BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 172

In the Matter of)

PORTLAND GENERAL ELECTRIC,)

2006 Resource Valuation Mechanism.)

OPENING TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

July 15, 2005

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My name is Bob Jenks, and my qualifications are listed in CUB Exhibit 101.

I. Introduction

This year's RVM, like each past one, is proving to be more complicated and more controversial than we had expected or hoped. We will address four issues in our testimony. First, as absurd as it may sound, PGE is proposing to charge customers twice for the same thing. In the Company's 2005 RVM, replacement power for a Sullivan outage was included. That outage was postponed by the Company until 2006, and so the Company believes that customers should pay for replacement power again in 2006, though we are already paying for it now. Second, the Company proposes another change to how hydro is modeled in Monet, despite the prohibition of modeling changes in the Stipulation the Company and Parties' signed in UE 149. Third, the Company again expects customers to pay the fixed cost of capacity contracts, which serve as a buffer for shareholders, but bring no rate benefits to customers, since they are not dispatched under the normalized conditions used in the RVM process. Finally, we take the time to reiterate our concern about the use, in the setting of customer rates, of a Company-produced forward price curve that has not been reviewed by either the parties or the Commission.

II. Sullivan Adjustment

The Company is projecting a planned outage for its Sullivan hydro facility and charging customers for replacement power associated with the outage. However, the Company did the same thing last year, and then postponed the outage.

> PGE has significant planned maintenance outages for Sullivan, North Fork, Faraday and River Mill during 2006. The Sullivan facility will be shut down for 4 months to build fish mitigation structures…The 2005 RVM included a similar shut-down for Sullivan, but the maintenance was postponed until 2006.

UE 172/PGE/100/19.

PGE included in the 2005 RVM a planned outage for maintenance at Sullivan, but after the Commission approved the 2005 RVM[1], PGE changed its plans and did not take Sullivan offline for that planned outage. Nevertheless, customers still paid rates that included replacement power for the planned outage that didn't happen. Now, the Company claims that the planned outage will happen this year, and wants customers to pay for it … again. It is not just and reasonable to charge customers twice for the same planned outage; the projected Sullivan outage should not be included in rates in 2006.

[1] OPUC Order 04-573, October 5, 2004.

A. The Problems With Charging Twice For A One-Time Cost

The Company's proposal to charge customers a second time for the same outage, an outage that has not yet occurred, produces a number of problems.

i. Disconnect Between Normalized Ratemaking In Rate Case Vs. RVM

Under traditional, normalized ratemaking such double-counting would not be allowed; in fact, the Sullivan outage would not appear in the revenue requirement in a traditional rate case at all. In a general rate case, when forecasting the future test year revenue requirement, we attempt to normalize the forecast with Type I and Type II adjustments. These adjustments remove nonrecurring events and annualize other events to make them representative of a single, future test year.

For example, to annualize normal, planned maintenance, we could take a 4-year rolling average of such maintenance. In the test year we would then forecast ¼ of the actual, normal maintenance costs from a past four-year period. However, a 4-month outage for installing fish mitigation structures is not a recurring event, and would not be included in the 4-year average of normal maintenance. Traditionally, one-time events are not included in a utility's revenue requirement in a general rate case. Unique events occur every year, and some of them will work in customers' favor while others will work in the Company's favor. This is a risk and reward balance that goes with normalized ratemaking. A utility can, when the cost of such an event is significant, request a deferral for that one-time cost, but we would not put such a cost into base rates.

While the RVM was presented as a way to update a handful of costs that are already part of rates in order to facilitate direct access, it has gone beyond that, and allows for recovery of costs that a utility would otherwise not recover. By addressing a specific year, rather than a normalized test year, the RVM allows the Company to seek recovery of one-time, nonrecurring costs, such as this planned Sullivan outage.

To make matters worse, by deferring the installation of the Sullivan fish mitigation structures, the Company has managed to turn a nonrecurring cost – which is not eligible for recovery in normalized ratemaking – into a cost the Company collects from customers not once, but twice.

ii. It Creates A Terrible Incentive & An Awful Precedent

If the Company is allowed to defer planned maintenance from one year to the next, and then use the RVM to charge customers twice for the cost of that planned maintenance, then the Company will have an incentive to err on the side of forecasting planned outages which might not happen.

PGE's plant operators supply the Company with their forecasts for planned outages, and, unlike the traditional 4-year rolling averages used prior to the RVM, planned outages are not based on empirical evidence. While we can calculate a plant's cumulative 4-year planned outage time based on historical data, we have to take the utility's word on a future planned outage.

The evidence does not suggest that the Company has tried to exaggerate planned outages in the past. However, a Commission decision granting the Company the right to double-charge for a single plant outage in this case would be an invitation to the Company to be more aggressive when forecasting planned outages. In addition, and perhaps more importantly, a Commission decision to allow any utility to recover twice for a single cost will be used as a precedent to justify the practice in the future.

iii. Is A Planned Outage a Known and Measurable Adjustment?

Planned outages are adjustments to a base Monet run to incorporate the effects of an expected event. Ratemaking adjustments traditionally must be known and measurable. To qualify for an adjustment in an RVM proceeding, an event should be more than simply planned; there should be a reasonable certainty both in the realization of the event, and in the actual cost of the event. By deferring the maintenance of Sullivan, PGE has raised the issue of whether the planned outage at Sullivan for the installation of fish mitigation equipment is, indeed, a known and measurable cost for the RVM year. If it might happen this year, or it might happen next year, at the Company's discretion, the outage begins to seem less known and less measurable as a 2006 cost.

B. The 2006 Planned Sullivan Outage Should Be Removed

The actions of the Company in 2005 undermine the classification of the Sullivan outage as a known and measurable change. In addition, the one-time installation of equipment at Sullivan is not a cost that would be included in a normalized test year in traditional ratemaking. Most importantly, it simply cannot be just and reasonable to charge customers for the same one-time event both in 2005 and in 2006. PGE customers have already paid for the replacement power costs for the Sullivan outage; the Company has been made whole. Recovery for additional costs related to Sullivan in 2006 should be denied.

The estimated effect of this adjustment is to reduce 2006 power costs by $2.725 million. Exhibit 102.[2]

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[2] Of course, the actual cost will depend on the cost of replacement power as determined by the forward price curve that will be filed after the Commission Order in this docket.

III. Hydro Adjustment

PGE has proposed yet another change to Monet in this proceeding. We oppose this on two grounds. First, the Company's proposed change is expressly prohibited by the Stipulation in UE 149. Second, the proposed change exemplifies one of the fundamental problems with the RVM proceeding. Though the Company's RVM was originally presented as a simple annual update, it is instead a lengthy, contentious, and time-consuming process, the scope of which (at least to date) does not seem containable.

A. The Parties Agreed Not To Propose Enhancements

The Stipulation resulting from PGE's 2004 RVM proceeding states:

> Other than the Identified Enhancements referenced in paragraph 5, above, the Parties agree that they will not propose in the 2005 or 2006 RVM proceedings any enhancements to the Monet model used in the Final RVM Filing, unless the Monet model is modified through a general rate case or by the unanimous agreement of the Parties … the term "enhancement" shall mean changes to the modeling code of the Monet model, or changes in the method used to compute input data to Monet…

UE 149 Stipulation, August 6, 2003.

The Company must have been aware that its proposed change for the 2006 RVM would cause consternation among the parties, as the Company's April RVM filing attempts to head-off the conflict from the beginning.

> Q. Has PGE made any scope changes or enhancements to the Monet model that are included in the 2006 RVM?
>
> A. No. We have not made any scope changes or enhancements to the Monet model for 2006 RVM. PGE has corrected the usable capacities of the Mid-Columbia hydro plants.

PGE/100/Tinker-Niman-Tooman/3.

In the 2004 Stipulation, we agreed to limit enhancements. We even made sure, in order to avoid arguing the finer points of linguistics, that we defined enhancements. That definition includes "changes in the method used to compute input data to Monet." PGE's attempts to change the method of computing hydro capacity, which is a Monet input, is not allowed under the terms of the UE 149 Stipulation.

The fact that the Parties in UE 149 found it necessary to put an agreement prohibiting modeling changes into the stipulation speaks directly to our, and we think other intervenors', frustration with the RVM process. The RVM has not been contained to its intended scope, or at least not to the scope as it was understood by us when the mechanism was first proposed. Whether PGE's hydro update is called a correction or an enhancement or an adjustment, it is still a modeling change which results in charging customers an additional $2.6 million[3].

IV. Capacity Tolling Contracts

Last November, after the Commission order approving the 2005 RVM, PGE added two capacity tolling contracts. In a memo to Judge Kirkpatrick, Assistant Attorney General David Hatton expressed Staff's concern that "the benefits of these capacity tolling agreements fall entirely to PGE's shareholders, despite the $2.174 million included in customers' rates."[4] CUB Exhibit 103.

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[3] UE 172/PGE/101-C/Tinker-Niman-Tooman/2.

[4] Hatton, David B., Assistant Attorney General, Regulated Utility & Business Section. Memo to Judge Traci Kirkpatrick. RE: Ratemaking Treatment of Capacity Tolling Agreements in Portland General Electric's 2005 Resource Valuation Mechanism. November 5, 2004.

A. The Problem

These capacity contracts are also included in this year's RVM filing, and, according to the Company's June update, these contracts are again not projected to produce any energy under normalized conditions. General ratemaking is based upon normalized conditions, so the fixed cost of these capacity tolling contracts are charged to customers, but the benefits from the contracts are not reflected in rates. These contracts are only dispatched when market conditions vary significantly from normal; so when rates are set, the fixed costs are included, but any benefits that result when the contracts are used for abnormal circumstances are not included, and shareholders, whose position is to take the risks and reap the rewards of variations in normal conditions, pocket those benefits without partaking in the fixed cost.

For example, hot weather in the Southwest combined with a major plant outage in the West could produce a market with high electricity prices relative to gas prices, making the dispatch of these contracts economic. The revenue from these sales-for-resale will flow to shareholders, not customers, though it was customers who paid the fixed costs of the contracts.

B. Commission Should Establish A Policy

Allowing the Company to charge customers for hedges, such as these capacity contracts, on a case-by-case basis is problematic. Hedges primarily benefit shareholders, and so there is an incentive for the Company to buy hedges against low hydro, load variations, abnormal weather, etc. As long as customers pay the cost of these hedges, why would shareholders not want that protection?

We recognize that hedges may have their place as an alternative to over-building or other risk-management strategies. What is lacking is a coherent policy on when the use of hedges is appropriate, and how the costs and benefits associated with them should be allocated. CUB recommends, rather than making this determination on an ad hoc basis, that the Commission consider a general proceeding to define a policy framework for hedges such that costs and benefits can be consistently and properly allocated. In this case, however, as none of the benefits are shared with customers, $2.87 million[5] for the fixed cost of these contracts should be removed from the RVM filing.

V. The Forward Price Curve

Though we have testified on this issue previously, it continues to concern us that the forward price curve used to set rates in the RVM process is internally produced by the Company, after the Commission's order in the proceeding, and is not verifiable by intervenors. There is a great deal of money at stake in the forward electricity price curve, yet it is currently impossible to challenge PGE's forward price curve. There is no documentation supplied to support the curve, and it is, of course, confidential. This means that a significant factor in rates is internally-produced, has undergone no review, has been subject to no verification, and cannot be discussed publicly. None of us should be comfortable with this process.

Given the impact that the forward price curve has on retail rates, and given the availability of independent price curves, PGE should use these independent curves, rather than its own, to increase transparency in the RVM process. We will address this issue in

[5] UE 172/PGE/101-C/Tinker-Niman-Tooman/5.

the RVM review that takes place in PGE's next general rate case, that the Company has told us to expect toward the end of this year.

VI. Conclusion

The Commission should remove $8.2 million from PGE's RVM filing to reflect the double-charging of customers for the planned Sullivan outage, the hydro modeling change we all agreed not to make, and the capacity tolling contracts that, in normalized ratemaking, benefit only shareholders. While we do not expect the Commission to change PGE's use of its own forward price curve in this proceeding, it is one of the issues related to the RVM that will have to be addressed when we review the RVM process.

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 308
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EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

PREVIOUS EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UG 152, UM 995, UM 1050, UM 1071, UM 1147, and UM 1121. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America

June 17, 2005

TO: Vikie Bailey-Goggins
OPUC

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-172
PGE Response to Staff Data Request
Dated June 3, 2005
Question 004

Request:

At Tinker – Niman – Tooman/19 lines 11-13 the company indicates that a shut-down at the Sullivan plant included in the 2005 RVM was postponed and is now included in the 2006 RVM.

a. Please indicate the timing and duration of the Sullivan shut-down included in the 2005 RVM.

b. Please quantify the replacement power costs associated with the Sullivan shut-down in the 2005 RVM.

c. Please indicate the timing and duration of the Sullivan shut-down included in the 2006 RVM.

d. Please quantify the replacement power costs associated with the Sullivan shut-down in the 2006 RVM.

e. Given that the Sullivan maintenance outage was included in the 2005 RVM and postponed, does including a similar outage in the 2006 RVM double-count the replacement power costs? If no, why not?

Response:

a. The entire Sullivan plant is shut down for all days in July through October for construction of fish migration structure. This amounts to 123 days.

b. Replacement power cost is $2.128 million, based on running MONET with and without the shutdown.

	NVPC ($000)	
With shutdown	491,304	based on Nov. 15, 2004 Suppl. RVM Case
Without shutdown	489,176	
Difference	2,128	

c. The entire Sullivan plant is shut down from June 12 through October for construction of fish migration structure. This amounts to 142 days.

d. Replacement power cost is $2.725 million, based on running MONET with and without the shutdown.

	NVPC ($000)	
With shutdown	646,765	based on April 1, 2005 RVM filing
Without shutdown	644,040	
Difference	2,725	

e. No. The event is an element of ratemaking. PGE prepares its power cost forecasts with the most current and best information available at that time. However, plant maintenance outages seldom perfectly match the forecast. These deviations from the actual power cost forecast can have positive or negative effects on PGE's actual power costs. For example, plant outages may occur at a different time and may be shorter or longer than forecast. In addition, PGE may need to schedule a plant outage that is not in the forecast. PGE does not collect for outages that are unscheduled or last longer than forecasted.

Attachment 004-A is a comparison between the thermal plant maintenance outages forecasted in Monet and actuals from 2003 though May 2005. It demonstrates that forecasts seldom match the actual outages for maintenance. For example, in 2003 the actual outage for Boardman was one day shorter than forecasted (29 days instead of 30 days), while the outage at Beaver was 47 days longer (75 days instead of the forecasted 28 days). For 2005, we reported preliminary actuals through May, as available.

HARDY MYERS
Attorney General

PETER SHEPHERD
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

November 5, 2004

TRACI KIRKPATRICK
ADMINISTRATIVE LAW JUDGE
OREGON PUBLIC UTILITY COMMISSION
550 CAPITOL STREET, N.E., SUITE 215
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RE: RATEMAKING TREATMENT OF CAPACITY TOLLING AGREEMENTS IN PORTLAND GENERAL ELECTRIC'S 2005 RESOURCE VALUATION MECHANISM (DOCKET UE 161)

Dear Judge Kirkpatrick:

On November 3, 2004, Portland General Electric (PGE) filed a draft MONET run in Docket UE 161. Staff has reviewed the updates made in the November 3rd draft MONET run and has identified the ratemaking treatment of capacity tolling agreements as an issue to bring to your attention. Because of Staff's concerns we request a pre-hearing conference be scheduled next week to further discuss this issue.

As PGE indicated in its cover letter accompanying the November 3rd draft MONET run, the company recently signed two new capacity contracts pursuant to its 2002 Integrated Resource Plan and the associated Request for Proposals. Both of these capacity contracts have delivery periods in 2005 and future years. As a result, PGE has modeled the dispatch of these contracts in the November 3rd draft MONET run.

The cost for each of these contracts is comprised of a capacity charge and an energy charge. PGE pays the capacity charge on a monthly basis whether or not it actually schedules any delivery of energy. For calendar year 2005, PGE estimates that the capacity payments for these two contracts will total $2.174 million. PGE pays the energy charge on a monthly basis for each megawatt-hour (MWh) of delivered energy. Based on its MONET modeling of the dispatch of these contracts, PGE estimates for ratemaking purposes, that it will not dispatch (i.e., not actually use) these contracts in 2005. Therefore, for calendar year 2005 the energy payments for these two contracts are estimated to be zero dollars. Consequently, the total cost of these two contracts that PGE has included in the 2005 RVM is $2.174 million.

The benefit of these contracts is comprised of the company's ability to reduce net variable power costs when market prices of electricity and natural gas make the dispatch of these contracts profitable. Both of these capacity tolling agreements have terms and conditions that suggest that economic dispatch will only occur during periods where the spread between market electricity prices and natural gas prices is extreme. The company, however, models net variable power costs in the MONET model on an expected price basis. Under normal, or expected, price conditions the likelihood that these capacity contracts will be economic to dispatch is low – hence in MONET energy payments modeled to be zero dollars in 2005. The uncertainty surrounding the dispatch of these capacity contracts complicates their treatment in PGE's rates.

Staff believes that the ratemaking treatment implied in PGE's November 3rd draft MONET run creates a significant mismatch between ratepayer costs and benefits. For 2005, PGE is asking its customers to pay $2.174 million in costs. In exchange, because rates are set on an expected price basis, the only benefit that customers could possibly receive is if an extreme price event occurs and the company or an intervening party anticipates the event and files an application for a power cost deferral. Absent that unlikely situation, the benefits of these capacity tolling agreements fall entirely to PGE's shareholders, despite the $2.174 million included in customers' rates.

Permanent remedies to this mismatch of ratepayer costs and benefits include: (1) Abandoning expected price modeling in MONET and implementing expected net variable power cost modeling, or (2) Establishing a permanent power cost adjustment mechanism that appropriately matches costs and benefits on a long-run basis. The first alternative involves an enhancement to MONET. Implementing this alternative in the 2006 RVM would require the consent of PGE, Staff, the Citizens' Utility Board, and the Industrial Customer's of Northwest Utilities (see Order 03-535 adopting stipulations in Docket UE 149) and significant analytical work. The second alternative is being considered in Docket UE 165.

To remedy this mismatch in the 2005 RVM, Staff recommends that the Commission remove the $2.174 million in capacity payments from PGE's net variable power costs. Under this approach, shareholders would bear all of the costs and receive all of the benefits of these contracts during 2005. This has the effect of matching the 2005 costs and benefits. It also reflects the fact PGE has traditionally borne the risk of extreme price events between rate cases. Staff is willing to consider other remedies that PGE or intervenors may propose.

As you know, PGE files its final MONET run on November 10, 2004. We request a pre-hearing conference next week to further discuss this issue.

Sincerely,

David B. Hatton
Assistant Attorney General
Regulated Utility & Business Section

DBH:nal/GENK7978.DOC

cc: UE 161 Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 15th day of July, 2005, I served the foregoing Testimony of the Citizens' Utility Board of Oregon in docket UE 172 upon each party listed below, by email and U.S. mail, postage prepaid, and upon the Commission by email and by sending 6 copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

Respectfully submitted,

Jason Eisdorfer

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Attorney for Citizens' Utility Board of Oregon

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