage Staff to refrain from judgments over the magnitude and direction of cost shifting."[19] Do you agree that Staff's statement is misplaced in this investigation?

A. No, I do not. This statement is important to help distinguish between a private benefit, enjoyed by the solar owner, and a ratepayer benefit that accrues to all. The reduction in a solar owner's bill is a benefit to the solar owner. This same

[19] RNW, OSEIA, NWEC, NW SEED/100, O'Brien/11.

benefit is, viewed in isolation, a cost to all other ratepayers. This is simply a restatement of the principals contained in the Ratepayer Impact Test, widely used in evaluation of demand-side programs around the world, in which lost revenue is counted as a cost of a demand-side program.[20]

Q. Mr. O'Brien states that "Oregon utilities do not currently collect extra revenues from customers who reduce their load due to energy efficiency investments."[21] Do you agree with this statement?

A. No, I do not. Portland General Electric has "revenue decoupling", in which utility rates are automatically adjusted to ensure collection of a targeted amount of revenue, insulating PGE's financial performance from the effects of customer adoption of energy efficiency.[22] Utilities frequently have a form of lost revenue recovery, which adjusts rates based on estimates of revenue lost due to energy efficiency. Even in the absence of a specific revenue adjustment mechanism, the reduced energy sales due to energy efficiency activities are reflected in the billing determinents in the next utility rate case, resulting in higher rates for both participants and non-participants in energy efficiency programs.

Q. Mr. O'Brien states that "the extent of cost-shifting, if any and in either direction, was to be determined by the balance between the costs and

[20] See, for example, the California Standard Practice Manual for Economic Analysis Of Demand-Side Programs And Projects, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf
[21] RNW, OSEIA, NWEC, NW SEED/100, O'Brien/10.
[22] http://www.puc.state.or.us/Pages/news/2013/2013008.aspx

benefits."[23] Do you agree that estimates of cost shifts must consider both the costs and the benefits of customer-owned solar?

A. Yes, I do. Viewed in isolation, the reduction in a solar owner's bill is a cost to all other ratepayers. However, at least a portion of this cost, and perhaps more, is offset by the value that the solar provides, which can be calculated using a methodology like the RVOS. The extent and direction of the cost shift caused by any particular group of solar installations depends on whether the benefits exceed the costs, or vice-versa.

Q. Does this conclude your testimony?

A. Yes, it does.

[23] RNW, OSEIA, NWEC, NW SEED/100, O'Brien/9.

CASE: UM 1716
WITNESS: ARNE OLSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Exhibits in Support
Of Cross Responsive Testimony

July 21, 2016

Oregon
Kate Brown, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301
Mailing Address: PO Box 1088
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1-800-522-2404
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June 29, 2016

JOSEPH F. WIEDMAN
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RE: Docket No. UM 1716 – TASC's First Set of Data Request
Staff Response to TASC's Data Request (DR 1 to 24)
Filed June 15, 2016 and due June 29, 2016

Enclosed are OPUC Staff Responses to TASC's DR 1 to DR 24.

Attachments to TASC's Question 2:
UM 1716 Idaho Attach to Staff DR 2_Attachment 2.xlsx
UM 1716 Idaho Responses to Staff DR 1-2.doc
UM 1716 PAC Attach OPUC 2-1.xlsx
UM 1716 PAC Responses to OPUC (1-2) 4-21-16.pdf
UM 1716 PAC Responses to OPUC (2)_1st Supplemental.5-3-16.pdf
UM 1716 PGE Attach OPUC_DR_002 Attachment_Utility Data Request 4-21-16
UM 1716 PGE Responses to OPUC_DR_002.pdf

Attachments to TASC's Question 13:
UM 1716 Staff Response to TASC DR 13_Attachment A UM 551 (1).pdf

Confidential CDs has been mailed to parties who have signed Protective Order No. 16-145.

/s/ Kay Barnes
PUC Utility Program,
(503) 378-5763

copy: stephanie.andrus@state.or.us. DOJ, (C)
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Date: June 29, 2016

TO: Joseph F. Wiedman
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FROM: Arne Olson, E3 and Cindy Dolezel, Oregon PUC

OREGON PUBLIC UTILITY COMMISSION (OPUC)
Docket No. UM 1716
OPUC Responses to TASC First Set of Data Request (01-24)

TASC Data Request 01:

Please provide all workpapers and any other documents used by witnesses Dolezel or Olson, or any supporting Commission or E3 staff, in the creation of testimonies for witness Dolezel or Olson or the creation of the methodology for determining the resource value of solar for Oregon.

Staff Response to TASC Request 01:

The only workpaper is the Microsoft Excel based model that was published along with the testimony. This model calculates the resource value of solar using the methodology described in the testimony. We also relied on filings previously submitted in this docket.

TASC Data Request 02:

Please provide copies of all data requests propounded by Staff and associated responses that were propounded during the development of testimony for witness Olson and witness Dolezel.

Staff Response to TASC Request 02:

Attached are the non-confidential responses from Idaho Power, Pacific Power and Portland General Electric. Confidential responses will be mailed to parties who have signed Protective order No: 16-145.

UM 1716 Idaho Attach to Staff DR 2_Attachment 2.xlsx
UM 1716 Idaho Responses to Staff DR 1-2.doc

UM 1716 PAC Attach OPUC 2-1.xlsx
UM 1716 PAC Responses to OPUC (1-2) 4-21-16.pdf
UM 1716 PAC Responses to OPUC (2)_1st Supplemental.5-3-16.pdf

UM 1716 PGE Attach OPUC_DR_002 Attachment_Utility Data Request 4-21-16
UM 1716 PGE Responses to OPUC_DR_002.pdf

TASC Data Request 03:

Both Staff witness Cindy Dolezel and E3 witness Arne Olson list the elements the methodology for Resource Value of Solar (RVOS) will include. These are summarized in the table below. Please state whether the table correctly summarizes the referenced testimony.

Element	Staff	E3
Energy	Y	Y
E3 includes in this:		
- **Operational impacts**		Y
- **Natural gas pipeline impacts**		Y
Generation Capacity	Y	Y
E3 includes in this:		
- **Natural gas pipeline impacts**		Y
- **Capital risk**		Y
- **Production impacts**		Y
- **Resource need**		Y
Line Losses	Y	Y
Transmission & Distribution Capacity	Y	Y
RPS Compliance	Y	Y
Integration	Y	Y
- **Reliability**		Y
- **Integration impacts**		Y
- **Ancillary services**		Y
Administration	Y	Y
E3 includes in this:		
- **Interconnection**		Y
Market Price Response	Y	Y
Hedging Costs	Y	Y
Environmental Compliance	Y	Y

Staff Response to TASC Request 03:

The table correctly summarizes our direct testimony.

TASC Data Request 04:

With reference to "Operational Impacts:"

i. On page 14 of his testimony (Exhibit 200), witness Olson lists "Operational Impacts" as one of twenty-six elements of potential solar value. Please describe what "Operational Impacts" includes from witness Olson's perspective and indicate where in the Xcel model the inputs can be found.

ii. Please state, for witness Dolezel, whether Staff agrees with the inclusion of "Operational Impacts" and, if true, what Staff defines this category to include.

iii. Please explain in detail – with reference to any relevant documents – how "Operational Impacts" were evaluated and valued in the methodology. If "Operational Impacts" were not evaluated or valued in the methodology, please provide an explanation for that decision.

iv. To ease review, please provide a reference to any workpapers or other documents from Question 1 used by witness Olson or witness Dolezel regarding the evaluation and consideration of "Operational Impacts."

Staff Response to TASC Request 04:

i. "Operational impacts" include any operational costs of producing energy, including but not limited to variable operations and maintenance costs. These costs are embedded in the marginal cost of energy, which in this case is assumed to be based on market prices at the Mid-Columbia trading hub. Energy costs can be found in the General Inputs tab, column E, rows 83-118.

ii. Arne Olson, from E3, is testifying on behalf of Staff and his position is Staff's position.

iii. See response to TASC Request 04i.

iv. All data used in the model is illustrative and not based on workpapers or other documents.

<u>TASC Data Request 05</u>:

With reference to "Natural Gas Pipeline Impacts:"

i. On page 14 of his testimony (Exhibit 200), witness Olson lists "Natural Gas Pipeline Impacts" as one of twenty-six elements of potential solar value. Please describe what "Natural Gas Pipeline Impacts" includes from witness Olson's perspective and indicate where in the model the inputs can be found
ii. Please state, for witness Dolezel, whether Staff agrees with the inclusion of "Natural Gas Pipeline Impacts" and, if true, what Staff defines this category to include.
iii. Please explain in detail – with reference to any relevant documents – how "Natural Gas Pipeline Impacts" were evaluated and valued in the methodology. If "Natural Gas Pipeline Impacts" were not evaluated or valued in the methodology, please provide an explanation for that decision.
iv. To ease review, please provide a reference to any workpapers or other documents from Question 1 used by witness Olson or witness Dolezel regarding the evaluation and consideration of "Natural Gas Pipeline Impacts."

<u>Staff Response to TASC Request 05</u>:

i. "Natural gas pipeline impacts" include any avoidable costs of firm natural gas transportation service. This could include, if necessary, expansion of the natural gas pipeline or storage infrastructure to accommodate the new firm service request. These costs are embedded in the burnertip price of natural gas through transportation and distribution components which are designed to recover the costs of natural gas pipeline infrastructure. The burnertip price of natural gas is, in turn, embedded in the price of energy so there is no specific input for natural gas pipeline impacts. Energy costs can be found in the General Inputs tab, column E, rows 83-118.

   The cost of acquiring firm natural gas transportation service, if any, is also incorporated into the generation capacity cost. This input can be found in the General Inputs tab, cell E32.

ii. Please see the response to TASC Request 04ii.

iii. See response to TASC Request 05i.

iv. All data used in the model is illustrative and not based on workpapers or other documents.

<u>TASC Data Request 06</u>:

With reference to "Production Impacts:"

i. On page 14 of his testimony (Exhibit 200), witness Olson lists "Production Impacts" as one of twenty-six elements of potential solar value. Please describe what "Production Impacts" includes from witness Olson's perspective and indicate where in the model the inputs can be found.
ii. Please state, for witness Dolezel, whether Staff agrees with the inclusion of "Production Impacts" and, if true, what Staff defines this category to include.
iii. Please explain in detail – with reference to any relevant documents – how "Production Impacts" were evaluated and valued in the methodology. If "Production Impacts" were not evaluated or valued in the methodology, please provide an explanation for that decision.
iv. To ease review, please provide a reference to any workpapers or other documents from Question 1 used by witness Olson or witness Dolezel regarding the evaluation and consideration of "Production Impacts."

<u>Staff Response to TASC Request 06</u>:

i. "Production impacts" is an element of value proposed by stakeholders that was defined as the impact on the IRP process and long-term costs. This element has been incorporated into generation capacity. This input can be found in the General Inputs tab, cell E32.

ii. Please see the response to TASC Request 04ii.

iii. See response to TASC Request 06i

iv. See response to TASC Request 06i.

v. All data used in the model is illustrative and not based on workpapers or other documents.

TASC Data Request 07:

With reference to "Capital risk:"

i. On page 14 of his testimony (Exhibit 200), witness Olson lists "Capital Risk" as one of twenty-six elements of potential solar value. Please describe what "Capital Risk" includes from witness Olson's perspective and indicate where in the model the inputs can be found.
ii. Please state, for witness Dolezel, whether Staff agrees with the inclusion of "Capital Risk" and, if true, what Staff defines this category to include.
iii. Please explain in detail – with reference to any relevant documents – how "Capital Risk" was evaluated and valued in the methodology. If "Capital Risk" was not evaluated or valued in the methodology, please provide an explanation for that decision.
iv. To ease review, please provide a reference to any workpapers or other documents from Question 1 used by witness Olson or witness Dolezel regarding the evaluation and consideration of "Capital Risk."

Staff Response to TASC Request 07:

i. "Capital risk" was an element of value proposed by some stakeholders that was defined as the risk associated with large, long-lived up-front investments. This element is captured through generation capacity and the financing levelization that captures these risks. This input can be found in the General Inputs tab, cell E32.

ii. Please see the response to TASC Request 04ii.

iii. See response to TASC Request 07i.

iv. All data used in the model is illustrative and not based on workpapers or other documents.

TASC Data Request 08:

With reference to "Security, Reliability, and Resiliency:"

i. On page 14 of his testimony (Exhibit 200), witness Olson lists "Security, Reliability, and Resiliency" as one of twenty-six elements of potential solar value. Please describe what "Security, Reliability, and Resiliency" includes from witness Olson's perspective and indicate where in the model the inputs can be found.
ii. Please state, for witness Dolezel, whether Staff agrees with the inclusion of "Security, Reliability, and Resiliency" and, if true, what Staff defines this category to include.
iii. Please explain in detail – with reference to any relevant documents – how "Security, Reliability, and Resiliency" were evaluated and valued in the methodology. If "Security, Reliability, and Resiliency" were not evaluated or valued in the methodology, please provide an explanation for that decision.
iv. To ease review, please provide a reference to any workpapers or other documents from Question 1 used by witness Olson or witness Dolezel regarding evaluation and consideration of "Security, Reliability, and Resiliency."

Staff Response to TASC Request 08:

i. Security, Reliability, and Resiliency" represent "the potential capability of solar, when deployed in combination with other technologies, to provide backup energy or microgrid islanding capabilities during a loss of service from the utility." (Olson direct testimony, page 23, row 11). This is a potential value that solar could provide in certain applications. It is therefore included in the list of potential solar values for the methodology. This value is not quantified at this time because such applications are not widespread.

ii. Please see the response to TASC Request 04ii.

iii. See response to TASC Request 08i.

iv. All data used in the model is illustrative and not based on workpapers or other documents.

TASC Data Request 09:

With reference to "Interconnection:"

i. On page 14 of his testimony (Exhibit 200), witness Olson lists "Interconnection" as one of twenty-six elements of potential solar value. Please describe what this includes from witness Olson's perspective and indicate where in the model "Interconnection" can be found.
ii. Please state, for witness Dolezel, whether Staff agrees with the inclusion of "Interconnection" and, if true, what Staff defines this category to include.
iii. Please explain in detail – with reference to any relevant documents – how "Interconnection" was evaluated and valued in the methodology. If "Interconnection" was not evaluated or valued in the methodology, please provide an explanation for that decision.
iv. To ease review, please provide a reference to any workpapers or other documents from Question 1 used by witness Olson or witness Dolezel regarding the evaluation and consideration of "Interconnection."

Staff Response to TASC Request 09:

i. "Interconnection" is the cost of interconnecting a solar generator to the electric utility system. Costs associated with this element include but are not limited to the physical cost of a new meter, the labor costs of installing the new meter, the labor costs of approving a safe electrical connection between the solar generator and the electric system, and any infrastructure upgrades to the distribution system that are necessary to safely incorporate the solar generator. These costs are embedded in the "Administration" element and can be found in the General Inputs tab, cell E71.

ii. Please see the response to TASC Request 04ii.

iii. See response to TASC Request 09i.

iv. All data used in the model is illustrative and not based on workpapers or other documents.

<u>TASC Data Request 10</u>:

With reference to Exhibit 201, General Inputs Sheet, "Administration" is quantified as a $/MWhr input.

i. Please explain why this element would scale with the amount of solar production, rather than the number of accounts.
ii. Does witness Olson believe that this element will experience economies of scale and, if so, at what level of MWhrs or accounts?
iii. Does witness Olson intend this element to capture any such costs associated with the account of rooftop solar customers or only the costs of such accounts that are incremental to the costs a utility incurs for any other specific type of customer account (and does not separately charge for)? If not, why not?

<u>Staff Response to TASC Request 10</u>:

i. Some components of the Administration element will scale with kWh solar production (or kW size of installed system) such as distribution system infrastructure upgrade costs which are included in interconnection portion of this element. Some components of the Administration element will scale with number of accounts such as meter costs. Some components of the Administration element will not scale with either solar production or number of accounts such as billing software costs.

   This element is incorporated as a $/MWh input because the resource value of solar is calculated on a $/MWh basis. The value should be thought of as an allocation of total Administration costs to all expected solar energy production. The utilities will need to calculate this $/MWh cost on an on-going basis. If the majority of these costs are fixed and solar generation grows over time, this $/MWh Administration cost will consequently decrease over time.

ii. It is expected that the $/MWh Administration cost would be lower if installations were higher.

iii. This component is only intended to capture costs that are both incremental to what the utility incurs for any other specific type of customer account and incremental to any portion of this cost that is paid by the interconnecting solar generator.

TASC Data Request 11:

With reference to Exhibit 200, Table 3, row 2 regarding Generation Capacity:
Is it witness Olson's understanding that during evaluation of a utility's resource deficiency, ongoing customer installations of rooftop solar, as well as energy efficiency and demand response measures, are considered in determining a utility's resource deficiency?
If yes, please explain why use of a utility's resource deficiency to lower the generation capacity value for existing solar resources is reasonable.

Staff Response to TASC Request 11:

Yes, utilities typically incorporate estimates of customer adoption of energy efficiency measures, behind-the-meter solar, and other technologies in their estimates of resource balance year (RBY). This line of questioning appropriately points out a potential "circularity" in the valuation process:

- The utility projects behind-the-meter solar adoption in determining its net load forecast;
- This projection may result in a later RBY, relative to a projection that does not include behind-the-meter solar adoption;
- A later RBY results in reduced capacity value for solar, and therefore a lower RVOS;
- If the lower RVOS results in lower compensation for behind-the-meter solar, then adoption may be lower than the utility's projection;
- Lower adoption would result in an earlier RBY;
- Etc.

This issue does not affect the current methodology for two reasons: 1) the current calculation of RVOS will not be used directly in formulating compensation for behind-the-meter solar at this time; and 2) the RVOS methodology does not estimate the value provided by solar resources *that are already installed*. Rather, the methodology calculates the *marginal* value of new, behind-the-meter solar systems that are installed in 2016. Because the focus is on the marginal value, it is reasonable to assume that these new systems do not result in changes to the utility's RBY.

It should be noted that this calculation of RVOS is consistent with how the utilities calculate avoided costs under the Public Utility Regulatory Policy Act (PURPA). Under PURPA, projects that are installed at a given point in time receive rates based on the utility's marginal avoided costs *at that time*. The rates are fixed for the duration of the contract. The current formulation of RVOS assumes similar treatment of smaller-scale behind-the-meter solar systems; i.e., the owner would be entitled to a stream of payments from the utility that is fixed for the duration of the system's economic lifetime (e.g., 25 years).

If a different form of compensation for behind-the-meter solar systems is adopted, then different choices would be necessary in the RVOS methodology. Specifically, if RVOS-based compensation were applied uniformly to all behind-the-meter systems, regardless of installation date, then the capacity value formulation would need be altered to consider the *average* value of *all* systems installed, rather than the *marginal* value of *new* systems.

TASC Data Request 12:

With reference to Exhibit 201, General Inputs, it appears that Ancillary Services encompasses Integration and is a cost of rooftop solar. Is this correct?

i. What assumptions did witness Olson make about the availability and adoption of smart inverters?

Staff Response to TASC Request 12:

Integration and Ancillary services are both captured through the Integration component in the General Inputs tab, cell E67. There are several potential categories of Ancillary Services and Integration costs:

- The cost of procuring additional regulation and load following grid services to accommodate the variability and uncertainty of solar production.
- The impact, if any, of behind-the-meter solar on the utility's procurement of contingency reserves (spinning and supplemental or "non-spinning" reserves).
- The cost of procuring any additional reactive power or voltage support services to meet needs on specific distribution feeders.

"Smart inverters" may enable behind-the-meter PV systems to be more responsive to grid conditions, particularly with respect to voltage conditions on the distribution feeder. However, these technologies are not widely adopted today. There is no specific assumption about smart inverters embedded in the methodology, but the utilities will need to incorporate any assumptions about the availability of smart inverters when they estimate this component of the RVOS in the future.

TASC Data Request 13:

On p. 10 of witness Dolezel's testimony, in recommending that the Commission adopt the proposed methodology, she states that "this methodology and model complements other avoided cost methodologies the Commission uses."

i. Please indicate specifically which avoided cost methodologies are being referenced in this statement.
ii. Please describe the manner in which the proposed methodology is complementary to the existing methods.
iii. Please describe which types of resources these other methodologies are currently used to evaluate.
iv. Please reference any recent cost benefit results from these existing methodologies when applied to these other resource types.
v. Are there specific thresholds that the Commission has used with respect to these results to determine that a given resource type is cost effective?

Staff Response to TASC Request 13:

i. All three Oregon investor-owned utilities calculated avoided costs that are used to compensate certain qualifying facilities (QFs). PacifiCorp avoided costs can be found through Schedule 37[1], PGE avoided costs can be found through Schedule 201[2], and Idaho Power avoided costs can be found through Schedule 85[3].
ii. Both methods use market prices in the near-term as the value for avoided costs and then transition to long-term costs when the utility reaches resource deficiency.
iii. Qualifying facilities include cogeneration plants and other renewable facilities such as wind, solar, and biomass plants.
iv. Because the costs to the utility (payments to the qualifying facilities) are based on the benefits to the utility (avoided costs), there is not a theoretical net benefit or cost to the utility when applied to these other resource types.
v. The PUC uses an avoided cost methodology to quantify the utility benefits of energy efficiency when evaluating its cost effectiveness. Energy Trust implements this determine which efficiency measures and programs to offer and utilities translate this methodology into their IRP processes when evaluating energy efficiency against other resource options in IRPs. (See UM 551, Order 94-590 in Attachment A). which is the standing order we reference regarding energy efficiency avoided costs and cost effectiveness.

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[1] https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/PURPA_Power_Source_Agreement/Schedule_37_Avoided_Cost_Purchases_From_Qualifying_Facilities_of_10000_kW_or_Less.pdf

[2] https://www.portlandgeneral.com/-/media/public/business/power-choices-pricing/documents/business-sched-201.pdf?la=en

<u>TASC Data Request 14</u>:

On p. 11 of witness Olson's testimony, he states that "there are a number of potential barriers that may prevent a utility from actually deferring a transmission and distribution system investment," and lists several barriers related to the operating parameters of certain distributed resources. However, despite certain operating constraints and new uncertainties and complexities associated with demand side resources, witness Olson acknowledges that, "If utility distribution planners do not account for these resources, they may overbuild the distribution system relative to desired reliability and not capture these potential benefits of demand-side resources."

i. What types of changes to utility planning processes would be required to ensure that the potential distribution avoided costs are fully realized?
ii. Are there aspects of the current utility business model that create additional barriers to realizing these potential cost reductions? Could the utility business model lead to utilities overbuilding the distribution system?

<u>Staff Response to TASC Request 14</u>:

i. It is not common practice for distribution engineers to consider customer-side or other distributed energy resources ("DER") as potential solutions to projected system needs. In some cases, utilities consider "non-wires" alternatives to investments in new transmission or distribution system facilities; however, such cases are relatively rare and are often conducted after a preferred "wires" solution has been identified. In order for the benefits of distributed energy resources to be fully realized, transmission and distribution planning would need to evolve to incorporate a suite of potential solutions including energy efficiency, demand response, customer-owned generation, energy storage, and others. Some jurisdictions, such as California and New York, are establishing proceedings to more fully integrate DER into distribution system investment decisions as well as to establish mechanisms to fairly compensate these resources.

ii. Regulated utilities typically earn profits by making capital investments. Because earnings are based largely on the quantity of invested capital, there is, and always has been, an incentive for the utility to "overinvest". This incentive is checked through effective oversight by regulatory bodies such as this Commission. In addition, the utility also has the incentive to prefer solutions that require utility investment, rather than solutions in which services are procured from third-party vendors. These incentives are also the subject of investigations into transmission and distribution system planning procedures in other jurisdictions.

TASC Data Request 15:

On p. 29 of witness Olson's testimony, he states that "This methodology can be thought of as an accounting framework that is entirely reliant on data provided by the utilities."

i. To the best of your knowledge, have there been other cost benefit methodologies or studies that have relied exclusively on data provided by utilities?
ii. Does relying exclusively on utility data raise any concerns about intervenor access to relevant data, due process or impartiality?
iii. Does witness Olson agree that it would be better to develop a model that uses publically available data?

Staff Response to TASC Request 15:

i. For vertically-integrated utilities, it is very common for studies to be based on data provided exclusively or almost exclusively by utilities. This is necessary because there are not always publicly-available data sources that accurately reflect the utility's actual avoided costs. For example, the E3 study on the impacts of net energy metering in Nevada[4] entirely relied on data provided by the utility NV Energy.

   In restructured jurisdictions such as California and New York, energy and capacity can be based on market prices or public forecasts of these prices. The E3 study on the impacts of net energy metering in New York[5] and California relied on a combination of market and utility data since investor-owned utilities in these jurisdictions are deregulated and operate under the market structure of an independent system operator (ISO).

   In all cases, benefits such as avoided distribution system infrastructure must be based on data provided by the utilities.

ii. The Commission routinely makes decisions with far-reaching financial consequences on the basis of data provided exclusively or nearly exclusively by utilities. Indeed, the Commission's core statutory mission is to set the rates paid by all customers of investor-owned utilities (IOUs). Oregon revenues for Commission-jurisdictional IOUs were as follows in 2014[6]:

   a. PGE: $1.69 billion
   b. PacifiCorp: $1.24 billion
   c. Idaho Power: $51 million

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[4] http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf

[5] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF4166D6E-CBFC-48A2-ADA1-D4858F519008%7D

[6] U.S. Energy Information Administration, 2014 Electric Sales and Revenue, Table 10, accessed at http://www.eia.gov/electricity/sales_revenue_price/pdf/table10.pdf

The Commission has a robust process for providing stakeholders an opportunity to review data, cross examine utility and intervenor witnesses, and present their own evidence within the context of a litigated case. To the extent that the RVOS is used for financial compensation of behind-the-meter solar PV installations, I would expect the Commission to follow a similar set of procedures as it uses to set utility rates.

iii. There is a balance between accuracy and transparency. All else being equal, use of publicly-available data is preferable because it is more transparent and easier for stakeholders to understand and verify. However, in some cases publicly-available data may not be accurate enough to provide a robust value for solar PV output. Particularly in the case of avoided transmission and distribution system investments, there is at present no alternative to data provided by utilities.

TASC Data Request 16:

On p. 29 of witness Olson's testimony, he describes ways in which utilities could input averaged energy values if hourly data is not available.

i. If inputting values other than hourly granularity, please describe the loss in accuracy with respect to coincidence of high value hours with the hours of solar generation.
ii. Would you agree that if a user of the model is not using hourly data, energy prices should only be averaged across time periods that do not split the hours of solar generation into multiple periods? For example, would you agree that averaging the 4pm to midnight period would significantly undervalue the solar generation that occurs between 4pm and 7pm in the summer? Similarly, would averaging energy prices between 4am to 9am tend to undervalue the solar generation that occurs between 7am-9am?

Staff Response to TASC Request 16:

i. The model incorporates hourly granularity in order to provide the opportunity for the utilities to match solar production with time-dependent avoided costs throughout the course of the calendar year, as described in Section 2 of my direct testimony. In some cases, it may be appropriate for values to be averaged over a larger number of hours. For example, most wholesale market transactions in the Western United States today occur in multi-hour blocks as defined in the Western Systems Power Pool (WSPP) agreement—where "Heavy-Load Hours" are defined as 6 AM – 10 PM Monday – Saturday, except North American Electric Reliability Council (NERC) holidays, and "Light-Load Hours" are defined as all other hours. Most commercially-available forward market price projections also use the same conventions. Because the utility's opportunities to buy and sell energy in the wholesale market are shaped by the prevailing method of transacting in that market, in this instance it may be appropriate for the hourly avoided energy costs to reflect the WSPP standard products.

ii. No, I do not agree that averaging necessarily needs to avoid splitting hours with solar production into multiple periods, or pairing daylight with nighttime hours. Whether a specific set of hours could appropriately be averaged depends on the fundamental economics that underlie the potential value, and is independent of solar production. For example, if a utility's Loss-of-Load Probability (LOLP) model indicated that loss of load occurred uniformly in the 4 pm to midnight period, then averaging the capacity value over that period would be appropriate. Because the averaging results in a $/MWh value which is then applied to solar, the averaging would neither over- or under-value solar output. If, on the other hand, the utility's LOLP were higher in the 4-7 pm block and lower in the 7 pm – midnight block, then it would not be appropriate to average the capacity value across a 4 pm – midnight block.

TASC Data Request 17:

On p. 33 of witness Olson's testimony describing the methodology for market price response, he indicates that the levelized value of this category is based on the change in market price multiplied by the utility's net short position, spread over the amount of solar production in each hour.

i. Please explain why this methodology only looks at net market purchases, rather than looking at all power transacted at the Mid-Columbia pricing hub.
ii. Assume there are two Oregon utilities: Utility A and Utility B. To the extent that solar generation within Utility A reduces the market price at Mid-Columbia, is it not true that Utility B would also benefit from that market price response?
iii. If the answer to part b) above is yes, please comment on how the geographic scope of analysis under the ratepayer impact measure can influence the magnitude of certain benefit categories. Are there other examples in addition to market price response where the total statewide value may be "more than the sum of its parts"; i.e. greater than the sum of values across individual utilities, circuits, or other geographic granularities?
iv. Would the additional market response benefit alluded to above be captured under the Societal Cost Test or Total Resource Cost Test?

Staff Response to TASC Request 17:

i. The methodology considers all power that a utility transacts at the Mid-Columbia pricing hub. The quantity of power transacted at the hub is generally shaped by the utility's net short or long position. For example, assume in a given hour that a utility has load equal to X MW and generation equal to Y MW. The utility's market transactions will be equal to (Y – X) during that hour. If Y < X, then the utility has a net short position and the reduction in market price due to solar will result in an additional benefit to the utility's ratepayers. If Y > X, then the utility has a net long position in that hour and the reduction in market price due to solar will result in a cost to the utility's ratepayers due to a loss of market revenue.

   For simplicity, this effect is rolled up and applied to the utility's annual net purchases or sales in the Excel model. To do this, I have assumed that the market price effect is proportional during all hours of the year, i.e., that the same price elasticity can be applied during all hours of the year.

ii. The methodology calculates an RVOS that is specific to each utility. Thus, the market price response is intended to capture the value that solar in a given utility's service area has for that utility's ratepayers. It is true that Utility A could experience a market price effect (cost or benefit) due to solar generation in the Utility B service area. However, this impact is not appropriate to consider for a Utility A-specific RVOS, because it does not accrue to Utility A ratepayers.

iii. No, as indicated in my direct testimony Table 2 (Olson testimony, p. 21), market price response is not a societal benefit; rather, it represents a transfer of value from sellers to buyers. Since market price response can be positive or negative for any given set of market participants, it is not possible to generalize whether the effect of a broader geography would be positive or negative. At the highest level of aggregation (the societal level), the total market price effect is zero. For every beneficiary of a lower market price (a net buyer), there is a loser (a net seller). This is further mediated by the fact that vertically integrated utilities serving bundled retail load are both buyers and sellers of wholesale power, depending on the year, season and time of day.

iv. See response to TASC Request 17iii.

TASC Data Request 18:

On p. 37 of witness Olson's testimony, he describes the way in which utility scale solar should serve as a benchmark for several of the avoided cost categories.

i. Is witness Olson advocating for use of utility-scale solar as a proxy resource for avoided cost frameworks and resource value of solar methodologies in this docket?
ii. Are there circumstances that might prevent the addition of utility-scale solar as the incremental resource in a given utility service area, such as permitting, limited land availability, and lack of transmission access?
iii. Does witness Olson agree that utility-scale solar would be subject to "Capital Risk" as the witness defines that term in Question 7.

Staff Response to TASC Request 18:

i. Yes, where utility-scale solar is the least-cost marginal resource, it should be used as the proxy resource for avoided costs frameworks.

ii. If such circumstances exist, then utility-scale solar may not be the least-cost marginal resource and would not be used in the avoided cost framework.

iii. Yes, as with generation capacity, the cost and risks of financing are embedded in the levelized cost of the resource.

<u>TASC Data Request 19</u>:

On p. 42 of witness Olson's testimony, he lists the T&D deferral value for his illustrative "medium case" as $49/kW-year.

i. Please describe the source (or general set of sources) which serves as the basis for this number or supports the notion that this value is a reasonable estimate.
ii. Please describe what this value is meant to represent and when a utility would typically develop this type of number. For example, is this meant to represent the marginal cost of transmission and distribution, as developed through a Marginal Cost of Service Study (MCOSS) and used as the basis to allocate costs across rate classes?

<u>Staff Response to TASC Request 19</u>:

i. This value is based on existing utility Marginal Cost of Service Studies. This is a reasonable estimate for the impact of solar on avoiding additional T&D infrastructure although more work may need to be done to ensure that this truly represents avoidable costs.

ii. This value is an estimate of the average T&D costs that the utility can avoid due to solar. T&D costs can be calculated at the system average level or for more specific locations such as utility distribution planning areas or even distribution feeders. Oregon IOU's do not currently produce values that specifically measure avoidable T&D costs. In the absence of more specific values, I believe that the MCOSS provide a reasonable basis for these sample values.

TASC Data Request 20:

On p. 43 of witness Olson's testimony, he lists "5% of energy" as the assumption for hedge value.

i. Please describe the source (or general set of sources) which serves as the basis for this number or supports the notion that this value is a reasonable estimate.
ii. Are the costs associated with financial hedging instruments the only hedging avoided costs that could be assumed in the model?
iii. Is it not true that alternative resources like solar provide a natural hedge against fossil fuel price volatility in markets where they serve as substitutes? For example, would increasing solar penetration act as a hedge against natural gas price volatility regardless of whether a utility engages in financial hedging?
iv. Wouldn't increasing proportions of solar in a portfolio reduce that portfolio's exposure to whatever fossil fuel price volatility that remains?

Staff Response to TASC Request 20:

i. A reasonable basis for this value would be the peer-reviewed paper "How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest."[7]

ii. Yes, the hedge value should be based on the utility' expected cost of hedging. This is equal to the expected cost difference between the utility's forward market purchases, made for the purpose of hedging, and the expected spot price over the period of the forward purchase, multiplied by the proportion of market purchases that are hedged. For example, if a utility typically hedges 50% of its market purchases, and it typically pays a 10% premium for those forward purchases relative to expected spot energy prices, then the avoidable hedging cost for the utility portfolio would be 50%*10% = 5% of the spot price forecast.

It should be noted that the "hedge value" calculated here is simply a function the utility's reduced cost of procuring energy, some of which is hedged through forward purchases. Utility ratepayers do not benefit from reduced electric rate volatility due to the behind-the-meter solar. To see this point, consider the following two utilities. Utility A hedges 90% of its market exposure, while Utility B hedges only 10% of its market exposure. Utility A will have much higher avoidable hedging costs than Utility B, despite the fact that Utility A's electric rates are much more stable than Utility B's, and Utility B's customers would therefore benefit much more from incremental utility hedging activity.

iii. Yes, to the extent that a utility acquires a solar resource as part of its generation portfolio, that resource allows the utility to avoid market purchases of electricity and/or natural gas and any associated hedging costs.

[7] DeBenedictus, Miller, Moore, Olson, Woo. How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest. 2011

However, for behind-the-meter generation, this value accrues to the owner of the solar installation, not to non-participating utility ratepayers. Solar owners acquire the resource for the purpose of offsetting all or a portion of their onsite consumption, thereby replacing their potentially variable electricity bill with a more stable cost stream based on the cost of solar ownership. The solar installation thereby provides a hedge value for the solar owner.

The remaining load does not experience a reduction in volatility as a result of the solar installation. Behind-the-meter solar does not become part of the utility's resource portfolio. Rather, behind-the-meter solar functions like direct access, in which the load is separated from the remaining bundled customers and served with a third-party resource, i.e., a resource that is outside the utility's portfolio. Since the utility does not own or contract directly with the solar PV resource, the utility therefore will need to continue to hedge any market transactions for the remaining load in the same proportion as if the solar installation had not occurred. As a result, the hedge value accrues to the system owner, and the remaining utility ratepayers do not experience a reduction in bill volatility.

iv. See response to TASC Request 20iii.

TASC Data Request 21:

Regarding the choice of resource deficiency year (also known as resource balance year (RBY)):

i. Is witness Olson aware of the recent decision in California that determined that it was appropriate to use prompt year RBY for the evaluation of all demand side resources? (*See* Final Decision in Rulemaking 14-10-003: Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Distributed Energy Resources.)
ii. Based on the rationale within that Decision, is it reasonable to assume that a prompt year RBY is appropriate for assessing the value of demand side resources in Oregon?

Staff Response to TASC Request 21:

i. Yes, I am aware of the California PUC decision to use a prompt-year RBY for evaluation of all demand-side resources.

ii. No, the use of a prompt-year RBY is not appropriate for assessing the RVOS in Oregon. The proposed decision is not based on a finding of fact that a prompt-year RBY is a more accurate representation of utility avoided costs for solar in a given year. Rather, the decision is based on unique California policy considerations, specifically, California's electric resource "loading order" that places a preference on demand-side resources such as energy efficiency and solar above fossil-fueled generation:

> "We find that the current system omits Commission clean energy policies, such as the loading order and ignores grid planning processes. As discussed in detail below, this omission places distributed energy resources at a disadvantage to fossil-fueled generation."[8]

The California PUC decision is designed to be generally applicable to all demand-side resources across a wide range of programs and time periods. However, as explained the response to TASC Request 11, the Oregon RVOS methodology is designed to estimate the marginal value of a solar resource installed in 2016, and is not intended to serve as a broad measure of the average value of all demand-side resources. Since the utility cannot avoid the cost of generation capacity investments until there is a system need for new generation capacity, the marginal capacity value of behind-the-meter solar is dependent on the timing of that need. Hence, using a prompt year RBY does not result in an accurate measure of the utility's avoided cost at any given point in time.

[8] California Public Utilities Commission, Decision 16-06-007, June 9, 2016

TASC Data Request 22:

i. At p. 40, witness Olson states "Utility-scale solar may also be dispatchable in response to grid conditions and can provide voltage support through power factor control." Please provide all reports, studies, or other written documents relied upon by witness Olson in making this statement.

ii. Does witness Olson agree that distributed solar resources could be made dispatchable and able to provide voltage support through the use of smart inverters and other enabling technologies?

iii. At p. 39, witness Olson asserts that, "Given the rapidly declining cost of solar (both utility scale and rooftop), it is necessary to include the functionality to calculate the value of distributed solar using a utility-scale solar proxy." Please explain why the rapidly declining cost of solar necessitates inclusion of utility-scale solar as a proxy for distributed solar within witness Olson's methodology.

Staff Response to TASC Request 22:

i. Wind and solar generation are routinely dispatched in response to grid conditions in organized markets across North America, as is documented in numerous papers and market reports. See, for example:

   a. In 2011, the Mid-Continent Independent System Operator (MISO) introduced market reforms that furthered renewable integration by allowing renewables to "participate fully in MISO's economic dispatch under a new resource designation: Dispatchable Intermittent Resources (DIR)." (https://www.misoenergy.org/AboutUs/MediaCenter/PressReleases/Pages/MISOFurthersIntegrationofWindResources.aspx)

   b. In 2014, Bird et al. found that economic curtailment of renewables was common throughout North America. (Bird, L., J. Cochran and X. Wang, Wind and Solar Energy Curtailment: Experience and Practices in the United States, National Renewable Energy Laboratory Technical Report, NREL/TP-6A20-60983, March 2014, http://www.nrel.gov/docs/fy14osti/60983.pdf)

   c. In 2015 the National Renewable Energy Laboratory's Western Wind and Solar Integration Study Phase 3 studied the potential for renewables to respond to contingencies such as the sudden loss of a large generator or transmission line. The study concludes that "Nontraditional frequency-responsive controls on wind, utility-scale solar photovoltaic power (PV), concentrating solar thermal power (CSP), and energy storage are effective at improving frequency response."

http://www.nrel.gov/electricity/transmission/western_wind.html

ii. Yes, in theory distributed solar resources could be made dispatchable as well as provide other services through enabling technologies. However, it is not common practice for transmission system operators to dispatch behind-the-meter solar PV installations. Moreover, the solar generator would need to be provided with an appropriate incentive in order to provide these services. For example, a solar generator that is compensated based on the amount of kWh generated, as is currently the case under Net Energy Metering or PURPA contracts, would not have an incentive to curtail or to provide grid services.

iii. Historically, the proxy resource used in avoided cost analysis has been either (1) a natural gas-fired, combined-cycle combustion turbine (CCCT) facility or, (2) a combination of market purchases and gas-fired capacity resources. However, due to the rapidly declining cost of both solar and wind resources, along with expected escalation in natural gas and CO2 prices, there are now scenarios in which the least-cost utility scale resource is no longer a gas-fired resource but rather a utility-scale wind or solar resource. In those scenarios, the wind or solar resource would be the most appropriate utility-scale proxy to use for avoided costing.

The use of wind as the proxy resource could introduce some complexity into the avoided cost calculation as wind and solar resources have very different output shapes, different capacity values, etc. For the Oregon RVOS methodology, I have adopted a simplified approach of using a utility-scale solar resource with performance that is identical to the behind-the-meter resource.

TASC Data Request 23:

Please provide an explanation for witness Olson's utilization of Energy: $27/MWh under the Medium Scenario discussed on p. 42.
Additionally, please provide reference to any workpapers that support this figure or explain the escalation to $97/MWh by 2040.

Staff Response to TASC Request 23:

These values are illustrative only, therefore there are no workpapers. These values are consistent with data provided by the Oregon IOUs. The price escalation is also reasonable and consistent with the latest EIA natural gas price forecast[9], a large driver of electricity prices.

[9] http://www.eia.gov/forecasts/aeo/data/browser/#/?id=13-AEO2015&region=0-0&cases=ref2015&start=2012&end=2040&f=A&linechart=ref2015-d021915a.58-13-AEO2015&ctype=linechart&sourcekey=0

<u>TASC Data Request 24</u>:

On pages 42-43 of his testimony, witness Olson lists the assumptions he used to calculate the low, medium and high scenario results. For each of the assumptions listed below, please provide a narrative discussion of how the value was arrived at and please provide any documents, workpapers or other materials relied upon during the formulation of each value.

Medium

i. Energy: $27/MWh (nominal) in 2016, escalating to $97/MWh by 2040
ii. T&D losses: 9%
iii. Generation capacity: $157/kW-yr ($2016)
   a. Annual energy revenues: $30/kW-yr
   b. Solar contribution to peak: 25%
   c. Resource deficiency year: 2021
   d. Fixed O&M: $13.45/kW-yr
iv. T&D deferral value: $49/kW-yr
   a. T&D coincidence factor: 26%
v. Carbon: $10/ton, escalating to $34/ton by 2040
vi. Hedge: 5% of energy
vii. Market price effect: +3/MWh
viii. Integration: $4/MWh
ix. Administration: $3/MWh

Low

i. Energy: multiplied by 80%
ii. Resource deficiency year: 2030
iii. Fixed O&M: $0/kW-yr
iv. T&D deferral value: $0/kW-yr
v. Carbon: $0/ton
vi. All other assumptions identical to Medium case

High

i. Energy: multiplied by $120
ii. Resource Deficiency year: 2016
iii. T&D deferral value: multiplied by 150%
iv. Carbon: multiplied by 200%
v. All other assumptions identical to Medium case

Utility Scale Proxy

i. Solar Price of $85/MWh (real levelized) replaces the following elements: energy, generation capacity, ancillary services, emissions, RPS compliance, hedge, market price effect, administration
ii. All other assumptions identical to Medium case

Staff Response to TASC Request 24:

Medium

i. These values are illustrative only. These values are consistent with data provided by the Oregon IOUs. The price escalation is also reasonable and consistent with the latest EIA natural gas price forecast[10], a large driver of electricity prices.

ii. These values are illustrative only. These values are consistent with data provided by the Oregon IOUs.

iii. These values are illustrative only. These values are consistent with data provided by the Oregon IOUs.

   a. These values are illustrative only. These values are consistent with E3 avoided cost analysis in California.[11]
   b. These values are illustrative only. These values are consistent with prior E3 experience performing this analysis.
   c. These values are illustrative only. These values are consistent with data provided by the Oregon IOU's.
   d. These values are illustrative only. These values are consistent with data provided by the Oregon IOU's.

iv. These values are illustrative only. These values are consistent with data provided by the Oregon IOU's.
   a. These values are illustrative only. These values are consistent with E3 avoided cost analysis in California[12].

v. These values are illustrative only. These values are consistent with E3 avoided cost analysis in California[13].

vi. These values are illustrative only. These values are consistent with the peer-reviewed paper "How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest."[14]

vii. These values are illustrative only. These values are consistent with the peer-reviewed paper "The Impact of Wind Generation on Wholesale Electricity Prices in the Hydro-Rich Pacific Northwest." While this paper focuses on wind generation instead of solar, I believe that this values are a reasonable proxy for the market price effect of solar in lieu of alternative sources of data.

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[10] http://www.eia.gov/forecasts/aeo/data/browser/#/?id=13-AEO2015&region=0-0&cases=ref2015&start=2012&end=2040&f=A&linechart=ref2015-d021915a.58-13-AEO2015&ctype=linechart&sourcekey=0
[11] https://ethree.com/public_projects/cpuc4.php
[12] https://ethree.com/public_projects/cpuc4.php
[13] https://ethree.com/public_projects/cpuc4.php
[14] DeBenedictus, Miller, Moore, Olson, Woo. How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest. 2011

viii. These values are illustrative only. These values are consistent with data provided by the Oregon IOU's.

ix. These values are illustrative only. These values are consistent with data provided by the Oregon IOU's.

Low

i. These values are illustrative only. I believe this to be a reasonable sensitivity factor.

ii. These values are illustrative only. I believe this to be a reasonable sensitivity factor.

iii. These values are illustrative only. I believe this to be a reasonable sensitivity factor.

iv. These values are illustrative only. I believe this to be a reasonable sensitivity factor.

v. These values are illustrative only. I believe this to be a reasonable sensitivity factor.

High

i. These values are illustrative only. I believe this to be a reasonable sensitivity factor.

ii. These values are illustrative only. I believe this to be a reasonable sensitivity factor.

iii. These values are illustrative only. I believe this to be a reasonable sensitivity factor.

iv. These values are illustrative only. I believe this to be a reasonable sensitivity factor.

Utility Scale Proxy

i. These values are illustrative only. These values are in-line with recent EIA levelized cost estimates[15] in conjunction with the 30% federal investment tax credit.

[15] https://www.eia.gov/forecasts/aeo/electricity_generation.cfm

ORDER NO. **94-590**

ENTERED APR 06 1994

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 551

In the Matter of the Investigation into the Calculation and Use of Cost-Effectiveness Levels for Conservation.	)))	ORDER

DISPOSITION: GUIDELINES ADOPTED

The Public Utility Commission of Oregon (Commission) opened this proceeding at a public meeting on February 9, 1993. The Commission held a prehearing conference on April 21, 1993, to discuss procedural issues. Participants met informally at five workshops to identify and discuss the issues to be addressed in the investigation and to review the proposed guidelines. Participants also filed written comments on the issues and on the draft order. A public meeting to consider the proposed guidelines was held on March 17, 1994.

PacifiCorp (Pacific); Portland General Electric Company (PGE); Idaho Power Company (IPCo); Northwest Natural Gas Company (Northwest); Cascade Natural Gas Corporation (Cascade); WP Natural Gas; the Northwest Power Planning Council (Council); the Solar Energy Association of Oregon (SEA of O); Oregon Housing and Community Services; Sun, Wind and Fire; Puget Sound Power & Light Company; Pacific Northwest Utilities Conference Committee; Portland Energy Office; Proven Alternatives; Eugene Water and Electric Board; the Northwest Conservation Act Coalition; Citizens' Utility Board; Northwest Environmental Advocates; General Electric Company; and the staffs of the Commission and the Oregon Department of Energy (staff) petitioned to intervene, filed written comments, or participated in the workshops.

BACKGROUND

Cost-effectiveness levels or limits are used in utility least-cost planning and conservation program design to identify cost-effective resources. The cost-effectiveness limit for a conservation measure or program reflects the value to the energy utility of avoiding the use of other resources to provide energy services to its customers. Utilities have generally calculated conservation cost-effectiveness limits based on their estimated avoided costs of energy and capacity, adjusted for sales for resale opportunities, line loss savings, and the ten percent conservation cost advantage. The limits are different for measures and programs with different expected lives and load factors (which reflect relative capacity and energy savings). All conservation resources that cost less than the cost-effectiveness limits are considered cost-effective to acquire.

During the review of Pacific's 1992 least-cost plan, SEA of O and the staff raised several questions about the company's cost-effectiveness tests. In its recommendations on the plan, the staff stated that it would propose opening a docket to examine and resolve issues affecting the calculation of conservation cost effectiveness. The staff made the recommendation to open a docket to investigate the calculation and use of conservation cost-effectiveness levels at the February 9, 1993, public meeting. We adopted the staff recommendation and initiated this proceeding.

ISSUES LIST, GUIDELINES, AND COMMENTS

The staff's recommendation to initiate this docket included an initial list of issues to be addressed in this proceeding. Participants proposed modifications to the list in written comments and through discussions at the workshops. The final list of issues was agreed to by all participants at the second workshop. The issues focus on determining the value of conservation savings to the utility (avoided costs related to conservation) and on application of the cost-effectiveness tests. The issues have provided a focus for the oral and written comments submitted and the guidelines developed during this proceeding.

We believe the guidelines developed by participants in response to the issues raised in this proceeding will provide greater clarity and consistency in the calculation and use of conservation cost-effectiveness limits and cost-effectiveness tests. We, therefore, adopt the 15 guidelines following the issues identified below.

1. Under what circumstances should the load and fuel price forecasts used to determine avoided costs differ from the base case forecasts in the utility's least-cost plan?

Load and fuel price forecasts used to determine avoided costs can differ from the base case forecasts in the utility's least-cost plan under the following circumstances:

- **a. When the source forecasts (e.g., DRI, GRI, Wharton) change significantly;**
- **b. When the preferred resource strategy and action plan are based on forecasts other than the "base" forecast;**
- **c. When it is shown that other circumstances have changed significantly, e.g., a Btu tax or other policy changes are implemented;**

d. **When utility avoided cost figures are to be used for interfuel cost comparisons; or**

e. **When a utility's load or fuel price forecasts in its unacknowledged least-cost plan are considered unacceptable for calculating avoided costs.**

The staff believes that, with limited exceptions, the load and fuel price forecasts used to determine avoided costs should be based on the base case forecasts in the utility's least-cost plan. The exceptions to this premise are incorporated in the guideline. The utility's base case should be clearly identified in its least-cost plan.

Northwest's comments expressed concern over the importance of ensuring comparability between gas and electric utility avoided cost estimates. The staff shared Northwest's concerns about the need to maintain avoided cost comparability for interfuel cost comparison. Item 1d is included in the guideline to recognize that it may be necessary to revise utility-specific electric and gas price forecasts, load forecasts, and other critical variables used in calculating avoided costs when the cost estimates are to be used for interfuel comparisons. However, the staff emphasized that the comparability issue should not become the primary determinant of utility planning methodologies.

SEA of O articulated several points in its comments that are discussed elsewhere in this order. SEA of O's comment that cost effectiveness should be evaluated from a societal perspective, rather than the utility's perspective is addressed in Issues 7, 11, and 12 below. Its comment that there is a need to include the value conservation provides in reducing risk and uncertainty is discussed in Issue 6.

The staff agreed with SEA of O that there is a need to understand how cost effectiveness is derived from avoided cost. The staff proposed that calculations of new cost-effectiveness limits for individual measures and programs be required in utility compliance filings within 60 days of the issuance of the UM 551 order. The staff and other parties would have the opportunity to review these filings for consistency with the guidelines adopted in this docket.

The staff also agreed with SEA of O that it is necessary to know what forecast will be used when a utility's least-cost plan is not acknowledged. A plan may not be acknowledged for a variety of reasons that are unrelated to the utility's load and fuel price forecasts. In that case, the staff supported the use of the utility's base case forecast used in the unacknowledged plan. If a utility's load or fuel price forecasts in its least-cost plan were unacceptable, then these would need to be revised before the Commission could approve the utility's avoided costs. Item 1e was added to the guideline to recognize this exception.

Pacific generally agreed with the staff that, if significant changes in assumptions or circumstances occur, then avoided costs can be adjusted accordingly. In addition, Pacific stated that the base integrated resource plan modeling runs should be used to calculate avoided cost. The staff agreed with Pacific but did not revise the guideline, which only addresses conditions for using different forecasts for the utility's least-cost plan and avoided costs.

We agree that, with the exceptions listed in the guideline above, the utilities' load and fuel price forecasts used to determine avoided costs should be consistent with the base case forecasts in the utilities' least-cost plans. We also adopt the staff's recommendation that, within 60 days of the effective date of this order, gas and electric utilities file documents detailing revised cost-effectiveness limits for individual demand-side measures and programs that are consistent with the guidelines adopted in this order.

2. Should demand-side measures be included in the resource stack used to compute avoided costs?

Avoided cost calculations should be based on the marginal costs of a fully-integrated resource stack, which includes both supply- and demand-side resources.

The staff stated that avoided cost estimates (and the cost-effectiveness limits derived from them) should provide a signal about what resources belong in the resource stack or portfolio that is least-cost for a utility and its customers. In general, any resource costing less than avoided costs (with any adjustments necessary to make the subject resource comparable to the avoidable resource) should be acquired, assuming that delay in acquiring the resource will not lower costs even more.

The staff argued that a portfolio limited to supply-side resources would not be least-cost, and avoided costs based on it would not correctly indicate what resources should be acquired. The staff illustrated its point with a simple example that assumes continuous supply curves for both supply- and demand-side resources. Assume that the incremental cost of the supply-side resource stack needed to meet load is 5 cents per kilowatt-hour (kWh), i.e., the highest-cost resource in the portfolio costs 5 cents per kWh. Acquiring all demand-side measures up to 5 cents per kWh would displace some of the supply-side resources, so that the most expensive of the remaining supply-side resources would cost something less, say 4 cents per kWh. The portfolio would then contain some demand-side measures that cost 5 cents per kWh and exclude some supply-side resources that cost just over 4 cents per kWh. However, replacing a 5 cent demand-side measure with a 4 cent supply-side resource would reduce total cost. When it is no longer possible to replace a demand-side measure with a lower cost supply-side resource, total cost would be minimized. At that point, the resource stack would be fully integrated, and the incremental cost of the demand- and supply-side resources would be the same (at, say, 4.7 cents per kWh).

The only parties disagreeing that an integrated resource stack should be used to compute avoided costs were SEA of O and Northwest. Using the staff's example, SEA of O's concern is that a 4.8 cent demand-side resource would not be deemed cost-effective using an integrated resource stack, even though it is cheaper than the incremental (5 cent) resource in a supply-side resource stack. According to SEA of O, it is wrong to use an integrated resource stack because 4.8 cent lost opportunity measures would not be implemented even though 5 cent supply-side resources will be acquired eventually. SEA of O also stated that it would be "less concerned" about this issue if risk and externality adders were applied to the costs of supply-side resources.

How to recognize the value of conservation in mitigating risk and avoiding external costs is addressed in this order under Issues 6 and 12, and we view it as an issue that is separate from whether to use an integrated or supply-side resource stack to compute avoided costs. SEA of O argued for the use of a supply-side resource stack even if risk and externality adders are applied, but it never explained how its approach would lead to a least-cost mix of resources, i.e., why it would make sense to acquire a 4.8 cent demand-side resource when supply-side resources costing no more than 4.7 cents per kWh are available.

Northwest also disagreed with the staff's position. The company offered the example of two electric utilities that are identical except for a difference in potential savings from low-cost energy efficiency improvements. Northwest asserted that the marginal demand-side resource should cost the same for each utility and that use of an integrated resource stack is inappropriate if it yields differing cost estimates for otherwise identical resources.

We disagree with Northwest. Avoided costs should be lower for the utility with greater access to low-cost resources. That does not mean that otherwise identical resources would have different cost estimates because the incremental resource for each utility would be different.

We agree that avoided costs and cost-effectiveness levels should be based on the marginal costs of an integrated resource stack.

3. How should utilities identify avoidable transmission and distribution (T&D) costs?

Utilities' avoided costs for conservation should include avoidable T&D costs consistent with each company's most recent Long-Run Incremental Cost (LRIC) estimates used to set rates or otherwise adopted by the Commission. When particular programs or measures provide geographically-specific T&D savings, the utility should adjust the T&D estimate included in the calculation of the conservation cost-effectiveness limit to evaluate the cost effectiveness of the program.

The staff believes that avoided costs used to determine conservation cost effectiveness should include all costs that can be avoided by the utility, including avoidable T&D costs. For consistency with T&D estimates used in other forums, the staff proposed that T&D costs used to determine general cost-effectiveness limits should be based on the most recent estimates adopted by the Commission. In situations where the utility wants to reflect specific estimates of T&D cost savings to evaluate the cost effectiveness of conservation measures and programs in certain geographic areas, the utility may propose a revised cost-effectiveness limit.

Parties generally agreed with the staff's recommendation. PGE proposed wording changes that helped to clarify the guideline.

SEA of O suggested that the staff should determine the value of avoided distribution cost. The staff reviews utility distribution cost estimates when LRIC studies are filed to support proposed Commission action (usually in a general rate case).

We concur with the approach to including avoidable T&D costs in cost-effectiveness limits proposed in this guideline.

4. What is the value of conservation regarding reliability before new capacity is required? (For example, utilities generally assign zero value to capacity until the year of load/resource balance.)

Demand-side resources (DSR) can provide the utility with increased reliability before new resources are brought on line. The value of DSR that is not sold is reasonably represented by the price of sold or purchased wholesale firm energy/commodity and capacity.

The staff noted that utilities often buy and sell capacity and firm energy/commodity. Recent laws and changes at the Federal Energy Regulatory Commission will reinforce this trend. DSR is typically treated as a firm resource for calculating load/resource balance. DSR reduces the need for or allows for the sale of firm energy/commodity and capacity.

In the past the value of conservation before resources were required was set at the short-term cost of production or the non-firm energy sales price, whichever was higher. This implicitly assumes a zero value for capacity. The staff proposed to substitute the value midway between recent firm sales and purchase prices. The proposed method would allow the use of firm energy/commodity contracts or nonfirm sales plus capacity contracts. This assumes conservation is as reliable as generation for capacity and firm energy.

The staff also suggested that purchase costs should include transmission costs and sales prices should be net of transmission costs. In calculating near-term DSR value, greater weight should be given to recent contracts and to contracts with durations similar to the period until resources are required. If the utility is unlikely to make any sales, only firm purchase prices should be used.

PGE disagreed with the staff's position for several reasons: the sales increments are larger than annual conservation acquisitions; prices are too speculative; the effect of using firm vs nonfirm sales for resale is infinitesimal over a one- to two-year deficit period; and short-term sales for resale provide the correct proxy value for reliability in the calculation of cost-effectiveness limits.

We disagree with PGE. Utilities can adjust the size of purchases based on planned DSR acquisition. For example, PGE is currently buying firm energy and capacity to replace the loss of Trojan. PGE planned to acquire 20 average megawatts (MWa) of DSR in 1994 when the company negotiated these purchases. This allowed the company to reduce the size of its purchases by 20 MWa. In addition, the prices of firm purchases and sales are no more speculative than many other assumptions in determining the value of conservation. PGE did not provide any evidence that the difference between short-term firm and nonfirm sales for resale prices is infinitesimal. That assertion would be relevant to an argument that nonfirm sales should be used as a proxy because it is somehow difficult to use firm sales or purchases to value reliability. PGE, however, did not make that claim, and we do not believe it would be difficult to use firm sales or purchases for the calculation. Finally, PGE expressed concern "that not all energy efficiency programs provide the same level of reliability and that an overall reliability adjustment fails to give recognition to the different values of various programs." As a solution PGE proposed continuing the current practice of using short-term sales for resale as the correct proxy value for DSR reliability. The effect of using this value is to assign a zero value to capacity or firmness. We agree with the staff that the different reliability contributions of various programs or measures should instead be recognized by applying the capacity savings of the programs or measures (determined through the use of conservation load factors or other methods, as discussed under Issue 8) to the capacity value ($/kW) derived from firm sales or purchases.

Pacific asserted that "Demand-side resources are unlikely to be as useful in meeting capacity requirements, and their value would therefore be lower than that of the SCE (Southern California Edison) purchase. Thus a value between zero and the price of the recent firm wholesale capacity purchases would provide a reasonable approximation for the capacity value of a demand-side resource prior to load resource balance."

Pacific has not shown why planned DSR does not displace the need for capacity purchases on a megawatt for megawatt basis. If DSR does not displace capacity equivalently, the capacity value of conservation has been calculated incorrectly. Pacific's recent winter capacity purchase from SCE could have been reduced or delayed if Pacific had planned more DSR for the 1993-1997 period. Planned conservation also allows additional sales of capacity or firm energy in the period before new resources are on line. There is an active market for capacity and firm energy in the western U.S. Pacific commonly makes such sales and purchases.

The Council indicated in its response to Issues 4, 5, and 6 that the value of conservation during surplus conditions should be treated like excess generating capacity during surplus conditions. The Council observed that PGE's Boardman plant was allowed into rates long before PGE was deficit. The Council also opposed a zero value for capacity in the cost-effectiveness limit. The Council argued that the market price of wholesale firm energy is a reasonable measure of the minimum value of conservation, while the maximum value is represented by the full cost of the next identified resource, provided it is not too far off in the future.

Conservation in Oregon is already treated in rates similar to supply-side resources. We agree with the Council that the full cost of the next identified resource can represent a reasonable value for increased reliability when a utility is adding resources. When loads and resources are roughly balanced, DSR can also allow reduced purchases or increased sales while keeping reliability constant. If a utility does not need new resources, the value of increased reliability from DSR will be less than the cost of new resources. Here again, DSR allows reduced purchases or increased sales.

At this time, we support the staff 's recommendation that the price from recent firm wholesale sales or purchases provides the best estimate of the reliability value of DSR before new resources are on line.

5. What is the wholesale resale value of saved energy and capacity?

Before new resources are brought on line, the value of saved energy and capacity is best approximated by the wholesale price of sales and purchases of firm energy/commodity and capacity.

PGE proposed a revised guideline which in effect would assign a zero value to the capacity or firmness of conservation before new resources are on line. We believe this value is too low.

Pacific indicated that the addition of a firm demand-side resource does not necessarily make possible corresponding additional wholesale sales--firm or non-firm. Pacific stated that the value of such wholesale sales is best approximated for each utility using a production cost model or nonfirm sales prices, whichever is higher. Again, this effectively assigns a zero value for conservation capacity before new resources are required.

SEA of O indicated that the value for capacity savings should be determined from the value for firm, shaped power sales for resale. This is consistent with the proposed guideline.

As discussed in Issue 4 above, we adopt the staff's recommendation that firm energy transactions are a good approximation of the value of conservation before new resources are brought on line.

6. What is the value, if any, of conservation regarding uncertainty about the ability to meet load growth?

The value is generally thought to be positive. Absent better uncertainty analysis in the least-cost planning process, this effect is included within the ten percent conservation cost advantage.

The staff stated that conservation tends to reduce uncertainty about the ability to meet load growth, mainly because acquisition through lost opportunity programs varies directly with the level of economic activity. Pacific pointed out an offsetting uncertainty about the effect of demand-side programs on loads (because of take-back, for example).

Pacific agreed with the staff that any effect of conservation on uncertainty about meeting loads should be included in the ten percent conservation cost advantage. PGE noted that the Council has identified load stability and predictability as a conservation benefit covered by the ten percent adder. PGE argued, however, that the ten percent figure should be revisited as benefits included in it are otherwise quantified and applied. Cascade stated that the ten percent adder previously used to account for external environmental costs should be eliminated for gas utilities because external costs will be recognized under the requirements of the Commission's order in UM 424 (Order No. 93-695). SEA of O, however, asserted that the ten percent adder should be applied after accounting for all quantifiable benefits of conservation, including those related to risk mitigation and externalities.

We disagree with Cascade. We noted in Order No. 93-695 that the ten percent conservation cost advantage covers more than external environmental effects and concluded that electric and gas utilities should continue to apply the ten percent figure. We also concluded in UM 424 that application of the ten percent adder should be reexamined when utility planning methods are better able to account for the advantages of conservation in limiting environmental impact and dealing with uncertainty. Parties may raise the issue in future reviews of the guidelines adopted in Order No. 93-695.

SEA of O also recommended that a utility should account for the risk mitigation value of conservation by setting higher demand-side targets than suggested by its expected economic growth scenario. We believe, however, that this issue should be addressed in the utility's least-cost planning process, not through an arbitrary adjustment of the cost-effectiveness limits.

We support the staff's position that the effect of conservation in reducing uncertainty in meeting load growth is included in the ten percent cost adder and that no separate adjustment is necessary.

7. Is a consistent tax treatment used to assess demand-side and supply-side resources?

As a general principle, tax treatment should be consistent between the two types of resources. Using a revenue requirements approach to calculating Total Resource Cost (TRC) will accomplish this goal. This approach treats taxes on all resources as costs.

In its comments, IPCo asked if conservation TRC should include revenue requirements. The California Standard Practice Manual and the Electric Power Research Institute's End-Use Technical Assessment Guide, which are guides to the calculation of standard demand-side cost-effectiveness tests, do not include revenue requirements in conservation TRC. TRC calculations in these manuals are based on the installed cost of the measure. Revenue requirements under the traditional TRC approaches are considered transfer payments (changes in dollar amounts that flow between the utility and its ratepayers) that are ignored in the calculation. However, revenue requirements of generation, transmission, and distribution are included in the avoided costs used as the basis for the calculation of conservation cost-effectiveness limits.

The staff concluded that, to be consistent, revenue requirements should also be included in the TRC of demand-side resources. The staff cited several reasons for advocating a revenue requirements approach to TRC and thereby including taxes. The staff argued that consistency requires that taxes be treated the same for all resources, which can be categorized as purchased power, purchased savings from energy service companies (ESCOs), utility generating resources, and utility conservation programs. First, it is not practical to remove taxes from purchased power costs or payments to ESCOs. Eliminating corporate income taxes from only utility resources or programs would bias TRC comparisons.

Second, the costs of fuel, pipelines, generating equipment, and demand-side measures can include other taxes as well. Some taxes represent user fees for services, e.g., property taxes that pay for police and fire protection. The choice of how far up the acquisition chain taxes are removed could bias results.

Third, some tax credits are explicitly designed to shift resource choices. The staff argued that it would be counter-productive to try to eliminate the effect on resource choice of the federal 1.5 cent per kWh tax credit on wind. As with taxes, policy-oriented tax credits are also found up the acquisition chain, e.g., federal tax credits for natural gas from coal seams.

Under the staff's proposed approach, the TRC of a demand-side measure or program would include the present value of retail revenue requirements associated with utility program activity plus the participant's costs for the measure, including operating costs, less quantified cost savings and other non-energy benefits.[1] Revenue requirements would include avoidable administrative costs. The participant's portion of measure costs and non-energy benefits and costs would be treated as if expensed. Taxes on all resources would be treated as costs. This approach would allow consistent comparisons of purchased power, savings from ESCOs, utility generated power, and utility conservation program savings. Application of this principle would mean that the Oregon Business Energy Tax Credit (BETC) and federal low-income conservation payments would be treated as real cost reductions. Currently, federal wind tax credits are considered real cost reductions.

SEA of O argued that taxes are transfer payments that should not be included as a cost in TRC, since cost effectiveness should be determined from a societal perspective rather than a utility cost perspective.

Whether taxes are costs or transfers depends on the frame of reference. For example, the Council uses the Northwest as the frame of reference. The goal is to minimize costs to the Northwest society as a whole. Federal taxes are viewed as costs but state and local taxes are viewed as internal transfers. Under the Council's method, the BETC does not reduce the TRC of a resource, but a federal tax credit would. Within this framework, the Council uses the revenue requirements approach to calculate conservation TRC.

ORS 469.020(3) provides only a little guidance on this issue:

> "Cost-effective" means that an energy resource, facility or conservation measure during its life cycle results in delivered power costs **to the ultimate consumer** no greater than the comparable incremental cost of the least cost alternative new energy resource, facility or conservation measure. (Emphasis added)

It is unclear whether the legislature intended taxes to be included in the "costs to the ultimate consumer."

We concur with the staff that consistent treatment of taxes requires that they be included in both demand-side and supply-side resources or excluded from both. Since no party presented a practical method for excluding taxes from power purchases and conservation supplied by ESCOs, the only practical alternative is to include taxes as costs for both demand-side and supply-side resources.

SEA of O also argued that taxes should not be included in TRC calculations because it is inconsistent to discount revenue requirements that include taxes with a discount rate based on the utility's after-tax cost of capital. SEA of O stated the approach results in a bias against capital-intensive resources such as conservation and renewables.

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[1]Recognition of cost savings and other non-energy benefits is discussed in Issues 11 and 12.

The Commission requires utilities to use an after-tax weighted-average cost of capital to discount the revenue requirements of utility resources. We formally adopted this approach at a June 11, 1991, public meeting, and summarized our decision in Order No. 91-1552. Utilities currently discount the revenue requirements of supply-side resource options that include taxes with their after-tax discount rates. We agree with the staff that this approach to discounting revenue requirements should be applied to demand-side as well as supply-side resources.

IPCo noted that supply-side resources are eligible for accelerated tax depreciation, but demand-side resources are amortized in a straight line for tax purposes, resulting in higher revenue requirements.

Tax law does raise the revenue requirements for a conservation measure relative to a supply-side resource with an identical first cost and financing period. Alternatively, if conservation expenditures were expensed, the tax cost of demand-side resources would be less. It would also raise short-term revenue requirements. Similarly, using rebates instead of utility financing and shorter amortization periods for conservation would lower TRC. These trade-offs should be considered in least-cost plans and program design. If changes to current Commission policy were to be made, Order No. 89-1700 would need to be modified.

8. What methods (such as conservation load factors) should be used to determine the capacity savings of different measures or programs?

Different demand-side resources have different effects on capacity requirements. Utilities should use empirically based methods, such as conservation load factors, to quantify capacity impacts. Utilities should use empirical data to support methods which adjust conservation cost-effectiveness calculations based on the effects of specific demand-side resources on capacity requirements.

Methods such as conservation load factors have been used by some utilities to estimate the benefit to the utility from reductions in peak requirements resulting from acquisition of different demand-side resources. They are used as an adjustment to conservation cost-effectiveness limits. The staff advocated the use of conservation load factors or other empirically based methods to better reflect the value of capacity reductions from different demand-side resources.

Pacific supported the use of empirically based data to develop conservation load factors and emphasized the importance of conservation load factors in understanding the capacity effects of various conservation programs.

While PGE supported further exploration on the issue of capacity effects, it urged that utilities be allowed rather than required to use the conservation load factor approach. The company stated that the term "conservation load factor" is unclear and proposed certain wording changes to the guideline.

Although the staff is unacquainted with methods other than the conservation load factor approach, it supported PGE's suggestion to allow utilities the flexibility to explore other approaches to estimate the effects of different demand-side resources on capacity.

SEA of O argued that empirical data often does not exist, and may never exist except in the form of engineering estimates. The staff agreed with the first part of SEA of O's statement, but believes that data on capacity effects can be gathered on almost all programs and measures (or groups of similar measures). The staff recommended that engineering estimates may be used until empirically based data is available.

The Commission agrees that the effects of different demand-side resources on capacity requirements should be evaluated by each utility using empirically based methods and data. Engineering estimates may be used until empirical data is available.

9. Should the underlying avoided cost stream begin in the current year or in the year in which the programs need to be fully implemented?

Utilities should use the avoided cost stream beginning in the current year to assess the cost effectiveness of individual measures and programs.

Demand-side measures and programs are tested for cost effectiveness against utility-specific avoided costs adjusted for certain factors. The issue was raised whether measures or programs should be tested against avoided costs beginning in the year the program is implemented or the year the program is expected to reach maturity or peak savings.

Pacific agreed with the staff that the avoided cost stream used to assess the cost effectiveness of individual measures should begin in the current year. Both SEA of O and the Council argued that conservation programs take time to develop infrastructure, test delivery mechanisms, or transform markets before full program ramp-up can be attained.

The staff did not disagree. However, it stated that, in general, programs which are not cost-effective tested by an avoided cost stream beginning in the current year should be recognized as noncost-effective. If such a program is likely to be cost-effective in the future (because avoided costs rise or program/measure costs fall) and the program cannot be changed frequently (as with building codes and the Super Good Cents program), then it might be allowed under the provisions discussed in Issue 13.

We agree with the staff that utilities should test the cost effectiveness of demand-side measures and programs against the avoided cost stream beginning in the year the program is implemented, unless the measure or program meets one of the exceptions listed in Issue 13.

10. How should the administrative costs of conservation programs be treated in determining cost effectiveness?

Administrative costs should be explicitly included in DSR cost when evaluating the cost effectiveness of programs, consistent with supply-side treatment. Administrative costs should not be applied to individual measures within a program except for those instances where the program consists of a single demand-side measure or where a single demand-side measure has identifiable incremental administrative costs that the utility could avoid by not including that measure.

The comments submitted were generally supportive of the staff's proposed guideline on how utility administrative costs should be treated in determining demand-side measure and program cost effectiveness. Pacific, PGE, and SEA of O, for example, generally agreed with the staff's proposal, but offered revisions to make the guideline more explicit about how to include administrative costs in the evaluation of demand-side measures and programs. The guideline was revised to address these concerns.

We support the treatment of administrative costs expressed in the guideline.

11. It is the Commission's policy to apply a Total Resource Cost Test, i.e., consider a measure cost-effective if the installed cost of the measure is less than the corresponding cost-effectiveness level, regardless of who pays for it. Are there circumstances in which other tests (such as a Utility Cost Test or Ratepayers' Impact Measure (RIM) Test) should be applied?

12. How should the non-energy benefits and costs of measures be treated?

(Combined Guideline for Issues 11 and 12)

The Total Resource Cost test should be used to determine program and measure conservation cost effectiveness. The TRC of a measure or program is the present value of retail revenue requirements plus the participant's cost for the measure(s), including operating costs, less quantified non-energy benefits and cost savings. TRC includes avoidable administrative cost. A program or measure passes the TRC test if the TRC is less than the conservation cost-effectiveness limit (CEL). The CEL is the present value of revenue requirements of avoided utility supply, transmission, and distribution costs and the value of firm wholesale sales or purchases before new resources are on-line. CEL for programs and measures also includes a minimum value of ten percent of these costs to account for risk and uncertainty. Consistent with OAR 860-27-310 (1) (c), the CEL for fuel switching does not include the ten percent adder. Externality values, consistent with the ranges in Order No. 93-695, should be included in the calculation of the CEL or supplied as an alternative CEL calculation. The savings estimate used in applying the TRC test to a measure should reflect interactions with other measures in the utility's program.

A utility should calculate cost savings and other non-energy benefits if they are significant and there is a reasonable and practical method for calculating them.

In general, utilities should set demand-side acquisition targets to minimize total resource cost. If a utility considers rate impacts in setting its demand-side targets, it should justify the decision in its least-cost plan. Utilities should offer incentives to end-users sufficient to meet or exceed acknowledged least-cost plan conservation targets.

This guideline clarifies and extends the Commission's long-standing policy to consider a measure or program cost-effective if the total cost of installing the measures, including the customer's out-of-pocket costs as well as the utility's incentives and administrative costs, is less than the value of the energy savings. The parties addressed two fundamental issues in the use of the TRC test: the treatment of non-energy benefits, and the relevance of other tests for identifying demand-side measures for acquisition.[2] We discuss these issues in turn and explain how utilities should incorporate external environmental costs to comply with Order No. 93-695.

Non-energy benefits. We have generally deemed a measure or program cost-effective if the total cost of the measure(s) is less than the energy benefits. Other customer benefits have been cited but not recognized in the cost-effectiveness test. These non-energy benefits include water savings from low-flow showerheads, maintenance cost savings from replacing incandescents with longer-lived compact fluorescents, improved lighting quality, and other amenities. The parties agree that quantifiable non-energy benefits should be included in determining cost effectiveness, so that a measure or program would be considered cost-effective if total benefits exceed total costs. In other words, measures should be installed if the total cost of acquiring the resource, minus quantified non-energy benefits, is less than the value of the energy savings.

We agree that total costs and total benefits should be weighed in judging cost effectiveness. We do not believe, however, that utility ratepayers in general should subsidize the cost of demand-side measures that exceeds the value of energy savings. If program participants are unwilling to pay that excess cost, then we would question the existence or magnitude of the claimed non-energy benefits. Where the cost effectiveness of a measure or program depends on non-energy benefits, the utility should quantify those benefits or, as discussed in Issue 13, limit program incentives so that customers will choose only those measures where total benefits exceed total costs.

[2] Other issues in determining total resource cost and cost-effectiveness limits are examined elsewhere in this order: the use of a revenue requirements approach (Issue 7), the treatment of administrative cost (Issue 10), avoidable transmission and distribution cost (Issue 3), wholesale prices as proxies for the value of demand-side resources before new resources are needed (Issues 4 and 5), and the ten percent cost advantage (Issue 6).

Other tests for demand-side resources. The Council and SEA of O believe that all cost-effective conservation (identified by applying the TRC test) should be acquired and that rate impacts should not be considered in setting targets for demand-side programs. The Council dismissed the utilities' competitive concerns by suggesting that they work creatively with regulators to devise acquisition methods and regulatory treatment to keep the rate impacts of conservation to a reasonable level. Pacific, however, argued that a variety of tests, including the ratepayer impact test, should be used to gauge cost effectiveness.

In Order No. 89-507, which established requirements for least-cost planning by energy utilities, the Commission stated that the primary planning criterion should be "least cost for the utility and its ratepayers consistent with the long-run public interest." That order was issued at a time when the rate impacts of utility demand-side activities were imperceptible. The staff believes that, with the current ramp-up of utility programs and the prospect of increased competition in electricity supply, it is an opportune time for the Commission to clarify its views on the issue of minimizing costs or rates.

The staff disagrees with the Council and SEA of O. The staff argued that there are two reasons to consider the rate impacts of utility demand-side programs. The first focuses on efficiency: rate impacts may lead customers to switch to energy services or suppliers that are less efficient, i.e., more costly in terms of TRC. The second is an equity concern: participants may receive (through incentives and bill savings) more than the net benefit of acquiring the demand-side resource.

The staff recommends using the TRC test to determine the cost effectiveness of demand-side measures and programs. However, a utility should be able to argue in its least-cost plan that the acquisition targets suggested by a strict cost criterion should be reduced because the rate impacts would cause inefficient switching or be inequitable. A utility arguing that there would be inefficient outcomes would need to show that: (1) the rate impacts would probably cause certain customers to switch, (2) the impact on those customers could not be addressed by offering special contracts, changing rate spread and rate design, or redesigning programs to achieve savings with a greater contribution from participants, and (3) switching to other energy services or providers would raise the TRC of meeting energy needs. A utility proposing to reduce targets because of equity concerns would need to show that the disparity in impacts on different customers cannot be reduced: (1) by offering a broad range of programs, or (2) by making the changes listed in the second criterion for inefficient switching. The staff was unable, however, to recommend a general guideline for concluding that equity impacts are severe enough to reduce targets to acquire cost-effective demand-side resources. That issue should be addressed in the context of each company's least-cost plan.

SEA of O disagrees with the staff proposal on two grounds. First, it argues that the staff is proposing a "no-losers" test. Second, it believes that allowing exceptions to use of the TRC test because of equity concerns is inconsistent with the way other potential subsidy issues are handled. The Council also recommended that we specify how the rate impacts should be measured.

We are not convinced that the rate impacts of near-term demand-side activity will be serious enough to back off from the targets suggested by a TRC criterion, but we believe that utilities and other parties should have the opportunity to make the argument. Each utility's least-cost planning process provides the appropriate forum for this issue. Anyone arguing that rate impacts would cause inefficient switching or be inequitable should make the showings enumerated by the staff above. We will not establish a standard for measuring rate impacts or gauging their severity in this proceeding. Those issues are better addressed when the argument is raised in a specific least-cost plan.

External Costs. Order No. 93-695 states:

> In that proceeding (UM 551), we (the Commissioners) ask utilities to identify the difference in resources that are cost-effective with and without the specific values in the second guideline adopted here . . . our purpose is to insure that we will have enough information to determine prudence in a future rate proceeding.

The staff believes costs related to total suspended particulates (TSP), nitrogen oxides (NO_x) and carbon dioxide (CO_2) are likely to be internalized in some form within the 20-year planning horizon. Sulfur dioxide (SO_2) costs were recently internalized. Internalization of NO_x is anticipated in the 1990 Clean Air Act Amendments. The Clinton plan to achieve 1990 levels of greenhouse gas emissions by 2000 was released in late 1993. The staff argued that limiting each utility's CO_2 emissions to 1990 levels is tantamount to internalization.

We believe that the utilities should provide the information required by Order No. 93-695 in their compliance filings in this proceeding. The utilities should determine the effect of applying each of the six sets of adders given in the second guideline of the order. The adders should be treated as costs imposed on the utilities beginning in 1994. Utilities are not required by Order No. 93-695 to include these adders in the cost-effectiveness levels used to design and run demand-side programs. If external costs are later internalized or scheduled to be internalized and utilities have not acquired all the cost-effective conservation, however, we may exclude some of the cost of supply-side resources during subsequent rate proceedings.

SEA of O proposed that we order utilities to include externality adders in determining the eligibility of demand-side measures for funding in utility programs. As we understand it, SEA of O would not change the CEL but would instead recognize lower emissions from demand-side measures as a non-energy benefit in the TRC test. We view SEA of O's proposal, however, as tantamount to requiring utilities to include externality adders in the CEL, and we do not adopt it.

The Oregon Department of Energy and Oregon Housing and Community Services (ODOE/Housing) proposed additional language to the guideline which states: "Weatherization programs for low income households should include all measures that are shown cost-effective in standard program energy audits." The ODOE/Housing language is consistent with current Commission policy and is addressed in 13g below.

13. Under what conditions should measures that are not cost-effective be included in utility programs?

Measures that are not cost-effective, i.e., those that fail the test described in Issues 11 and 12 above, could be included in utility programs if it is demonstrated that:

a. **The measure produces significant non-quantifiable non-energy benefits. In this case, the incentive payment should be set no greater than CEL less the perceived value of bill savings, e.g., two years of bill savings;**

b. **Inclusion of the measure will increase market acceptance and is expected to lead to reduced cost of the measure;**

c. **The measure is included for consistency with other DSM programs in the region;**

d. **Inclusion of the measure helps to increase participation in a cost-effective program;**

e. **The package of measures cannot be changed frequently, and the measure will be cost-effective during the period the program is offered;**

f. **The measure or package of measures is included in a pilot or research project intended to be offered to a limited number of customers;**

g. **The measure is required by law or is consistent with Commission policy and/or direction.**

These conditions apply both to measures and programs with the exception of Item 13d. The utility or another party should show that one or more of these factors offsets the likely costs associated with applying measures that are not cost-effective.

The staff argued that under most conditions measures or packages of measures promoted by utilities should be cost-effective under the TRC test described in Issues 11 and 12 above. The staff acknowledged, however, that under some conditions it is appropriate to include measures that are not cost-effective in utility programs. The first condition (Item 13a) addresses non-energy benefits that are not recognized in the TRC test because they are difficult to quantify. Some measures or programs that are not cost-effective under the TRC test would be cost-effective if a value could be assigned to these non-quantifiable benefits. The staff believes that utility incentives can be designed to promote these measures. As noted in the discussion of Issues 11 and 12, measures should be acquired if energy benefits plus non-energy benefits exceed total costs. The staff pointed out that a customer would be inclined to install the measures if utility incentives (a rebate or loan subsidy, for example) plus the value of bill savings plus non-energy benefits exceed total costs. Combining these two principles suggests that utility incentives equal to the cost-effectiveness limit (which measures energy benefits) less the value of bill savings will lead customers to select measures where total benefits exceed total cost. The staff stated that two years of bill savings is a common payback requirement for energy efficiency improvements and could be used to represent the perceived value of bill savings.

The principle behind most of the other conditions is that costs will be lower over time if noncost-effective measures are included now. This could occur if measure or program costs are likely to fall with greater availability and use (Items 13b and 13c); including the measures leads to greater and earlier adoption of other program measures that are cost-effective (Item 13d); or the measures cannot easily be added to a program when they do become cost-effective (Item 13e).

The Commission has approved individual utility filings to include noncost-effective measures for many of the reasons listed in this guideline. The staff argued that this docket is an appropriate forum to adopt a comprehensive list as Commission policy.

Pacific offered three additional conditions under which noncost-effective measures could be included in utility programs. One of the company's suggestions was added as Item 13f above. The second proposal, "Offering the noncost-effective measure or bundles of measures will result in legislative or code adoption that will yield a cost-effective acquisition of resources," is covered by Item 13b. The third suggestion, "If a non-cost-effective measure is an integral component of a larger package of measures that in aggregate are cost-effective," was not added to the guideline. This condition is included in several of the conditions listed above, e.g., Items 13c, d, and e.

Sun, Wind and Fire suggested that an additional condition for inclusion of a measure should be measures with a high market value. This condition is essentially covered in Item 13a above and is not added separately.

We adopt the exceptions to the general cost-effectiveness standard proposed in this guideline.

14. How should the costs of measurement and evaluation of conservation programs be treated in determining cost effectiveness?

The present value of measurement and evaluation revenue requirements attributable to the program should be levelized over the expected program life for TRC calculations.

The staff argued that measurement and evaluation (M&E) costs should be included with other administrative costs in determining program cost effectiveness and that programs should be evaluated over their expected lives. M&E costs are generally concentrated in the first few years of the program when savings are low. In order to avoid burdening the cost-effectiveness evaluation with front-loaded M&E expenses, utilities should estimate the revenue requirements of M&E costs over the program life. The present value of the costs should be levelized and divided by annual savings attributable to the program to estimate the real levelized cost of M&E.

The Council asked for clarification about how M&E costs are applied to program savings. Savings attributable to the program will continue over the lives of all measures installed. If the annual savings are roughly constant, simple levelization of the present value of M&E costs and division by annual savings will yield a reasonable approximation of M&E costs per kWh saved. If necessary, the present value of M&E costs can be converted into more complex patterns of year-by-year costs to match the time stream of annual savings.

PGE indicated that M&E costs should not be amortized over the life of the program, because they are comparable to O&M expenses which should be expensed in the year incurred. PGE's point is a cost recovery issue. This is separate from the issue of including M&E costs in cost-effectiveness calculations, which is the subject of this guideline. The guideline has been changed to clarify this difference.

We believe the approach proposed by the staff for including program M&E costs in TRC calculations is reasonable, and is adopted.

15. Should lost revenues and DSM incentives to utilities be considered in the calculation of DSM measure/program cost effectiveness?

Utilities' lost revenues should not be included in the calculation of TRC, because they represent transfer payments from consumers. DSM incentives increase the present value of revenue requirements and should be recognized as a cost of conservation.

Pacific argued that when calculating the cost to the utility of undertaking a demand-side program, the cost of the incentive is an additional cost associated with the investment. The DSM incentive is an explicit cost that is above and beyond the opportunity cost associated with an alternative investment and should, therefore, be included in the TRC test. In contrast, the lost revenue adjustment is simply an accounting treatment that trues up what would otherwise occur in a normal rate case. Lost revenues should continue to be treated as a transfer payment between ratepayers and the utility rather than a DSM cost.

The staff generally agreed with Pacific. Although current standard calculations of TRC do not include DSM incentives to utilities as costs, consistent application of the revenue requirements approach to TRC would include incentives as costs. To the extent that the utility has a pure shared savings incentive mechanism, however, the company could make a qualitative argument that the incentive would not result in making a cost-effective program noncost-effective.

PGE argued that utility DSR incentives are "simply transfer payments and as such should not be included" in the calculation of cost effectiveness. Although taxes may also be considered transfers, we have determined that they should be included in TRC calculations. Incentive payments are a cost to ratepayers to attract utility capital for DSR. Lost revenues are transfers to other ratepayers, not to utility shareholders or governments, and should not be included in TRC.

SEA of O stated that incentive payments are an administrative cost which should also be counted in the program cost. The staff stated that it views incentive costs as more analogous to a regulatory risk premium on the cost of capital. Incentives to energy service companies would include similar costs. The result of the guideline, however, is consistent with SEA of O's recommendation.

We agree that incentives paid to utilities for implementing DSM programs increase the cost of the investment and should be included in future calculations of TRC.

ADDITIONAL GENERAL COMMENTS

In addition to comments on specific issues, the Council and SEA of O offered general comments for consideration. The Council proposed a guiding principle: Conservation should be treated like generation as much as possible. This principle is consistent with the Commission's first substantive requirement of the least-cost planning process included in its least-cost planning order: "All resources must be evaluated on a consistent and comparable basis." We continue to support this principle.

SEA of O expressed concern that in selecting the UM 551 issue list, the staff did not include all of the concerns SEA of O has expressed in this area. It believes these concerns would largely be addressed if the staff: (1) articulated a definition of cost effectiveness consistent with Oregon statute; (2) enumerated the applications where the cost-effectiveness concept is applied in program planning; and (3) included the cost of environmental externalities as required by statute and Commission order.

In response to SEA of O's concerns, the staff:

1. Included the definition of "cost-effective" as it relates to Oregon statutes in the discussion of Issue 7 above;

2. Stated that the TRC calculations are to be used in least-cost planning, utility acquisition decisions, and rate cases. The goal is to have a consistent metric for all forums; and

3. Pointed out that the Commission's authority and policy is described in Order No. 93-695. According to the Attorney General's Office, the Commission can disallow only costs based on internalized costs. The Commission can require utilities to estimate what resources would have been cost-effective under specific externality assumptions. It cannot require utilities to acquire them. The externality calculations required with utility CEL calculations resulting from this order can be used in later rate cases as evidence of the impact of anticipating that externalities would become internalized.

We concur with the staff's responses to SEA of O.

ORDER

IT IS ORDERED that the guidelines for calculation and use of conservation cost-effectiveness limits described in this order are adopted. Within 60 days of the effective date of this order, electric and natural gas utilities shall file compliance reports showing revised cost-effectiveness limits based on the guidelines adopted in this order. The filings should also include the externality information related to cost-effectiveness levels required by Order No. 93-695, as described in Issues 11/12 of this order.

Made, entered, and effective APR 0 6 1994.

Joan H. Smith
Chairman

Ron Eachus
Commissioner

Roger Hamilton
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-14-095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-13-070(2)(a). A party may appeal this order to a court pursuant to ORS 756.580.