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September 13, 2013

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 1088
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RE: Docket No. UE 267 : In the Matter of PACIFICORP, dba PACIFIC POWER, Transition Adjustment, Five-Year Cost of Service Opt-Out.

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff's Reply Testimony.

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PUBLIC UTILITY COMMISSION
OF OREGON

UE 267

STAFF REPLY TESTIMONY OF

GEORGE R. COMPTON

In the Matter of
PACIFICORP, dba PACIFIC POWER,
Transition Adjustment, Five-Year Cost of Service Opt-Out.

SEPTEMBER 13, 2013

CASE: UE 267
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Reply Testimony

September 13, 2013

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

A. My name is George R. Compton. I am a Senior Economist employed in the Rates, Finance, and Audit Section of the Energy Division of the Public Utility Commission of Oregon's (OPUC or Commission) Utility Program. My business address is 3930 Fairview Industrial Dr SE., Salem, Oregon 97308.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I will describe PacifiCorp's (or Company) proposed Five-Year Cost of Service Opt-Out Program, and then present Staff's recommendations regarding how PacifiCorp's proposal should be modified—in some cases, severely.

Q. Are you attaching other exhibits to this testimony besides your qualifications exhibit?

A. Yes, two. Exhibit Staff/102 is a replication of PacifiCorp's Exhibit PAC/201 Duvall/2. It shows the various components of what PacifiCorp proposes to charge its five-year opt-out direct access customers. Exhibit Staff/103 consists of copies of staff data requests and company responses.

Q. How is your testimony organized?

A. It is organized as follows:

Summary of Testimony

Q. Would you please summarize your Reply Testimony in PacifiCorp Docket UE 267?

A. In compliance with OPUC Order No. 12-500 of Docket UM 1587[1], PacifiCorp has filed a proposal for an "opt-out program that allows a qualified customer to go to direct access and pay fixed transition charges for the next [i.e., subsequent] five years, and then to be no longer subject to transition adjustments." Fundamental to PacifiCorp's proposal are a number of elements designed to prevent cost shifts to other customers and to minimize administrative costs. A positive example of this is the Company's proposal to incorporate in the rates to be charged to the direct access customers its forecasted increases in fixed generation costs during the five-year transition period. The Company's proposal also lists reasonable minimum qualifications for individual customer participation in such a program, and suggests a reasonable jurisdictional participation upper limit. However, two onerous features to PacifiCorp's proposal would render the upper limit for direct access enrollment irrelevant owing to the fact that it is difficult to imagine any large established customer availing itself of five-year direct access opt-out under the auspices of such features.

The first onerous feature I discuss is the proposed requirement that over the course of the five years when the direct access rates would be in effect, the Company would collect revenues based not only on those five years' worth of fixed costs, but would also collect revenues based on the subsequent fifteen years of escalated fixed costs. Staff believes the PacifiCorp proposal goes too far in its zeal to protect against stranded costs, and in so doing may make it unlikely for customers to ever choose this permanent direct access option. Stranded costs from a loss of retail sales are unlikely to persist for even five years, much less twenty. Projected system load growth will take up any slack in unused capacity; and expensive front-office transactions can be scaled back owing to

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[1] Dated Dec. 30, 2012; *see* page 10.

the reduced direct-access-related loads. Staff recommends that fixed cost recovery for the five-year opt-out customers be limited to only five years' worth of fixed costs.

The other feature that renders PacifiCorp's proposal prohibitively unattractive is the risk associated with a requirement that the five-year direct access customers forfeit any potential for a return to cost-of-service status no matter how exorbitantly expensive becomes the market prices for the alternative power that serves the direct access customers. Generally speaking, the return to standard cost-of-service status of loads of former direct access customers who provide sufficient warning of that return is no more burdensome to the system than would be the case had those customers never elected direct access status. Accordingly, it would be unfair, not to mention unrealistic, to deny such a return. Staff recommends that the five-year opt-out direct access customers be permitted to return to cost-of-service status following a five-year advanced notification period.

Staff's other objection to PacifiCorp's proposal has to do with basing the transition adjustment credits on existing Schedule energy 201 rates, which ignore heavy-load-period versus light-load-period cost distinctions[2]. Unable to fix large-customer Schedule 201 rates in this docket, it is Staff's recommendation that since the transition adjustment credits are to be built off of what are retail rates that do not distinguish meaningfully between the heavy and the light load hours, that the transition adjustment credits themselves also should make no such distinction.

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[2] The HLH/LLH rates differential for Schedules 47/48 is only 0.05 cents. *See* Schedule 201, page 2.

Overview of the PacifiCorp Proposal

Q. Please provide a general description of a utility's direct access program and explain what primary purpose is served by such a program?

A. Under direct access a customer bypasses the utility as its ultimate power supplier and instead obtains energy from some third-party source. These customers continue to rely upon the utility's distribution system to obtain the power from some transmission point of delivery, and accordingly pay standard distribution charges. The purpose of the direct access program is to provide customers with a competitive choice for their electricity.

Q. The subject of this case is PacifiCorp's five-year opt-out proposal. Are other direct access offerings already in place?

A. Yes. For some time, PacifiCorp has made one-year and fixed three-year direct access offerings. In addition to these shorter-term programs, PGE (Portland General Electric) has also offered a five-year-minimum plan, at least since 2008. A significant share of PGE's distribution load is accounted for under its five-year direct access option. PGE, Staff and other interested parties recently stipulated to refinements to that program as part of PGE's general rate case Docket UE 262. I was the author of Staff's direct access testimony in that docket. Many of the same issues dealt with in the UE 262 docket are also addressed here. Staff's methods of analysis and approach in this docket are the same as were used in UE 262, which should dispel any concerns about inconsistent regulatory treatment.

Q. You mentioned that direct access customers pay distribution charges on the same basis as customers who receive their power from the utility. Do the direct access customers pay other charges as well?

A. Yes they do. Besides the extensive "applicable adjustment schedules" (i.e., schedules not directly related to current energy production costs), the utilities tack on extra fees whose intended purpose is to avoid direct access imposing a burden on other ratepayers. PacifiCorp's direct access customers currently pay the same Schedule 200 rates as do retail customers in the same class. Schedule 200 covers the Company's fixed production costs. Payments under that schedule by direct access customers prevent fixed costs from having to be borne by other ratepayers when retail sales are lost that would have generated revenues for supporting the fixed costs. Transition adjustment credits/surcharges also appear. They apply to the net variable costs portion of PacifiCorp's power costs. These costs are recovered from retail customers through Schedule 201. Transition adjustment credits/surcharges prevent the Company or its ratepayers from reaping a windfall gain or incurring a burden owing to lost Schedule 201 sales.

Q. Please elaborate upon the foundation for the transition adjustment credits/ surcharges?

A. When a utility loses a sale, one of two things will happen with respect to a particular interval of time: 1) a lesser quantity of energy will be produced or purchased by the utility, or 2) the utility will produce or purchase the same amount of energy but sell it at a profit off-system instead of to the direct access customer. Producing or purchasing a lesser quantity of energy will be *advantageous* (thereby contributing to a credit) if the avoided energy fuel/purchase cost exceeds the Schedule 201 rate that would have been charged to the direct access customer. The lesser quantity of energy will be *disadvantageous* if the lost Schedule 201 revenue would exceed the avoided fuel costs. An unchanged amount of energy is disadvantageous when the utility can profitably sell off-system the surplus energy made available from the loss to direct access, but the revenues would fall short of the lost Schedule 201 revenues. But newly surplus energy in the presence of off-system sales prices in excess of the Schedule 201 rates would lead to an increase to the credits portion of the transition adjustment.

Q. Have you supplied a numerical exhibit whose intent is to reveal specifics of how PacifiCorp proposes to calculate its transition adjustments?

A. Yes I have. It is Exhibit Staff/102 Compton/1, which is a replication of PacifiCorp's Exhibit PAC/201 Duvall/2. I will be discussing some calculation specifics in detail in the "Key Proposal Element D" portion of this testimony.

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Q. What is the basic distinction between PacifiCorp's proposed new "five-year cost of service opt-out program" and the shorter-term direct access programs that are already in effect?

A. At the end of its chosen shorter-term direct access period the customer can revert to receiving its energy from the utility on a standard cost-of-service basis, with no penalty.[3] Under the Company proposal, customers choosing the five-year opt-out plan would never have the right to return as conventional cost-of-service customers. While a direct access customer under the shorter-term programs continues to pay the fixed-cost fees every year it is in its program, under the five-year opt-out program the customer is freed from having to pay the fixed production costs after the fifth year of making payments. As regards PGE on this matter, the current tariff for the five-year-minimum option[4] allows a direct access customer to return to receiving its energy on a standard cost-of-service basis following an advanced notification of two years.[5]

Q. Do you support PacifiCorp's projected escalation of its fixed generation costs in the construction of the Schedule 200 base supply portion of the direct access?

A. Yes. The desired escalation can be achieved using two approaches. The first is to forecast escalation in fixed generation costs as PacifiCorp has done (aside from the staff recommendation of limiting those charges to a five-year period forecast). The second is to update the applicable fixed generation rates as PacifiCorp has those rates changed through general rate cases. The latter approach was supported in the Docket UE 262 settlement. Staff is fine with either approach.

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[3] The customer can also choose to re-enroll in one of the short-term direct access offerings.

[4] *See* Original Sheet No. 483-6, Effective September 1, 2009.

[5] The recent stipulation in Docket UE 262 increased the minimum notification period to three years.

Q. You mentioned that both the current shorter-term direct access customers and the five-year opt-out customers pay fixed production costs during their respective rate-effective periods. Under PacifiCorp's proposal would those fixed production charges be the same for both types of direct access services?

A. No. Both types do pay/receive the transition adjustment credits/surcharges, and during the rates-effective period both pay rates under Schedule 200, which is designed to recover annual fixed production costs. But in addition, under the PacifiCorp proposal, the five-year opt-out customers would pay over the course of those same five years the levelized present value of fifteen *additional* years of fixed production costs, net of the year-by-year transition adjustment credits/surcharges.[6] PGE's five-year-minimum direct access program limits the recovery to the initial five years of fixed costs (again net of transition adjustments).

Staff finds it inconsistent to deny a customer who pays the PacifiCorp proposed twenty years of fixed production charges the opportunity to return to cost of service rates while allowing direct access customers who pay three years of stranded cost charges the option to return to cost of service rates. The objective should be to prevent cost shifts. Staff believes five years of transition charges plus a five year notice-of-return achieves that objective. The PacifiCorp proposal of basing rates on twenty years of stranded plant charges is unreasonable and inhibits the development of competitive generation markets.

Q. You have discussed the basic purpose served by direct access and how PacifiCorp's five-year opt-out proposal differs from that company's shorter-term offerings and from PGE's five-year program. Besides what goes into the direct access tariff charges for which you have provided an overview, are there other key tariff elements in PacifiCorp's proposal that are pertinent to this case?

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[6] Refer again to Exhibit Staff/102 Compton/1 (i.e., Exhibit PAC/201, Duvall/2), which illustrates this twenty-year formulation.

A. Yes. One is the subject of the next section of this testimony; another is the subject of the last section of this testimony.

Key Proposal Element A: Eligibility Requirements and Limitations

Q. Is there typically a set of "rules of engagement" with which the direct access customers must comply?

A. Yes, there is. A brief period of advanced notification is currently required prior to switching to an alternative energy supplier, along with a commitment to not take the contracted-for quantity of power from the utility for a specified minimum period. The Company would also limit five-year opt-out participation to customers who, individually, would take at least two megawatts of demand (as billed previously by PacifiCorp) from the alternative energy supplier, and who, cumulatively, would take no more that 175 average megawatts. Each individual point of delivery which combines to make up a customer's required two megawatts would have a billing demand of at least 200 KW.

Q. The sentence beginning on the last line of PAC/100 Steward/4 says, "A customer electing the Five-Year Program must take service from the ESS for all points of delivery." What if a customer has some points of delivery that meet the 200 kW threshold but for which for some reason the customer wants to continue taking power from the utility itself. Is there a problem here?

A. No. In its reply to a Data Request on this subject (i.e., OPUC Data Request 1), PacifiCorp stated as clarification, "The Company's proposal is that the customer must purchase energy from an ESS for all points of delivery *that were used to reach the 2 MW threshold* [emphasis added]."

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Q. How does the Company justify its 200 kW and 2 MW minimum requirements?

A. Company witness Joelle Steward said, "Keeping the eligibility criteria for the new Five-Year Program consistent with the current three-year opt-out program will minimize customer confusion and administrative costs."[7]

Q. Does Staff view those requirements as reasonable?

A. Yes.

Q. The Company lists several justifications for its 175 aMW cap on the total five-year opt-out direct access load. Does Staff also view this limitation as reasonable?

A. Yes. As further support of the 175 aMW figure, in PacifiCorp's response to OPUC Data Request 2 the Company said, "The 2013 IRP [Integrated Resource Plan] load forecast shows that on a system basis PacifiCorp will add cumulative load of approximately 175 aMW (1,533 GWh) in 2017 or approximately four years." The implication is that there would not be stranded production resources because load growth would take up the capacity slack prior to when Schedule 200 (i.e., fixed production costs) payments by the direct access customers ended.

Key Proposal Element B: Twenty Years of Fixed Production Costs to be Recovered in Five Years

Q. Earlier in your direct testimony you said that "under the PacifiCorp proposal, the five-year opt-out customers would pay over the course of those same five years the levelized present value of fifteen *additional* years of fixed production costs, net of the year-by-year transition adjustment credits/surcharges." How does the company justify this additional charge?

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[7] *See* PAC/100 Steward/4, lines 19-21.

A. Company witness Duvall[8] states the following in answering why this Consumer Opt-Out Charge is "necessary":

> The Consumer Op-Out Charge is necessary to minimize cost shifting to nonparticipating customers when customers in this program cease paying Base Service in Schedule 200 after five years. In essence, departing customers are charged a five-year levelized payment to cover the [fifteen years of] fixed costs they would otherwise have paid for from years six through twenty. As shown in Exhibit PAC/202, the Company estimates that without this charge, in 2014 dollars, approximately $141 million in costs could be shifted to nonparticipating customers."

Q. Do you believe it is necessary for customers to pay for twenty years of "stranded costs" to hold other customers harmless?

A. No. Five years of direct access charges should be sufficient.

Q. Please explain.

A. First, as I stated earlier, based upon IRP input from the Company it will take less than five years for expected system load growth to fill the maximum void created by the departing five-year opt-out direct access customers. In essence the new loads will be utilizing, and therefore paying for, the production resources otherwise dedicated to the departed direct access customers.

Second, 175 aMW of PacifiCorp capacity costs are hardly fixed—especially here on the west side of the Company's system. PacifiCorp's recently filed 2013 IRP document shows its preferred portfolio as including an average of over 1000 megawatts of summer peak season front-office-transaction (FOT) capacity for the next dozen years in its western control area. These transactions typically take place on a year-by-year (or so) basis—meaning they can be adjusted downwards in a timely manner (i.e., within the five-year direct access fixed costs payment period) in the presence of direct access load losses. The point is that between new loads and an ability to shrink production resources, there should be no problem—at least after a five-year adjustment period—of resources not having loads to bear their costs.

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[8] *See* PAC/200 Duvall/6, lines 9-16.

Q. But isn't it the case that under the 2010 Multi-State Protocol that Oregon will be allocated costs as if the entire direct access load is still requiring resources for their supply—even after the five year adjustment period in the case of five-year opt-outs?

A. To the extent that is true,[9] I am confident the matter will be rectified prior to the year 2016, when there will be an automatic reversion to the Revised Protocol in the event states don't come to some alternative agreement. In the current Multi-State-Process discussions on allocation methodologies post 2016, Staff has already broached in preliminary negotiations the notion that it is unacceptable for Oregon to have to pay fixed costs for five-year opt-out direct access loads beyond the five-year transition adjustment period, i.e., when those loads have chosen what may be permanent direct access and have completed the five years of transition payments.

Q. Do any other arguments come to mind against establishing charges based upon cost projections for fifteen years following the initial five-year opt-out period?

A. Yes, a major one. Columns (a) and (b) of the Compton/Duvall Exhibit Staff/102 should make clear that basing "real live" rates on market prices and even on a Company's own embedded costs (which are affected by market prices) twenty years out in the future is highly speculative and questionable on its face.

Q. What is Staff's recommendation regarding the five-year opt-out direct access charges that we have just discussed?

A. Staff objects to direct access customers having to pay fixed production costs beyond those expressly pertinent to the initial five years of direct access enrollment. Stranded

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[9] PacifiCorp's response to OPUC Data Request 5 includes the following: "As such, resources that were planned to meet direct access *eligible* [my emphasis] loads continue to be allocated to Oregon and the costs and benefits of those resources remain in Oregon, including potential stranded costs and benefits. If a direct access customer notifies the company that the company should no longer plan for the customer on a permanent basis, then that customer's loads would no longer be included in the integrated resource plan load forecast and would be excluded for the purposes of allocating the costs of *new* [my emphasis] resources to the remaining Oregon customers." The implication is that an additional share of *old* resources would still be allocated to Oregon.

fixed costs would not persist beyond that time for two reasons: Projected system load growth will take up any slack in unused capacity; expensive front-office load-meeting transactions can be scaled back in anticipation of the reduced direct-access-related loads.

Key Proposal Element C: Permanent No-Right-of-Return

Q. A key feature of PacifiCorp's five-year opt-out direct access proposal that distinguishes it from PGE's current tariff offering is the clause prohibiting a direct access customer from ever returning to standard cost-of-service status. Does the Company's opening testimony express some justification for taking such a position?

A. Yes. Beginning at the bottom of page 7 of her testimony, Company witness Steward says, "Consistent with ORS 757.603, a customer electing this option will not be eligible to return to cost-based supply service from the Company." Her attached footnote then says, "ORS 757.603 *authorizes* [emphasis added] the Commission to 'prohibit or otherwise limit the use of a cost-of-service rate by retail electricity consumers who have been served through direct access….'"

Q. Since the operative term is "authorizes" rather than "mandates," did you pursue this matter via a data request in order to attempt to obtain a more compelling justification?

A. Yes, Staff analyzed the issue through OPUC Data Request 3.

Q. What was asked and how was it answered?

A. The question: "If [direct access] customers are fully paying for the economic effects of leaving the PacifiCorp system, what is the economic basis of precluding a return by such customers to standard cost of service rates?"

The answer:

> The Company assumes that customers that select direct access would do so to reduce their costs. Similarly, the Company assumes that if a customer were to return to cost of service schedules, it would also be to reduce their costs[,] which would occur when market price exceeds the Company's embedded cost.

> The Company would then be required to sell at embedded cost and purchase supply at the higher market price, thereby incurring costs to serve the new load that would be partially funded by existing customers at the time the direct access customer returned to cost of service schedules.

Q. Do you agree with that answer?

A. The last sentence could use some clarification to achieve accuracy. Having done that simplifies my *disagreement* with the implication of that answer.

Q. Would you please supply your clarification and then explain your disagreement?

A. To achieve a more formal accuracy, I would substitute “burdensome to” for “partially funded by.” Now the bases for my disagreement: When the market prices upon which a utility relies in order to serve marginal loads exceeds its average embedded costs, then, on the margin *all* normal loads[10] are burdensome to the rest of the customers (normal and abnormal alike) in the sense that average system costs are elevated by the purchases made in behalf of those loads. There is no special distinction between existing customers and returning direct access customers in the effects of their loads on contemporaneous utility costs. I might add that under the PacifiCorp twenty-year approach, one could also argue that direct access customers have a particular right to return to cost of service since under that proposal they have paid in advance for another fifteen years of fixed costs.

Q. But hasn’t a five-year opt-out direct access customer distinguished himself by virtue of having freely made that election?

A. I would say that as long as a direct access customer’s departure from cost-of-service status imposed no harm to the other customers (and the whole point of the fixed-cost and transition charges is to prevent such harm), then, with suitable advanced notification, that customer is entitled to the same cost-of-service privileges that would be enjoyed by an existing customer of a similar size who had never elected to be a

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[10] Lighting is excluded since on the margin it is seldom necessary to rely on expensive market purchases to meet lighting loads since they are mostly off-peak.

direct access customer and who therefore, by standard reckoning, had itself imposed no harm to the other existing cost-of-service customers.

Q. How did you come to recommend that five-year advance notification to return to cost-of-service rates was the correct period of time?

A. Various avenues are afforded to PacifiCorp to accommodate new expected load growth, which would be equivalent to an announced return of a major direct access load(s). According to the Company's First Supplemental Response to Staff Data Request 2, the required accommodation periods range from "within days to months" for front office transactions (FOT) to "within four to 4 ½ years" for the "[a]cquisition of new thermal resources procured through a request for proposals (RFP)…." Staff's five-year recommendation is obviously conservative.

Q. Earlier in this testimony you mentioned that PGE's five-year opt-out direct access customers are permitted to return to standard cost-of-service status. As the Staff witness on this subject in Docket UE 262 what statement did you make regarding the right-of-return issue?

A. Beginning on line 8 of Staff/300 Compton/10, in docket UE 262, my statement proceeds as follows:

> We [Staff] do not support precluding customers from returning to cost of service generation rates as long as customers have paid the five years of transition charges to exit the utility generation service and have given the indicated five years advanced notice of their desire to so return. Consider a situation in the future where non-utility energy service becomes very expensive, making direct access cost-prohibitive in terms of a number of large customers' ability to stay in business. As a practical matter, one can imagine the pressure that would be brought to bear – in the interest of saving jobs, etc. – to allow the at-risk customers back into cost-of-service status. And from a legal point of view, what if the customer had actually gone out of business for a spell and then been acquired by a different owner? Could the associated load then be treated as that of a new customer rather than a permanently non-qualifying customer?
>
> Also, if the non-direct-access customers had been held harmless by the direct access customers' departure from cost-of-service status, why shouldn't they [the latter] be treated at some future date on the same terms as any other large

new customer – having served notification sufficient for the utility to most efficiently serve the returning loads?

Q. One more thought: What if the customer gives the desired notification but then refuses to abandon his alternative source of power?

A. Consistency would suggest that the customer should be required to pay for another five years of Schedule 200 fixed costs (tempered by the customary transition adjustment credits).

Q. What is Staff's recommendation regarding the right of a five-year opt-out direct access charges to return to conventional cost-of-service status?

A. To paraphrase from above: Staff does not support precluding direct access customers from returning to cost of service generation rates as long as they have paid the five years of transition charges to exit the utility generation service and have given five years advanced notice of their desire to so return. Five years should be sufficient for PacifiCorp to add to its supply portfolio in a manner that optimizes costs (i.e., duly considering risks) for accommodating prospective total loads.

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Key Proposal Element D: Time-of-Use Transition Adjustments Absent Meaningful Time-of-Use Rates

Q. Would you please give us a brief reminder of the role played by the transition adjustments and what underlies their formulations?

A. The role of PacifiCorp's transition adjustments is to make the direct-access-induced loss of retail sales net revenue neutral in the energy costs[11] realm. Offsetting added profits or ratepayer benefits are revenue credits applicable to the segment of sales for which, on average, the Company would reap benefits from the foregone retail sales due to either the fact that the Schedule 201 retail sales price was beneath the Company's marginal costs (i.e., of fuel or market purchases) or the revenues from off-system sales made possible by the freed-up energy exceed both the marginal production costs and

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[11] These other-than-fixed production costs are referred to as "net power costs" and are recovered from all retail customers through Schedule 201.

the lost Schedule 201 retail energy revenues. Conversely, the direct access customers pay a surcharge for a segment of lost retail sales to make up for the lost net revenues associated with the fact that the Schedule 201 retail energy revenues would have exceeded both the fuel/purchase costs of supplying that energy and the revenues that could have been generated from the added off-system sales.

The two "segments of sales" referred to here for PacifiCorp are sales made over the course of a year in the heavy load hours (HLH) and the sales made in the light load hours (LLH).[12] PGE combines those segments into one—thereby obtaining a single transition adjustment rate that is applied to the annual direct access sales for each particular customer class.[13] /

Q. What you just described sounds very complicated. How, in practice, does PacifiCorp estimate/calculate the transition adjustment credits/surcharges?

A. In answering your question I will refer in part to the material on this subject provided by PacifiCorp witness, Gregory Duvall[14], the associated exhibit to which is replicated as my Exhibit Staff/102 Compton/1. In what follows I shall first focus on the year 2013 row in the exhibit. To begin, GRID, a model which provides estimates of hourly production costs, is run with and without the projected direct access loads. The resulting annual cost estimates distinguish between heavy-load hours (HLH) and light-load hours (LLH). The difference in costs between the two GRID runs are then determined on a per-MWh basis. Those *differences* (i.e., \$32.94/MWh for HLH and \$23.19/MWh for LLH) are then compared with the average retail energy rate of Schedule 201, \$25.66/MWh, to produce the HLH and LLH transition adjustments which are, respectively, minus \$7.29/MWh (or \$25.66 - \$32.94) and plus \$2.47/MWh (or \$25.66 - \$23.19). These are the average net energy opportunity costs of losing sales to direct access. The \$2.47 is a surcharge levied to direct access customers for

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[12] HLH: 6 a.m. to 10 p.m., Monday through Saturday. LLH: All other hours.

[13] *See* PGE Schedule 129.

[14] *See* PAC/200, Duvall/4.

their loads during the light load hours in order to offset the revenue loss of $25.66 per MWh in the presence of costs of only $23.19. The $7.29/MWh is credited to direct access customers because of a combination of avoiding very high fuel/purchase costs on the margin during some of the heavy load hours and achieving a greater opportunity to make lucrative off-system opportunity sales during other heavy load hours would mean that the Company/other ratepayers would, absent the credit, benefit by that amount on average by virtue of customers switching from Schedule 201 cost-of-service retail rates to direct access.

Q. While actual HLH and LLH Transition Adjustment numerical amounts are not at this time shown on page 3 of PacifiCorp's proposed Schedule 296[15], actual numbers are shown in Compton/Duvall Exhibit Staff/102, with the "Example Calculation" caveat in the exhibit title (fourth line). I see that the difference between the HLH and the LLH "NPC Impact" in Column (b) is about $10/MWh for the first five years, and difference between the HLH and the LLH Transition Adjustment is about $14/MWh for the 5-year Nominal Levelized Payment shown in the lower portion of the exhibit. Are those differences compatible with the amount supplied by the Company in the time-varying costs and rates investigative docket UM 1415?

A. Yes.

Q. Having agreed with the Column (b) NPC impact in the Compton/Duvall exhibit, do you in principle accept the HLH and LLH Transition Adjustments shown in Column (c) as being cost based?

A. They may reflect the system net revenue impacts of the loss of HLH and LLH direct access loads, but those figures are certainly not cost based. Column (b) in the exhibit is presumably cost-based, but Column (a) is *not* cost-based. As a consequence, Column (c), the difference between the two columns, would not itself be cost-based.

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[15] *See* Exhibit PAC/101 Steward/3.

Q. Are you saying that Column (a) does not represent the "Schedule Average," as labeled?

A. It does, I assume, represent the weighted HLH and LLH tariff average, but the difference in those rates for the indicated Schedule 201 tariff for Schedule 47/48 is only \$0.50/MWh[16], which is far from a cost-based difference even on an embedded cost basis, much less a marginal cost basis.

Q. What would happen to the Transition Adjustments if Column (a) were appropriately divided into two columns that contained Schedule 201 HLH and LLH rates that were truly cost-based?

A. The HLH Transition Adjustment credit would shrink dramatically and the LLH Transition Adjustment would go from being a surcharge to a credit.

Q. Earlier you said that the Column (c) Transition Adjustments reflected the HLH and LLH system net revenue impacts even though the underlying Schedule 201 HLH and LLH rates were themselves not cost based. Would you please clarify that statement?

A. To put it simply, the HLH credits of Column (c) are quite large because when HLH retail sales are under-priced relative to the opportunity costs of those sales, then it is a major advantage to the utility to not have to make such sales (i.e., hence the large credit).

Q. This docket is obviously not the forum for putting cost-based Schedule 201 HLH and LLH rates into effect. So what can be done?

A. Staff recommends eliminating the HLH and LLH distinction in Columns (b) and (c), and instead do as PGE has done—rely for each customer group upon a single annual transition adjustment figure. It is noteworthy that even though PGE has five times PacifiCorp's spread in its large industrial energy rates, that company—perhaps for

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[16] *See* Schedule 201, page 2.

reasons of rates simplicity—has chosen single transition adjustment rates rather than splitting them into separate HLH and LLH rates.[17] A common transition adjustment credit across all hours would avoid the relative inducement on the part of PacifiCorp's transition adjustment rates to encourage on-peak demand by the direct access customers.

Q. The current short-term direct access transition adjustment rates distinguish between the heavy-load and the light-load hours. Wouldn't the inconsistency between the two-factor (HLH and LLH) rates for shorter-term direct access and the single factor rate for the five-year program trouble you?

A. No. The professionals who buy and sell the large volumes of power associated with direct access will have little difficulty adapting to two different kinds of rates. Besides, many of those same professionals are dealing with both PGE and PacifiCorp and their direct access programs, and what was here proposed makes PacifiCorp's and PGE's long-run direct access programs more consistent with each other.

Q. Does this conclude your direct reply testimony?

A. Yes.

[17] *See* PGE Schedule 129 Long Term Transition Cost Adjustment.

CASE: UE 267
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statements

September 13, 2013

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
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EDUCATION: Doctor of Philosophy, Economics (1976)
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Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

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EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah, I also taught Economics part-time for about ten years at BYU.

Prior to my utility regulatory career, I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California.

I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), an Avista General Rate Case (UG 181), PGE General Rate Cases (UE 197, UE 215, and UE 262), PacifiCorp General Rate Cases (UE210, UE 246, and UE 263), the NW Natural General Rate Case (UG 221), and the Idaho Power General Rate Case (UE 233).

CASE: UE 267
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PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 102

Exhibits in Support
Of Reply Testimony

September 13, 2013

Exhibit PAC/201
Duvall/2

Exhibit PAC/201
Schedule 47/48 Transmission
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation
Assuming Average Market Prices for Electricity and Natural Gas

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 175 aMW Leaving System		Transition Adjustment		Schedule 200 - Base Supply	Customer Opt Out Charge	
		HLH	LLH	HLH	LLH		HLH	LLH
	(a)	(b)		(c)		(d)	(e)	
	(a)=Sch Avg	(b)=GRID Study		(c)=(a)-(b)		(d)=Sch Avg	=49.42-37.93	=49.42-24.02
2013	$25.66	$32.94	$23.19	($7.29)	$2.47	$25.25		
2014	$25.28	$33.38	$24.36	($8.10)	$0.92	$25.73	$11.49	$25.41
2015	$25.83	$34.25	$25.10	($8.42)	$0.73	$26.22	$11.49	$25.41
2016	$26.71	$35.02	$25.74	($8.31)	$0.97	$26.72	$11.49	$25.41
2017	$27.02	$36.38	$26.93	($9.36)	$0.09	$27.23	$11.49	$25.41
2018	$27.89	$38.61	$28.50	($10.72)	($0.61)	$27.75	$11.49	$25.41
2019	$28.76	$43.31	$33.99	($14.55)	($5.23)	$28.28		
2020	$29.67	$47.28	$39.03	($17.61)	($9.36)	$28.82		
2021	$31.31	$51.74	$42.86	($20.43)	($11.55)	$29.37		
2022	$32.09	$58.42	$49.27	($26.33)	($17.18)	$29.93		
2023	$32.91	$61.13	$51.63	($28.22)	($18.72)	$30.50		
2024	$33.41	$61.58	$52.55	($28.17)	($19.14)	$31.08		
2025	$33.87	$61.54	$52.49	($27.67)	($18.62)	$31.67		
2026	$35.21	$64.36	$55.07	($29.15)	($19.86)	$32.27		
2027	$36.03	$65.56	$56.13	($29.53)	($20.10)	$32.88		
2028	$39.10	$67.26	$58.09	($28.16)	($18.99)	$33.50		
2029	$39.07	$62.28	$53.77	($23.21)	($14.70)	$34.14		
030	$40.30	$62.17	$54.11	($21.87)	($13.81)	$34.79		
2031	$41.36	$66.25	$57.83	($24.89)	($16.47)	$35.45		
2032	$42.47	$70.39	$62.08	($27.92)	($19.61)	$36.12		
2033	$43.61	$71.19	$63.12	($27.58)	($19.51)	$36.81		
20-Year Net Present Value (1)				($154.88)	($98.07)	$201.81	$46.93	$103.74
5-year Nominal Levelized Payment				($37.93)	($24.02)	$49.42	$11.49	$25.41

Notes:
(1) 2014 through 2033 using a 7.154% Discount Rate
(2) Transmission Losses at 5.00%

CASE: UE 267
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 103

Exhibits in Support
Of Reply Testimony

September 13, 2013

OPUC Data Request 1

Regarding PAC/100, Steward/5, lines 1 and 2, if a customer has loads at different points of delivery, with each point of delivery having more than 200 kW of billing demand at least once in the previous 13 months and where the total across all points of delivery is at least two MWs, (a) what is the basis for requiring the customer who chooses the five-year program to take service from an ESS for all of its points of delivery that meet the 200 kW threshold even if the two MW minimum total criterion could be met while excluding one or more otherwise qualifying points of delivery? (b) Are points of delivery which don't meet the 200 kW threshold automatically excluded from shared participation in the five-year program?

Response to OPUC Data Request 1

(a) For clarity, the referenced testimony should have stated that customers electing the Five-Year Program "must take service from an ESS for all points of delivery under this schedule" in order to be consistent with the language in the proposed tariff. See Exhibit PAC/101. The Company's proposal is that the customer must purchase energy from an ESS for all points of delivery that are used to reach the 2 MW threshold. If the customer has other points of delivery that meet the 200 kW threshold in excess of those required to meet the 2 MW minimum, then the customer is not required to take service from the ESS for those points of delivery. This is consistent with the Company's qualifications for the three-year cost of service opt-out program.

(b) Yes, points of delivery which do not meet the 200 kW threshold are automatically excluded from shared participation in the five-year program.

OPUC Data Request 2

Regarding PAC/100, Steward/6, lines 5 through 11, (a) what number of years is it typically necessary for the company to adjust its resources and power purchase commitments in order to economically serve new load? (b) On a PacifiCorp system basis, how many years of load growth are needed to reach a cumulative load growth of 175 aMW? (c) On an Oregon basis, how many years of load growth are needed to reach a cumulative load growth of 175 aMW?

Response to OPUC Data Request 2

(a) The Company uses its Integrated Resource Plan (IRP) process, which utilizes a 20-year planning horizon, to identify the appropriate mix of resources to economically serve load. The Company files an IRP every other year. As a general matter, the cited portion of Ms. Steward's testimony does not address new load; rather, it addresses load that is lost from customers departing to direct access.

(b) The 2013 IRP load forecast shows that on a system basis PacifiCorp will add cumulative load of approximately 175 aMW (1,533 GWh) in 2017 or approximately four years.

(c) The 2013 IRP load forecast does not show Oregon loads growing by 175 aMW (1,533 GWh) cumulatively in the forecasted 20-year horizon.

OPUC Data Request 2

Regarding PAC/100, Steward/6, lines 5 through 11, (a) what number of years is it typically necessary for the company to adjust its resources and power purchase commitments in order to economically serve new load? (b) On a PacifiCorp system basis, how many years of load growth are needed to reach a cumulative load growth of 175 aMW? (c) On an Oregon basis, how many years of load growth are needed to reach a cumulative load growth of 175 aMW?

1st Supplemental Response to OPUC Data Request 2

Pursuant to a telephone conversation with OPUC Staff that occurred on July 27, 2013, the Company provides the following supplemental response to subpart (a) of this request:

(a) The Company uses its Integrated Resource Plan (IRP) process to develop a preferred portfolio that meets the needs for its customers over a 20-year planning horizon. The time required to acquire resources depends upon the timing and level of anticipated load growth and the types of resources needed. Front office transaction (FOT) resources can be acquired relatively quickly (within days to months, depending upon the volume, market hub, and term). New demand side resource load management resources can be acquired within 18-24 months and the Company used its best estimate of demand side energy efficiency resource acquisitions in ramp rate assumptions used to develop the resource supply curves. Acquisition of an existing supply-side resource can be completed within one to two years. Acquisition of new thermal resources procured through a request for proposals (RFP) can be acquired within four to 4 ½ years. Acquisition of new renewable resources procured through an RFP can be completed within one to two years.

OPUC Data Request 3

Regarding PAC/100, Steward/6, lines 5 through 11, and PAC/200, Duvall/5, lines 14 through page 6: (a) What is the basis for the selection of twenty years? For example is PacifiCorp stating that its generation resources have a depreciable life of twenty years? (b) If customers are fully paying for the economic effects of leaving the PacifiCorp system, what is the economic basis of precluding a return by such customers to standard cost of service rates? (c) What harm would be imposed on nonparticipating customers if customers were allowed to return to cost of service rates after the customer has paid the five years of transition and opt-out charges as proposed by the Company—in other words how would nonparticipating customers be worse off in the case of a direct access customer returning to cost of service rates at the end of say, one year following the five-year transition period, versus the latter customer's never having left cost of service at all?

Response to OPUC Data Request 3

(a) Twenty years was selected to represent a reasonable time to recover stranded costs from departing customers which is consistent with the planning horizon used in the Company's Integrated Resource Plan (IRP). Also, the Company's long run marginal cost results filed in Oregon have used a 20-year time horizon. Stranded costs are typically associated with stranded capital investment for facilities with lives that extend beyond 20 years. The Company could have proposed a longer time period to determine the Consumer Opt-Out Charge, but chose to limit the calculation to 20 years. The impact of the additional stranded costs associated with year 21 and beyond would diminish over time due to the effect of discounting the values to a current net present value.

(b) The Company assumes that customers that select direct access would do so to reduce their costs. Similarly, the Company assumes that if a customer were to return to cost of service schedules, it would also be to reduce their costs which would occur when market price exceeds the Company's embedded cost. The Company would then be required to sell at embedded cost and purchase supply at the higher market price, thereby incurring costs to serve the new load that would be partially funded by existing customers at the time the direct access customer returned to cost of service schedules.

(c) Please refer to the Company's response to subpart (b) above.

OPUC Data Request 4

Does the company agree that conceptually, once a customer has departed the system after paying five years of transition charges, that the loads of that customer should not be included in the calculation of cost allocations to Oregon? Please explain.

Response to OPUC Data Request 4

No. The suggestion is inconsistent with Section X of the 2010 Protocol which has been approved by the Public Utility Commission of Oregon for inter-jurisdictional cost allocation purposes. See Order No. 11-244, Docket UM 1050.

OPUC Data Request 5

Assume that a 100 MWa customer elects permanent direct access service under a five-year transition adjustment payments plan. Assume that the Company has full confidence that the customer will *never* return to cost-of-service (COS) status. Assume also that at the beginning of the same five-year transition period another customer announces his firm intention to add 100 MWa of COS load at the precise time that the former 100 MWa converts to direct access service. As background assume that the Company experiences otherwise normal growth and is able to fully utilize its generation and transmission resources. Which of the following best describes how the Company would plan for these combined opt-out and new-load eventualities?

A. One hundred additional MWa of production resources would be added to the Company's capability by the end of the subject five-year period beyond what would otherwise have been necessary to accommodate both normal growth *plus* the retention *on COS status* of the first 100 MWa load,
B. One hundred incremental MWa of production resources would *not* be added to the Company's capability by the end of the subject five-year period owing to the incremental load because that need was obviated by the conversion of the 100 MWa COS load to direct access status, or
C. Other—please describe in detail.

Response to OPUC Data Request 5

C. Load changes are input into the integrated resource planning models and a least cost, least risk portfolio is chosen taking into account changes in loads, resources, market prices and other factors. The Company does not plan on an aMW basis in its integrated resource plan, but rather on a peak basis. Nonetheless, no one particular load causes the addition of or avoidance of a particular resource addition. As such, the hypothetical example proposed in the question does not reflect how the Company conducts its integrated resource planning process.

Consistent with the policy goals of the Revised Protocol and 2010 Protocol, the policy decisions of one state should not affect other states positively or negatively – a policy goal directly aimed at Oregon's direct access programs. As such, resources that were planned to meet direct access eligible loads continue to be allocated to Oregon and the costs and benefits of those resources remain in Oregon, including potential stranded costs or benefits. If a direct access customer notifies the company that the company should no longer plan for the customer on a permanent basis, then that customer's loads would no longer be included in the integrated resource plan load forecast and would be excluded for the purposes of allocating the costs of new resources to the remaining Oregon customers.

OPUC Data Request 6

Here make the same assumptions as above except allow the opting out customer to return to COS status following a five-year notification period *and* assume that at the end year-three of the initial five-year transition period that the subject direct access customer provides a five-year notification of an intent to return to COS status—and by a prior Oregon PUC ruling dating from the beginning of the five-year transition adjustment period, that intent must be honored. In this context now choose among a., b., and c., above.

Response to OPUC Data Request 6

Please refer to the Company's response to OPUC Data Request 5.

OPUC Data Request 7

Does the Company believe that the transition adjustment fees and/or customer opt-out charges should be different if there is a five-year-notification, opt-back-in capability versus if there were no opportunity to return to cost-of-service status? If so, please describe the differences in detail.

Response to OPUC Data Request 7

No, the proposed transition adjustment fees and customer opt-out charges would not be different. The Company's proposed transition adjustment fee and permanent customer-opt out charge appropriately accounts for the fixed generation costs incurred by the Company to serve customers who elect direct access while minimizing cost-shifting to non-direct access customers. However, if the Company's proposal were modified to include notification and the ability of a permanent opt-out customer to opt back in to cost-of-service status, such an option would also potentially shift costs to non-participating customers. Therefore, it may be appropriate for the Company to charge a return-to-service charge for those customers who elect the permanent five-year opt out option, but then later elect to opt back in to cost-of-service status.

UE 267 SERVICE LIST

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CERTIFICATE OF SERVICE

UE 267
Reply Testimony

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 13th day of September, 2013 at Salem, Oregon

Kay Barnes

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