BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1716

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation to Determine the Resource Value of Solar.

THE ALLIANCE FOR SOLAR CHOICE
CROSS RESPONSIVE TESTIMONY
OF
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July 21, 2016

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I. Benefits Not Directly Quantified in the Tool

Q: **Do any parties argue for the inclusion of additional benefit categories not currently captured by the draft E3 tool?**

A: Yes, several parties argue that there are benefits that the tool is not currently capturing. The Citizens' Utility Board of Oregon (CUB), for example, argues that the value of solar during low hydro conditions is not properly captured. Several parties, including CUB and the Joint Parties[1] highlight that the value of resiliency/security is left out. The Oregon Department of Energy (ODOE) points to several types of omitted benefits to the distribution system (voltage support, frequency ride-through, etc.).

Q: Do you agree that it is reasonable for these additional benefits to be included in the RVOS methodology?

A: Yes, I believe stakeholders should have the capability within the tool to model these types of benefits. These parties have highlighted value categories that are not always included in typical cost benefit evaluations, but do have the potential to result in direct utility avoided costs. To the extent that parties are able to provide compelling evidence that these categories result in quantifiable reductions in utility costs, they should be able to model these values directly within the tool.

[1] Renewable Northwest (RNW), the Oregon Solar Energy Industries Association (OSEIA), the NW Energy Coalition (NWEC), and Northwest Sustainable Energy for Economic Development (NWSEED).

Q: Do you believe E3 should attempt to quantify these additional categories?

A: Not necessarily. While I believe that E3 should include placeholders for user-defined $/kWh inputs, I acknowledge that the consultant may desire to adhere only to well-accepted methodologies for standard benefit categories. However, if a stakeholder is able to provide evidence for the utility avoided cost value of resiliency/security or additional values to distribution operations, they should be able to enter that value into the RVOS tool through this kind of user-defined input so that it can be easily included within the record of future proceedings.

Q: Has E3 included this kind of user-defined input in previous models to capture values where there isn't agreement on how they should be calculated?

A: Yes. In the *CA NEM 2.0 Public Tool*, E3 provided stakeholders with the option of including additional benefits that were not directly quantified within the model. Granted, these categories were considered societal benefits in the CA NEM 2.0 proceeding, which are outside the scope of this proceeding. But the principle remains the same: it was determined to be prudent and reasonable to allow stakeholders to model additional benefit categories to the extent they were able to provide reasonable evidence on the record. Below is a screenshot from the inputs tab of the CA NEM 2.0 Public Tool, where "other" categories were made available to input costs/benefits in terms of $/kWh of thermal generation, $/kWh of NEM generation, or $/kW-yr of NEM capacity. The same types of flexible inputs could be made available for the additional direct utility avoided costs mentioned above.

Societal Inputs	2015 Value (2015 $)	Esc	Units
Societal Cost of Carbon		5%	$/tonne CO_2
Societal Cost of PM-10		5%	$/lb
Societal Cost of NO_x		5%	$/lb
Externality Costs Related to RPS Assets		5%	$/kW-yr RPS-Qualifying Capacity
Energy Security Cost		5%	$/kWh Thermal Generation
Other		5%	$/kWh Thermal Generation
Other		5%	$/kWh NEM Generation
Other		5%	$/kW-yr NEM Capacity

II. Response to Party Comments on Specific Value Categories

Comments on Generation Capacity:

Q: **PacifiCorp Witness Dickman states on p.16 that "the resource deficiency period for the RVOS should be determined consistent with the [qualifying facility (QF) avoided cost] methodology, including any changes or updates to the methodology used to determine resource deficiency for QF avoided costs." Do you agree?**

A: I do not. Behind the meter (BTM) solar, since it is smaller scale and installed onsite, is more akin to other customer-side resource like demand response (DR) and energy efficiency (EE). In some states, including Oregon, the methodologies used to value the capacity from those demand-side management (DSM) resources are justifiably different than the QF avoided cost methodology.

Q: Can you point to any examples where the Oregon Public Utility Commission (OPUC) has approved valuation methodologies that differ from the QF avoided cost?

A: Yes. Below is an excerpt from Idaho Power's Annual DSM Report that describes the different approach taken for the valuation of demand response:

"OPUC order No. 13-482, defined the annual cost of operating the three demand response programs for the maximum allowable 60 hours to be no more than $16.7 million. This $16.7 million value is the levelized annual cost of a 170-megawatt (MW) deferred resource over a 20-year life. The demand response value calculation will include this value even in years when the IRP shows no peak-hour capacity deficits."[2]

Q: What is the significance of this example?

A: While this methodology resulted from a stipulation agreement, and therefore does not necessarily create a precedent for using a similar methodology in all cases, the fact that parties agreed to this approach does show some degree of acknowledgment that it is reasonable to value demand-side resources (DSR) in a different way then wholesale market resources like QFs.

Q: Have other states chosen to value DSR resources differently than their QF avoided cost rate?

A: Yes, California has also determined that it is appropriate to value the capacity from DSM resources differently than supply-side resources. A recently issued Order on the valuation

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[2] Idaho Power Company, *Demand-Side Management 2015 Annual Report*, Supplement 1: Cost-Effectiveness (Mar. 15, 2016), pp. 2-3, *available at* https://www.idahopower.com/pdfs/AboutUs/RatesRegulatory/Reports/DSM_2015Supplement1.pdf.

of DSRs does away with the concept of Resource Balance Year (RBY) altogether for the valuation of DSRs.[3] In the Order, the California Public Utilities Commission (CPUC) finds that "eliminating the resource balance year provides distributed energy resources with the appropriate value of avoided supply side capacity," that "the use of the resource balance year ignores the fact that the short lead times of distributed energy resources add value to the system," and that continuing to rely on the RBY framework "ignores the value of the role distributed energy resources played in past planning decisions."[4]

Q: Are there any additional arguments to support a methodology that differs from the approved QF avoided cost method?

A: Yes. I would like to highlight Staff's response to TASC DR-11 attached as TASC Exhibit 201 to this testimony:

"TASC DR-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."

[3] CPUC, Decision 16-06-007, Rulemaking 14-10-003 (June 9, 2016), pp. 12-17

[4] *Id.* at pp. 17, 23 (Finding of Fact 27).

Staff responded by acknowledging that "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.

Staff qualified this by saying that this potential circularity does not apply to the RVOS methodology because "the current calculation of RVOS will not be used directly in formulating compensation for behind-the-meter solar at this time."

Q: Do you agree with Staff's response to TASC DR-11?

A: I agree with Staff's acknowledgement of the potential for this circularity in the valuation process. This potential for circularity, and to undervalue BTM solar capacity, is one reason why the CPUC recently did away with the concept of Resource Balance Year in the decision referenced above.

Q: Do you agree with Staff's statement that "the current calculation of RVOS will not be used directly in formulating compensation for behind-the-meter solar at this time"?

A: Staff states that the potential circularity is not relevant because the RVOS methodology is not intended to be used directly in formulating compensation for BTM solar, but this highlights the fact that the appropriate methodology for RVOS is tied in some ways to how it will be used. The statement implies that if the RVOS methodology were to be used as the basis for compensating BTM solar, that the methodology for calculating the capacity value may be inappropriate. TASC notes that PacifiCorp explicitly states that they believe the RVOS methodology should form the basis for compensation of BTM solar,[5] and therefore recommends that the way in which the methodology is to be used should be clarified at this stage of the proceeding before the detailed work begins of calculating utility-specific RVOS values for each utility.

Q: Do other parties point to any additional shortcomings of attributing capacity value only to years after the resource deficiency year?

A: Yes. CUB points to the history of energy efficiency in Oregon, which is relevant to this discussion. As CUB Witnesses Jenks and Hanhan describe, the 1990s saw a period of low short-term avoided costs, and an expectation that there was ample energy supply available in the market. When the state experienced a low hydro year in 2001, which was compounded by the California energy crisis, it became clear that short-run avoided costs were not an adequate way to value the long-term contributions toward mitigating the

[5] PAC/11 at p. 4.

effects of extreme weather patterns or other types of tail events. Valuing resources based only on the short-run avoided costs risks undervaluing those resources, and therefore underinvesting in them.

Comments on Avoided T&D Benefits

Q: Is there agreement among parties with respect to the appropriate methodology for calculating the avoided cost benefits associated with Transmission and Distribution Capacity?

A: No there is not. Utilities seem to be resistant to the idea that a fleet of rooftop solar systems can avoid or defer capital spending on T&D capacity expansion. In particular, there is a common belief that data availability is a huge hurdle to calculating (or even acknowledging) this benefit category.

Q: Are utility concerns with respect to data availability a sufficient justification for assuming the value of the T&D avoided costs is zero?

A: No. While it's true that the absence of granular hourly load data at the substation or circuit level limits the types of analysis that can be used to assess this benefit category, there are reasonable proxies that can be used in the absence of this ideal data. For example, most utilities develop marginal transmission and distribution costs as part of their general rate cases. These marginal cost values can be allocated to specific hours through Loss of Load Probability or Probability of Peak analysis. But if that analysis has not been done, then the top 100 or 150 system load hours could serve as a reasonable proxy, where those hours receive a load-weighted allocation, normalized to a total of 100%. Taking the position that the absence of ideal data justifies a zero value for a particular category is not reasonable in my opinion.

Q: In response to TASC DR-19, Staff states that "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 investor-owned utilities (IOUs) do not currently produce values that specifically measure avoidable T&D costs. In the absence of more specific values, I believe that the [Marginal Cost of Service Study (MCOSS)] provide a reasonable basis for these sample values." Do you agree?

A: Yes. In the absence of more granular data, the values derived from the MCOSS provide a reasonable basis for the average avoided T&D costs. To the extent utilities feel that this framework does not properly account for the avoidable costs in this category, they will be able to propose an alternative methodology based on available data for consideration by stakeholders and the Commission in the appropriate venue. Staff's response to TASC Data Request 19 is attached as TASC Exhibit 202 to this testimony.

Q: In response to TASC DR-14, Staff states that "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 distributed energy resources into distribution system investment decisions as well as to establish mechanisms to fairly compensate these resources." Do you agree?

A: Yes. Failure to take into account the potential of non-wires alternatives within the planning process creates a barrier to realizing the avoided transmission and distribution (T&D) benefits. To overcome that barrier, utility planning processes need to consider the potential of non-wires alternatives. This is starting to become more widespread for transmission planning. FERC Orders 1000 (released in 2011) and 890 (released in 2007) have both emphasized "comparable treatment" of non-wires alternatives in transmission planning. California has taken the concept a step further by including the requirement directly in the Public Utilities Code.[6] These requirements have already led to significant benefits: the California ISO's most recent transmission plan, for example, has called for the cancellation of $192M of previously approved transmission upgrades that are no longer needed due to the effects of EE and distributed generation (DG).[7]

With respect to distribution planning, a small number of states are showing leadership in reforming these processes to remove the financial disincentive most utilities have to avoid the building of new infrastructure. As Witness Olson references, California and New York are looking for ways to integrate DERs into the planning processes that drive investment decisions, and to enable them to be compensated based on providing that

[6] Cal. Pub. Util. Code § 1002.3: "In considering an application for a certificate for an electric transmission facility pursuant to Section 1001, the commission shall consider cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable, and affordable supply of electricity, including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation, as defined in Section 353.2, and other demand reduction resources."
[7] CAISO Board-approved 2015/2016 Transmission Plan.

value. Staff response to TASC Data Request 14 is attached as TASC Exhibit 203 to this testimony.

Q: On p.14 of Portland General Electric Company's (PGE) testimony, PGE's Witnesses Brown and Murtaugh suggest that the avoided T&D benefit should apply "only for solar systems that are capable of reliably delivering output during a system peak event, as mentioned above, and are large enough, in aggregate, to defer the needed capacity." Do you agree with this statement?

A: No. First, individual systems are unlikely to be large enough on their own to defer an entire piece of distribution infrastructure. The only reason to implement this narrow requirement for recognizing T&D value from DG installations is to support a view that the T&D benefit at zero. Such a view has no basis in real planning constraints, however. In fact, a fleet of aggregated DERs benefits from geographic diversity with respect to the solar generation profile, and has a reduced risk of outage for a given amount of installed kWs given that there are single points of failure like there would be for a single large system. For this reason, it is reasonable to look at the fleet of distributed solar generators in aggregate, and determine the capabilities and benefits of the fleet as a whole. With respect to the concept of "reliably delivering output during a peak event," PGE does not explain in sufficient detail what this means, and it is therefore not actionable. Given the uncertainty with respect to when the peak occurs and how long it will last, a probabilistic approach is warranted.

PGE states that loss-of-load probability (LOLP) "is not the correct data to accurately value this benefit. Although not currently available, hourly usage data by feeder is the correct data to measure peak usage and accurately estimate avoided T&D benefit."[8] TASC disagrees, and believes it is the appropriate information from which to develop a proxy value in the absence of circuit-level load data. While LOLP data may more typically be used to assess system reliability metrics and the need for additional planning reserves, it also provides a good high-level assessment of the range of hours where the system is most likely to be stressed. While not ideal for all purposes, in the absence of more granular load data it is a reasonable proxy for allocating the avoidable marginal costs to specific hours.

TASC reiterates that the absence of ideal data is not sufficient justification for assuming a benefit category is zero. There are ways of developing reasonable proxy values from available data, and in Phase 2 of this proceeding, we hope that utilities put forth methodologies that acknowledge the potential of DG to defer or avoid upgrades over the planning horizon, and thereby reduce infrastructure spending to the benefit of all ratepayers.

Q: On p.17, PacifiCorp Witness Dickman, with regard to avoided T&D benefits, suggests that "a symmetrical component of the calculation should be included: costs associated with accelerated transmission and distribution investments." Do you agree?

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[8] PGE/100 at p. 11.

A: TASC does not disagree that it is theoretically possible for additional costs to be incurred when there is a very high penetration of DG solar on certain circuits. In cases where such upgrades do not have a more cost-effective non-wires alternative, it may be reasonable to make those investments. However, TASC would like to highlight that there are alternative solutions available to distribution planners in many of these situations to mitigate these issues at low cost. SolarCity's grid engineering team has produced a whitepaper that explains some of the common mitigation solutions that utilities tend to propose to address perceived issues on high penetration circuits, and provides alternative solutions that can achieve the same reliability benefits at little to no cost. These alternative solutions can include changing settings on existing protection equipment or providing the same reliability benefits with smart inverters.[9] Before attempting to quantify this kind of "symmetrical" cost component, the potential for non-wires alternatives should first be explored.

RPS Value:

Q: Did any parties object to the methodology for RPS value described on p.32 of Staff Witness Olson's testimony?

A: Yes. PacifiCorp witness Dickman states on p.17 that "With respect to RPS Compliance, to the extent distributed solar generation does not provide the utility with RPS value, the value should be zero." Similarly, PGE Witnesses Brown and Murtaugh state that "This

[9] SolarCity, Technical Brief on Utility Mitigation Requirements, *available at* http://www.solarcity.com/company/distributed-energy-resources#.

element would apply only if the RPS compliance is truly avoided and PGE gets the RECs from the solar production."

Q: **Do you agree that Avoided RPS Value requires that the BTM solar generation qualifies to provide RECs to the utility?**

A: No, and I believe this represents a fundamental misunderstanding of what this category is intended to represent. The compliance value doesn't stem from providing eligible REC credits directly. Rather, the benefit comes from reducing the retail load on which the compliance obligation is based. To the extent that contracting with RPS-eligible generators leads to above-market costs, the lower retail sales would reduce the cost of RPS compliance by (market costs * the RPS%).

Carbon compliance benefits:

Q; **On p.8 of PacifiCorp Witness Dickman's testimony, he states that "PacifiCorp currently incurs no monetary cost of carbon for environmental compliance, so this element should either be excluded or set to zero." Based on your experience with long-term resource planning, does this approach to resource valuation follow industry best-practices?**

A: No. In long-term planning, analysts do their best to estimate a reasonable set of assumptions to represent future conditions, which inherently involves uncertainty. To assume future benefits are zero simply because those benefits can't be realized in 2016 under current planning frameworks and regulatory regimes doesn't mean that they should be assumed to be zero out of hand.

Taking such a position in long-term planning would in general be imprudent given the high likelihood of carbon compliance costs being implemented during the planning horizon. In fact, in PacifiCorp's most recent IRP, the company is modeling a number of possible scenarios taking into account possible Clean Power Plan rules, as required by the OPUC's 2015 IRP order.[10] In a recent stakeholder presentation, the company also lists several Oregon-specific GHG regulations that could impact the costs of future resource portfolios, including an emissions performance standard of 1,100 lb CO2/MWh, and the Clean Electricity and Coal Transition Plan (SB 1547) which is designed to ensure GHG reductions from the electric sector.[11]

Ancillary Services Benefits and Renewable Integration Costs

Q: Please describe your understanding of the benefit associated with avoided ancillary services procurement.

A: To the extent a balancing area authority procures ancillary services as a percentage of load, the reduction in retail load reduces the need for these types of ancillary services.

[10] OPUC Docket No. LC 62.
[11] PacificCorp, 2017 Integrated Resource Plan, Public Input Meeting 2 (July 20, 2016), http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_2017_IRP_PIM02_7-20-16.pdf.

Q: Please describe your understanding of what Renewable Integration Costs are meant to capture.

A: Calculated integration costs typically attempt to capture the anticipated increase in operational costs required to manage the intermittency of incremental renewable generation. This increase in operational costs is typically driven by an increase in requirements for frequency regulation, load following, or other types of ancillary services.

In the 2014 E3 PUCN Report, E3 conducted a literature review to arrive at an estimated integration cost of $.002 per kWh.[12] In E3's 2013 California NEM Impact Evaluation, the integration costs in the base case were estimated at $.0025 per kWh.

Q: Despite the differences between avoided ancillary services and integration costs, these categories are combined in the RVOS methodology. Did any parties highlight this inconsistency in their testimony?

A: Yes. The Joint Parties highlight this inconsistency, and suggest that the two categories should be disaggregated.[13]

Q: Do you agree with the Joint Parties assertion that these two categories should be separated into distinct value and cost categories?

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[12] 2014 PUCN NEM Evaluation, p. 61.
[13] RNW, OSEIA, NWEC, NW SEED/100 at pp. 7-8.

A: I do. The Joint Parties state that the current implementation "does not seem to comport with the definition discussed by stakeholders during the initial part of Phase 1, Investigation 1, of UM 1716."[14] While I did not attend the discussion among stakeholders that the Joint Parties reference, I agree that it would be reasonable to separate these categories into distinct value/cost streams rather than combining them as is the case in the current tool.

Q: In previous studies, has E3 included as a benefit the reduced need for ancillary services?

A: Yes. For example, in the 2013 NEM Evaluation Report, E3 bases this benefit on the fact that "reductions in demand at the meter result in additional value from the associated reduction in required procurement of ancillary services."[15] In the CA NEM study, E3 approximated this value of the reduced need for ancillary services based on reduced load at 1% of the energy cost of serving load. In E3's 2014 PUCN NEM Report in Nevada, this benefit category was again calculated by taking the total projected spinning reserve spending and dividing by the total energy production cost spending. This resulted in estimated avoided costs of .5% and 2% of total energy production costs for NVE South and NVE North respectively, which was applied in the same proportion to levelized energy generation avoided costs.[16] This same approach would be a reasonable approximation for estimating this benefit for OR as well.

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[14] *Id.*
[15] E3 2013 NEM Evaluation Report, p. C-39.
[16] E3 PUCN Report, p. 63, *available at* http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf.

Q: Does this conclude your testimony?

A: Yes it does.

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TASC EXHIBIT 201

Staff Response to TASC Data Request DR-11

July 21, 2016

<u>TASC Data Request 11</u>:

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.

<u>Staff Response to TASC Request 11</u>:

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.

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TASC EXHIBIT 202

Staff Response to TASC Data Request DR-19

July 21, 2016

TASC Data Request 19:

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?

Staff Response to TASC Request 19:

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.

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TASC EXHIBIT 203

Staff Response to TASC Data Request DR-14

July 21, 2016

TASC Data Request 14:

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?

Staff Response to TASC Request 14:

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.