Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● mail@dvclaw.com
Suite 400
333 SW Taylor
Portland, OR 97204

June 2, 2005

Via Electronic Mail and US Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem, OR 97308-2148

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY
Application for a Hydro Generation Power Cost Adjustments Mechanism
Docket No. UE 165

Dear Filing Center:

Enclosed please find an original and six copies of the Stipulation Testimony of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities in the above-captioned Docket.

Please return one file-stamped copy of the document in the self-addressed, stamped envelope provided. Thank you for your assistance.

Sincerely,

/s/ Ruth A. Miller
Ruth A. Miller

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Stipulation Testimony of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities, upon the parties on the official service in Docket No. UE 165, shown below, by causing the same to be electronically served, as well as mailed, postage-prepaid, through the U.S. Mail.

Dated at Portland, Oregon, this 2nd day of June, 2005.

/s/ Ruth A. Miller
Ruth A. Miller

STEPHANIE S ANDRUS DEPARTMENT OF JUSTICE REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@state.or.us	JASON EISDORFER CITIZENS' UTILITY BOARD OF OREGON 610 SW BROADWAY STE 308 PORTLAND OR 97205 jason@oregoncub.org
RANDALL J FALKENBERG RFI CONSULTING INC PMB 362 8351 ROSWELL RD ATLANTA GA 30350 consultrfi@aol.com	MAURY GALBRAITH PUBLIC UTILITY COMMISSION PO BOX 2148 SALEM OR 97308-2148 maury.galbraith@state.or.us
ROBERT JENKS CITIZENS' UTILITY BOARD OF OREGON 610 SW BROADWAY STE 308 PORTLAND OR 97205 bob@oregoncub.org	PGE- OPUC FILINGS RATES & REGULATORY AFFAIRS PORTLAND GENERAL ELECTRIC COMPANY 121 SW SALMON STREET, 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com
DOUGLAS C TINGEY PORTLAND GENERAL ELECTRIC 121 SW SALMON 1WTC13 PORTLAND OR 97204 doug.tingey@pgn.com	S BRADLEY VAN CLEVE DAVISON VAN CLEVE PC 333 SW TAYLOR, STE 400 PORTLAND OR 97204 mail@dvclaw.com

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 165

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Application for Approval of a Hydro Generation Adjustment Tariff.	)
	)
	)

STIPULATION TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 2, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350. I am the same Randall J. Falkenberg who previously filed testimony in UE 165.

I. INTRODUCTION

Q. WHAT IS THE PURPOSE OF THIS STIPULATION TESTIMONY?

A. The purpose of this testimony is to address the stipulations between the Oregon Public Utility Commission ("OPUC" or the "Commission") Staff and Portland General Electric Company ("PGE" or the "Company") filed in Docket Nos. UE 165 and UM 1187. In addition, I will address the testimony submitted by Staff and PGE in support of the stipulations in UE 165 and UM 1187.

Q. VERY BRIEFLY DESCRIBE UE 165 AND UM 1187.

A. PGE filed a request in UE 165 on May 18, 2004, seeking approval of a Hydro Generation Adjustment ("HGA") tariff that, according to PGE, "tracks the costs and value associated only with hydro generation assets and contracts." Advice No. 04-11, Hydro Generation Adjustment at 3 (May 18, 2004). In that case, parties filed two rounds of direct and rebuttal testimony discussing the merits of the HGA.

PGE filed a request in UM 1187 on December 30, 2004, seeking authorization to defer "excess" costs related to an alleged hydro generation deficit in 2005. Re PGE, OPUC Docket No. UM 1187, Application at 1 (Dec. 30, 2004). PGE's initial application in UM 1187 requested that the Commission authorize deferred accounting as a means of implementing the HGA effective January 1, 2005. Id. On January 21, 2005, PGE submitted an amended application requesting that the Commission authorize deferred accounting regardless of whether the Commission approved the HGA. Re PGE, OPUC Docket No. UM 1187, Amended Application at 2 (Jan. 21, 2005).

On April 11, 2005, PGE and Staff filed separate stipulations in UE 165 and in UM 1187. It appears that Staff and PGE intend that the stipulations be read together to resolve all issues in both Dockets.

Q. COMPARE THE STATE OF THE RECORDS IN UE 165 AND UM 1187 AT THE TIME PGE AND STAFF FILED THE STIPULATIONS.

A. In UE 165, the record was well developed. The parties had presented a number of issues to the Commission, and there were competing viewpoints regarding the need for and design of an appropriate HGA. In UM 1187, however, there was no evidence in the record at the time the stipulation was filed. There had been no testimony filed, little or no discovery conducted, and no informal workshops or other meetings had been held. The only evidence in the record in UM 1187 at this point is the testimony supporting the stipulation.

Q. HOW DO THE STIPULATIONS RESOLVE THE ISSUES IN THE TWO CASES?

A. Although there are two separate stipulations in UE 165 and UM 1187, both deal with the same subject matter, so I will refer to them collectively as the “the Stipulation.” The Stipulation creates a Power Cost Adjustment (“PCA”) mechanism that is fundamentally different from anything that was discussed on the record in UE 165. Staff and PGE propose to create a System Dispatch Power Cost Adjustment Mechanism (“SD-PCAM”) and request that the SD-PCAM become effective *retroactive* to January 1, 2005, and remain in effect through

2006. Despite the fact that PGE's initial request in UE 165 was for approval of a tariff that would result in recovery of costs related to hydro variability only, the SD-PCAM would result in recovery of cost variations due to: 1) variation in hydro generation; 2) fluctuation in gas prices; and 3) fluctuations in wholesale electric prices. In order to implement the mechanism, PGE will be required to develop a substantially adjusted Monet model run that uses a mix of actual and projected input data to be used in determining the balance of the "System Dispatch Cost Variance" ("SDCV") deferred account. The Commission would decide at an unspecified later date the amortization schedule for any SDCV deferral; however, because the Stipulation provides that the SD-PCAM is an "automatic adjustment clause," it appears there be will no detailed review of development of the SD-PCAM Monet model run or the calculation of the deferral balance prior to amortization.

The SD-PCAM would have a deadband of plus $15.0 million and minus $7.5 million. Deferrals outside of the deadband would be subject to an earnings test and an 80/20 sharing mechanism. As I describe the SD-PCAM more fully elsewhere in this testimony, I will not further elaborate on the details at this point.

The Stipulation also requires PGE to fund a consultant's study of ways to improve the Monet model in the future, and Staff and PGE agree to use a forthcoming rate case as the forum to discuss a permanent PCA.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE STIPULATION?

A. I recommend the Commission reject the Stipulation in its entirety and dismiss both the UE 165 and UM 1187 proceedings for the following reasons:

1. Approval of the SD-PCAM retroactively to January 1, 2005, would constitute retroactive ratemaking. The SD-PCAM provides for recovery of cost variations due to fluctuations in electric and gas prices regardless of whether any variation in hydro generation occurs. This is a broader scope than the "hydro only" deferred account requested by PGE. Even if the Commission approves the SD-PCAM, under no circumstances should it authorize PGE to implement that mechanism retroactively;

2. The Commission decided in Docket No. UM 1071 that deferred accounting was inappropriate for hydro variations and financial impacts of the magnitude that PGE has experienced in 2005;

3. The proposed resolution in the Stipulation does not fall within the range of outcomes supported by the evidence in the record in UE 165;

4. The deadband and sharing mechanism in the SD-PCAM is without analytical support and is inconsistent with the deadbands and sharing mechanisms adopted by the Commission in the past; and

5. PGE's and Staff's request for approval of the SD-PCAM requires the Commission to accept substantial modeling changes that are incomplete and unproven at this time. Moreover, because the SD-PCAM is an automatic adjustment clause, the opportunity to review the appropriateness of the model changes and the accuracy of the calculation produced by those changes will be limited.

If the Commission rejects the Stipulation and PGE or Staff still desire to implement a HGA or PCA, that issue can be litigated in the general rate case that PGE has stated it intends to file by the end of the year. If the Commission does not desire to dismiss the case, but seeks an alternative solution to PGE's hydro generation situation, ICNU's alternative proposal for an extreme event "hydro hedge" tariff is still a viable option. See Re PGE, OPUC Docket No. UE 165, ICNU/100, Falkenberg/29-32 (Feb. 14, 2005).

II. DISCUSSION

Retroactive Ratemaking

Q. THE STIPULATION WOULD ALLOW PGE TO APPLY THE SD-PCAM RETROACTIVE TO JANUARY 1, 2005. WOULD THIS RESULT IN RETROACTIVE RATEMAKING?

A. Absolutely. This is the first major flaw in the Stipulation.

Q. STAFF CONTENDS THAT BY VIRTUE OF THE DEFERRAL APPLICATION FILING MADE BY PGE IN UM 1187, DEFERRAL OF SD-PCAM COSTS IS PERMISSIBLE AND NOT RETROACTIVE RATEMAKING. EXPLAIN WHY YOU DISAGREE.

A. The retroactive ratemaking aspects of the Stipulation are comparable to those raised by Staff's proposed PCA in UE 165. I addressed the retroactive ratemaking issues related to Staff's proposed PCA in my rebuttal testimony in UE 165 and those arguments are equally applicable here. Re PGE, OPUC Docket No. UE 165, ICNU/200, Falkenberg/11-14 (Mar. 15, 2005).

Q. PROVIDE A FOUNDATION FOR YOUR COMMENTS CONCERNING RETROACTIVE RATEMAKING.

A. PGE's initial application for deferred accounting in UM 1187 requested the permission to defer specific costs related to an expected shortfall of hydro generation:

> Pursuant to ORS 757.259 and OAR 860-027-0300, [PGE] hereby requests authorization to defer for later ratemaking treatment *certain costs or revenues associated with variation in hydro generation* from the levels assumed for purposes of establishing rates in UE 161. Pending before the Commission is Docket UE 165, regarding PGE's proposed Schedule l28, a Hydro Generation Adjustment. PGE makes this request to preserve the positive or negative variance in the Deferral Period for treatment either under Schedule 128, or in some other manner as decided by the Commission in this docket or docket UE 165.

OPUC Docket No. UM 1187, Application at 1 (emphasis added).

In its amended application for deferred accounting, PGE was quite specific in its request for deferral of hydro-related costs only, and the Company even proposed a specific method for calculating these costs:

> PGE proposes to establish a new account, the Hydro Generation Balancing Account ("HGBA"). The HGBA is described in more detail in the attached proposed Schedule 128. PGE will defer into the HGBA the hydro generation cost variance ("HGCV") (the "Deferred Amount") as that term is defined in Schedule 128. The HGCV tracks the market value of the difference in hydro generation between the baseline amount set in PGE's annual [resource valuation mechanism ("RVM")] process and actual hydro generation. The variation in generation from the baseline, after application of a deadband and valued at the market index price, will be added to a balancing account.

OPUC Docket No. UM 1187, Amended Application at 2 (internal citation omitted).

Both the original and the amended applications for deferral discuss PGE's view of the necessity of deferring costs related to variations in hydro generation conditions. Neither application discussed or requested permission to defer costs *unrelated* to hydro conditions, including costs due to changes in wholesale electric prices and natural gas prices. In short, under the method for calculating the balance of the deferred account originally requested by PGE, there would be no balance unless there was a variation in hydro generation.

The Commission might reasonably allow PGE to compute the deferral of hydro-related costs in a different manner than proposed by the Company (as noted by the Company itself in the original application quoted above). However, it cannot allow deferral of costs *unrelated* to hydro variations without engaging in retroactive ratemaking.

Q. DOES THE STIPULATION ALLOW FOR DEFERRAL OF COSTS UNRELATED TO HYDRO VARIATIONS?

A. There is no question that it does. Even OPUC Staff witness Mr. Galbraith admits this is the case:

> Q. CAN THE MONET UPDATE METHODOLOGY RESULT [IN] A COST VARIANCE EVEN IF ACTUAL HYDRO CONDITIONS TURN OUT TO BE NORMAL?
>
> A. Yes. Even if normal hydro conditions were to actually occur, the MONET update methodology could still produce a positive, or negative, SDCV due to changes in market energy prices.

Re PGE, OPUC Docket No. UE 165, Staff/300, Galbraith/6 (Apr. 18, 2005). PGE also acknowledges that the SD-PCAM is broader in scope than the hydro-only mechanism the Company originally requested: "The [SD-PCAM] considers not only the value of deviations in PGE's hydro production from expected levels assumed in the RVM process, but also the value gained or lost from the redispatch of PGE's thermal plants, given electric and gas prices that also vary from levels assumed in the RVM process." Re PGE, OPUC Docket No. UM 1187, PGE/100, Dahlgren-Tinker/6 (Apr. 18, 2005).

This acknowledgment of the expanded scope of the SD-PCAM is ironic, because Mr. Galbraith testifies in UM 1187 that the Commission has the discretion to authorize PGE to defer hydro-related costs, but he does not contend that the Commission has the discretion to authorize deferred accounting for costs that are unrelated to variations in hydro conditions. Instead, he argues that the Commission has the authority to adopt a *method* for calculating the deferred account balance that differs from the method originally requested by PGE:

> Q. DOES THE COMMISSION HAVE THE ABILITY TO CONDITION THE GRANT OF A DEFERRAL APPLICATION SO AS TO MORE ACCURATELY CAPTURE THE COSTS AND BENEFITS OF THE UNDERLYING EVENT?
>
> A. Yes. As I indicated in my direct testimony, Staff believes the Commission *has the discretion to authorize PGE to defer costs related to variation in its hydro generation* in a manner that will most accurately capture the costs and benefits associated with that variation. The Commission is not obligated to accept PGE's proposed method for capturing those costs, which is the Hydro Adjustment Tariff originally proposed by PGE. Rather, it has the discretion to select an alternate method for determining the costs and benefits associated with hydro generation variation.

Re PGE, OPUC Docket No. UM 1187, Staff/102, Galbraith/15 (Apr. 18, 2005) (emphasis added).

Setting aside the issue of the Commission's discretion for a moment, Staff's attempt to distinguish the *method* of determining the costs to be deferred from the actual costs that are deferred misses the point. Regardless of whether the Commission has discretion to adopt a different method to establish a "hydro only" deferred account as originally requested by PGE, the Commission cannot authorize a deferred account that is not "hydro only" unless the Company has requested such a deferral. Although Staff attempts to characterize the SD-PCAM as merely a different method to calculate the deferred account balance, it is the SD-PCAM itself that is the problem, because it will result in a deferral balance (due to variations in natural gas and wholesale power prices) even if hydro conditions are normal.

Q. EXPLAIN HOW THE SD-PCAM WOULD ALLOW DEFERRAL OF COSTS UNRELATED TO HYDRO VARIATIONS.

A. The use of a Monet backcast allows actual gas and power prices to be used in addition to actual hydro generation levels. Because the baseline Monet run has substantial amounts of gas and wholesale purchased power included in the run, any subsequent changes in gas and power prices will change the final Monet model results. This change in cost, whether positive or negative, will result in deferral of a cost unrelated to hydro variations. As Mr. Galbraith has testified, even if hydro conditions were exactly as assumed in the final 2005 RVM study, changes in gas or wholesale power prices would produce a cost variance. As a consequence, the SD-PCAM really rests on a mechanism that defers cost variations due to three causes: 1) hydro generation; 2) gas prices; and 3) wholesale power prices. However, PGE requested authorization to defer costs due to hydro variations *only*, not cost variations due to changes in gas and power prices. Thus, Staff and PGE are proposing the Commission allow ultimate recovery of costs for which no deferral mechanism has ever been requested. This clearly would be retroactive ratemaking if the Commission authorized recovery of those costs in rates.

In addition, the Staff and PGE proposal also is troubling because in negotiating PGE certainly had prior knowledge of the impact of allowing retroactive deferrals to take place. This raises questions about the fairness of the negotiation when one party had much more knowledge of the relevant facts than the other parties. Further, from a policy perspective, the negotiation is tainted because one or more of the parties may have negotiated a settlement based on its expected results, rather than with an eye towards the mechanism that provided the best solution to the issues in the case.

Q. COULD YOU PROVIDE AN EXAMPLE THAT ILLUSTRATES THE INEQUITY OF THIS APPROACH?

A. One example might be if the Commission decided to implement a generation performance incentive mechanism. Such mechanisms have been used by regulatory commissions to provide incentives to reduce generator outage rates. Without going into depth regarding the merits of such mechanisms, it is reasonable to assume that the utility should have an equal chance of earning rewards as penalties.

If, however, the Commission decided to institute such a program retroactively right after a major unit outage, any impartial observer would have to question the fairness of that mechanism. Conversely, if a utility requested retroactive implementation of such a program after a period of outstanding generator availability, one might certainly complain that the company was asking for a "gift." In neither case would a retroactively applied program be a fair regulatory policy because to a certain extent the party would be rewarded or punished for past circumstances it had no ability to change. Good regulatory policy would not operate in a manner that implements one-sided policy changes. As in the case of gas and power price variations, it is not proper to provide a financial incentive to PGE (or conversely a penalty) for events unrelated to hydro variation that have already happened.

Q. IS IT POSSIBLE THAT THE COMMISSION COULD ACCEPT THE SD-PCAM BECAUSE IT BELIEVED IT WAS A MORE ACCURATE METHOD FOR COMPUTING COSTS DUE TO HYDRO VARIATIONS?

A. Yes. As Mr. Galbraith has pointed out, the Commission could use a different methodology than proposed by PGE to compute costs due to hydro variations. It might even use a method requiring use of the Monet model instead of the Dow Jones index. However, with respect to events that occur prior to any Commission approval of the SD-PCAM or another method, the Commission's discretion should be limited to methods that deal with hydro cost variations alone. While it may not be possible to enumerate all of the methods the Commission might consider, one element must be common to all reasonable methods: *if there is no hydro generation variation between actual and forecast, whatever method used should result in zero deferred costs.* This is an acid test that distinguishes between an allowable method and one that is not allowable for any mechanism that the Commission intends to implement retroactively to January 1, 2005. By Mr. Galbraith's own admission, the SD-PCAM fails to meet this requirement. Instead of allowing deferral of only one cost (hydro variation), the proposal allows deferral of two unrelated costs (gas and power price variations) as well.

Q. IS IT POSSIBLE THAT THE POWER PRICE VARIATIONS ARE RELATED TO HYDRO VARIATIONS, I.E., COULD HYDRO VARIATIONS ACTUALLY "DRIVE" GAS PRICE VARIATIONS?

A. Market prices for power are driven by many factors and hydro is only one minor influence. The regional supply of hydro certainly impacts regional supply and demand, which impacts power prices. However, power prices are also affected by many other factors, included load variations, weather, general economic activity, gas and oil prices, plant outages, and construction of new resources. At the very best, hydro is one of many drivers of regional power prices. There is no evidence that hydro has any measured or even measurable impact on regional power prices. This again was discussed in my direct testimony in UE 165, and never contradicted elsewhere.

Gas prices also are driven by many factors, including the worldwide supply and demand for oil, the national economy, weather, and a myriad of other factors. There is nothing to suggest that gas prices are impacted in any meaningful or measurable way by regional hydro conditions.

Q. HAVE THERE BEEN OTHER CASES WHERE A UTILITY COMMISSION DENIED A REQUEST FOR DEFERRAL BASED ON RETROACTIVE RATEMAKING CONCERNS?

A. Yes. PacifiCorp filed two cases in Wyoming (Docket No. 20000-EP-01-167, a request for a PCA, and Docket No. 20000-ER-00-160, a request to defer excess power costs) related to the Western Power Crisis in 2000 to 2001. In its application for deferral, filed on November 1, 2000, PacifiCorp requested to "defer with interest certain excess net purchased power costs it incurred, consisting of extremely high wholesale purchased power costs of what it terms an "unprecedented" nature which were substantially higher than the net power costs then factored into its existing Wyoming retail electric utility rates." Re PacifiCorp, Wyoming Public Service Commission Docket Nos. 20000-EP-01-167 and 20000-ER-00-160, Order Granting Motion to Exclude Hunter Generator-Related Costs from Case at 1 (Nov. 9, 2001). Subsequent to filing the request, in late November 2000, PacifiCorp's Hunter unit 1 generator failed, resulting in an outage that lasted more than five months. Early in 2001, PacifiCorp filed a request to implement a PCA to recover the deferred excess power costs. PacifiCorp acknowledged during the course of these cases that its calculation of excess power costs included costs related to the Hunter outage as well as costs related to the power crisis.

One of the intervenors in the Wyoming cases, the Wyoming Industrial Energy Consumers ("WIEC"), filed a motion to exclude the Hunter outage costs on the basis of retroactive ratemaking. WIEC contended that:

> [T]he Hunter costs were not properly or adequately made a part of the case, and that to allow inclusion of the costs in this case would constitute prohibited retroactive ratemaking. WIEC argued that the accounting application and order did not contemplate the inclusion of the Hunter costs and that those costs represented a quantum shift in the magnitude and the character of the case before us, accounting for perhaps two thirds of the $46.8 million being sought, greatly exceeding the amount originally estimated by PacifiCorp and vastly enlarging the number and scope of issues to be considered.

Id. at 3. WIEC argued that the original deferral application was limited to excess purchased power expenses and obviously made no mention of the Hunter deferral. Ultimately, the Wyoming Commission granted WIEC's motion to remove Hunter outage costs from the proceeding.

The similarities between the Wyoming cases and the instant proceedings are substantial. Both instances involved a request for deferral and a related request for implementation of a PCA mechanism. In both instances, the utility ultimately sought to recover a blended collection of costs stemming from higher market prices for power and higher costs from a generation deficit. In both cases, elements of retroactive ratemaking were present because the deferral application never requested deferral of some of the costs whose recovery was later sought in the PCA mechanism. Consequently, the Wyoming proceeding offers a valid reference point for the Oregon Commission to consider.

Q. BASED ON THE INFORMATION CONTAINED IN PGE'S RESPONSE TO ICNU DATA REQUEST NO. 8.2, IT APPEARS THAT GAS PRICES ARE NOW LOWER THAN FORECASTED IN THE FINAL MONET RUN USED IN RVM 2005. DOES THIS UNDERMINE YOUR ARGUMENT REGARDING RETROACTIVE RATEMAKING?

A. No. The prohibition against retroactive ratemaking is a two-way street. Whether it reduces or increases the deferral balance, it should not be allowed. Further, given the unequal availability of information to the negotiating parties, PGE may well have been able to negotiate a better settlement for itself because it had better knowledge of the changes in gas and power prices to date.

Q. COULD THE COMMISSION REQUIRE THE STIPULATION TO BE CHANGED SO THAT THE RETROACTIVE RATEMAKING CONCERNS ARE ELIMINATED?

A. This is not a practical solution, as the stipulating parties negotiated the settlement as an integrated agreement. Further, it is not clear how the Commission might accomplish this goal or what a settlement free of retroactive ratemaking concerns might have entailed. Even if the Commission were convinced that the SD-PCAM provides a fair solution to the issues regarding hydro variability, it should only apply that mechanism prospectively, due to the retroactive ratemaking concerns that exist otherwise. However, there are more compelling reasons why the Commission should reject the Stipulation completely, as I will now discuss.

UM 1071 Precedent

Q. PUTTING ASIDE THE RETROACTIVE RATEMAKING ISSUE, IS THE STIPULATION CONSISTENT WITH THE UM 1071 PRECEDENT?

A. No. This is a second major flaw in the Stipulation. In effect, the Stipulation would grant the request for deferral in UM 1187 even though the Commission flatly denied a similar request for deferral of hydro cost variances in UM 1071. For the Stipulation to provide a reasonable outcome of UM 1187 and UE 165, it requires one to assume that the Commission would grant the deferral request. The precedent in UM 1071 suggests that was an unlikely outcome of UM 1187.

In UM 1071, an entirely analogous set of circumstances as in UM 1187 was presented to the Commission. In that case, PGE requested permission to defer costs related to hydro variations during 2003. In denying the deferral request, the Commission found that hydro cost variations were a "stochastic risk" and therefore inappropriate costs for purposes of a deferral mechanism:

> We agree with Staff that risks normally included in modeling power costs (stochastic risks) are not appropriate for deferred accounting, as long as those risks are reasonably predictable and quantifiable and have no substantial financial impact on the utility. Here, hydro variability has been included and modeled to set PGE's base rates. The hydro year on which PGE bases its application is, as CUB points out, a 1 in 4.5 year event. This cause is not extraordinary enough to justify deferred accounting.

Re PGE, OPUC Docket No. UM 1071, Order No. 04-108 at 9 (Mar. 2, 2004).

Q. WAS THE COMMISSION'S DECISION IN UM 1071 WELL FOUNDED?

A. Yes. The Order was very well reasoned, providing no basis for assuming that it does not apply to the deferred accounting request at issue in UM 1187. The Commission was correct to recognize that "stochastic risks" are already addressed in setting normalized rates. The recognition of hydro variability as a stochastic risk is important because the Commission already allows for recognition of variations in hydro generation levels via its normalization of net power costs. In Monet, the Company uses a sixty-year average of hydro conditions to develop normalized power costs. For this reason, the likelihood of both good and bad hydro conditions is already reflected in rates, and granting of a deferral in a poor hydro year would amount to double recovery.

Q. CAN YOU PROVIDE AN EXAMPLE TO ILLUSTRATE THIS?

A. Table 1 presents a hypothetical example to explain this problem. In the example, the utility uses a power cost model to compute normalized power costs on the basis of five different hydro generation scenarios.[1/] The table shows a hypothetical company that has an average of 700 MW of hydro and replacement power costs $50/MWh. It shows that under normalized ratemaking customers are charged $600 million per year as the average cost of power based on average hydro over a five-year period (simplified from sixty years, which is actually what is used). Over five years, the results would all average out and customers would pay what power actually costs, $3.0 billion. The $3.0 billion figure includes both good and bad hydro years. The normalized cost of $600 million is lower than the cost of power in below average hydro years, but higher than the cost of power in good hydro years. By using the average value, a "premium" is built into the

[1/] PGE actually averages the hydro inputs in Monet in a single run, rather than performing a multiple water year run. However, the use of this approach is not conceptually different from the method shown in the table.

normalized cost of power in good years that provides a form of "insurance" against bad hydro years.

Assume now that year five is the worst hydro year and the utility requests a deferral to allow it to ultimately recover the additional power costs. If regulators allow the utility to have a deferral in a bad hydro year, it gets the benefit of the "premium" built in during the good years, and then effectively charges the actual cost in year five. Under this scenario, ratepayers pay the normalized cost of power ($600 million) for the first four years and the actual cost of power in year five. The total cost of power to customers in that scenario is $3.044 billion, resulting in an overcharge to customers of $44 million.

Table 1
Example of Overcollection Problem
(millions of dollars)

Year	Hydro (aMW)	Net Power Costs	Normalized Ratepayer Cost	Ratepayer Cost With Deferral in Year 5
1	800	$556.2	$600.0	$600.0
2	750	$578.1	$600.0	$600.0
3	700	$600.0	$600.0	$600.0
4	650	$621.9	$600.0	$600.0
5	600	$643.8	$600.0	$643.8
Average	700	$600.0	$600.0	
Total Ratepayer Cost		$3,000.0	$3,000.0	$3,043.8
			Overcollection	$43.8

In the example above, the higher than normal costs of a bad hydro year ($43.8 million) are averaged into rates every year. However, instead of getting a "free pass" when the bad hydro year actually arrives, customers are now required to pay for bad hydro conditions as well. When above normal hydro conditions occur, customers pay the normalized cost and the utility keeps the savings. When below normal hydro conditions occur, the utility changes the rules of the game and asks for recovery of the total cost. So this is a "heads I win, tails you lose" type of hydro normalization that should not be allowed by regulators. The Commission was wise to have recognized this problem in UM 1071. It should not abandon its reasoning from UM 1071 in this case.

Q. IT MIGHT BE SUGGESTED THAT INSTITUTION OF THE SD-PCAM WOULD MITIGATE THE PROBLEM OF UNEQUAL TREATMENT IN GOOD AND BAD HYDRO YEARS BY DEVELOPING A PREDETERMINED TREATMENT OF HYDRO COST VARIATIONS. DO YOU AGREE?

A. No. First, this regulatory change is being suggested in a year in which the utility already expects poor hydro conditions to prevail. Thus, the mechanism virtually assures PGE of a positive recovery balance in year one. Further, without a deferral, PGE is now earning well below its regulated rate of return. As a result, even if hydro conditions were to improve dramatically in the months ahead, there is very little chance ratepayers would benefit from a negative deferral due to the earnings test contained in the Stipulation. This would be comparable to placing your bet in a casino after the roll of the dice is known. For the approach to be fair, it can only be applied on a prospective basis where there is no reason to expect the initial experience would differ from the long-term average.

Second, the SD-PCAM is only a temporary mechanism. After two years, it may be replaced by some other (as yet unknown) mechanism or there may be no mechanism at all. There is nothing to require PGE to seek a PCA in the future should hydro conditions suddenly appear more favorable. For the SD-PCAM to be a fair solution, it would have to be in effect long enough so that ratepayer benefits in good hydro years would balance out with the expected high cost in the first year. The SD-PCAM, however, would only be in effect through 2006. Recall that Mr. Galbraith testified that revenue neutrality was a desirable goal for a PCA mechanism in his direct testimony in UE 165. Re PGE, OPUC Docket No. UE 165, Staff/100, Galbraith/12 (Feb. 14, 2005). Allowing implementation of the SD-PCAM after it is known to produce a positive cost variance in the very first year is inequitable. This, of course, is yet one more reason why it should not be implemented retroactive to January 1, 2005.

Q. WERE THE HYDRO CONDITIONS AT ISSUE IN UM 1071 COMPARABLE TO CURRENT HYDRO CONDITIONS?

A. Yes. In UM 1071, the Commission found that the then expected hydro deficit amounted to a one in 4½-year event. OPUC Docket No. UM 1071, Order No. 04-108 at 9. In this case, the Company now estimates that the hydro deficit will result in a generation shortfall of 568,000 MWh. OPUC Docket No. UM 1187, PGE/100, Dahlgren-Tinker/3. Exhibit ICNU/301 demonstrates that based on the sixty years of hydro data used in computing normalized power costs, the current hydro deficit is a one in five year event. ICNU/301, Falkenberg/1-2. Thus, it does not differ materially from the deficit level the Commission found beneath its materiality threshold in UM 1071:

> We agree with Staff that risks normally included in modeling power costs (stochastic risks) are not appropriate for deferred accounting, as long as those risks are reasonably predictable and quantifiable and have no substantial financial impact on the utility. Here, hydro variability has been included and modeled to set PGE's base rates. The hydro year on which PGE bases its

> application is, as CUB points out, a 1 in 4.5 year event. This cause is not extraordinary enough to justify deferred accounting.

OPUC Docket No. UM 1071, Order No. 04-108 at 9.

Q. DOES THE STIPULATION DEPART FROM THE PRECEDENT SET IN UM 1071 IN OTHER WAYS?

A. Yes. In UM 1071, the Commission also determined that an event that represents a stochastic risk must have a "substantial" financial impact on the utility:

> The magnitude of the financial effect on the utility is also a factor in our consideration under the discretionary stage of the decision process. For a stochastic risk to justify deferred accounting, the financial impact must be substantial. Although we decline to set a numerical criterion, we can give negative and positive examples. In UM 995, for instance, we established a deadband around PacifiCorp's baseline of 250 basis points of return on equity. We allowed no recovery of costs or refunds to customers within that deadband, reasoning that the band represented risks assumed, or rewards gained, in the course of the utility business. In the Idaho Power cases, discussed below, we allowed partial recovery for a financial impact that represented approximately 700 basis points of Idaho Power's return on equity.
>
> * * *
>
> In the present application, PGE claims that it has incurred $31.6 million in excess NVPC, only some of which is attributable to hydro replacement costs. PGE asserts that this excess NVPC amounts to 172 basis points of return on equity. This is well short of the 250 basis points of return on equity within which we allowed no recovery in UM 995.

<u>Id.</u>

While the Commission did not articulate a hard and fast standard, it is clear that it considered an impact within a 250 basis point deadband inadequate in the PacifiCorp case, and that PGE's projected hydro variance of $31.6 million was inadequate in UM 1071.

Q. HOW DO THESE STANDARDS RELATE TO THE INSTANT CASES?

A. Based on PGE's UM 1187 testimony, the Company estimates the current cost of the hydro deficit to be $30 million. OPUC Docket No. UM 1187, PGE/100, Dahlgren-Tinker/3. Obviously this differs little from the projection in UM 1071, and falls well short of the 250 basis point deadband adopted in the PacifiCorp case. This implies strongly that the Commission should deny the request for deferral in UM 1187 on the same basis as it denied the request in UM 1071. Further, there is the strong implication that the SD-PCAM deadband (which is far less than 250 basis points) is also inconsistent with the precedent of UM 1071.

Q. CAN YOU TIE ALL THESE POINTS TOGETHER?

A. The Stipulation requests that the Commission authorize a deferred account that is broader than PGE's application in UM 1187. The Commission set a precedent in UM 1071 that suggests it should deny the UM 1187 deferral application because: 1) hydro variability is a stochastic risk; 2) the particular level of hydro variability experienced in 2005 was contemplated when power costs were set in PGE's last RVM proceeding; 3) the financial impact of this variance in hydro conditions is not "substantial;" and 4) the SD-PCAM has a deadband and sharing mechanism that is inconsistent with the Commission's stated views in UM 1071. This is a serious flaw in the Stipulation as it runs contrary to existing Commission precedent.

Other Issues

Q. ARE THERE OTHER REASONS WHY YOU BELIEVE THAT ACCEPTING THE STIPULATION WOULD PRODUCE A POOR RESULT FROM A POLICY PERSPECTIVE?

A. Yes. The Stipulation would resolve two separate cases in which the records were in very different states at the time the Stipulation was filed. In UE 165, there had been two rounds of testimony and the record was fairly complete at the time PGE and Staff executed the Stipulation. In UM 1187, however, there had been no discovery and no testimony or other evidence presented. Thus, the record in UM 1187 was very limited at the time the Stipulation was filed. For this reason, any settlement was premature. The Commission's order in UM 1071 made clear that authorization of a deferred account is a factual matter and that evidence was required to demonstrate the type of event underlying the deferral and the magnitude of the financial impact. OPUC Docket No. UM 1071, Order No. 04-108 at 8-9. Given the similarity of the facts in UM 1187 and UM 1071, it appears that parties were "overly anxious" to settle the case. While it is certainly understandable that PGE would wish to settle the case, Staff's agreement is quite puzzling. This is particularly true when one considers that Staff had opposed the comparable PGE deferral request in UM 1071, and that the Commission agreed with Staff in that case.

Q. DOES THE SD-PCAM ADDRESS PGE'S ALLEGED HYDRO VARIABILITY PROBLEM IN A MANNER THAT IS SUPPORTED BY THE RECORD IN UE 165?

A. No. This is another serious defect in the Stipulation. Settlements make sense in a regulatory setting when parties develop compromises that are consistent with the possible outcomes supported by the record of evidence. For example, if PGE requested a ROE of 11% in a general rate case and Staff recommended 10%, any figure within that range could be considered as supportable from the evidence. If the parties were to agree on 10.5% ROE, that would certainly provide a compromise consistent with the record in the case.

Likewise, one could easily imagine a case where there was a dispute on revenue allocation, with one party proposing a 10% industrial increase, but none for any other class, while another proposed a 10% residential increase, but none for any other class. If the parties settled on a 5% increase for both classes, that would represent a compromise within the range of the outcomes contained in the record of evidence.

In UE 165, however, the compromise on the SD-PCAM is not similar to anything advocated on the record in the case. Indeed, that mechanism differs substantially from all of the proposals made by the parties. This would be akin to the revenue allocation dispute referenced above being settled by the parties agreeing to a "compromise" where classes not represented in the case (e.g. commercial) were assigned a 10% increase, but no increase was adopted for any other class. In that case, the compromise would clearly be outside of the range of outcomes supportable by the evidence, and the Commission would be unwise to adopt it.

In this case, no party proposed a solution appearing remotely similar to the SD-PCAM. PGE presented the HGA, a mechanical application of the wholesale market index to hydro generation variances. ICNU and CUB opposed the HGA, although ICNU suggested a "hydro hedge" concept as an alternative. Even Staff, who presented a comprehensive, extreme event PCA did not propose a mechanism comparable to the SD-PCAM. While the PGE and ICNU proposals would have dealt only with hydro variations in a formulistic approach, Staff's proposed PCA relied on actual costs. In contrast, the SD-PCAM relies on the Monet model rather than a formulistic approach and it ignores actual power costs. This is a radically different solution than anything proposed on the record in UE 165.

Q. WHY IS IT A PROBLEM THAT THE SD-PCAM IS NOT SUPPORTED BY THE RECORD IN UE 165?

A. Had the SD-PCAM concept been introduced into the record in the case, it would have been possible for parties to study it in more detail, and possibly test its validity. Potential flaws and problems in the approach might have been uncovered and perhaps substantial improvements could be made in the methodology. The introduction of the SD-PCAM at this late stage denies the Commission the opportunity to fully examine the concept and how it might best be applied. This is particularly troubling because, as described below, implementation of the SD-PCAM is requiring PGE to develop a substantially modified Monet model run that the Company has not yet completed, and it appears that, if there is any future review of the changes to the model or calculations of the deferred amounts, it will be limited.

This also is troubling because Staff had discussed the concept of a hydro-related PCA based on Monet Backcast studies in UM 1071, and the Commission expressed some interest in it in the final order in that docket. OPUC Docket No.

UM 1071, Order No. 04-108 at 5-6, 10-12. Given this history, the record would have been much better served if Staff had proposed the concept in its initial round of testimony. Instead, Staff proposed a full PCA, which was far outside the boundaries of a case filed by PGE to address hydro variability. This was discussed in depth in my rebuttal testimony in UE 165.

Q. ARE THERE OTHER PROBLEMS WITH THE SD-PCAM METHOD?

A. As noted above, this method as proposed will allow PGE to defer (and ultimately collect) costs related to gas and power price changes. In UE 165, neither the Company, nor ICNU proposed a mechanism intended to allow deferral of anything except hydro costs. Thus, the Stipulation provides for deferral of costs never previously requested by the Company.

Q. DO YOU HAVE ANY COMMENTS CONCERNING THE DEADBAND USED IN THE STIPULATION?

A. Yes. I am concerned that there is no analytical support for the proposed deadband. While Mr. Galbraith proposed that a PCA mechanism should be revenue neutral, there has been no evidence offered to demonstrate that the proposed deadband will assure revenue neutrality.

Q. IS THE SHARING MECHANISM CONSISTENT WITH PAST COMMISSION PRACTICE?

A. No. The sharing mechanism is far more generous than those adopted in the past by the Commission. In UM 995, the Commission required 50/50 sharing on excess power costs between 250 and 400 basis points, and 75/25 sharing above 400 basis points. In the nine and fifteen-month PCAs approved pursuant to the settlement in UE 115, the Commission used a 50/50 sharing for power cost variances between $28 and $38 million per year. The 80/20 sharing percentage in the SD-PCAM is far more generous than the Commission has authorized in the past.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE STIPULATION?

A. Yes. The Stipulation treats the SD-PCAM as an automatic adjustment clause:

> 8. The deferral and amortization of power cost variances described in this Stipulation constitutes an automatic adjustment clause under the terms of ORS 757.210.

Re PGE, OPUC Docket No. UE 165, Stipulation at 4 (Apr. 11, 2005).

ORS § 757.210 defines an automatic adjustment clause as follows:

> The term "automatic adjustment clause" means a provision of a rate schedule which provides for rate increases or decreases or both, without prior hearing, reflecting increases or decreases or both in costs incurred or revenues earned by a utility and which is subject to review by the commission at least once every two years.

In addition, the deferred accounting statute states:

> Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts described in this section shall be allowed in rates only to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral.

ORS § 757.259(5).

The testimony supporting the Stipulation does not discuss any review process or other mechanism for parties to review and challenge the validity of the SD-PCAM deferrals. Based on the definition of an automatic adjustment clause within the statute, it appears that there would be no opportunity for parties to review or present evidence concerning the SD-PCAM calculations. While the

SD-PCAM itself is subject to review every two years, the Stipulation testimony does not address what the review might entail or what the scope of such a review would be. Typically such a review would only amount to a perfunctory analysis to ensure that the tariff is recovering the amount of costs deferred, not a review of the reasonableness of the amount of costs computed.

Q. WHY IS THIS A CONCERN?

A. The use of a computer model such as Monet to derive the power cost variance calculation without any possibility of a hearing is quite troubling. Monet is a very complex model, and PGE is changing the model substantially to permit the calculations required in the SD-PCAM to be computed. Exhibit ICNU/302 is a copy of a number of PGE's responses to data requests in UE 165 in which ICNU asked the Company to identify all of the input data and calculations that will be changed to implement the Stipulation, to explain the changes that will be made to the model, or to provide the actual data that will be used to perform the calculation of the SD-PCAM balance. The Company generally responded that it had not completed the model changes and did not have all the actual data. In addition, PGE indicated in certain responses that ICNU should be able to determine the inputs of the model that will be changed "based on the terms of the stipulation." ICNU/302, Falkenberg/1.

Given the complexity of Monet and the generalized manner in which the Stipulation describes the changes that are necessary, it would be extremely difficult for ICNU to precisely determine all of the input and model changes that must be made to implement the SD-PCAM. Indeed, based on PGE's responses to

ICNU's data requests, it is unclear if PGE has even determined all of the inputs and model changes that must be made, because changing one aspect of the model may result in unanticipated effects on other areas.

For the model changes that the Stipulation does generally describe, those changes are problematic, particularly given the lack of opportunity for review. While Monet uses a monthly gas price now, the SD-PCAM requires a daily gas price. In addition, the methodology for computation of the hourly market price inputs will change in Monet. Under the current method, Monet hourly prices are determined by a forecast of monthly standard product prices applied to an input set of price shapes. Under the new methodology, hourly prices will be based on a daily Mid-C index, shaped with an hourly Mid-C price index. I will discuss some technical concerns with the approach later. However, a basic problem with this approach is the fact that there is likely to be a systematic difference between the input price shapes and hourly Monet (input) price shapes. This could well lead to a change in the SD-PCAM, even if the underlying average monthly market prices did not change at all.

Further, many of the Monet inputs will remain unchanged, but many will be altered. PGE did not identify the specific Monet inputs that will change and indicated that doing so would be a burdensome task. ICNU/302, Falkenberg/1. Consequently, it is not reasonable to consider this a good candidate for an automatic adjustment clause because the calculations are quite complex and not transparent.

Finally, changing the Monet model logic to accommodate the new inputs required in the Stipulation may impact the program itself in some unanticipated way. In essence, PGE and Staff ask the Commission to approve the SD-PCAM on the basis of substantial modeling changes and complex calculations that are incomplete and unproven, which is a substantial concern given that the SD-PCAM is an automatic adjustment clause that will be implemented without any hearing or other opportunity for review. Indeed, there is no language in the Stipulation concerning a review of the Monet model changes or the amounts of deferred costs. Based on this, it appears that Staff has no intention of reviewing or analyzing the deferral amounts. This is a great concern because of the complexity of the calculations involved. While it is unclear whether this reflects the intentions of the parties to the Stipulation, the supporting testimony provides no reason to believe that any review process or hearing will occur. If the Commission does not reject the SD-PCAM altogether, parties should at least have the opportunity to present evidence concerning the changes to the Monet model and the calculations of the power cost variances to be deferred under the mechanism.

Q. IS PGE'S AGREEMENT TO SPEND $100,000 ON A CONSULTANT'S STUDY TO IMPROVE MONET A SUBSTANTIAL CONCESSION?

A. No. The Company should investigate improvements in the model for regulatory purposes as a matter of course. Staff has indicated an interest in stochastic modeling, thus it would make sense for the Company to investigate this option even without the Stipulation. Even if the consultants do identify a way to incorporate stochastic modeling into Monet, it is very difficult to view this as a substantial enough ratepayer benefit to overcome all of the other disadvantages of the Stipulation that I have already discussed.

Q. DOES THE STIPULATION PROVIDE A REASONABLE MEASURE OF EXTRA POWER COSTS INCURRED BY PGE?

A. Based on a comparison of the figures shown in PGE's response to ICNU Data Requests 8.2 and 8.5 in UE 165, the SD-PCAM approach provides for a higher deferral balance for the period January to March 2005 than PGE's actual power cost variance. While the power costs reflected in rates are $7.0 million less than actual costs for January to March 2005, PGE has indicated that the SD-PCAM would defer $11.1 million during that period. ICNU/303, Falkenberg/2. The latter figure is based on PGE's best approximation of the results of the SD-PCAM deferral, without any deadband. Consequently, for at least the first three months of 2005, the Stipulation would allow PGE to defer costs in excess of its actual recovery shortfall. This illustrates the problem with allowing deferral of a single cost element, such as hydro, when the overall cost picture is much more complex. It also illustrates that the financial impact of PGE's alleged power cost recovery deficit is overstated, and provides additional justification to deny the UM 1187 deferral.

<u>Galbraith UM 1187 Testimony</u>

Q. IN UM 1187, MR. GALBRAITH TESTIFIES IN SUPPORT OF THE STIPULATION ON THE BASIS THAT "AN AUTOMATIC ADJUSTMENT CLAUSE IS PREFERABLE TO THE PERIODIC USE OF DEFERRED ACCOUNTING." DO YOU AGREE?

A. No. There may be times when deferred accounting is appropriate. Certainly one would not want to implement an automatic adjustment clause every time a utility encounters an unexpected cost. However, in this case, Mr. Galbraith has "missed the boat" completely because the testimony assumes that deferred accounting is appropriate and justified. The Commission already decided in UM 1071 that it would not allow deferred accounting for stochastic risks such as a hydro deficit. Thus, it is not realistic to view an automatic adjustment clause as the likely alternative to the selective use of deferred accounting.

Q. MR. GALBRAITH TESTIFIES THAT THE SCOPE OF UM 1187 SHOULD LARGELY BE DETERMINED BY THE UNDERLYING CAUSE OF THE DEFERRAL APPLICATION—THE ECONOMIC IMPACT OF VARIATION IN HYDRO GENERATION. DO YOU AGREE?

A. Mr. Galbraith forgets that the Commission already voiced its opposition to such deferrals in UM 1071. Putting that aside, however, I agree with Mr. Galbraith's statement. What puzzles me, however, is why Staff has agreed to support deferral of costs that by Mr. Galbraith's own admission are completely unrelated to the variation in hydro generation.

Q. MR. GALBRAITH TESTIFIES THAT NET POWER COSTS ARE A WELL DEFINED SET OF INTERRELATED COSTS. DO YOU AGREE?

A. No. I am surprised Mr. Galbraith would make this statement given that he testified in UE 165 in favor of changing the very definition of net power costs to include gas resale revenues. OPUC Docket No. UE 165, Staff/100, Galbraith/16-17. This is an item never previously included in power costs that Mr. Galbraith proposed to include in the Staff PCA.

Joint Stipulation Testimony

Q. PGE AND STAFF TESTIFY THAT THE STIPULATION ADDRESSES THE CONCERNS OF ICNU AND CUB CONCERNING THE ROLE OF GAS FIRED GENERATION IN PGE'S RESPONSE TO HYDRO DEFICITS. PLEASE COMMENT.

A. The Joint Stipulation testimony is contradicted by PGE's rebuttal testimony with respect to gas generation. While the Joint Stipulation testimony suggests that use of the Monet backcast method addresses the changes in gas-fired generation resulting from hydro generation variances, PGE argued strongly in its UE 165 rebuttal testimony that Monet has been a very poor predictor of gas generation:

> PGE Exhibit 901 shows differences between actual and expected hydro and gas-fired generation (MWh) on a monthly basis for the 2002-04 period. Expected generation is based on Monet runs for UE-115 and PGE's 2003 and 2004 RVMs. The Exhibit shows no systematic relationship between changes from expectations in PGE's hydro and gas-fired production.

Re PGE, OPUC Docket No. UE 165, PGE/900, Lobdell-Niman-Tinker/5 (Apr. 18, 2005). Thus, PGE seems to have proven that Monet does a poor job of predicting changes in hydro and gas-fired production. It appears unwise, under these circumstances, to use Monet to compute the SD-PCAM hydro deferrals using altered gas price assumptions.

Q. DO YOU HAVE ANY COMMENTS CONCERNING THE METHODOLOGY CONTAINED IN THE STIPULATION FOR DEVELOPMENT OF THE ACTUAL POWER PRICE INPUTS FOR MONET?

A. The Stipulation requires that PGE develop hourly price inputs for Monet by spreading daily Mid-C index standard product prices to hours based on the Mid-C hourly price index. This procedure is questionable because if one already has an hourly market price index, there is no reason why it should not be used directly.

There is no reason to believe that this process "improves" the quality of the final result, and there is no reason to believe the daily price indices are superior to the hourly price index.

Q. HAVE YOU COMPARED THE DAILY AND HOURLY PRICE INDICES?

A. Yes, and the results suggest that both data sources are questionable. I compared the average hourly price for each day (to date) in 2005 to the average price for each day in 2005 based on the standard product index. The results demonstrate substantial disparities between the two data series. Because both series represent a measure of daily market prices, one should expect the two to produce equal results on average and exhibit a very high degree of correlation.

Instead, as shown on the table below, the correlation between these data series is erratic and inconsistent at best. For example, in March 2005, the correlation coefficient is only 34%, while for January through March 2005, the correlation coefficient is only 65% overall. Further, as the data shows, the daily Dow Jones index produces prices that are typically $1/MWh higher.

This is troubling because these inconsistent inputs will be used in Monet to develop an artificial actual price for each hour. Rather than simply using the hourly index without adjustment, the Stipulation requires that the daily index will take precedence over the hourly index. Because PGE is a net purchaser and because there is a hydro deficit for 2005, it appears the reliance on the daily index instead of the hourly index will increase costs to customers.

Table 2
Average Daily Mid C Price
Based on Dow Jones Hourly and Daily Standard Product Prices

	Correlation	Hourly	Daily
Jan 1 - Mar 31, 2005	65%	46.51	47.33
Jan-05	74%	45.57	46.32
Feb-05	62%	45.75	45.67
Mar-05	34%	48.14	49.83

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

ICNU/301

Comparison of Projected 2005 Hydro
Deficit to Historical Averages

Exhibit ICNU/301
Comparison of Projected 2005 Hydro Deficit to Historical Averages

	Year	Hydro Production (MWa)	% of Average	mWh Deficit	Deficit GT Projected 2005 Deficit =	-568 Avg. mW
1	1929	466.6	82.5%	-868.0	1	
2	1930	456.3	80.7%	-958.2	1	
3	1931	457.0	80.8%	-952.1	1	
4	1932	557.1	98.5%	-75.2	0	
5	1933	611.3	108.1%	399.6	0	
6	1934	569.9	100.7%	36.9	0	
7	1935	524.8	92.8%	-358.2	0	
8	1936	494.4	87.4%	-624.5	1	
9	1937	496.5	87.8%	-606.1	1	
10	1938	554.3	98.0%	-99.8	0	
11	1939	484.4	85.6%	-712.1	1	
12	1940	488.6	86.4%	-675.3	1	
13	1941	495.1	87.5%	-618.4	1	
14	1942	518.7	91.7%	-411.6	0	
15	1943	575.0	101.6%	81.6	0	
16	1944	449.2	79.4%	-1020.4	1	
17	1945	497.9	88.0%	-593.8	1	
18	1946	588.4	104.0%	199.0	0	
19	1947	586.4	103.7%	181.4	0	
20	1948	614.4	108.6%	426.7	0	
21	1949	555.6	98.2%	-88.4	0	
22	1950	664.3	117.4%	863.8	0	
23	1951	651.6	115.2%	752.6	0	
24	1952	565.8	100.0%	1.0	0	
25	1953	594.8	105.1%	255.0	0	
26	1954	649.8	114.9%	736.8	0	
27	1955	603.9	106.8%	334.7	0	
28	1956	643.5	113.8%	681.6	0	
29	1957	560.6	99.1%	-44.6	0	
30	1958	586.9	103.7%	185.8	0	
31	1959	643.8	113.8%	684.3	0	
32	1960	581.5	102.8%	138.5	0	
33	1961	595.8	105.3%	263.8	0	
34	1962	576.6	101.9%	95.6	0	
35	1963	547.8	96.8%	-156.7	0	
36	1964	589.0	104.1%	204.2	0	
37	1965	585.0	103.4%	169.2	0	
38	1966	552.2	97.6%	-118.2	0	
39	1967	574.4	101.5%	76.3	0	
40	1968	590.0	104.3%	213.0	0	
41	1969	588.6	104.1%	200.7	0	
42	1970	531.4	93.9%	-300.4	0	
43	1971	639.7	113.1%	648.3	0	
44	1972	672.3	118.8%	933.9	0	
45	1973	517.5	91.5%	-422.1	0	

46	1974	665.1	117.6%	870.8	0
47	1975	618.8	109.4%	465.3	0
48	1976	627.7	111.0%	543.2	0
49	1977	493.4	87.2%	-633.2	1
50	1978	559.5	98.9%	-54.2	0
51	1979	508.3	89.9%	-502.7	0
52	1980	542.9	96.0%	-199.6	0
53	1981	581.2	102.7%	135.9	0
54	1982	637.1	112.6%	625.6	0
55	1983	634.4	112.1%	601.9	0
56	1984	619.0	109.4%	467.0	0
57	1985	526.5	93.1%	-343.3	0
58	1986	576.4	101.9%	93.8	0
59	1987	499.0	88.2%	-584.2	1
60	1988	503.3	89.0%	-546.5	0
		565.7		Number	12
					20.0%
				One in	5.00 Years

ICNU/302

PacifiCorp's Responses to
ICNU Data Request Nos. 8.3, 8.4, 8.11,
8.12, 8.13, and 8.14

May 3, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165 /UM-1187
PGE Response to ICNU Data Request 8.3
Dated April 21, 2005
Question 038

Request:

Please provide a copy of the final 2005 RVM Monet model with all input data that will be modified in computation of the deferral highlighted in color.

Response:

PGE objects to this request on the basis that it is unduly burdensome. PGE provided ICNU a copy of the final 2005 RVM Monet model and ICNU can do this work based on the terms of the stipulation.

May 3, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165/UM-1187
PGE Response to ICNU Data Request 8.4
Dated April 21, 2005
Question 039

Request:

Please provide a list of all calculations in Monet that will be changed in order to compute the deferral under the Stipulation.

Response:

PGE objects to this request on the basis that it is unduly burdensome. PGE has not completed the modifications necessary to implement the stipulation. When PGE finishes its modifications, we will provide a copy of the Monet model to all parties.

May 12, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 8.11
Dated April 21, 2005
Question 046

Request:

Reference Staff-PGE/100, Galbraith-Tinker/3: "In addition to the actual hourly generation figures, PGE will also update the monthly actual hydro generation for these plants. These monthly actual generation figures will then flow through the model to affect three other power cost components -- the Wells Settlement Agreement, PGE's Mid-C indexed purchase from the Confederated Tribes of the Warm Springs, and the Priest Rapids Renewal Contract Reasonable Portion Auction Payment."

Please provide a sample calculation showing how these computations will be performed for each month from January 2005 to present. Please note that, like all ICNU data requests, this is a continuing request that should be updated as new data becomes available. To the extent that insufficient actual data is available to perform this calculation, please provide a sample calculation using hypothetical or estimated data.

Response:

PGE objects to this request on the basis that the ongoing nature is unduly burdensome. Without waiving its objection, PGE replies as follows:

PGE has not yet completed the Monet enhancements that will affect the Wells Settlement Agreement, PGE's Mid-C indexed purchase from the Confederated Tribes of the Warm Springs, and the Priest Rapids Renewal Contract Reasonable Portion Auction Payment. See Attachment 036-A for a comparison of our current modeling and the provisions of the stipulation for these items.

May 12, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 8.12
Dated April 21, 2005
Question 047

Request:

Reference Staff-PGE/100, Galbraith-Tinker/3: "PGE will also make an adjustment to reflect Daylight Savings Time, something Monet does not model directly."

Please explain specifically how this adjustment will be made.

Response:

As noted in Attachment 036-A to PGE's response to ICNU Request No. 036, PGE has not yet modified the Monet model to reflect Daylight Savings Time.

May 12, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 8.13
Dated April 21, 2005
Question 048

Request:

Reference Staff-PGE/100, Galbraith-Tinker/3: "PGE will start with actual day-ahead on and off-peak prices from the Dow Jones Mid-Columbia Daily Electricity Price Index and the actual shape of hourly prices from the Dow Jones Mid-Columbia Hourly Electricity Price Index. PGE will apply the hourly index shape to the daily forward on and off-peak index prices to obtain hourly prices that are consistent with the daily on and off-peak prices, but which follow the observed hourly shape. We will fill any gaps in the hourly data with available data from similar periods."

Please provide a sample calculation showing how these computations will be performed for each month from January 2005 to present. Please note that, like all ICNU data requests, this is a continuing request that should be updated as new data becomes available. To the extent that insufficient actual data is available to perform this calculation, please provide a sample calculation using hypothetical or estimated data.

Response:

PGE objects to this request on the basis that the ongoing nature is unduly burdensome. Without waiving its objection, PGE replies as follows:

As noted in PGE's response to ICNU Request No. 036, PGE has not yet completed all of the Monet enhancements necessary to implement the stipulation. Attachment 036-A compares our "Current Model" with what will be necessary to implement the stipulation. PGE's response to ICNU Request No. 036 also includes Attachment 036-C, which contains hourly Mid-C electric prices for the first three months of 2005. PGE developed these hourly prices according to the methodology described in the response to ICNU Request No. 036.

May 12, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 8.14
Dated April 21, 2005
Question 049

Request:

Reference Staff-PGE/100, Galbraith-Tinker/4: "First, PGE will enhance Monet so that it can accept daily gas prices, as it currently runs based on monthly gas prices."

Please explain specifically how this logic change will be implemented, within Monet. Identify worksheets and subroutines that will change, and how the input data will be changed.

Response:

PGE has not yet completed the enhancements that will allow Monet to accept daily gas prices. Attachment 036-B provides actual daily gas prices for the first three months of 2005.

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ICNU/303

PacifiCorp's Response to ICNU Data
Request No. 8.2

May 12, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 8.2
Dated April 21, 2005
Question 037

Request:

Please provide a calculation using either the RVM 2005 Final Monet model or hourly diagnostic reports from that run illustrating how the deferral calculation will be performed in the modified Monet model based on actual data starting January 2005 to present. Please note that, like all ICNU data requests, this is a continuing request that should be updated as new data becomes available.

Response:

PGE objects to this request on the basis that the ongoing nature is unduly burdensome. Without waiving its objection, PGE replies as follows:

Attachment 037-A is an Excel file on CD, "MonetJan-Mar2005," which provides the PC-Input sheet and the summary output files from a Monet run for the first three months of 2005. As discussed in PGE's response to ICNU Request No. 036, PGE has not yet completed all enhancements in the Monet model necessary to implement or model the stipulation. The Monet run that is the source of Attachment 037-A is consistent with the "Current Model" described in Attachment 036-A. Attachment 037-A is confidential and subject to the Modified Protective Order in this docket (OPUC Order No. 04-406).

The deferral calculation is not performed in the Monet model. Rather, as discussed in the stipulation, the variance is calculated by comparing the base and updated Monet runs. ICNU can compare the power cost output information in Attachment 037-A with the power cost output information in PGE's final 2005 RVM Monet model run. PGE has not performed this calculation except for the first three months of 2005 as in the table below:

Monet Run	Jan-Mar 2005 Power Costs
Base 2005 RVM	$124,112,000
Attachment 037-A	$135,228,000
Variance	$ 11,116,000

We do not know what will happen during the remainder of 2005. However, if the annual variance were $11.116 million, i.e. annual net variable power costs $11.116 million more than forecasted in the RVM Monet run, then the mechanism would indicate "no deferral," as $11.116 million falls within the dead band. The variance figure in the above table comes from a three-month period. Annualized, it would be $44.464 million. In the case of a $44.464 million annual variance, the mechanism would indicate a deferral (subject to an earnings test) of $23.571 million. The first $15 million would fall in the deadband; the sharing parameter would then allocate 80 percent of the remaining $29.464 million, or $23.571 million, to customers.

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