PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

August 22, 2008

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Vikie Bailey-Goggins, Administrator
Regulatory and Technical Support

Re: Docket No. UE 200
PacifiCorp's 2009 Renewable Adjustment Clause
Rebuttal Testimony and Exhibits

PacifiCorp dba Pacific Power submits for filing an original and five (5) copies of PacifiCorp's Rebuttal Testimony and Exhibits of Andrea L. Kelly, Mark R. Tallman, R. Bryce Dalley and Judith Ridenour in the above-referenced proceeding. The confidential exhibits to the testimony of Mark R. Tallman are provided in separate envelopes and sealed pursuant to the Protective Order in this proceeding. Also enclosed are three (3) CDs containing the electronic workpapers for Mark R. Tallman, R. Bryce Dalley and Judith Ridenour.

The Company has waived confidential protection of the annual capacity factors and the ACC analysis results for the Glenrock and Rolling Hills resources that are cited in Mark Tallman's Rebuttal Testimony PPL/203. Although these data are confidential and subject to protection under the Protective Order in this proceeding, for ease of reference the Company is waiving confidentiality of these items.

Please direct informal correspondence and questions regarding this filing to Joelle Steward, Regulatory Manager, at (503) 813-5542.

Very truly yours,

Andrea L. Kelly /JS

Andrea L. Kelly
Vice President, Regulation

Enclosures

cc: UE 199 Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 22nd day of August, 2008, I caused to be served, via E-Mail and Overnight Delivery (to those parties who have not waived paper service), a true and correct copy of the foregoing document on the following named person(s) at his or her last-known address(es) indicated below.

SERVICE LIST
UE-200

OPUC Dockets (W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
dockets@oregoncub.org

Robert Jenks (W) (C)
Citizens' Utility Board of Oregon
610 Broadway, Suite 308
Portland, OR 97205
bob@oregoncub.org

Irion A. Sanger (C)
Davison Van Cleve PC
333 SW Taylor, Suite 400
Portland, OR 97204
ias@dvclaw.com

Michael T. Weirich (C) (W)
Assistant Attorney General
Regulated Utility & Business Section
1162 Court St, NE
Salem, OR 97301-4096
michael.weirich@doj.state.or.us

John W. Stephens (W) (C)
Esler Stephens & Buckley
888 SW Fifth Ave, Suite 700
Portland, OR 97204-2021
stephens@eslerstephens.com

Katherine A. McDowell (W)
McDowell & Rackner PC
520 SW Sixth Ave, Suite 830
Portland, OR 97204
katherine@mcd-law.com

Ryan Flynn (W) (C)
PacifiCorp
825 NE Multnomah, Suite 1800
Portland, OR 97232
ryan.flynn@pacificorp.com

Oregon Dockets (W)
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

Randall Dahlgreen (W)
Portland General Electric
121 SW Salmon St. 1WTC 0702
Portland, OR 97204
pge.opuc.filings@pgn.com

Douglas C. Tingey (W)
Portland General Electric
121 SW Salmon St. 1WTC 13
Portland, OR 97204
doug.tingey@pgn.com

Judy Johnson (W) (C)
Oregon Public Utility Commission
P.O.Box 2148
Salem, OR 97308-2148
Judy.johnson@state.or.us

Deborah Garcia (W) (C)
Oregon Public Utility Commission
PO Box 2148
Salem, OR 97308-2148
Deborah.garcia@state.or.us

Lisa C. Schwartz (W) (C)
Oregon Public Utility Commission
PO Box 2148
Salem, OR 97308-2148
Lisa.c.schwartz@state.or.us

Ken Dragoon (W) (C)
Renewable Northwest Project
917 SW Oak, Suite 303
Portland, OR 97205
ken@rnp.org

Ann English Gravatt (W) (C)
Renewable Northwest Project
917 SW Oak, Suite 303
Portland, OR 97205
Ann@rnp.org

Jesse Jenkins (W)
Renewable Northwest Project
917 SW Oak, Suite 303
Portland, OR 97205
jesse@rnp.org

Randall J. Falkenberg (C)
PMB 362
8343 Roswell Road
Sandy Springs, GA 30350
consultrfi@aol.com

Ariel Son
Coordinator, Administrative Services

BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

PACIFICORP

2009 RENEWABLE ADJUSTMENT CLAUSE (RAC)

Rebuttal Testimony and Exhibits

August 2008

Case UE-200
Exhibit PPL/101
Witness: Andrea L. Kelly

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Andrea L. Kelly

August 2008

Q. Are you the same Andrea L. Kelly who provided direct testimony in this proceeding?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony:

- provides an overview of the rebuttal case of PacifiCorp dba Pacific Power (PacifiCorp or the Company) in this proceeding offered in response to the adjustments proposed by Oregon Public Utility Commission (Commission) Staff (Staff) and the Industrial Customers of Northwest Utilities (ICNU);
- discusses Staff's proposal to exclude the Glenrock III and Seven Mile Hill II wind generating resources from the Renewable Adjustment Clause (RAC) update; and
- responds to ICNU's proposal that the Company be required to establish a regulatory liability in the amount of the current market value for the Company's Renewable Energy Credits (RECs).

Overview of the Company's Rebuttal Case

Q. Please summarize the Company's rebuttal case.

A. The Company's rebuttal case can be broken into three categories. First, there are updates to the revenue requirement calculation that reflect new information since the Company's April filing. Second, there are certain recommendations made by Staff and/or ICNU to which the Company is willing to agree. Third, there are certain recommendations made by Staff and/or ICNU to which the Company is opposed.

Q. What update is the Company proposing in its rebuttal filing?

A. As discussed in the testimony of Company witness Mr. R. Bryce Dalley, the Company updated its revenue requirement calculation based on current information and data. This update reflects changes to capital costs, forecasted Operations & Maintenance expense, and forecasted state and federal tax credits. As a result, the revenue requirement has decreased by $1.7 million, from $39.0 million to $37.3 million for an overall average increase of 3.8 percent.

Q. What are the recommendations made by parties to which the Company is willing to agree?

A. There are four recommendations to which the Company is willing to agree, at least in part. First, as discussed in Staff witness Mr. Steve Storm's testimony, the Company agrees to Staff's interpretation of the steps for establishing specific RAC Schedule rates using 2009 forecasted loads. Company witness Ms. Judith M. Ridenour sponsors rebuttal testimony on this issue.

Second, the Company is agreeable to adopting ICNU's adjustment to include a reduction to rate base of the Goodnoe Hills resource associated with the recovery of liquidated damages by the Company. As discussed in Mr. Dalley's rebuttal testimony, the Company has included an estimate of the recovery of liquidated damages of $4.1 million in this filing. The Company will update the RAC revenue requirement for the amount of liquidated damages actually recovered if the amount is known prior to the December 1, 2008 update. If it is not known by December 1, 2008, the Company will seek to defer any difference between the estimate and the actual amount in the RAC deferral account.

Third, the Company is willing to accept Staff's recommendation that it not include the Glenrock III and Seven Mile Hill II resources in this RAC and instead use the RAC deferral mechanism to ensure timely recovery of the fixed costs of these resources. The benefits of the near-zero cost energy will need to be addressed in Docket UE 199, the Company's Transition Adjustment Mechanism (TAM), to ensure symmetrical treatment.

Fourth, the Company accepts, in-part, Staff's recommendation that the capacity factor assumption for Glenrock be updated to reflect the best available information based on third-party information. As discussed in Company witness Mr. Mark R. Tallman's testimony, there is new information available associated with the Glenrock resource that was not available at the time Staff prepared its reply testimony.

Q. What are the recommendations to which the Company is opposed?

A. The most significant recommendation to which the Company is opposed relates to the Rolling Hills wind resource. Both Staff and ICNU have recommended that the Commission disallow all or a portion of the cost of this resource based on a finding of imprudence related to the method by which it was acquired. As I discuss below, these adjustments are particularly distressing to the Company given the state policy directives that have been clearly articulated by the Oregon legislature and this Commission, and the Company's good faith efforts to comply with these policy directives. Indeed, Staff's recommendations in reply testimony are internally inconsistent in at least one key area. In addition, Mr. Tallman's rebuttal testimony definitively demonstrates that the costs of the Rolling Hills facility are reasonable, prudent and in the best interest of customers.

The second recommendation to which the Company is opposed is Staff's "alternate" adjustment to the capital costs of the Glenrock resource. As discussed by Mr. Tallman, there is no justification for any adjustment as the issue is merely one of which data set to use in the GRID model. In addition, the Company has agreed to update the Glenrock capacity factor for the most recently available information. As such, no "adjustment" should be accepted, and the Company should merely update the estimated capacity factor data with the most recently available information.

The final recommendation to which the Company is opposed relates to ICNU's suggestion that the Company be required to establish a renewable energy credit (REC) liability account. I discuss later in my testimony why this is unnecessary in light of the REC banking provisions of Oregon's Renewable Portfolio Standard (RPS) law.

Proposed Disallowances Related to Rolling Hills

Q. What disallowances have Staff and ICNU proposed with respect to the Rolling Hills resource?

A. Staff proposes alternative adjustments related to the Rolling Hills resource that are supported by ICNU. Staff proposes either that the Commission impute a higher capacity factor for this facility or that the Commission impute a reduction to the capital costs of the project. Staff also proposes further disallowances associated with phantom tax credits and phantom RECs. In the alternative, ICNU has also proposed that the costs and benefits of the resource be excluded from Oregon rates in totality.

Q. Please respond to these alternative approaches.

A. As detailed in Mr. Tallman's rebuttal testimony, Staff's proposed Rolling Hills disallowances focus narrowly upon projected capacity factors while ignoring the cost-effectiveness of the resource. Staff's disallowances would result in resource costs in rates far below market for un-differentiated and non-RPS compliant power. As a policy matter, Oregon should not refuse to pay the true costs of a resource and expect to receive the renewable attributes of the resource for compliance with Oregon's RPS law.

Indeed, under Staff's proposal, not only would Oregon refuse to pay the true costs of the resource, but Staff would then impute phantom RECs and phantom federal tax credits. The Staff proposal is clearly asymmetrical and violates a fundamental principle of regulation. The Company submits that the Commission should accept renewable resources as prudent, along with a full REC allocation, or reject them as imprudent and remove them from rates completely, with no REC or other resource benefit allocation to Oregon. This is the only equitable result if the Commission somehow finds this resource to be imprudent.

Q. How would the Company implement a Commission decision that rejected the Rolling Hills resource?

A. The Company would exclude all costs and benefits of the resource from the Oregon revenue requirement and would exclude the resource from the dispatch stack in its net power cost models. Similarly, any RECs from the resource would not be assigned to Oregon. In effect, the resource would be displaced by other company resources, renewable resources acquired in the future, and/or undifferentiated market purchases.

Q. Has the Company ever made such an adjustment?

A. Yes. In 1984, the Washington Utilities and Transportation Commission ordered the Company to exclude from Washington rates the investment in Colstrip 3. Since that time, the Company has implemented an identical approach to that described above and will continue to do so over the life of the asset.

Q. You stated earlier that the Company finds the recommendations of Staff and ICNU particularly distressing given the state policy directives that have been clearly articulated by the Oregon legislature and this Commission, and the Company's good faith efforts to comply with these policy directives. Please explain further.

A. The state of Oregon, through its Governor and Legislature, has established a clear policy directive that emphasizes an energy future that is built around significant investment in renewable resources, aggressive pursuit of conservation and increases in the efficiency of energy usage. The aggressive targets set forth by the state of Oregon will only be met through an all-out, creative, timely and collaborative approach.

The Company has undertaken an approach that will allow it to achieve the policy directives of this state in a cost-effective manner and in advance of some of the target dates; in return, Staff and ICNU propose that the Company be penalized financially. It is particularly distressing that Staff would seek to punish the

Company for acquiring cost-effective renewable resources given the clear state energy policy directives and the recent and ongoing rapid escalation of the costs of renewable resources.

Q. Are Commission findings of imprudence a frequent occurrence?

A. Not for PacifiCorp. In fact, none of PacifiCorp's six state Commissions have entered a finding of imprudence on PacifiCorp's owned generation fleet. It is also ironic that we have one Staff witness in this case arguing that the RAC may reduce the Company's risk of cost recovery and have another Staff witness proposing a prudence disallowance.[1]

Q. What is Staff's and ICNU's theory behind the proposed imprudence finding?

A. Staff and ICNU argue that Rolling Hills fails to meet the standard of prudence and that the Company should be penalized for not using a Commission-approved request for proposal (RFP) process to acquire the facilities. Staff theorizes that if PacifiCorp had issued an RFP instead of advancing the Rolling Hills resource, the Company would likely have acquired a resource with a higher capacity factor.

Q Was the Company's decision to acquire Rolling Hills prudent?

A. Yes. The Company's decision was objectively reasonable based on the information available at the time. Even Staff agrees with the Company that the expected costs of the resource were reasonable. Mr. Tallman discusses the prudence of the Company's decision in detail in his rebuttal testimony.

[1] PacifiCorp will respond to any Staff proposals related to cost of equity impacts of the RAC in an appropriate proceeding; this issue is not within the scope of the RAC.

Q. Even if the Commission decides that the Company's decision to acquire Rolling Hills was imprudent, are Staff's proposed disallowances reasonable?

A. No. Staff explicitly found that the expected costs for the facilities were reasonable. Staff witness Ms. Deborah Garcia testified that *"procurement and installation of the resources on a capacity basis appear to be within a reasonable range."* Staff/100, Garcia/8, lines 22–23. Neither Staff nor ICNU presented any evidence rebutting Mr. Tallman's testimony that the Rolling Hills resource is cost effective. The Commission may disallow costs for an imprudently acquired facility that are above what the utility should reasonably have paid for that facility. In this case, as demonstrated by Mr. Tallman, the cost the Company paid for the facilities was reasonable, so there is no basis for a disallowance.

Q. How do you respond to Staff's argument that the Company could have acquired facilities with a higher capacity factor if it had issued an RFP for the facilities?

A. There are a number of problems with Staff's argument. First, I understand that the Commission's prudence standard does not require that the utility make decisions based on what Staff believes was the best course of action for the utility. The standard is objective reasonableness — whether, based on the information the utility knew or should have known at the time, the utility's decision was reasonable. In its UE 199 Surrebuttal Testimony on Rolling Hills, Staff states that "there is no price discovery to demonstrate that Rolling Hills was the *best resource* for ratepayers." UE 199, Staff/600, Schwartz/3, lines 18–19 (emphasis added). While the Company believes the resource was the best choice given the then-existing circumstances, I am informed by counsel that Oregon law does not require it to show that Rolling Hills was the “best resource” — only that the decision to acquire the resource was objectively reasonable.

Staff’s interpretation of prudence would essentially turn the management of utility resource acquisition over to Staff. Such a result is not in line with the Commission’s previous orders on prudence or case law on the subject. The Company’s testimony in this case shows that its decision to acquire Rolling Hills was objectively reasonable and meets the Commission’s prudence standard.

Second, Staff presents no evidence that the Company knew or should have known of higher capacity factor acquisition options that would have been so economically preferable to Rolling Hills that to not pursue those options in lieu of Rolling Hills was objectively unreasonable. Staff asserts, without supporting evidence or experience, there were likely alternative wind projects available to the Company in Wyoming during the relevant time period. In contrast, Mr. Tallman has the experience of adding hundreds of megawatts of wind facilities to the Company’s portfolio and is in the renewable energy market literally every day. Mr. Tallman testifies in his rebuttal testimony that Staff’s assertion is simply not accurate.

Finally, even if a higher capacity option was available in the relevant time frame, Staff has not presented evidence that those options would have been more cost effective than Rolling Hills. Staff is assuming that capacity factor is the sole determinant of cost and the Company could have acquired a resource with a higher capacity factor that would have been more beneficial to customers than

Rolling Hills. The first assumption is demonstrably inaccurate, and the second assumption is not founded upon any evidence. There is no evidence to support the notion that a third-party constructed, owned, and operated wind resource would pass any cost benefit associated with a higher capacity factor project onto the Company and its customers.

Q. Do the Commission's competitive bidding guidelines address whether projects in close proximity to one another should be deemed to be one project for purposes triggering a Commission-approved RFP requirement?

A. No. The Commission never addressed this issue. Commission Order No. 06-446 sets forth that the Company must issue a Commission-approved RFP when the Company is acquiring a "Major Resource." A Major Resource is a resource greater than 100 MW in size and greater than 5-years in duration. Determining if a resource is a Major Resource does not include a proximity test. The Rolling Hills wind project is not a Major Resource as defined by Commission Order No. 06-446.

Q. Do Staff and ICNU ask the Commission to make this determination in this case?

A. No. They argue that the RFP guidelines impliedly contain this directive.

Q. Is there anything in the record in Docket UM 1182 that supports this position?

A. No. The question was never raised or briefed.

Q. Are there serious policy issues raised by Staff's position?

A. Yes. Staff's assertion in UE 199, and tangentially via UE 200, is that a 5-mile distance criterion applies to each resource in the Company's portfolio. Under such a new criterion, any acquisition of another resource within 5-miles of a pre-existing resource would trigger an assessment to determine if the existing resource plus the new resource constitute a Major Resource under Commission Order No. 06-446.

The effect of such a criterion would be to create a 5-mile exclusion zone around every resource in the portfolio. The Company could not pursue a resource opportunity that is within 5-miles of any other resource for fear that the Commission would declare the Company to be in violation of the RFP Guidelines and potentially subject to penalty or disallowance.

In this case, the Commission should clarify that no such proximity or distance-based criteria is currently in effect by Commission rule or order other than as applicable toward PURPA qualifying facilities. If the Commission wishes to consider such a rule for the future, it should open a rulemaking or investigation and fully consider the issues implicated before making such a major change in policy.

Q. Should the Commission impose a real penalty on PacifiCorp for Staff's opinion that the competitive bidding guidelines contain an implied requirement?

A. No. One of the five goals the Commission identified for its RFP Guidelines was that they be "Understandable and fair." There is nothing understandable and fair about imposing real penalties for implied requirements especially when the proposal, as in this case, is to do so retroactively. In any event, such an approach is antithetical to encouraging the Company to expeditiously acquire and/or invest in renewable resources.

Q. What is the Company's focus related to renewable resource acquisition?

A. The Company's focus is on complying with the policies of the Legislature and the Commission to increase renewable resources in the Company's portfolio within the confines of law and regulations. To meet its renewable resource acquisition commitments and goals, the Company needs the flexibility to pursue multiple, conjunctive acquisition strategies—building <u>and</u> buying through competitive bidding <u>and</u> bilateral transactions <u>and</u> self development. The current rules in Oregon permit the Company to pursue resources under 100 MW and/or for an amount greater than 100 MW and with a duration of less than 5 years (whether via power purchase agreement or via ownership) without the requirement to utilize a formal Commission-approved RFP process.

Q. Has the Company taken steps to acquire renewable resources that do not qualify as a "Major Resource" through a competitive bid solicitation?

A. Yes. As discussed in Mr. Tallman's direct testimony, the Company issued a renewable resource RFP in January 2008. The Company is evaluating the bids received and is in active negotiations.

Q. If the Commission determines that the Rolling Hills resource constitutes a Major Resource pursuant to Order No. 06-446, what is the Company's position?

A. If the Commission determines that Rolling Hills constitutes a Major Resource pursuant to Oregon's competitive bidding guidelines, then the Company will file a request that the Commission waive the application of the competitive bidding guidelines to the acquisition of the Rolling Hills resource pursuant to Guideline 2 of Order No. 06-446.

New Resources in the RAC

Q. Why is Staff objecting to the Company's inclusion of the Glenrock III and Seven Mile Hill II wind resources in its RAC update to be filed by December 1, 2008?

A. Staff claims that the Company cannot add new resources to the RAC update that were not included in its April 1 filing.

Q. Does the Company agree with the Staff position?

A. No, but for purposes of this case, the Company agrees not to include Glenrock III and Seven Mile Hill II in the RAC in this proceeding and will seek deferral of the costs, as recommended by Staff, in the RAC deferral mechanism.

REC Liability Account Proposal

Q. Why has ICNU proposed that the Company maintain a regulatory liability in the amount of the current market value of the Company's RECs?

A. ICNU is concerned that the Company will sell Oregon allocated RECs, rather than bank them to use when the Company is required to demonstrate compliance with Oregon RPS in future years.

Q. What is the Company's position on ICNU's recommendation?

A. ICNU's proposal is unnecessary. The Company is currently and plans to continue banking Oregon's allocated share of RECs for the benefit of customers in complying with Oregon's RPS law. If, however, the Company ever did sell

Oregon-allocated RECs associated with the resources included in this and future RAC proceedings, the Company would flow through to customers the revenues from such sales either in a general rate case proceeding or through the RAC mechanism.

Q. Does this conclude your testimony?

A. Yes.

Case UE-200
Exhibit PPL/203
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Mark R. Tallman

August 2008

Q. Are you the same Mark R. Tallman who provided direct testimony in this proceeding?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (1) provide updated capacity factor information based upon final build design projections for the Company's wind resources now under construction; (2) demonstrate that the Rolling Hills resource was acquired through prudent decision-making, is cost effective and is in the best interest of customers; (3) rebut Staff's and ICNU's arguments to the contrary, based on the allegation that PacifiCorp violated the Commission's competitive bidding guidelines; (4) rebut Staff's proposed Operation and Maintenance (O&M) disallowances for wind plant operating costs; and (5) explain why the next highest alternative cost for compliance (ACC) analysis method is preferable to Staff's recommendation and why Staff's concerns are unfounded.

Update for Most Recent Capacity Factor Projections

Q. Staff has proposed to increase the capacity factor of two wind resources, Rolling Hills and Glenrock. As a part of the construction process, has the Company recently received third-party technical studies updating the capacity factor estimates for these resources based upon the final build design?

A. Yes. Confidential Exhibits PPL/204 and PPL/205 are the final build design energy projections for Rolling Hills and Glenrock. Based upon final project design, the current estimated capacity factor of Rolling Hills is 33.8 percent, up from the estimated capacity factor of 31 percent at project approval, supported by the wind study submitted as Exhibit PPL/401 in the Transition Adjustment Mechanism (TAM) proceeding, Docket UE 199. The current estimated capacity factor of Glenrock is 37.4 percent, down from the estimated capacity factor at project approval of 38.6 percent and the capacity factor of 41 percent contained in the interim study filed in this case as Staff/202, Schwartz/57.

Q. Are estimated capacity factor updates available for other wind resources included in this case?

A. Yes. The final build design capacity factor of Seven Mile Hill is 40.3 percent, down from the 41.3 percent estimate at project approval. The third-party wind study for Seven Mile Hill is attached as Confidential Exhibit PPL/206.

Q. Why did the estimated capacity factors of these resources change?

A. These resources are still under construction. The change in estimated capacity factor reflects the final construction design of the resources, as well as additional information on wind climatology for the sites.

Q. Will the Company obtain additional capacity factor technical studies at project completion?

A. Yes. If there are material changes from the capacity factor estimates at final build design to the capacity factor estimates at project completion, the Company will include this information in a future RAC update or filing.

Q. How should this new capacity factor information be reflected in rates?

A. In its RAC filing and its TAM filing, the Company included the capacity factor estimates and associated wind profiles used for project approval for the new wind resources. In their testimony, Staff and ICNU have both proposed to increase the Glenrock resource's capacity factor to reflect a capacity factor estimate contained in an interim third-party technical study. For resource review and analysis in this case, and for the associated wind profiles in the TAM, PacifiCorp does not object to updating the estimated capacity factors to reflect the most recent technical studies or other capacity factor evaluation of resources under construction. Accordingly, the Company will reflect the then-current capacity factor information in future TAM and RAC proceedings. However, the Company does have some important qualifications on Staff's position in this case, as noted below.

Q. Staff proposes a $14.2 million capital disallowance (system) for Glenrock based on its view that a 41 percent capacity factor is appropriate for that project, instead of a 38.6 percent capacity factor. Are disallowances in the RAC appropriate for updated capacity factor projections?

A. No. Staff's proposed $14.2 million disallowance and Staff's proposed production tax credit (PTC) and renewable energy credit (REC) disallowances in UE 199 and in this docket are conceptually flawed. The ratemaking issue associated with capacity factors relates to which wind profile to use in calculating the Company's net power costs in the TAM. The prudence of the Glenrock resource is not at issue and it is inappropriate for Staff to propose a capital disallowance in this case associated with updates to the Glenrock resource's projected capacity factor.

Q. Do you have other concerns about updating capacity factors in this case for projects under construction?

A. Yes. I have three other concerns. First, updates should be made in a manner that is consistent among resources, symmetrically updating for both increases and decreases in projected capacity factors. Second, capacity factors should be updated in the same manner in the RAC, TAM and any other related dockets to avoid cost, revenue and resource attribute mismatches. Third, in assessing the prudence of a renewable energy resource, the projected capacity factor estimate at the time of the decision to proceed with a purchase power agreement (PPA) or other form of resource is the relevant information since it represents the information available to the Company at the time of the business decision.

Q. Is a project's capacity factor the sole determinant in whether a project is cost effective?

A. No, capacity factor is just one element of the all-in costs that determine net cost effectiveness over the expected life of the resource. In the case of a PPA, such costs include payments to third parties; net of other associated benefits and costs. In the case where the Company will own the resource, such costs include the cost to construct, own, and operate the resource; net of other associated benefits and costs, including, among others, operations, maintenance, taxes and tax credits.

Average Wyoming Wind Capacity Factors

Q. Are the capacity factors for the Glenrock and Rolling Hills resources in line with the average capacity factor for Wyoming wind resources already serving the Company?

A. Yes. The average capacity factor for the Company's Wyoming wind resources is approximately 35.0 percent if the Glenrock, Rolling Hills and Seven Mile Hill resources are excluded. If the wind resources in this case are included, the average capacity factor increases to 35.5 percent, based on the capacity factor estimates used for project approval of the new resources or 35.6 percent, based upon the final build design estimates.

The average capacity factor of the Glenrock and Rolling Hills resources is 34.8 percent based upon project approval estimates and 35.6 percent based upon the final build design estimates.

Q. Are the capacity factors for the Glenrock and Rolling Hills resources in line with the proxy capacity factor assumed for Wyoming wind resources in the acknowledged 2007 Integrated Resource Plan (IRP)?

A. Yes. The Company's 2007 IRP used a 35 percent capacity factor to model proxy Wyoming wind projects. After initially considering an increase to 38 percent for the next IRP, the Company has concluded that 35 percent remains a valid assumption.

Q. In Staff's direct testimony in UE 199, Staff cites a data request response in another docket, Staff Data Request 36-b in UM 1368, as the basis for its testimony that the average capacity factor for wind plants in Wyoming serving the Company is 38 percent. Staff/203, Schwartz/6-9 in UE 199. Please reconcile this data request response with the information just provided.

A. The Company responded to Staff DR 36-b in UM 1368, relying on a May 22, 2008 IRP public presentation listing 38 percent as the preliminary planning projection for proxy Wyoming wind resources in the next IRP. The initial IRP projection of 38 percent for future proxy resources has since been revised downward because the Company was unable to substantiate an assumption higher than the 35 percent assumption contained in the acknowledged 2007 IRP. The current estimate remains equal to the IRP proxy of 35 percent from the 2007 IRP. Indeed, the Wyoming qualifying facility (QF) PPA contracts I address later in my testimony are projected to have capacity factors of approximately 35 percent. The Company has supplemented the response to Staff DR 36-b in UM 1368 to reflect this more recent information.

Rolling Hills: Economic Issues

Q. Has any party in the proceeding challenged the prudence of the Leaning Juniper 1, Marengo, Goodnoe Hills, Marengo II, Seven Mile Hill, Glenrock, or Blundell Bottoming Cycle resources?

A. No. Staff and ICNU challenge only one wind resource included in the Company's filing, Rolling Hills, as being imprudent on the basis of acquisition method.

Q. Did the Company follow the same general business review process for its investment decision in Rolling Hills as the other seven resources included in this case?

A. Yes. The review process included the unique nature of each resource and the evolving nature of the Company's economic modeling; resulting in project-specific analyses and decisions based on project-specific information.

Q. What is the magnitude of Staff's proposed disallowance with respect to the Rolling Hills resource?

A. Based only on the claim that Rolling Hills was improperly acquired outside of a Commission-approved request for proposal (RFP), Staff recommends a net present value disallowance of approximately $45 million on a system basis. This represents a 22 percent reduction in the resource's expected capital cost or a reduction of $452 per kilowatt (kW) against a projected capital cost of $2,085 per kW. As stated in my rebuttal testimony in UE 199, Staff's disallowance has a nominal value of $115 million over the life of the resource. While Staff disputes the appropriateness of representing the adjustment in nominal dollars, they do not dispute the accuracy of the nominal value calculation.

Q. Taking into consideration Staff's proposed disallowance, would the resulting capital costs of the Rolling Hills resource be lower than any other resource in this case?

A. Yes. Staff's proposed disallowance would produce projected capital costs of $1,633 per kW. This is far lower than any of the other resources in the case, including the Leaning Juniper 1 resource — at $1,748 per kW — completed two years ago in September 2006.

Q. Has Staff increased their proposed disallowance since filing direct testimony?

A. Yes. In its UE 199 surrebuttal testimony, Staff increases its proposed disallowance by fictitious Federal PTCs based on Staff's proposal to deem 60,801 megawatt-hours (MWh) per year in phantom energy production from the Rolling Hills resource. The Company estimates the present value of these fictitious PTCs to be more than $22 million on a nominal basis and approximately $14.5 million on a present value basis[1]; representing an additional $146 per kW of incremental disallowance proposed by Staff on a present value basis.

Q. Is Staff recommending an even further disallowance based on deemed energy production?

A. Yes, in its UE 199 surrebuttal testimony, Staff further increases its proposed disallowance based on RECs associated with fictitious generation. The amount of Staff's deemed REC disallowance is equal to 60,801 MWhs per year of deemed energy production multiplied by $5.00 per MWh for a period of five years. This further disallowance represents approximately $1.5 million on a nominal basis and approximately $1.28 million on a present value basis[2] (approximately $13 per kW).

Q. Taking into consideration Staff's proposed further disallowances, what would be the resulting capital costs of the Rolling Hills resource?

A. Staff's proposed disallowances would produce capital costs in rates equal to

[1] 2007$
[2] 2007$

$1,474 per kW ($2,085 per kW less $452 per kW less $146 per kW less $13 per kW) or approximately 73 percent of the IRP proxy assumption of $2,011 per kW referenced in Staff's testimony. As I address later in my testimony, the cost of the proxy in the 2007 IRP is represented in 2006 dollars and, therefore, must be escalated if it is to be compared to the Rolling Hills resource.

Q. Is Staff asking for the Commission to declare the Rolling Hills resource imprudent on the basis of cost?

A. No. Staff witness Ms. Deborah Garcia concluded that the capital costs of all renewable resources in the filing, including the Rolling Hills resource, are reasonable.

Q. Does Staff contend that the Rolling Hills acquisition was inconsistent with the Company's IRP?

A. No. Staff witness Ms. Lisa C. Schwartz concludes that the acquisition was consistent with the Company's IRP. However, Ms. Schwartz does testify that the projected construction costs of the Rolling Hills resource are above the 2007 IRP proxy assumption of $2,011 per kW.

Q. Is Rolling Hills above the 2007 IRP proxy cost assumption?

A. No. The 2007 IRP proxy cost estimate of $2,011 per kW was in 2006 dollars. An accurate comparison to 2008 resource costs requires escalation of the IRP proxy estimate. As Ms. Garcia points out, the nature of the wind resource construction market does not lend itself to predicting future costs by merely applying inflation adjustments to historical costs (Staff/100, Garcia/7-8). A wind resource cost escalation rate of between 10 percent and 20 percent or more per year is a reasonable assumption. On this basis, the IRP projected costs range as follows:

IRP Proxy (2006$)	Wind Resource Cost Inflation	IRP Proxy (2007$)	IRP Proxy (2008$)
$2,011/kW	10%	$2,212/kW	$2,433/kW
$2,011/kW	15%	$2,313/kW	$2,660/kW
$2,011/kW	20%	$2,413/kW	$2,896/kW

As shown on Ms. Garcia's Exhibit Staff/102, Garcia/1, the Rolling Hills resource is expected to cost $2,085 per kW, which is well below the adjusted IRP amounts above.

Q. Does Ms. Schwartz similarly misapply the IRP proxy in discussing the Rolling Hills resource economics?

A. Yes. In her testimony, Ms. Schwartz points first to the IRP proxy economics for wind resources in Wyoming as being about $55 per MWh and then to an exhibit showing the Rolling Hills resource economics to be much higher (Exhibit Staff/202, Schwartz/10). For three reasons, such a comparison is inaccurate. First, the IRP proxy is dated. Second, the IRP reference does not include integration costs whereas the Rolling Hills citation does. Third, the IRP reference is on a real-levelized basis whereas the Rolling Hills value is on a nominal-levelized basis. Real-levelized representations and nominal-levelized representations cannot be directly compared.

Q. What is the appropriate comparison?

A. A more appropriate approach is to compare the IRP proxy (with integration costs) to the projected cost of the Rolling Hills resource, both on a real-levelized basis. Confidential Exhibit PPL/207 demonstrates that, when the comparison is done correctly, the projected cost of the Rolling Hills resource is well below[3] the IRP proxy.

Q. For comparison purposes, how do the projected costs for Rolling Hills compare to Oregon avoided costs?

A. For comparison purposes, Oregon's Schedule 37 avoided cost is currently $60.54 per MWh on a real-levelized basis (without integration). As shown in Confidential Exhibit PPL/208, the projected cost of the Rolling Hills resource is lower than Oregon's Schedule 37 avoided cost.

Q. ICNU and Staff represent the costs of the Rolling Hills and Glenrock resources[4] during the test year. Is this the appropriate economic reference for a prudence review?

A. No, such a review should take into account the economics of the resource over the life of the resource. Viewed in the correct manner, the projected costs of the Rolling Hills and Glenrock resources are much lower than ICNU's and Staff's representations. For example, ICNU and Staff overstate the cost of the Rolling Hills resource by as much as $36 per MWh by representing the information only on a test year basis instead of more correctly over the life of the resource. See Confidential Exhibit PPL/209.

Q. What is the project-specific ACC for Rolling Hills?

A. As described in my direct testimony, "ACC" is a project-specific analysis that allows the Company to compare the resource against the potential next highest

[3] The comparison in Confidential Exhibit PPL/207 is understated since the Company conservatively escalated the 2007 IRP proxy, which is in 2006 dollars, by 2% instead of an annual rate in line with wind resource cost escalations the industry has experienced and continues to experience.
[4] Staff lists Seven Mile Hill whereas ICNU does not.

alternative cost for compliance. Based upon the capacity factors used for project approval, the ACC for the Rolling Hills resource is $4.53 per MWh on a nominal-levelized basis.

Q. Do Staff or ICNU dispute that the $4.53/MWh nominal-levelized ACC for Rolling Hills represents a reasonable amount for renewable portfolio standards (RPS) compliance?

A. No. Neither Staff nor ICNU dispute that $4.53 per MWh nominal levelized is a reasonable level. In fact, at $4.53 per MWh nominal levelized, the ACC for Rolling Hills is below the implied $6.37 per MWh nominal-levelized ACC for the Goodnoe Hills resource. The Goodnoe Hills resource includes an Energy Trust of Oregon, Inc. (Energy Trust) grant that Staff helped negotiate[5]. No party has challenged the prudence of the Goodnoe Hills resource on any basis, including the fact that it is projected to have a capacity factor of approximately 32.4 percent or was acquired outside of a Commission-approved RFP.

Q. How do the overall resource economics for Rolling Hills change using the most recent projected capacity factor of 33.8 percent?

A. Using an estimate of 33.8 percent yields a projected resource cost as shown in Confidential Exhibit PPL/207 on a real-levelized basis. The nominal levelized ACC is negative $2.91 per MWh which can be compared to the nominal-levelized ACC of positive $4.53/MWh using the initially conservative estimate of 31 percent. The result is a beneficial movement of $7.44 per MWh on a nominal-

[5] In fact, Staff originally helped negotiate two separate Energy Trust grants for two 56 MW wind projects (Goodnoe Hills West and Goodnoe Hills East) that were in close proximity to one another, would have been constructed at the same time by a single contractor and would have shared a single collector substation and single transformer.

levelized basis; placing the projected resource economics below market.

Q. How does a final build design estimate of 37.4 percent impact the economic analysis for the Glenrock resource?

A. The ACC becomes negative $6.51 per MWh on a nominal-levelized basis, remaining below market.

Q. How does a final build design estimate of 40.3 percent impact the economic analysis for the Seven Mile Hill resource?

A. The analysis results in an ACC equivalent of negative $5.27 per MWh on a nominal-levelized basis, remaining below market.

Q. Citing the third-party wind study for Rolling Hills, both ICNU and Staff raise concerns that the projected capacity factor information available to the Company for Rolling Hills was inadequate. Is this a fair reading of the wind study?

A. No. The resource was supported by long-term on-site data, and selectively quoting from the wind study does not change this fact. Fairly read, the reference in the report to "best guess" was another way of the consultant saying "based on the information available." In addition, Staff and ICNU take the reference to "non-standard industry practice" out of context. It would have been non-standard to rely solely on the ridge data without taking other information into account. Finally, the Company's consultant recommended additional on-site data collection to supplement the data set. The Company followed the consultant's recommendation, installed four additional on-site meteorological towers during December 2007 and collected supplementary data. This is evidenced on page 5 and 6 of the most recent final build design estimate prepared by the Company's consultant. See Confidential Exhibit PPL/204.

Q. Did the Company have adequate information on estimated capacity factor at the time it made its decision to advance the Rolling Hills resource?

A. Yes. While the on-site data was ultimately supplemented, the information available to the Company was sufficient at the time to make the "go/no go" decision. This was especially true taking into account the conservative nature of the projected capacity factor of 31 percent, arising from the fact that the Company's consultant appropriately utilized a de-rated power curve, a lower availability assumption, and a lower efficiency factor to account for potential turbulence.

Q. ICNU claims that the Company usurped its "ordinary process" used to project wind resource capacity factors. Is ICNU correct?

A. No. As noted above, the Company followed the same general business process with respect to each of the investment decisions in this case. In any event, it is not clear what "ordinary process" ICNU is describing since wind resource development remains relatively new and historically non-routine.

Q. ICNU claims that the Company did not meet the "reasonable person" prudence standard. Does the Company agree?

A. No. The Company **does** meet the prudence standard because based on the information available to it, an expectation of a 31 percent capacity factor was reasonable. Furthermore, the Company's economic analysis was conservative as it did not factor in the terminal value that customers will enjoy, avoided lease costs, portfolio risk reduction values or the possibility (now borne out) that the estimated capacity factor would increase.

Rolling Hills: Penalty Issues

Q. Are the Staff and ICNU proposed disallowances for Rolling Hills based upon the premise that the Company violated the Commission's competitive bidding guidelines and should suffer a penalty?

A. Yes. For the reasons stated in my UE 199 rebuttal testimony, and as set forth in Ms. Andrea L. Kelly's rebuttal testimony in this docket, the Company disagrees with the premise and theory of Staff's and ICNU's proposed adjustments. In this testimony, I address additional issues raised by these proposed adjustments to which the Company has not yet responded.

Q. Staff claims that its "single project" theory is supported by certain criteria the Oregon Department of Revenue uses in evaluating business energy tax credit applicability. Did Staff omit certain key criteria?

A. Yes. Staff failed to mention two key criteria contained in OAR 330-090-0120(7)(a). These criteria are:

> *"(B)What are the applicable permits, licenses, or site certificates and how are they distinct"* and
>
> *"(D) How, when, and from whom was the generating equipment procured for the facility and how is the procurement distinct?"*

The Company has testified that the Rolling Hills resource is a separate and distinct resource from the Glenrock resource as evidenced by the fact that the Company made the decision to advance Rolling Hills materially later than

Glenrock. Each resource obtained separate and distinct certificate of public convenience and necessity certifications from the Wyoming Public Service Commission, each resource has a stand alone construction contract obligation, each resource has stand alone collector substations and transformers, and each resource procured its wind turbines at two separate and distinct points in time and via separate and distinct commercial negotiations. Finally, each resource was presented to the Wyoming Industrial Siting Commission (ISC) as such and the ISC had the purview to permit none, one or both resources.

Q. What is the Company's response to Staff's claim that a better alternative would have been found if only the Company had issued a RFP?

A. The Company does not agree with Staff's assertion that the Company could have acquired a resource with better economics and ICNU inappropriately suggests that other wind resources in the Company's portfolio serve as a proxy for competitive alternatives available to the Company. The Company's view is that the Commission must assess the prudence of the Rolling Hills resource in the context of long-term benefits to customers (i.e., the balance between cost and risk) and the portfolio objectives established by the acknowledged 2007 Integrated Resource Plan (IRP).

Q. Does any party present any evidence to support their theory that a more economic resource alternative existed?

A. No party presents any valid evidence to suggest that a viable alternative existed.

Q. What about ICNU's claim that other PPA contracts in the Company's portfolio serve as an alternative?

A. ICNU recommends a disallowance based on the cost of what it represents to be "competitive projects." These resources are the Mountain Wind I, Mountain Wind II, and Spanish Fork QF PPAs. None of these projects are competitive projects. The term "competitive" implies the QF PPAs were similar to the Rolling Hills and Glenrock resources and served as viable alternatives.

The QF contracts are not similar because each is smaller in size[6], were executed in 2006, have a term shorter than the expected lives of Rolling Hills and Glenrock, and provide no terminal benefits to the Company's customers.

Moreover, the decisions to advance Glenrock and Rolling Hills were made significantly later (May 31, 2007 and December 20, 2007, respectively). Finally, with respect to Spanish Fork, the project is located in Utah and, similar to Oregon's treatment of QF PPAs, the Company does not own title to the RECs. Therefore, unless the Company procures RECs separately, the project cannot be used to satisfy any RPS and the RECs cannot be sold by the Company to bring value to customers. Obviously, the PPAs are not as comparable in benefit to customers as the Glenrock and Rolling Hills resources.

Q. ICNU cites the average cost of the QF PPAs to be $60.25 per MWh and then makes a comparison to the test-year costs of Rolling Hills and Glenrock. Is this an appropriate comparison?

A. No. As I explained earlier, ICNU's representation of the Rolling Hills and

[6] Rounding down, the size of the QF PPAs are approximately 18 MW, 60 MW and 79 MW for Spanish Fork, Mountain Wind I and Mountain Wind II respectively. The Mountain Wind I and Mountain Wind II resources are located within close proximity to one another.

Glenrock costs are on a test-year basis, which is not appropriate because they do not represent the costs of these resources over their lives. When appropriately represented over their entire lives, the costs of the Rolling Hills and Glenrock resources compare favorably to the QF PPAs.

Q. Were there viable Wyoming alternatives as Staff claims?

A. No. There were no other viable alternatives in Wyoming as evidenced by Exhibit PPL/210. The Company was the first entity to be issued a wind project permit by the Wyoming ISC since 2003. As a result, Staff's assertion that the Company could have acquired another wind resource in Wyoming with a better capacity factor is false as there were literally no other similar projects being permitted by the Wyoming ISC at that time. Indeed, even as of the date this testimony was drafted, no entity other than the Company has even made application to the Wyoming ISC for a wind project other than for those listed in Exhibit PPL/210.

Q. Does the Company's Large Generator Interconnection Agreement (LGIA) Queue show active requests for wind projects in Wyoming with an in-service date during 2008?

A. No. All non-Company active LGIA wind requests have an in-service date after 2008 or are associated with projects that the Company was already pursuing (for example, the Mountain Wind QF PPAs). The fact that no entity had an ISC permitted site and there is no active LGIA application with an in-service date of 2008 demonstrates that the Company did not have a viable alternative site in Wyoming for placement of 66 turbines.

Q. How long does it take to complete the Company's FERC-compliant LGIA process?

A. While the time varies based on actions of the interconnection customer, a length of 18-months is not unusual.

Q. Even if other wind developers were actively seeking a permit with the Wyoming ISC, could the Company have practically administered a Commission-approved RFP to determine if an alternative similar to the Rolling Hills resource existed in Wyoming?

A. No. Staff's assertion that, instead of advancing the Rolling Hills resource, the Company had *"all of 2007 to undertake a competitive solicitation for resources with a 2008 in-service date"* is flawed for two reasons.

Q. Please explain these two reasons.

A. First, the formal RFP processes in Oregon and Utah takes approximately a year or more. Contrary to Staff's claim that such a RFP can be processed quickly, one need only look to the most relevant example, RFP 2008R-1 in Docket UM 1368. The Company filed its application for RFP 2008R-1 on March 4, 2008. As of the date this testimony was drafted, the Commission has not ruled on the issues raised by parties on the draft RFP 2008R-1. Once the Commission rules, the Company will quickly move to issue the RFP which has an anticipated 180-day cycle time. When complete, the Company estimates that RFP 2008R-1 will have taken approximately one-year or more from start to finish.

Second, a RFP would not have yielded a choice between Rolling Hills and another resource but rather would have resulted in the loss of the Rolling Hills resource opportunity as currently implemented. This is because the Company would not have been able to hold the turbines made available to it for the duration of the RFP process. Instead, the Company would have had to attempt re-selling the turbines back into the market or default on its turbine supply agreement.

Q. Is the Company suggesting any party in UM 1368 is inappropriately slowing the process down?

A. No. To the contrary, the Company acknowledges that all parties have diligently processed RFP 2008R-1. This is especially true with respect to Staff.

Q. Is the Company suggesting ways to shorten the RFP cycle time?

A. Yes. First, the Company and renewable energy developers reached an agreement upon 2008 legislation in Utah (SB 202) that now allows the Company to add renewable energy resources (PPAs or ownership alternatives) of 300 MW or less without the need to use an extended RFP process in Utah. Instead, the Company will be issuing renewable energy solicitations each year that the Company anticipates a continued need for renewable resources, with the target of completing each annual solicitation within approximately 180 days.

Second, via the RFP 2008R-1 process in Oregon, the Company has sought Commission approval to use a standard, pre-approved form and format for future renewable resource solicitations; thus reducing the cycle time. A faster cycle time is important to the Company because the renewable resource market is fast moving. The Company believes it is important to be constantly in the renewable resource market via RFPs, bi-lateral transactions and/or via self development, and anticipates that an ongoing RFP presence will ameliorate many of the concerns raised by Staff in this docket.

Q. Notwithstanding efforts to streamline the RFP process, how does the time to process a RFP compare with the current renewable resource market?

A. The time to process any RFP, even the most efficient RFPs, is in stark contrast to how fast the renewable resource market moves. Opportunities can come and go many times over while a RFP is in process. The Company has experienced situations where it had time-limited opportunities (a week or weeks) to decide whether to purchase scarcely available wind turbines. Fortunately, the fact that the Company and its sister utility, MidAmerican Energy Company, have quickly become experienced developers and utility owners of renewable energy facilities allows us to respond quickly to such opportunities.

A prime example is the wind turbines made available to the Company for the Rolling Hills resource. The turbine supplier made the turbines available on a time limited basis and the Company had to necessarily be flexible and react quickly if it were to capture the benefit of having that equipment in the portfolio for the long-term benefit of customers. For this reason, the Company needs the flexibility to supplement the RFP process with cost-effective opportunistic acquisitions to meet its renewable energy acquisition targets.

Q. Staff testifies that the Company could have re-sold the wind turbines or used the turbines for a cost-based alternative in a RFP process or for building a project on a site offered by a bidder for development. Are these practical assertions?

A. No. As my testimony demonstrates, there were no viable third party sites available to the Company, and the Rolling Hills wind turbines were set to deliver during 2008. Contrary to Staff's inference, the resale of wind turbines is not so easily done as the Company did not hold the outright contractual right to re-sell the turbines for another project and any assignment of the turbine supply agreement requires the consent of the turbine supplier. The Company's action to construct the Rolling Hills resource was the least cost/least risk action for the long-term benefit of customers.

Operations and Maintenance (O&M)

Q. What O&M disallowance is Staff proposing associated with the wind resources?

A. Ms. Garcia proposes an O&M adjustment associated with wind resources of $4.6 million system ($1.2 million Oregon allocated using the SG factor of 26.4114 percent).

Q. Is Staff's proposed disallowance appropriate?

A. No. Staff's proposed O&M adjustment fails to assess the overall economics of each wind resource and determine whether the overall cost of the resource is in the best interest of customers. In addition, Staff fails to recognize that the Company's projected O&M costs are primarily associated with pre-determined contractual obligations.

Q. Why else are Staff's proposed O&M adjustments inappropriate?

A. Staff's proposed O&M adjustments amount to a back-door prudence challenge for each wind resource and ignore the fact that the Company is asking the Commission to render a prudence decision for the entirety of each wind resource, not just portions of it. O&M costs are a material component of owning and operating a wind resource and these costs were forecasted in the economic assessment used by the Company when it made its decision to advance each resource. In addition, key O&M costs at some resources were linked to the Company's ability to acquire the resource in the first place.

Q. Has the Company updated its projections of O&M costs?

A. Yes. As Mr. R. Bryce Dalley's testimony explains, the Company has updated its O&M projections based on current information. This provides further evidence that the Company's economic analysis for Rolling Hills was conservative.

Q. In making its O&M recommendation, Staff considers Leaning Juniper 1 as an O&M benchmark and relies on a U.S. Department of Energy (DOE) report to support its position. Do you agree with Staff's conclusions?

A. No. I disagree for three reasons. First, Staff bases its conclusion solely on an analysis of O&M cost per kW as compared to Leaning Juniper 1. Second, Staff incorrectly concludes from the DOE report that O&M costs are predicted to fall for the size and type of turbines the Company is installing. Third, Staff's conclusion that the Company's forecasted O&M costs have no certainty is false. A material portion of the Company's O&M costs are indeed known in advance.

Q. Please further explain the first reason.

A. An analysis based solely on the Leaning Juniper 1 resource is faulty because it homogenizes O&M costs across all of the wind resources and fails to assess the Company's O&M obligations at each wind resource. The Company's O&M obligations at each resource vary due to a number of factors, including O&M

contracts specific to each resource, permit conditions specific to each resource, land leases specific to each resource, taxes specific to each resource and/or taxes specific to the state or county the resource resides in. Other resource specific factors include land related contracts or additional resource specific caretaking expenses. Indeed, the DOE report cited by Staff states that *"O&M costs are a significant component of the overall cost of wind projects, <u>but can vary widely among projects.</u>"* (Emphasis added.)

Q. Please discuss your concerns about Staff's reliance on the DOE report.

A. Staff's conclusion that the DOE report provides the Commission a foundation from which to reduce O&M costs is in error. The O&M aspect of the DOE report is based on a limited sample size and, more importantly, addresses O&M trends since 1980, not forward looking trends. The report expressly cautions the reader that historical trends are not necessarily useful for modern turbines. As such, the DOE report is inapplicable to the Company's resources.

Q. What cautions are you referring to?

A. The DOE report devotes less than two pages to the topic of O&M costs. A simple reading of this minimal information reveals significant cautions that Staff failed to heed. For example, two DOE cautions related to O&M costs across projects include:

> *"Operation and maintenance (O&M) costs are a significant component of the overall cost of wind projects, <u>but can vary widely among projects.</u>"* (Emphasis added.)

> *"The data exhibit considerable spread, demonstrating that O&M costs are far from uniform across projects."* (Emphasis added.)

These DOE cautions invalidate Staff's conclusion that there should be a single benchmark for every wind resource in the Company's portfolio.

Q. Did DOE have cautions applicable to Staff's conclusion that O&M costs will decline in the future?

A. Yes. DOE said:

> *"Even where these data are available, care must be taken in extrapolating historical O&M costs given the dramatic changes in wind turbine technology that have occurred over the last two decades, not least of which has been the up-scaling of turbine size…."* (Emphasis added.)

> *"Though interesting, the trends noted above are not necessarily useful predictors of long-term O&M costs for the latest turbine models."* (Emphasis added.)

These DOE cautions invalidate Staff's conclusion that O&M costs are declining on a forward-looking basis.

Q. Is the Company using contemporary turbine designs at resources in this docket?

A. Yes. The turbines at each of the wind resources that are the subject of this docket are modern, contemporary in design and large in megawatt size.

Q. Did DOE have cautions about the depth of data from which the DOE report is based?

A. Yes. DOE said:

> *"Market data on actual project-level O&M costs for wind plants are scarce."*

> *"A full-time series of O&M cost data, by year, is available for only a small number of projects; in all other cases, O&M cost data are available for just a subset of years of project operations."*

> *"Note that, for each group, the number of projects used to compute the average annual values shown in the figure is limited…."*

Q. Did DOE have a single overriding caution that Staff failed to heed?

A. Yes. DOE cautioned:

> *"<u>Given the scarcity and varying quality of the data, caution should be taken when interpreting the results shown below.</u>"* (Emphasis added.)

Q. Did Staff rely solely on the DOE report to substantiate their proposed disallowances?

A. Yes. Staff appears to have relied solely on the DOE report.

Q. Staff declares that projected O&M costs are not known. Is this correct?

A. No. It is incorrect for Staff to declare that projected O&M costs are not known. The Company has O&M contracts in place for many of its wind resources. Some of these O&M contracts were linked to the Company's overall ability to effectuate the project. For example, the O&M contracts for the Leaning Juniper 1, Marengo, Marengo II and Goodnoe Hills resources were required if the Company is to enjoy the benefit of warranties. Indeed, the Leaning Juniper 1 O&M agreement was required by the seller of the project asset and, as such, the seller negotiated a price that it took into account within the context of the overall transaction. The Company has no way of knowing if the seller subsidized the Leaning Juniper 1 asset sale with the O&M agreement or vice versa. In any event, this is further evidence that O&M costs can vary widely among wind projects.

Q. Staff recommends that an audit be performed on the O&M costs for the wind resources. Does the Company object to this?

A. No, but if the Commission believes it is necessary, the audit recommendation should be adopted in lieu of the proposed O&M disallowance.

Q. What conclusion and recommendation do you have for the Commission with respect to Staff's proposed O&M adjustments?

A. I recommend the Commission reject Staff's recommendation.

ACC Method

Q. What concerns does Staff express with respect to the ACC method of evaluation?

A. Staff witness Ms. Kelcey Brown expresses concern that the ACC analysis method can lead to potential under or over valuation of energy depending on a specific resource's wind profile as compared to that of the uncommitted portfolio of renewable resources. To help assess if such an under/over valuation is taking place, Staff recommends that the Company be required to perform both the

PVRR(d) and the ACC methods using the same forward price curve (FPC). Finally, Staff concludes that the ACC method does not adequately capture locational diversity of wind resources and that the PVRR(d) method provides a reasonable assessment of site-specific energy value due to the use of the GRID model underpinning in the PVRR(d).

Q. Staff recommends to the Commission that the Company be required to perform the PVRR(d) and ACC analysis methods using the same FPC. Will Staff's recommendation provide useful results?

A. No. Ms. Brown contends her recommendation is necessary for the purpose of ascertaining if wind profiles are systematically being under or over valued. For reasons I more fully explain later, Staff's recommendation will not achieve the desired results. Instead, running the two analysis methods using the same FPC will primarily demonstrate the value of the IRP preferred portfolio to the system. The Company has already performed this type of evaluation via the IRP process.

Q. How does the ACC method contrast to the PVRR(d) method with respect to the IRP preferred portfolio?

A. Where the PVRR(d) method does not include the IRP preferred portfolio, the ACC method evolves the Company's analysis methodology toward inclusion of the entire IRP preferred portfolio. Staff characterizes the material difference between the PVRR(d) and ACC methods as being the difference between the projected wind profiles. This is not the case. The material difference between the two methods is between having and not having the IRP preferred portfolio in the analysis methodology. Indeed, the complementary linkage with the IRP is one reason the Company evolved toward the ACC method.

Q. Has the Commission given guidance that supports the Company's evolution toward an analysis method with IRP linkages?

A. Yes. First, in Order No. 04-091, approving RFP 2003-B, the Commission adopted the Staff report discussing how the Company's IRP and RFPs could be functionally integrated. One specific suggestion in the Staff report related to the use of IRP portfolio analysis in evaluating RFP bids for renewable resources. Second, Oregon's generic RFP Guidelines, set out in Order No. 06-446 (UM 1182), specifically address the IRP/RFP relationship. Guideline 7 makes approval of an RFP contingent in part on "alignment of the utility's RFP with its acknowledged IRP." More directly to the point on the analytics, Guideline 9b states in part, "The portfolio modeling and decision criteria used to select the final short-list of bids must be consistent with the modeling and decision criteria used to develop the utility's acknowledged IRP Action Plan." Order No. 06-446 at 10-11.

Q. How does the ACC method account for differences in wind profiles?

A. To the extent there are differences between the projected wind profile of a specific resource and that of the uncommitted IRP wind proxies, Staff's concerns of under/over valuation are unfounded because any such difference is not material in the context of making new resource decisions.

Q. Why is Staff's concern over varying wind profiles unfounded?

A. Staff's concern is unfounded for two reasons. First, the IRP contemplates that wind resource profiles are intermittent. As such, inputting a static wind profile into a production cost model (be it GRID or the PaR model) is in itself a modeling simplification. It is for this reason that the Company studied integration costs and reported its findings in Appendix J to the IRP. The fact that the production cost model itself accounts for the effects of inter-hour integration and the Company adds intra-hour integration costs as part of the ACC and PVRR(d) methods demonstrates that the system cost effects of varying wind profiles are analytically accounted for in both methods.

Second, the renewable resources used in the IRP are proxy resources and, as a result, are approximations of what the Company might obtain. As such, the ACC method's removal of the yet uncommitted IRP renewable resource proxies is entirely appropriate as there is no guarantee that the Company will be able to obtain resources with the proxy energy shape or proxy capacity factor. Indeed, as my testimony demonstrates, it is the overall projects economics that is most important. Not just energy shape or capacity factor.

Q. In UM 1368, does the Independent Evaluator (IE) express an opinion regarding the ACC method and wind profile valuation?

A. Yes. The IE acknowledged that the ACC method captures value associated with differing wind profiles when the IE said:

> *"However, bids that are offered into this RFP can gain advantages from their locations if, because of better wind conditions, they operate more in peak hours and months."*

Q. Staff asserts that the GRID model is a reasonable way to assure that site specific energy value is captured. Is this correct?

A. No. Staff's assertion that use of the GRID model is a more reasonable way to capture site specific energy value is not correct, and Staff offers no applicable evidence to support its conclusion. To the contrary, the IE report reference by Staff does not support Staff's position since the IE report is addressing capacity valuations related to locational diversity for the purpose of ranking bids, not resource prudence determination. In fact, the IE discusses that it is the IRP process, and not the production cost model, where locational diversity is taken into account.

Q. What does the IE say about locational diversity and its valuation?

A. The IE comments that:

> *"the IRP process, which guides the acquisition amounts in this RFP, does take into account capacity benefits and <u>locational diversity.</u>"* (Emphasis added.)

While the IE believes there may be some incremental value that can be associated with locational diversity and quantified via capacity contribution, the IE is careful to point out:

> *"Presently, there is no easy way that we know of to accurately calculate this dollar value. <u>We note that the value is likely to be smaller relative to the net benefits calculated in the ACC method</u>."* (Emphasis added.)

Finally, the IE did not suggest that the GRID model would be a superior model over the PaR model to assess locational diversity. This is intuitive because both models are production cost models. The PVRR(d) method uses GRID and the ACC method uses PaR.

Q. Does the Company agree with the IE's view?

A. Yes, the Company agrees that the IRP process takes locational diversity into account in setting acquisition targets. In addition, the Company agrees with the IE where the IE states:

> *"[T]he Company's ACC method does nicely take into account the risk of key market variables like natural gas prices and wholesale power costs. It also accounts for key costs and benefits such as wind integration costs."*[7]

The stochastic nature of the ACC method is another reason why the Company evolved toward this more advanced approach. For example, the ACC method demonstrates that the risk profile of the portfolio increases unless renewable resources are pursued. Unfortunately, the Company has yet to determine how to translate that result into a project-specific benefit but Staff has previously inferred that the benefit could be as much as $5.00 per MWh. While the Company did not include this additional benefit in its assessment of project economics, the value of risk avoidance due to wind resources is yet another example that the Company's evaluations were conservative.

---

[7] The ACC method uses the Planning and Risk (PaR) model, which includes a stochastic evaluation of 100 iterations with market prices, gas prices, hydro generation, retail load, and forced outage rates. These inputs are allowed to change using Monte Carlo simulation and cover the period from 2007 through 2026, which is consistent with the Integrated Resource Planning modeling.

Q. Staff's testimony leaves some doubt as to whether both the ACC and PVRR(d) methods are project specific. Do both methods produce project specific results?

A. Yes, as highlighted in my direct testimony, both methods are indeed project specific and produce project specific results.

Q. Staff is concerned that the ACC method lacks an embedded capability to run scenario analysis and, as such, Staff believes that project size should be an output instead of an input? Is Staff's recommendation practical?

A. No. Staff is not recognizing that the ACC method is a tool intended to assess the value of a project once the input parameters are established. It is unreasonable for Staff to expect the Company to have an all knowing - all seeing model as such a model would be prohibitively expensive to try to develop. The Company uses the IRP process to establish and analyze multiple scenarios. The ACC method is intended to perform resource specific evaluations. Every project is unique and every variation of a project has variation-specific assumptions and limitations that are not easily modeled. Staff would have the Commission believe the Company can run endless scenarios when, in fact, the Company is limited to taking action against what it practically achievable.

Q. Staff is concerned that the ACC method does not include an embedded REC assumption and, as such, Staff believes the method leaves an undefined decision point. Is a pre-defined REC assumption necessary or desirable?

A. No. A pre-defined REC assumption is neither necessary nor desirable, and this is another reason the Company evolved toward the ACC method. The ACC method does not include a REC value by design. The Company is banking all Oregon RECs and, as a result, Oregon RECs have value only in the context of an avoided cost of compliance. Because it is the Company's intent to comply with RPS laws, the ACC method produces an outcome that Company management can assess on a relative basis as the FPC periodically changes.

Q. Are there other reasons the ACC method is beneficial?

A. Yes. The output of the ACC method is in $ per MWh. This is the same metric that the Commission will establish an alternative compliance rate pursuant to ORS 469A.180. In addition, it is uncertain when a RPS will be established at the federal level and if a federal penalty will be above the $20 per MWh level, as previous versions of federal legislation suggest, and how it might compare with the alternative compliance rate to be set by the Commission. The intent of the ACC method is to give the Company a common decision-making tool that can be applied across the organization to make renewable resource acquisition decisions. The Company's long-term renewable resource needs are compelling and the Company needs analysis methods and result metrics that can be used on an efficient and ongoing basis. An embedded REC value assumption is not a necessary pre-condition for such methods.

Q. It appears that Staff prefers analysis results presented in dollars instead of $ per MWh. Is this an issue the Commission should be concerned with?

A. No. The ACC output of $ per MWh can easily be converted to dollars and the dollar output from the PVRR(d) method can easily be converted to $ per MWh. In fact, it is the $ per MWh output format of the ACC method that enables Staff to more easily make its own assumption of REC value or avoided compliance costs if it so chooses.

Q. Does this conclude your testimony?

A. Yes.

Case UE-200
CONFIDENTIAL
Exhibit PPL/204
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL Exhibit Accompanying Rebuttal Testimony of Mark R. Tallman

AUGUST 14, 2008 CONSULTANT REPORT ON ROLLING HILLS

August 2008

CONFIDENTIAL EXHIBIT PPL/204
PROVIDED UNDER SEPARATE COVER
SUBJECT TO PROTECTIVE ORDER

PPL/205
Tallman Exhibit

Case UE-200
CONFIDENTIAL
Exhibit PPL/205
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL Exhibit Accompanying Rebuttal Testimony of Mark R. Tallman

AUGUST 14, 2008 CONSULTANT REPORT ON GLENROCK

August 2008

CONFIDENTIAL EXHIBIT PPL/205
PROVIDED UNDER SEPARATE COVER
SUBJECT TO PROTECTIVE ORDER

Case UE-200
CONFIDENTIAL
Exhibit PPL/206
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL Exhibit Accompanying Rebuttal Testimony of Mark R. Tallman

AUGUST 14, 2008 CONSULTANT REPORT ON SEVEN MILE HILL

August 2008

CONFIDENTIAL EXHIBIT PPL/206
PROVIDED UNDER SEPARATE COVER
SUBJECT TO PROTECTIVE ORDER

Case UE-200
CONFIDENTIAL
Exhibit PPL/207
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL Exhibit Accompanying Rebuttal Testimony of Mark R. Tallman

ROLLING HILLS COSTS VS. IRP PROXY COSTS

August 2008

CONFIDENTIAL EXHIBIT PPL/207
PROVIDED UNDER SEPARATE COVER
SUBJECT TO PROTECTIVE ORDER

Case UE-200
CONFIDENTIAL
Exhibit PPL/208
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL Exhibit Accompanying Rebuttal Testimony of Mark R. Tallman

ROLLING HILLS COSTS VS. AVOIDED COSTS

August 2008

CONFIDENTIAL EXHIBIT PPL/208
PROVIDED UNDER SEPARATE COVER
SUBJECT TO PROTECTIVE ORDER

Case UE-200
CONFIDENTIAL
Exhibit PPL/209
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL Exhibit Accompanying Rebuttal Testimony of Mark R. Tallman

STAFF/ICNU OVERSTATEMENT OF ROLLING HILLS COST

August 2008

CONFIDENTIAL EXHIBIT PPL/209
PROVIDED UNDER SEPARATE COVER
SUBJECT TO PROTECTIVE ORDER

PPL/210
Tallman Exhibit

Case UE-200
Exhibit PPL/210
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Mark R. Tallman

JULY 29, 2008 LETTER FROM

WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY

August 2008

PPL/210
Tallman/1

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Dave Freudenthal, Governor

John Corra, Director

July 29, 2008

Kelley Pearson
Hickey & Evans
1800 Carey Avenue
Cheyenne, WY 82001

WIND ENERGY PROJECT PERMITTED
BY THE WYOMING INDUSTRIAL SITING COUNCIL

Ms. Pearson:

The Siting Council issued four permits for wind energy projects:

1. Kennetech/Chandar in eastern Carbon County, February, 1995
2. Uinta County Windfarm LLC in western Uinta County, July, 2003
3. PacifiCorp Energy in eastern Carbon County, February, 2008
4. PacifiCorp Energy in central Converse County, February 2008

The Council will hear the application for a permit for PacifiCorp Energy for a project in eastern Albany County in September, 2008.

Sincerely,

Tom Schroeder

Tom Schroeder
Program Principal

Herschler Building • 122 West 25th Street • Cheyenne, WY 82002 • http://deq.state.wy.us

ADMIN/OUTREACH	ABANDONED MINES	AIR QUALITY	INDUSTRIAL SITING	LAND QUALITY	SOLID & HAZ. WASTE	WATER QUALITY
(307) 777-7937	(307) 777-6145	(307) 777-7391	(307) 777-7369	(307) 777-7756	(307) 777-7752	(307) 777-7781
FAX 777-3610	FAX 777-6462	FAX 777-5616	FAX 777-5973	FAX 777-5864	FAX 777-5973	FAX 777-5973

Case UE-200
Exhibit PPL/303
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of R. Bryce Dalley

August 2008

Q. Are you the same R. Bryce Dalley who provided direct testimony in this proceeding?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your revenue requirement rebuttal testimony?

A. My testimony addresses the calculation of the updated $37.3 million revenue requirement increase requested in this proceeding. In support of this calculation I will discuss the revenue requirement components that have been updated from the Company's original revenue requirement increase request of $39.0 million.

Q. Please describe Exhibit PPL/304.

A. Exhibit PPL/304 reflects the Company's updated summary of the 2009 revenue requirement associated with renewable resources that are currently in service, or projected to be in service prior to January 1, 2009. This exhibit has been prepared using the same format and methodology as Exhibit PPL/301, which was filed with my direct testimony.

Q. Please describe the revenue requirement components which have been updated from the Company's original filing, as shown in Exhibit PPL/304.

A. Each of the revenue requirement cost component updates is discussed below.

Capital Costs for Resources Currently in Service

Capital costs, accumulated depreciation, and depreciation expense have been updated to reflect actual results through July 2008 for resources that are currently in service. These resources include Leaning Juniper 1 (September 2006), Marengo I (August 2007), Blundell Bottoming Cycle (December 2007), Goodnoe

Hills (May 2008), and Marengo II (June 2008). The associated deferred income tax and property tax calculations have also been updated to reflect these changes using the same methodology as the Company's original filing.

Capital Costs for Resources not yet in Service

The capital costs of Glenrock and Seven Mile Hill have been updated to reflect the costs used in the economic analysis models described in the direct testimony of Company witness Mark R. Tallman. The Company's original filing included costs for these two resources based on forecasts from the Company's accounting system (SAP) shortly before the Company's filing date. The associated impacts to accumulated depreciation, depreciation expense, deferred income taxes, and property taxes have also been updated to reflect these changes using the methodologies described in my direct testimony. No changes have been made for capital, accumulated depreciation, depreciation expense, deferred income taxes, or property taxes related to Rolling Hills.

Forecasted Operation and Maintenance (O & M) Costs

The O & M costs included in Exhibit PPL/304 have been modified based on updated projections. This update results in changes to O & M expenses for Leaning Juniper 1, Marengo I, Blundell Bottoming Cycle, Goodnoe Hills, Marengo II, Glenrock, and Rolling Hills.

Energy Trust of Oregon Contribution

Exhibit PPL/304 properly reflects an O & M expense reduction for Goodnoe Hills as a result of the pledged contribution from the Energy Trust of Oregon. The impact of this contribution reduces 2009 O & M expenses by $2.5 million on a total company basis. As a result, Goodnoe Hills O & M expenses included in the Company's rebuttal position are $7,300 on a total company basis, net of the contribution.

Forecasted Federal Energy Tax Credit

Since the Company's original filing, the Internal Revenue Service (IRS) revised the federal energy tax credit for renewable electricity production from 2.0 cents to 2.1 cents per kilowatt hour of electricity produced. The federal renewable tax credits reflected in Exhibit PPL/304 have been updated using the revised rate of 2.1 cents, multiplied by the kilowatt hours of production for each resource as dispatched by the GRID study included in the Company's July 2008 TAM update (Docket UE 199).

Forecasted State Energy Tax Credits

The kilowatt hours of production component of the Utah State Renewable Energy System tax credit calculation for the Blundell Bottoming Cycle has been updated to reflect the production as dispatched by the GRID study included in the Company's July 2008 TAM update (Docket UE 199). The Utah state tax credit rate per kilowatt hour of production remains the same as the Company's original filing.

Other Forecasted Costs

Franchise taxes and uncollectible expenses have been updated to reflect the changes to the cost components described above. The methodology of determining these amounts is consistent with the Company's original filing as described in my direct testimony.

Q. Has there been any change to the allocation methodology used to develop the Oregon revenue requirement?

A. No. The same Revised Protocol allocation methodology, factors and percentages used in the Company's original filing, as discussed in my direct testimony, have been applied in Exhibit PPL/304.

Q. Are liquidated damages related to Goodnoe Hills reflected in the Company's rebuttal filing?

A. Yes. $4,128,000 of estimated total company liquidated damages related to Goodnoe Hills has been reflected as a reduction to rate base in Exhibit PPL/304. This amount reflects the maximum amount of liquidated damages the Company projects to receive related to this resource. Actual liquidated damages are unknown at this time since the contractor has submitted claims, or is expected to submit claims, that if valid, would erase a significant portion of the potential liquidated damages.

Q. Does the Company intend to update the revenue requirement calculation for actual liquidated damages later in this proceeding?

A. Yes. The Company will include actual liquidated damages in its December 1, 2008 update if the data is available prior to that filing. If actual data is not available at that time, the Company intends to seek deferred accounting treatment, as provided by Section 6(f) in the Stipulation in UM 1330, for any variance from the amount included in this proceeding.

Q. Will the revenue requirement increase shown in Exhibit PPL/304 be updated later in this proceeding?

A. Yes. As provided for in the all-party Stipulation and Commission Order No. 07-572 in Docket UM 1330, the Company will update the revenue requirement in the Company's December 1 filing update. The December 1 update will reflect the actual costs of the resources, or forecasted costs where appropriate, and any changes to other cost components.

Q. Please describe Exhibit PPL/305.

A. Exhibit PPL/305 is an update of Exhibit PPL/302 filed with my direct testimony. As described in my direct testimony, this exhibit complies with the provision in the Stipulation and Commission Order in Docket UM 1330.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Case UE-200
Exhibit PPL/304
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of R. Bryce Dalley

REVENUE REQUIREMENT

August 2008

Pacific Power
Oregon
Renewable Adjustment Clause - Rebuttal Position
Total Revenue Requirement

	CY 2009											
	Leaning Juniper	**Marengo**	**Blundell Bottoming Cycle**	**Goodnoe Hills**	**Marengo II**	**Glenrock**	**Seven Mile Hill**	**Rolling Hills**	**Total**	**Factor**	**Factor %**	**Oregon Allocated**
Electric Plant In Service	176,808,299	246,199,900	25,897,115	192,642,189	131,283,960	218,386,360	214,859,086	206,460,230	1,412,537,139	SG	26.4114%	373,071,257
Estimated Liquidated Damages	-	-	-	(4,128,000)	-	-	-	-	(4,128,000)	SG	26.4114%	(1,090,264)
Depreciation Reserve	(20,142,345)	(18,426,412)	(1,242,980)	(8,430,048)	(5,449,989)	(4,731,704)	(4,655,280)	(4,473,305)	(67,552,063)	SG	26.4114%	(17,841,466)
Accumulated DIT Balance	(43,762,088)	(50,563,152)	(5,378,180)	(22,556,200)	(15,868,162)	(28,041,002)	(27,588,096)	(26,509,676)	(220,266,556)	SG	26.4114%	(58,175,547)
Net Rate Base	112,903,866	177,210,336	19,275,955	157,527,941	109,965,809	185,613,654	182,615,709	175,477,249	1,120,590,519			295,963,980
	11.26%	11.26%	11.26%	11.26%	11.26%	11.26%	11.26%	11.26%	11.26%			11.26%
Pre-Tax Return on Rate Base	12,709,001	19,947,646	2,169,794	17,732,102	12,378,280	20,893,564	20,556,101	19,752,562	126,139,051			33,315,127
Operation & Maintenance	3,386,951	4,629,233	510,000	7,300	2,320,617	3,845,966	3,551,906	3,383,278	21,635,250	SG	26.4114%	5,714,179
Depreciation	7,072,332	9,847,996	813,428	7,540,568	5,251,358	8,735,454	8,594,363	8,258,409	56,113,909	SG	26.4114%	14,820,486
Property Taxes	100,000	1,547,903	168,372	1,375,981	960,533	1,621,305	1,595,118	1,532,765	8,901,978	GPS	28.4419%	2,531,895
Federal Renewable Energy Tax Credit	(10,398,726)	(13,422,652)	(2,973,660)	(9,484,651)	(6,711,326)	(11,319,981)	(12,229,954)	(9,088,235)	(75,629,186)	SG	26.4114%	(19,974,749)
Oregon/Utah State Energy Tax Credits	(523,780)	-	(322,147)	-	-	-	-	-	(845,926)	SG	26.4114%	(223,421)
Rev. Reqt. Before Franchise Tax & Bad Debt	12,345,779	22,550,126	365,788	17,171,299	14,199,462	23,776,309	22,067,535	23,838,780	136,315,076			36,183,517
Franchise Taxes	297,800	543,945	8,823	414,199	342,514	573,523	532,304	575,030	3,288,138			872,804
Bad Debt Expense	82,916	151,449	2,457	115,324	95,365	159,684	148,208	160,104	915,507			243,012
Total Revenue Requirement	**12,726,494**	**23,245,520**	**377,068**	**17,700,823**	**14,637,340**	**24,509,516**	**22,748,047**	**24,573,913**	**140,518,721**			**37,299,333**

Case UE-200
Exhibit PPL/305
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of R. Bryce Dalley

REVENUE AND TAXES PURSUANT TO OAR 860-022-0041

August 2008

Pacific Power
Oregon
Renewable Adjustment Clause - Rebuttal Position
Total Revenue Requirement
($ 000's)

Description of Account Summary:	CY 2007 UE 179 Unadjusted	UE 191 TAM	*PacifiCorp Rebuttal UE 200* 2009 RAC	*PacifiCorp July 2008 TAM Update UE 199* 2009 TAM	Total
Operating Revenues					
General Business Revenues	890,034	22,422	37,299	56,896	1,006,651
Interdepartmental	0				-
Special Sales	278,958				278,958
Other Operating Revenues	35,635				35,635
Total Operating Revenues	1,204,627	22,422	37,299	56,896	1,321,244
Operating Expenses:					
O & M Expenses	754,387	22,422	5,957	56,896	839,662
Depreciation/Amortization	139,978	-	14,820		154,798
Taxes Other Than Income	46,996	-	3,405		50,401
Income Taxes - Federal	64,398	-	(39,549)	-	24,849
Income Taxes - State	9,002	-	(3,913)	-	5,089
Income Taxes - Def Net	5,252	-	32,430	-	37,682
Misc Revenue & Expense	(3,168)	-	-	-	(3,168)
Total Operating Expenses	1,016,845	22,422	13,149	56,896	1,109,312
Operating Revenue for Return	187,782	-	24,150	-	211,932
Total Rate Base	2,301,339	-	295,964	-	2,597,303

Case UE-200
Exhibit PPL/405
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Judith M. Ridenour

August 2008

Q. Are you the same Judith M. Ridenour who provided direct testimony in this proceeding?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your rebuttal testimony?

A. I present the Company's position on the rate design test period in response to the testimony of Staff and Industrial Customers of Northwest Utilities (ICNU).

Rate Design Test Period

Q. What was Staff's recommendation regarding the rate design test period?

A. Staff interpreted the Stipulation adopted by the Commission in Order 05-572 (Stipulation) to direct the development of the Renewable Adjustment Clause (RAC) rates upon the forecast sales volumes for the period during which the RAC rates will be in effect.

Q. Does the Company agree with Staff's interpretation of the Stipulation?

A. Yes. The Company accepts this as a reasonable interpretation of the Stipulation. The Company agrees to use the forecast year in which the RAC rates will be applicable as the rate design test period in this filing and in future RAC filings.

Q. Is a forecast of energy (kWh) for 2009 available for use in this case?

A. Yes. A 2009 forecast of energy by class is available and can be used for the rate design test period in this case by spreading the energy to schedules based on the spread of energy from the last general rate case.

Q. Have you prepared an exhibit which shows how the 2009 forecasted energy by class has been spread to the rate schedules?

A. Yes. Exhibit PPL/406 shows the 2009 energy forecast by class and the spread of that forecast to rate schedules by class, voltage level and rate tier. The energy was spread based on the forecast billing determinants from the last general rate case, UE 179.

Q. Have present Schedule 200 revenues been updated for the 2009 rate design test period as described in Staff witness Mr. Steve Storm's testimony?

A. Yes. Consistent with the description of the rate spread method described in Mr. Storm's testimony beginning on page 2, line 18, I have recalculated present Schedule 200 revenues on the 2009 test period.

Q. Is Staff's methodology logical?

A. Yes. In order to avoid a mismatch between the units used to calculate the present revenues and the units used to calculate the RAC rates, present revenues must be re-calculated from present Schedule 200 rates and the 2009 forecast kilowatt-hours. Present revenues for the forecasted 2009 rate design test period are calculated in the right-hand column of Exhibit PPL/406 and summarized in Column 4 of Exhibit PPL/407.

Q. Does updating the present revenues for the forecasted 2009 rate design test period produce a rate spread in this case consistent with the generation revenue rate spread approved in UE 179?

A. Yes. The present Schedule 200 rates were developed based on the generation revenue rate spread approved in UE 179, therefore the 2009 present revenues calculated using those rates are consistent with the rate spread approved in UE 179.

Q. Do you agree with ICNU witness Mr. Randall J. Falkenberg that this change in rate design test period does <u>not</u> reduce the Company's revenue requirement?

A. Yes. Mr. Falkenberg's testimony states:

> "Q. DOES THIS ADJUSTMENT REDUCE THE COMPANY'S REVENUE REQUIREMENT IN ANY WAY?
> A. No. …" page 6, lines 1-3

I agree with his assessment. There is no revenue requirement reduction associated with this change. This is simply a change to the energy volumes used to calculate the final RAC rates for Schedule 202.

Q. Have you prepared an exhibit showing the calculation of the RAC adjustment on the forecasted 2009 test period?

A. Yes. Exhibit PPL/407 shows the revised calculation of RAC adjustment rates on the forecast 2009 test period. The RAC revenue requirement of $37.3 million presented here is consistent with the amount presented in the rebuttal testimony of Mr. R. Bryce Dalley.

Q. Does this conclude your rebuttal testimony?

A. Yes.

PPL/406
Ridenour Exhibit

Case UE-200
Exhibit PPL/406
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Judith M. Ridenour

SCHEDULE 200 BLOCKING BY CLASS

April 2008

PACIFIC POWER & LIGHT COMPANY
State of Oregon
2009 Energy Forecast by Schedule Based on UE-179 Billing Determinants
Forecast 12 Months Ended December 31, 2007
Forecast 12 Months Ended December 31, 2009

2009 Energy Forecast by Class	kWh
Residential	5,500,858,427
Commercial	4,939,486,372
Industrial	3,413,981,137
Irrigation	257,547,612
Public Street and Highway Lighting	43,032,241
Total	14,154,905,788

Schedule	UE-179 Forecast 1/07 - 12/07 kWh	Forecast 1/09 - 12/09 kWh		2009 Present Price		2009 Present Dollars
Schedule No. 4						
Residential Service						
Energy Charge (Sch 200)						
First Block kWh	2,474,417,701	2,508,444,232	kWh	3.454	¢	$86,641,664
Second Block kWh	1,527,383,052	1,548,386,598	kWh	4.106	¢	$63,576,754
Third Block kWh	1,421,647,102	1,441,196,638	kWh	5.082	¢	$73,241,613
Total	5,423,447,855	5,498,027,469	kWh			$223,460,031
Schedule No. 4 - Employee Discount						
Residential Service						
Energy Charge (Sch 200)						
First Block kWh	8,365,190	8,480,222	kWh	3.454	¢	$292,907
Second Block kWh	6,322,885	6,409,833	kWh	4.106	¢	$263,188
Third Block kWh	6,952,739	7,048,348	kWh	5.082	¢	$358,197
Total	21,640,814	21,938,404	kWh			$914,292
Total Employee Discount						($228,573)
Schedule No. 23/723 - Commercial						
General Service (Secondary)						
Energy Charge (Sch 200)						
1st 3,000 kWh, per kWh	873,544,410	883,927,755	kWh	4.433	¢	$39,184,517
All additional kWh, per kWh	256,519,381	259,568,487	kWh	3.274	¢	$8,498,272
Total	1,130,063,791	1,143,496,242	kWh			$47,682,789
Schedule No. 23/723 - Industrial						
General Service (Secondary)						
Energy Charge (Sch 200)						
1st 3,000 kWh, per kWh	19,314,090	21,851,318	kWh	4.433	¢	$968,669
All additional kWh, per kWh	5,854,584	6,623,681	kWh	3.274	¢	$216,859
Total	25,168,674	28,474,999	kWh			$1,185,528
Schedule No. 23/723 - Commercial						
General Service (Primary)						
Energy Charge (Sch 200)						
1st 3,000 kWh, per kWh	656,686	664,492	kWh	4.317	¢	$28,686
All additional kWh, per kWh	211,803	214,321	kWh	3.190	¢	$6,837
Total	868,489	878,813	kWh			$35,523

PACIFIC POWER & LIGHT COMPANY
State of Oregon
2009 Energy Forecast by Schedule Based on UE-179 Billing Determinants
Forecast 12 Months Ended December 31, 2007
Forecast 12 Months Ended December 31, 2009

2009 Energy Forecast by Class	kWh
Residential	5,500,858,427
Commercial	4,939,486,372
Industrial	3,413,981,137
Irrigation	257,547,612
Public Street and Highway Lighting	43,032,241
Total	14,154,905,788

Schedule	UE-179 Forecast 1/07 - 12/07 kWh	Forecast 1/09 - 12/09 kWh		2009 Present Price		2009 Present Dollars
Schedule No. 23/723 - Industrial General Service (Primary)						
Energy Charge (Sch 200)						
1st 3,000 kWh, per kWh	16,720	18,917	kWh	4.317	¢	$817
All additional kWh, per kWh	28,355	32,080	kWh	3.190	¢	$1,023
Total	45,075	50,997	kWh			$1,840
Schedule No. 28/728 - Commercial Large General Service - (Secondary)						
Energy Charge (Sch 200)						
1st 20,000 kWh, per kWh	1,369,106,215	1,385,380,032	kWh	4.114	¢	$56,994,535
All additional kWh, per kWh	558,013,343	564,646,143	kWh	4.001	¢	$22,591,492
Total	1,927,119,558	1,950,026,175	kWh			$79,586,027
Schedule No. 28/728 - Industrial Large General Service - (Secondary)						
Energy Charge (Sch 200)						
1st 20,000 kWh, per kWh	84,617,663	95,733,604	kWh	4.114	¢	$3,938,480
All additional kWh, per kWh	37,904,496	42,883,884	kWh	4.001	¢	$1,715,784
Total	122,522,159	138,617,488	kWh			$5,654,264
Schedule No. 28/728 - Commercial Large General Service - (Primary)						
Energy Charge (Sch 200)						
1st 20,000 kWh, per kWh	9,595,990	9,710,052	kWh	4.036	¢	$391,898
All additional kWh, per kWh	12,510,625	12,659,332	kWh	3.926	¢	$497,005
Total	22,106,615	22,369,384	kWh			$888,903
Schedule No. 28/728 - Industrial Large General Service - (Primary)						
Energy Charge (Sch 200)						
1st 20,000 kWh, per kWh	2,763,962	3,127,054	kWh	4.036	¢	$126,208
All additional kWh, per kWh	1,834,397	2,075,376	kWh	3.926	¢	$81,479
Total	4,598,359	5,202,430	kWh			$207,687

PACIFIC POWER & LIGHT COMPANY
State of Oregon
2009 Energy Forecast by Schedule Based on UE-179 Billing Determinants
Forecast 12 Months Ended December 31, 2007
Forecast 12 Months Ended December 31, 2009

2009 Energy Forecast by Class	kWh
Residential	5,500,858,427
Commercial	4,939,486,372
Industrial	3,413,981,137
Irrigation	257,547,612
Public Street and Highway Lighting	43,032,241
Total	14,154,905,788

Schedule	UE-179 Forecast 1/07 - 12/07 kWh	Forecast 1/09 - 12/09 kWh		2009 Present Price		2009 Present Dollars
Schedule No. 30/730- Commercial						
Large General Service - (Secondary)						
Energy Charge (Sch 200)						
1st 20,000 kWh, per kWh	136,986,259	138,614,540	kWh	4.486	¢	$6,218,248
All additional kWh, per kWh	789,017,131	798,395,746	kWh	3.881	¢	$30,985,739
Total	926,003,390	937,010,286	kWh			$37,203,987
Schedule No. 30/730 - Industrial						
Large General Service - (Secondary)						
Energy Charge (Sch 200)						
1st 20,000 kWh, per kWh	49,010,611	55,448,972	kWh	4.486	¢	$2,487,441
All additional kWh, per kWh	272,402,036	308,186,586	kWh	3.881	¢	$11,960,721
Total	321,412,647	363,635,558	kWh			$14,448,162
Schedule No. 30/730 - Commercial						
Large General Service - (Primary)						
Energy Charge (Sch 200)						
1st 20,000 kWh, per kWh	8,879,233	8,984,776	kWh	4.395	¢	$394,881
All additional kWh, per kWh	64,056,347	64,817,749	kWh	3.791	¢	$2,457,241
Total	72,935,580	73,802,525	kWh			$2,852,122
Schedule No. 30/730 - Industrial						
Large General Service - (Primary)						
Energy Charge (Sch 200)						
1st 20,000 kWh, per kWh	1,703,720	1,927,532	kWh	4.395	¢	$84,715
All additional kWh, per kWh	10,077,524	11,401,375	kWh	3.791	¢	$432,226
Total	11,781,244	13,328,907	kWh			$516,941
Schedule No. 41/741						
Agricultural Pumping Service (Secondary)						
Energy Charge (Sch 200)						
Winter, 1st 100 kWh/kW, per kWh	1,370,427	1,641,775	kWh	5.968	¢	$97,981
Winter, All additional kWh, per kWh	1,734,976	2,078,506	kWh	4.045	¢	$84,076
Summer, All kWh, per kWh	104,546,144	125,246,570	kWh	4.045	¢	$5,066,224
Total	107,651,547	128,966,851	kWh			$5,248,281

PACIFIC POWER & LIGHT COMPANY
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Schedule	UE-179 Forecast 1/07 - 12/07 kWh	Forecast 1/09 - 12/09 kWh		2009 Present Price		2009 Present Dollars
Schedule No. 41/741						
Agricultural Pumping Service (Primary)						
Energy Charge (Sch 200)						
Winter, 1st 100 kWh/kW, per kWh	0	0	kWh	5.810	¢	$0
Winter, All additional kWh, per kWh	0	0	kWh	3.940	¢	$0
Summer, All kWh, per kWh	537,491	643,916	kWh	3.940	¢	$25,370
Total	537,491	643,916	kWh			$25,370
Schedule 33 - USBR\UKRB						
KWh						
Rate 35	48,977,004	58,674,586	kWh			
Rate 40	55,431,149	66,406,670	kWh			
Rate 33TX	2,383,625	2,855,590	kWh			
Total	106,791,778	127,936,846	kWh			
Schedule No. 47/747 - Industrial						
Large General Service - Partial Requirement (Primary)						
Energy Charge (Sch 200)						
per on-peak kWh	99,451,751	112,516,397	kWh	3.736	¢	$4,203,613
per off-peak kWh	62,290,040	70,472,875	kWh	3.636	¢	$2,562,394
Total	161,741,791	182,989,272	kWh			$6,766,007
Schedule No. 47/747 - Commercial						
Large General Service - Partial Requirement (Transmission)						
Energy Charge (Sch 200)						
per on-peak kWh	2,447,836	2,476,932	kWh	3.569	¢	$88,402
per off-peak kWh	1,533,164	1,551,388	kWh	3.469	¢	$53,818
Total	3,981,000	4,028,320	kWh			$142,220
Schedule No. 47/747 - Industrial						
Large General Service - Partial Requirement (Transmission)						
Energy Charge (Sch 200)						
per on-peak kWh	26,467,191	29,944,098	kWh	3.569	¢	$1,068,705
per off-peak kWh	16,577,308	18,755,014	kWh	3.469	¢	$650,611
Total	43,044,499	48,699,112	kWh			$1,719,316

PACIFIC POWER & LIGHT COMPANY
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Schedule	UE-179 Forecast 1/07 - 12/07 kWh	Forecast 1/09 - 12/09 kWh		2009 Present Price		2009 Present Dollars
Schedule No. 48/748 - Commercial Large General Service (Secondary)						
Energy Charge (Sch 200)						
per on-peak kWh	230,944,487	233,689,598	kWh	3.915	¢	$9,148,948
per off-peak kWh	146,160,484	147,897,814	kWh	3.815	¢	$5,642,302
Total	377,104,971	381,587,412	kWh			$14,791,250
Schedule No. 48/748 - Industrial Large General Service (Secondary)						
Energy Charge (Sch 200)						
per on-peak kWh	258,270,016	292,198,089	kWh	3.915	¢	$11,439,555
per off-peak kWh	163,454,306	184,926,755	kWh	3.815	¢	$7,054,956
Total	421,724,322	477,124,844	kWh			$18,494,511
Schedule No. 48/748 - Commercial Large General Service (Primary)						
Energy Charge (Sch 200)						
per on-peak kWh	252,378,230	255,378,112	kWh	3.736	¢	$9,540,926
per off-peak kWh	159,725,504	161,624,074	kWh	3.636	¢	$5,876,651
Total	412,103,734	417,002,186	kWh			$15,417,577
Schedule No. 48/748 - Industrial Large General Service (Primary)						
Energy Charge (Sch 200)						
per on-peak kWh	823,361,671	931,523,957	kWh	3.736	¢	$34,801,735
per off-peak kWh	521,090,339	589,544,244	kWh	3.636	¢	$21,435,829
Total	1,344,452,010	1,521,068,201	kWh			$56,237,564
Schedule No. 48/748 - Industrial Large General Service (Transmission)						
Energy Charge (Sch 200)						
per on-peak kWh	314,115,541	355,379,855	kWh	3.569	¢	$12,683,507
per off-peak kWh	246,564,714	278,955,101	kWh	3.469	¢	$9,676,952
Total	560,680,255	634,334,956	kWh			$22,360,459

PACIFIC POWER & LIGHT COMPANY
State of Oregon
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2009 Energy Forecast by Class	kWh
Residential	5,500,858,427
Commercial	4,939,486,372
Industrial	3,413,981,137
Irrigation	257,547,612
Public Street and Highway Lighting	43,032,241
Total	14,154,905,788

Schedule	UE-179 Forecast 1/07 - 12/07 kWh	Forecast 1/09 - 12/09 kWh		2009 Present Price		2009 Present Dollars
Schedule No. 54/754						
Recreational Field Lighting						
Energy Charge (Sch 200)						
per kWh	836,416	846,358	kWh	1.656	¢	$14,016
Total	836,416	846,358	kWh			$14,016
Schedule No. 15 - Residential						
Outdoor Area Lighting Service						
Energy Charge (Sch 200)						
per kWh	2,792,556	2,830,958	kWh	2.239	¢	$63,385
Total	2,792,556	2,830,958	kWh			$63,385
Schedule No. 15 - Commercial						
Outdoor Area Lighting Service						
Energy Charge (Sch 200)						
per kWh	8,339,544	8,438,672	kWh	2.239	¢	$188,942
Total	8,339,544	8,438,672	kWh			$188,942
Schedule No. 15 - Industrial						
Outdoor Area Lighting Service						
Energy Charge (Sch 200)						
per kWh	401,614	454,373	kWh	2.239	¢	$10,173
Total	401,614	454,373	kWh			$10,173
Schedule No. 15 - PS&HW Lighting						
Outdoor Area Lighting Service						
Energy Charge (Sch 200)						
per kWh	20,820	24,027	kWh	2.239	¢	$538
Total	20,820	24,027	kWh			$538
Schedule No. 50						
Mercury Vapor Street Lighting Service						
Energy Charge (Sch 200)						
per kWh	11,406,000	13,162,874	kWh	1.862	¢	$245,093
Total	11,406,000	13,162,874	kWh			$245,093

PACIFIC POWER & LIGHT COMPANY
State of Oregon
2009 Energy Forecast by Schedule Based on UE-179 Billing Determinants
Forecast 12 Months Ended December 31, 2007
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2009 Energy Forecast by Class	kWh
Residential	5,500,858,427
Commercial	4,939,486,372
Industrial	3,413,981,137
Irrigation	257,547,612
Public Street and Highway Lighting	43,032,241
Total	14,154,905,788

Schedule	UE-179 Forecast 1/07 - 12/07 kWh	Forecast 1/09 - 12/09 kWh		2009 Present Price		2009 Present Dollars
Schedule No. 51/751						
High Pressure Sodium Vapor Street Lighting Service						
Energy Charge (Sch 200)						
per kWh	15,574,917	17,973,931	kWh	2.939	¢	$528,254
Total	15,574,917	17,973,931	kWh			$528,254
Schedule No. 52/752						
Company-Owned Street Lighting Service						
Energy Charge (Sch 200)						
per kWh	1,827,840	2,109,383	kWh	2.252	¢	$47,503
Total	1,827,840	2,109,383	kWh			$47,503
Schedule No. 53/753						
Customer-Owned Street Lighting Service						
Energy Charge (Sch 200)						
per kWh	8,459,069	9,762,025	kWh	0.962	¢	$93,911
Total	8,459,069	9,762,025	kWh			$93,911
TOTAL OREGON	13,577,545,612	14,154,905,790				$556,118,174
Employee Discount						($228,573)
TOTAL OREGON (WITH EMPLOYEE DISCOUNT)						$555,889,601

PPL/407
Ridenour Exhibit

Case UE-200
Exhibit PPL/407
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Judith M. Ridenour

2009 kWh RAC CALCULATION

August 2008

PACIFIC POWER & LIGHT COMPANY
DEVELOPMENT OF RAC ADJUSTMENT FOR JANUARY 1, 2009
FORECAST 12 MONTHS ENDED DECEMBER 31, 2009

Line No.	Description	Sch No.	kWh	Sch 200 Present Revenue	RAC Adjustment Revenue	RAC Adjustment Cents\kWh
	(1)	(2)	(3)	(4)	(5)	(6)
						(5)/(3)
	Residential					
1	Residential	4	5,498,027,469	$223,460,031	$14,854,965	0.270
2	**Total Residential**		5,498,027,469	$223,460,031	$14,854,965	
	Commercial & Industrial					
3	Gen. Svc. < 31 kW	23	1,172,901,051	$48,905,680	$3,251,106	0.277
4	Gen. Svc. 31 - 200 kW	28	2,116,215,477	$86,336,881	$5,739,422	0.271
5	Gen. Svc. 201 - 999 kW	30	1,387,777,276	$55,021,212	$3,657,648	0.264
6	Large General Service >= 1,000 kW	48	3,431,117,599	$127,301,361	$8,462,620	0.246
7	Partial Req. Svc. >= 1,000 kW	47	235,716,704	$8,627,543	$573,534	0.246
8	Agricultural Pumping Service	41	129,610,767	$5,273,651	$350,577	0.270
9	Klamath Basin Irrigation[1]	33	127,936,846		$345,429	0.270
10	**Total Commercial & Industrial**		8,601,275,720	$331,466,328	$22,380,335	
	Lighting					
11	Outdoor Area Lighting Service	15	11,748,030	$263,038	$17,486	0.149
12	Street Lighting Service	50	13,162,874	$245,093	$16,293	0.124
13	Street Lighting Service HPS	51	17,973,931	$528,254	$35,117	0.195
14	Street Lighting Service	52	2,109,383	$47,503	$3,158	0.150
15	Street Lighting Service	53	9,762,025	$93,911	$6,243	0.064
16	Recreational Field Lighting	54	846,358	$14,016	$932	0.110
17	**Total Public Street Lighting**		55,602,601	$1,191,815	$79,228	
18	**Total Sales to Ultimate Consumers**		14,154,905,790	$556,118,174	$37,314,528	
19	**Employee Discount**			($228,573)	($15,195)	
20	**Total Sales with Employee Discount**		14,154,905,790	$555,889,601	$37,299,333	

[1] Schedule 33 rate set equal to Schedule 41 rate.