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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE INVESTIGATION OF THE COSTS AND BENEFITS OF PACIFICORP'S NET METERING PROGRAM	Docket No. 14-035-114

DIRECT SURREBUTTAL TESTIMONY OF JEREMY I. FISHER REGARDING NET METERING

[Redacted Public Version]

HEAL Utah ("HEAL") hereby submits the redacted public version of the prefiled Direct Surrebuttal Testimony of Jeremy I. Fisher in this docket regarding PacifiCorp's benefit/cost assessment of distributed generation net metering in Utah.

DATED this 8th day of August, 2017.

Respectfully submitted

By: /s/ *Phillip J. Russell*
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Certificate of Service
Docket No. 14-035-114

I hereby certify that a true and correct copy of the foregoing redacted public version of the prefiled Direct Testimony of Jeremy I. Fisher was served by email this 8th day of August, 2017, on the following:

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BEFORE THE
PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program	Docket 14-035-114

Surrebuttal Testimony of Jeremy I. Fisher, PhD

On Behalf of
HEAL Utah

PUBLIC VERSION

August 8, 2017

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1. <u>Introduction and Purpose of Testimony</u>

Q Please state your name, business address, and position.

A My name is Jeremy I. Fisher. I am a Principal Associate with Synapse Energy Economics, Inc. ("Synapse"), which is located at 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Are you the same Jeremy Fisher who provided Direct Testimony in this docket on June 8, 2017?

A Yes, I am.

Q What is the purpose of your testimony?

A My testimony responds to certain claims made by PacifiCorp ("Company") witnesses Mr. Michael Wilding, Mr. Robert Meredith, and Dr. Gary Hoogeveen, and by Utah Department of Public Utilities ("DPU") witness Mr. Stan Faryniarz.

In particular, I address three areas of contention:

1. The relationship between the 2017 Integrated Resource Plan ("IRP") and the value of rooftop solar;
2. The validity of the GRID model for the purposes of estimating *marginal* changes in net power cost due to solar distributed generation;
3. That the above-retail costs of various of the Company's coal fleet are not comparable to the costs incurred for residential net metering.

2. <u>Relationship between the 2017 IRP and the value of rooftop solar</u>

Q Which of these witnesses addressed the relationship between the 2017 IRP and the impact of distributed generation?

A In direct testimony, multiple witnesses, including myself, referenced the lower system cost of an IRP run with substantial additional distributed, or private, generation, demonstrating that there were long-term system benefits accrued within PaciCorp's model. This reference to the 2017 IRP was touched upon by Company witnesses Mr. Meredith and Mr. Wilding, and DPU witness Mr. Faryniarz.

Mr. Meredith's primary stated concern is that the 2017 IRP private generation sensitivities, which demonstrated a net system benefit for NEM, are too uncertain and not representative of value. Mr. Wilding's only stated concern is that the 2017 IRP did not demonstrate a near-term capacity need that could be deferred or avoided by rooftop solar. Mr. Faryniarz's stated concern is altogether different - that the IRP is still not approved, and to evaluate a system-benefit of solar, the IRP would have to be configured with a "well-constructed with-and-without analysis."[1]

Q Please describe the nature of Mr. Meredith's stated concerns using the IRP for any form of valuation.

A In his testimony, Mr. Meredith seeks to distinguish rooftop solar as a generation source distinct from any other resource – supply or demand-side – considered by the Company, and rejects the notion that rooftop solar may provide system benefits outside of the immediate test year. He states:

> The IRP sensitivities [of private generation] are not a net benefit analysis. Private generation is modeled as a reduction to load without any assignment of the incremental cost of private generation that non-participating customers pay in the form of bill credits. Also, the IRP is used to prepare a long-term resource plan that is based on a 20-year planning horizon… [and captures]

[1] Rebuttal Testimony of DPU witness Mr. Stan Faryniarz at 802-803.

> changes to long-term system costs that are increasingly uncertain over the 20-year forecast used for any given IRP.[2]

Mr. Meredith states that "a determination of the costs and benefits of NEM should not rely on the difference between a pair of IRP sensitivity runs, because they include benefits that are anticipated many years into the future."[3]

Q Are the IRP sensitivities of private generation a "net benefit analysis"?

A While these sensitivities were probably not designed for net benefit analysis, they certainly provide key components of that function. Mr. Meredith's concern that the lack of "incremental costs of private generation" are not captured in the IRP is misplaced. The IRP is agnostic to rate structures and seeks only to characterize system cost impacts from different resource portfolios. Irrespective of if we consider a bill credit a payment or a transfer, the overall system benefit is incontrovertible – substantial increases in customer-sited generation reduce PacifiCorp's overall net system costs and defer capacity additions.

Q Are long-term system costs increasingly uncertain over the 20-year forecast used in the IRP?

A Absolutely. But the purpose of long-range resource planning is to account, as best as possible, for that uncertainty and to make decisions on the basis of robust forecasts.

Q Does long-term uncertainty stop the utility from making long-term investments?

A No. PacifiCorp regularly seeks to make investments on the basis of long-run benefits. As one particularly notable example, docket 17-035-40 is PacifiCorp's application to approve new wind and transmission. In that docket, a substantial

[2] Rebuttal Testimony of Company witness Robert M. Meredith at 345-353.

[3] Rebuttal Testimony of Company witness Robert M. Meredith at 357-359.

component of the Combined Project benefit cited by PacifiCorp occurs between 2036 and 2050, an *extremely* long analysis period and a reliance on benefits anticipated many years into the future. Mr. Meredith's objection to long-term uncertainty is in direct contrast to the Company's standard practices.

Q Is it appropriate that the determination of the costs and benefits of rooftop solar should rely on the difference between a pair of IRP sensitivity runs?

A Yes. Mr. Meredith's concern that valuation should not be based on paired IRP runs also runs contrary to the Company's standard practices. The Company has a long history of using paired IRP sensitivity runs to establish the value of power plants, large capital investments, and transmission lines.[4] Again, looking to contemporaneous docket 17-035-40, PacifiCorp establishes that "net customer benefits are calculated as the [difference in present value of revenue requirements] PVRR(d) between two simulations of PacifiCorp's system," in which "one simulation includes the Combined Projects, and the other simulation excludes the Combined Projects."[5] The simulations are conducted using the same model and framework as used in the IRP,[6] testing sensitivities from the self-same 2017 IRP. [7]

Under Mr. Meredith's logic that benefits anticipated "many years into the future" should be excluded from consideration, no capital retrofit, transmission investment, fuel contract, or really any capital investment would be considered or approved. PacifiCorp – and every other utility – rely on forecasts of future conditions to assess the costs and benefits of contemporary projects and programs.

[4] For example, Volume III analyses in 2013 and 2015 IRP; voluntary pre-approval application for emissions controls at Jim Bridger 3 & 4 in Utah docket 12-035-92; certificate of public convenience and necessity for emissions controls at Naughton 3 in Wyoming 20000-400-EA-11; evaluation of transmission alternatives in 2013 IRP.

[5] Direct Testimony of Company witness Mr. Rick Link in Utah 17-035-40 (June 30, 2017) at 372-374.

[6] Direct Testimony of Company witness Mr. Rick Link in Utah 17-035-40 (June 30, 2017) at 368-369.

[7] Direct Testimony of Company witness Mr. Rick Link in Utah 17-035-40 (June 30, 2017) at 133-155.

Mr. Meredith's attempt to cast rooftop solar as a generation source distinct from any other system resource and ineligible to provide system benefits should be rejected.

Q What is Mr. Wilding's stated concern with respect to the 2017 IRP and this instant docket?

A Unlike Mr. Meredith, Mr. Wilding relies on an outcome of the IRP to identify a capacity "deficiency period," and rejects the idea that distributed generation – or any other resource – may have a capacity benefit prior to 2029.[8] Deficiency period—a term of art used for Schedule 37 and 38 tariffs for qualified facilities under PURPA—is, as Mr. Wilding states, the year in which the next major thermal resource acquisition is identified in the Company's IRP.

Q Why would a deficiency period in 2029 suggest that there is no capacity value for rooftop solar?

A Mr. Wilding is equating the treatment of distributed generation solar customers with general qualified facilities. Utah has adopted a framework by which qualified facilities are not compensated for a capacity benefit unless the Company's IRP demonstrates a resource need. While an intriguing concept if executed reasonably and without respect to bilateral capacity trades, this framework unfortunately may provide a strong incentive for the Company to adjust the IRP such that the next major resource is identified in a far future year. In the 2017 IRP, the resource deficiency period is a particularly striking fiction.

Q How is the resource deficiency period of the 2017 IRP a fiction?

A Resource deficiencies at PacifiCorp are driven, almost exclusively, by coal plant retirements. As such, we have to turn back to how coal plants were assessed in the 2017 IRP and a process designed to select against plant retirements. We find that the major resource acquisition dates are a direct outcome of a non-optimized,

[8] Rebuttal Testimony of Company witness Mr. Michael Wilding at 69-75.

subjective and non-documented process in the IRP, decided upon by a small group of PacifiCorp executives and lawyers.[9]

But for one case, coal retirements in the 2017 IRP are not optimized in any way for least cost. The Company created five "Regional Haze" alternative scenarios meant to illustrate potential negotiating positions with EPA with respect to regional haze compliance options. Irrespective of the dubious legality of these alternative compliance options, their design is completely opaque.

In general, the alternatives seek slightly earlier retirement dates (than approved book lives) in hopes that EPA will loosen environmental obligations at other units. In reviewing the IRP, parties asked PacifiCorp to provide its explanation and workpapers justifying the Regional Haze scenario creation, but the Company demurred with objections, generalities, and insisted that the IRP itself was sufficient evidence.[10] In assessing these scenarios, I found (on behalf of Sierra Club) that PacifiCorp's preferred portfolio results in substantially higher emissions than the control case.[11] In order to be viable alternatives, the resulting emissions and visibility improvements from the Regional Haze alternatives should have been better than EPA's Best Available Retrofit Technology (BART).

The Regional Haze Alternatives, including the preferred portfolio, were created independently of any least cost scenario planning. The deficiency date of 2029 is based only on the Company's assumption that Dave Johnston plant will retire at the end of its approved depreciable life,[12] resulting in a capacity shortage sufficient to trigger a new thermal resource.

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[9] Oregon LC 67 (2017 IRP) SC DR 1.1 (June 13, 2017). Attached as HEAL___(JIF-SR1).

[10] Oregon LC 67 (2017 IRP) SC DR 1.1(a). (June 13, 2017)

[11] Refer to public comments from Sierra Club in Oregon LC 67 (2017 IRP). Page 20, "With respect to NOx emissions … the Company's Preferred Portfolio is far worse than BART…. The Preferred Portfolio is consistently higher than the Reference Case by 10,000 to 13,000 tons NOx every year from 2023 to 2032, or an average of 58% higher from 2022 to 2037."

[12] 2017 IRP, page 195

Q Would a reasonable planning process result in an earlier resource deficiency date?

A Probably, although PacifiCorp notably did not provide sufficient information to decisively answer this question. After substantial stakeholder feedback during the IRP process,[13] PacifiCorp finally acquiesced to a single run in which it would allow for "endogenous retirement" of coal plants. In that run, called "Regional Haze Alternative 6", it allowed six units – Hunter 1 and 2, Huntington 1 & 2, and Jim Bridger 1 & 2 – to retire early rather than install environmental controls.[14] As a consequence, Jim Bridger 2 was shown to retire in 2021. Notably, PacifiCorp did not allow any of its other 18 units to retire early, despite evidence that some of these units are non-economic today.

Thus, while it is clear that Jim Bridger 2 would retire by 2021 if faced with a large capital investment, it is also quite possible and arguably likely that other units, given the option, would retire even earlier. Operating economically, PacifiCorp should have a capacity deficiency today.

Q What do you conclude with respect to Mr. Wilding's stated concern about the deficiency date?

A Mr. Wilding's reliance on the 2017 IRP's notional deficiency date is problematic and inconsistent with least cost planning and his assumption that because of this

[13] Comments from Sierra Club (7-14-2016). Available online at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/Sierra_Club_2017_IRP_Stakeholder_Comments_Form_07122016.pdf.

Comments from Sierra Club, Idaho Conservation League, HEAL Utah, NW Energy Coalition, Western Clean Energy Campaign, and Powder River Basin Council – CPP and Regional Haze Scenarios (9-14-16). Available online at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/Sierra_Club_et.al_2017_IRP_Feedback_Form_9-14-16(joint%20comments).pdf.

Comments from Utah Clean Energy (9-15-2016). Available online at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_Feedback_Form_UCE%20Comments_on_Portfolio_Development_and_Supply_Side_Resources(2)_9.15.16.pdf

[14] Oregon LC 67 (2017 IRP) Sierra Club Discovery Response 1.3 (June 13, 2017). Attached as HEAL___(JIF-SR2).

deficiency date there is no capacity benefit – either real or notional – for a resource capable of reducing requirements at PacifiCorp's load centers is troubling. Mr. Wilding highlights the extraordinary importance of understanding – and correcting – PacifiCorp's deficiency date in the 2017 IRP.

Q What is Mr. Faryniarz's stated concern with respect to the use of the IRP in the valuation of rooftop solar?

A In contrast to Mr. Wilding's adoption of the 2017 IRP outcomes, Mr. Faryniarz is concerned that a reliance on the 2017 IRP to determine a value for solar is premature.

I would suggest that the 2017 IRP is indicative, if not definitive. There are clear problems with the construct of the 2017 IRP, as I discussed previously and in other forums, but at the moment it provides the only long-term valuation construct available to this Commission.

Q Mr. Faryniarz suggests that "instead of attempting to update an IRP in estimating the value of solar," "distributed solar generation [should be included] as a resource in the IRP, perhaps in a well-constructed with-and-without analysis."[15] What is your reaction to this recommendation?

A I'm cautiously optimistic about this approach, but such an analysis would require an extraordinary amount of oversight and review. Hypothetically, if the Company's model were able to adjust all relevant factors including not only the variable cost of existing generation but the avoided fixed cost of retiring generators, avoided fuel contracts, avoided major transmission investments, and deferred capacity, a "well-constructed with-and-without" analysis could be quite instructive.

However, the Company's long-term modeling operates by locking down many key assumptions including transmission builds, coal retirements, and carbon caps.

[15] Rebuttal Testimony of DPU witness Mr. Stan Faryniarz at 799-805.

Avoided distribution costs, avoided emissions costs, and avoided coal mine capital are simply not built into the model framework, and thus – like other jurisdictions – we are compelled to estimate on the basis of available information.

That being said, the Commission has a unique opportunity to seek a long-term benefit study from the Company structured to elicit as much valuable information as possible with the least number of adjustments *post hoc.* It is my opinion that the valuation using a series of adjustments or "updates" is more indicative than the truncated one-year analysis provided by the Company.

3. THE VALIDITY OF THE GRID MODEL FOR THE PURPOSES OF ESTIMATING MARGINAL CHANGES IN NET POWER COST DUE TO SOLAR DISTRIBUTED GENERATION

Q What are your concerns with respect to the GRID model and the Net Power Cost findings?

Overall, I'm increasingly concerned that the GRID model is an inappropriate framework for assessing changes in marginal costs (or benefits) as used by the Company in this docket. In his rebuttal testimony, Mr. Wilding states that "the GRID model optimizes all Company resources to meet the additional load at the lowest possible cost,"[16] but I believe this is rebutted by Mr. Wilding's corrections and findings from a concurrent docket in Oregon.

These concerns are as follows:

1. Variable operations and maintenance ("VOM") costs are not applied to dispatch, and are under-represented on the margin;
2. GRID does not capture minimum fuel take contracts;
3. GRID does not capture multi-tier fuel contracts;

[16] Rebuttal Testimony of Company witness Mr. Wilding at 104-110.

4. GRID does not capture unit commitment decisions;

While potentially minor for determining total NPC as used in rate cases, these flaws with the GRID model framework undermine its value in reviewing differences between model runs, as used in this valuation docket.

Q What is your concern with respect to VOM costs as represented in GRID?

A My concern is three-fold. First, I believe that Mr. Wilding used the wrong VOM value. Second, the VOM numbers associated with 2015 are not reasonable for a 2016/2017 filing. Third, Mr. Wilding misrepresented the way VOM was used within GRID.

Mr. Wilding, responding to intervenor concerns, states that he added "the annual weighted average variable O&M cost for coal and natural gas plants … to the 2015 actual unit costs for coal and natural gas, respectively… The result was an annual weighted average variable O&M cost of $1.22/MWh for coal plants and $0.24/MWh for gas plants, respectively."[17]

An average VOM, weighted by 2015 annual generation is <u>not</u> indicative of the marginal cost of VOM in the PacifiCorp system. As shown in his workpapers, VOM for coal units spans a range from $0.59 to $1.73/MWh, a span of $1.44/MWh. Notably, [redacted] has one of the highest VOM costs at $[redacted] As I discussed in my direct testimony, the GRID model shows that [redacted] generation represents [redacted] of the margin.[18] Therefore, the appropriate marginal VOM cost would have been at least $[redacted]

In addition, as a 2015 model, the VOM at Jim Bridger would likely not have included the cost of the selective catalytic reduction ("SCR") equipment at Jim

[17] Rebuttal Testimony of Company witness Mr. Wilding at 58-62.

[18] See Direct Testimony of Jeremy Fisher, page 9 at 4-6

Bridger 3, which only became operational November 25, 2015, or at Bridger 4 a year later in November 2016.[19] According to the Company's workpapers filed with the 2017 IRP, the SCRs increased the cost of VOM at Jim Bridger 3 & 4 by nearly 40%.[20]

[redacted] the marginal VOM today for the coal units should be [redacted] – about 80% higher than used by Mr. Wilding.

Finally, it is notable that Mr. Wilding only applied VOM *post-hoc* to the GRID model, and did not include it as an adjustor to dispatch. Comparing Table 1 in Mr. Wilding's rebuttal to Table 1 in his direct testimony, we see coal represents exactly the same amount of generation displaced by residential solar. Had VOM been included as an adder to dispatch, we would have expected more coal to be displaced, decreasing the net purchases on the margin. Because this incremental coal would have been more expensive than the offset purchases, the overall savings due to rooftop solar would have been incrementally higher. So not only did Mr. Wilding use an inappropriately low VOM cost, he neglected to show the full value of the displacement due to the incremental VOM.

Q What is a "minimum fuel take" and why is it important in GRID?

A The Company's contracts for received coal often include a minimum take provision, which requires that PacifiCorp's plants receive (and pay for) a minimum amount of fuel each year, even if economically the plant would have burned less. GRID does not have the capacity to natively assesses these limits, and thus may be tweaked *post-hoc* to ensure the right amount of coal is consumed. In response to discovery in a concurrent Oregon case, Mr. Wilding described it as follows:

[19] US EPA, Air Markets Program Database. Accessed August 2017.

[20] Workpapers from Utah docket 17-035-16 (2017 IRP Review) provided in response to HEAL DR 2.1(a). Workpapers\CONF\Data Disk 2_CONF\Assumptions + Inputs Conf.zip\Assumptions + Inputs\Master Assumptions, CONF\Vol III RH5\2017 IRP Alt. Case RH-5 20161212.xlsx, tab "2 - NonCAI O&M (Nom$)." Comparison of F66:F67 (Jim Bridger 1 & 2 in 2017) to F68:F69 (Jim Bridger 3 & 4 in 2017).

> The dispatch in GRID is a result of GRID logic that only supports a single incremental fuel price in the dispatch decision for each coal unit. Consequently, iterative GRID runs may be necessary to ensure that coal burn volumes are consistent with minimum take requirements across the coal fleet. If the coal volumes determined by GRID are below the minimum take requirements at a given coal plant, the incremental coal price input is reduced (driving up coal volume determined by GRID) until the minimum coal volume is achieved or the incremental fuel price reaches approximately zero.[21]

This type of provision could be significant in a case such as this proceeding, where the Company may have conducted multiple runs, using incrementally non-economic coal prices to achieve the "correct" dispatch at units like Naughton, Johnston, Hunter, Huntington, or Wyodak. Indeed, the model might otherwise seek to find substantially better savings through the reduction of these units, but manual overrides by PacifICorp's modelers would preclude these outcomes.

Fuel contracts with multiple price tiers are similarly not supported in GRID, and it is debatable that *post-hoc* adjustments in the model to land closer to "actuals" are actually indicative of least cost performance.

Q What do you mean that GRID doesn't capture unit commitment decisions?

A This is maybe one of the most important shortcomings of GRID with respect to the Company's thermal fleet and changes on the margin. As explained by Mr. Wilding in the concurrent OR UE 323 docket:

> GRID does not model full shutdown of coal plants. Instead, the GRID model will operate coal plants at their minimum capacity

[21] Oregon Docket UE 323 (Transition Adjustment Mechanism, TAM). Sierra Club DR 2.7, May 25, 2017. Attached as HEAL___(JIF-SR3).

> when they are uneconomic to dispatch. In actual operations, the Company has shut down coal plants for very short periods of time due to economics.

The decision to turn on a plant on any given day is a "commitment" decision, and for large steam boilers, the decision to commit is substantial. Turning on during a low market price period risks operating at a loss for an extended period of time, and so marginal plants – or plants that are barely economic on a running cost basis – make commitment decisions in regular intervals.

In the context of the GRID model, the decision to shut down avoided fuel (and now VOM) costs, replacing it with lower market energy prices. In the context of this case, this decision could be particularly influential in the calculation of avoided cost, depending on how often the marginal plant was displaced offline by low energy prices and rooftop solar.

Q What are your conclusions with respect to modeling avoided cost using GRID?

A I think GRID is likely a reasonable first-order model for net power cost proceedings (NPC) and has been tweaked and adjusted for many years to yield results that are reasonably representational of actual costs. However, Mr. Wilding's assertion that "the GRID model optimizes all Company resources to meet additional load at the lowest possible cost" is not reasonable. I believe that prior to being used to even assess the marginal cost of energy, GRID should be assessed for its ability to successfully model marginal changes.

My direct testimony conclusions that the value of rooftop solar programs must take into account long-term system resource benefits is unchanged.

4. THE COST OF COAL GENERATION IS RELEVANT TO THE TREATMENT OF ROOFTOP SOLAR

Q Dr. Hoogeveen argues that "comparing private solar generation with base load [coal] resources is not a fair comparison" as "the Company has an obligation to serve its customers and… cannot rely on intermittent resources alone to meet that obligation." What is your response?

A Dr. Hoogeveen's absolutes are neither useful nor informative, and run in contrast to the Company's concurrent approval filing for wind and transmission investments. In docket 17-035-40, the Company states that their own substantial wind investment would

> …produce zero-fuel-cost energy that will lower net power costs ("NPC"); generate renewable-energy credits ("RECs"), which can be sold in the market to create additional revenues that would lower net customer costs; and help decarbonize PacifiCorp's resource portfolio, which will mitigate long term risk associated with potential future state and federal policies targeting carbon dioxide ("CO_2") emissions reductions from the electric sector.[22]

The rooftop solar offered by customers provides all the same benefits (minus the RECs, which are retained by residential owners) and more, as discussed by other intervenors. The issue here is not about the intermittency of renewable energy or the dispatchability of the Company's coal units, but rather the system benefits – and costs – accrued through different resources. My point, raised in direct testimony, was that the Company's protest of cost-shifting due to relatively small increments of distributed generation was misplaced: if the Company was looking to reduce ratepayer impacts, it should address its problematic coal fleet first – or at least with equal rigor.

[22] Utah Docket 17-035-40. Direct Testimony of Rick Link, lines 46-53. June 30, 2017.

Q **Dr. Hoogeveen complains that distributed generation cannot be considered a system resource as "NEM customers have no obligation to serve … and can simply draw on that power as they see fit." Does this disqualify rooftop solar as a system resource?**

A No. The Company fulfills – and plans on fulfilling – its requirements from a variety of resources, including central station generators, short and long-run market transactions, demand response programs, and energy efficiency programs. As a parallel, no customer on a Class 2 demand-side management ("DSM") program has an "obligation" to use an efficient appliance, stop using older light bulbs, or close the window while the air conditioner is on – but the Company nonetheless (rightfully) assumes that, *en masse*, customers served by DSM programs will act predictably.[23] The same principal applies to rooftop solar installations: customers are not obligated to keep the panels plugged in, or use their energy predictably – but will act predictably *en masse*. The Company can, and does, estimate how much distributed generation will be installed in their service territory, and adjusts planning accordingly. For all intents and purposes, rooftop solar is a system resource and is directly comparable to other system resources.

Q **Mr. Meredith critiques your analysis comparing the cost of the Company's coal generators against net metering customers, stating that "the costs of the Company's coal generators as opposed to the cost of bill credits paid for private generation are not remotely similar." What is your response?**

A I recognize that Mr. Meredith's expertise is in cost of service and not in resource valuation. However, his declaration that my premise is faulty and therefore requires no inquiry does a disserve to the Company and this Commission. Had

[23] Indeed, the Company actually defines Class 2 DSM as "repeatable and predictable voluntary actions by customers to manage the energy use at their facility or home." Wyoming Annual Demand-Side Mangement Report. July 31, 2017. Page 12. Available online at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/2016/2016_WY_Annual_DSM_Report_(7-13-17).pdf

Mr. Meredith bothered to verify the calculations I provided in workpapers, I think he would have been floored to note the extraordinary expense of various of the Company's coal fleet relative to residential retail rates. Residential retail rates are comprised of rate base, transmission and distribution costs, operation and maintenance costs, fuel costs, and net purchases. To have a single resource type – in this case three prominent coal units – with "all-in" costs *above* residential retail rates should be a red flag to any utility.[24] Indeed, the fact that the Company is currently paying bill credits to rooftop solar providers at (not above) residential retail rates is the cause of this proceeding in the first place.

Mr. Meredith is, however, correct in one way. The costs incurred to current PacifiCorp customers for net metering and non-economic coal units are not remotely similar. The Company was able to identify an arguably flawed $1.7 million cost shift (which it claims has grown to $6.5 million),[25] and yet non-economic coal plants have cost PacifiCorp customers an order of magnitude more in the same time period.

Q **Are you recommending that the Commission make a definitive finding with respect to the Company's coal plants as a result of the instant proceeding?**

A No, but I think that the comparison is worth bearing in mind as the Company, Commission, and intervenors look for a common and sustainable solution.

Q **Does this conclude your testimony?**

A It does.

[24] See Direct Testimony of Jeremy Fisher, page 6 at 8-12.

[25] Rebuttal Testimony of Company witness Joelle Steward at 39-40.

BEFORE THE
PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program	Docket 14-035-114

Exhibit HEAL___(JIF-SR1)
Oregon LC 67 (2017 IRP) Sierra Club Discovery Response 1.1(c)

August 8, 2017

Sierra Club Data Request 1.1

Refer to the 2017 IRP, pages 170-171, "Regional Haze Case Definitions." Also refer to Public Input Meeting 3 (August 26, 2016) stakeholder materials, pages 15-18 on "Scenario Development Considerations".

(a) Describe the process used by PacifiCorp to develop Regional Haze Cases RH-1 through RH-5, including any considerations of timing and type of alternatives, estimated emission reductions from compliance alternatives, visibility impairment mitigation, cost effectiveness on a per-ton or per deciview basis, Best Available Retrofit Technology (BART) equivalency, or "better than BART" applicability.

(b) Provide any work papers used by PacifiCorp to develop Regional Haze Cases RH-1 through RH-5, including assessments of timing and type of alternatives, estimated emission reductions from compliance alternatives, visibility impairment mitigation, cost effectiveness on a per-ton or per deciview basis, Best Available Retrofit Technology (BART) equivalency, or "better than BART" applicability.

(c) Identify and provide the title for the individual or individuals responsible for the development of RH-1 through RH-5.

(d) Provide any written correspondence between the individual or individuals responsible for the development of RH-1 through RH-5 and the System Optimizer modeling team with respect to the definitions, applicability, or outcomes of RH-1 through RH-5.

(e) Identify any legal memoranda, presentations, white papers or communications supporting the development or continued use of RH-1 through RH-5. Identify originating party, receiving party, date, and topic.

(f) Provide any legal memoranda, presentations, white papers or communications supporting the development or continued use of RH-1 through RH-5.

(g) Identify any other regional haze scenarios considered between August 25, 2016 and April 4, 2017 but not modeled or presented in the IRP. Provide the full definition of such cases and an explanation as to why the case was not modeled or presented in the IRP.

Response to Sierra Club Data Request 1.1

PacifiCorp objects to this request because it is unduly burdensome, not reasonably calculated to lead to the discovery of admissible evidence, and requests disclosure of information protected by the attorney-client privilege or attorney work product doctrine.

Without waiving these objections, PacifiCorp responds to subparts (a) - (c) and (e) - (g) as follows:

(a) PacifiCorp developed its regional haze scenarios based on known state and federal compliance obligations with consideration of upcoming regional haze planning period timelines, ongoing litigation, and a general understanding of regional haze settlements and settlement approaches that have been deployed across the industry, either complete or nearing completion. The regional haze scenarios were developed to reflect a range of plausible compliance alternatives with a graduated path to reduce emissions and provide relative cost information between cases. The overall intent was to provide a bookended set of information that reflects the balance between emission reductions and potential cost impact on customers while also meeting customers load and resource needs. The process used was simply to reflect current compliance obligations in the reference case and then to reflect graduated alternative compliance approaches out through the end of depreciable life for individual units for the review and consideration of IRP stakeholders. As noted in the 2017 IRP, individual unit outcomes under the Regional Haze Rule will ultimately be determined by ongoing rulemaking activities and the results of litigation, along with potential discussions with state and federal agencies, partner plant owners, and other vested stakeholders. The Company is making no individual unit commitments in the 2017 IRP.

(b) PacifiCorp provided the work papers used to develop Case RH-1 through Case RH-5 assumption on the confidential data discs that accompanied the 2017 Integrated Resource Plan (IRP) at the following locations:

Case RH-1: Data Disk 2_CONF\Assumptions + Inputs Conf.zip\Assumptions + Inputs\Master Assumptions, CONF\Vol III RH1

Case RH-2: Data Disk 2_CONF\Assumptions + Inputs Conf.zip\Assumptions + Inputs\Master Assumptions, CONF\Vol III RH2

Case RH-3: Data Disk 2_CONF\Assumptions + Inputs Conf.zip\Assumptions + Inputs\Master Assumptions, CONF\Vol III RH3

Case RH-4: Data Disk 2_CONF\Assumptions + Inputs Conf.zip\Assumptions + Inputs\Master Assumptions, CONF\Vol III RH4

Case RH-5: Data Disk 2_CONF\Assumptions + Inputs Conf.zip\Assumptions + Inputs\Master Assumptions, CONF\Vol III RH5

(c) The key individuals responsible for the development of RH-1 through RH-5 are:
    (1) Chad Teply, Vice President of Strategy and Development,
    (2) Bill Lawson, Director of Environmental Services,

(3) Irene Heng, Principal Planning and Financial Specialist.

(e) The IRP itself and presentation materials discussing and detailing Case RH-1 through Case RH-5 are responsive to this request and can be accessed on PacifiCorp's 2017 IRP website page by utilizing the following website link:

http://www.pacificorp.com/es/irp/pip.html

(f) Please refer to subpart (e) above.

(g) The Regional Haze Cases considered in conjunction with the 2017 IRP were modeled and presented therein.

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Exhibit HEAL___(JIF-SR2)
Oregon LC 67 (2017 IRP) Sierra Club Discovery Response 1.3

August 8, 2017

Sierra Club Data Request 1.3

Refer to the 2017 IRP, pages 170-171 with respect to Regional Haze Case 6. Was System Optimizer configured to allow the endogenous retirement of any coal unit aside from Hunter 1, Hunter 2, Huntington 1, Huntington 2, Jim Bridger 1 or Jim Bridger 2? For any units not configured to allow endogenous retirement, explain why not?

Response to Sierra Club Data Request 1.3

Endogenous retirement were allowed on Hunter Unit 1, Hunter Unit 2, Huntington Unit 1, Huntington Unit 2, Jim Bridger Unit 1 and Jim Bridger Unit 2 as stated on Table 7.10 – Regional Haze Case Assumptions in the 2017 Integrated Resource Plan (IRP) Volume I, Chapter 7 – Modeling and Portfolio Evaluation Approach, on page 171. The RH-6 study was done in response to stakeholder feedback and request. Naughton Unit 3 and Cholla Unit 4 considered no gas conversion versus early retirement, and Craig Unit 1 considered no selective catalytic reduction (SCR) equipment versus early retirement in Case RH-6. Only those coal fueled units where a major decision on emissions compliance investment would be required as part of an ongoing federal and/or state Regional Haze implementation plans process were analyzed.

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In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program	Docket 14-035-114

Exhibit HEAL___(JIF-SR3)
Oregon Docket UE 323 (Transition Adjustment Mechanism, TAM).
Sierra Club Discovery Response 2.7

August 8, 2017

Sierra Club Data Request 2.7

Refer to the direct testimony of Dana Ralston, page 15 at 1-13 with respect to coal minimum-take requirements and dispatch projections.

(a) Provide a narrative of the mechanism used to determine the fuel-based cost of production for dispatch at coal plants with minimum take provisions.

(b) Provide an example work paper demonstrating such mechanism.

(c) To the extent that any fuel costs (supply or delivery) are excluded from the cost of production, describe which costs these are and how the Company accounts for such costs (e.g. via fixed O&M cost, etc…)?

Response to Sierra Club Data Request 2.7

The Company objects to this request on the basis that it not likely to lead to admissible evidence to the extent that the information sought is not relevant to Company's forecast of 2018 net power costs (NPC). Please refer to the Direct Testimony of Company witness, Dana M. Ralston, page 15 at 9-13 which states: "there are no adjustments in the Company's 2018 Transition Adjustment Mechanism (TAM) initial filing reflecting minimum-take requirements." Notwithstanding the foregoing objection, the Company responds as follows:

(a) The information requested in subpart (a) is outside the scope of the Mr. Ralston's Direct Testimony and is better directed to Company Witness, Michael G. Wilding. The response below is provided by Mr. Wilding:

The 2018 TAM does not include any adjustments to reflect the minimum take requirements at any of the coal plants.

The Generation and Regulation Initiative Decision Tool (GRID) uses two "tiers" of fuel prices for coal plants:

- **Dispatch Tier:** This is the incremental coal fuel price which is used along with the thermal resource attributes and heat rate inputs to determine the dispatch decision in GRID. For contract coal this price is generally determined by the terms of the contract which may include minimum take requirements. For coal sourced from Company-owned mines this price is determined by the operating cost required to produce the next ton of coal.

- **Costing Tier:** This is the average cost of the total coal tonnage in the forecast period and is applied to the coal volumes as determined by GRID. The resulting total fuel costs are reported in the net power costs (NPC) results as total coal fuel burn expense.

Coal volumes are determined by GRID based on the economic dispatch of the coal plant. The dispatch in GRID is a result of GRID logic that only supports a single incremental fuel price in the dispatch decision for each coal unit. Consequently, iterative GRID runs may be necessary to ensure that coal burn volumes are consistent with minimum take requirements across the coal fleet. If the coal volumes determined by GRID are below the minimum take requirements at a given coal plant, the incremental coal price input is reduced (driving up coal volume determined by GRID) until the minimum coal volume is achieved or the incremental fuel price reaches approximately zero.

(b) The information requested in subpart (b) is outside the scope of the Mr. Ralston’s Direct Testimony and is better directed to Mr. Wilding. The response below is provided by Mr. Wilding:

A work paper has not been prepared because the 2018 TAM does not include any adjustments to reflect the minimum take requirements at any of the coal plants.

(c) Bridger Coal mine production cost excludes fines and penalties (including legal fees associated with the fines and penalties), and in Oregon regulatory filings are adjusted to exclude management overtime and 50 percent of annual incentive plan (AIP) payments.