ORDER NO. 04 108

ENTERED MAR 02 2004

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1071

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Application for an Order Approving the Deferral of Hydro Replacement Power Costs.	)))))))	ORDER

DISPOSITION: APPLICATION DENIED

Procedural and Factual Background. On February 11, 2003, Portland General Electric Company (PGE) filed an application for deferral of costs associated with below normal hydro conditions. PGE asserted that below normal hydro conditions caused power shortfalls, requiring the company to purchase replacement power from higher cost resources. PGE requests authorization to defer the cost of replacement power purchased during the period February 11, 2003, to December 31, 2003. PGE requests the deferral pursuant to ORS 757.259(2)(e).[1]

PGE's energy rates for 2003 were established in UE 139, the 2003 Resource Valuation Mechanism (RVM) proceeding. The 2003 energy rates paid by PGE's customers for service during 2003 were based on PGE's forecast power costs for 2003. These costs were forecast in a final run of PGE's power cost model (MONET) on November 14, 2002. PGE is allowed to update its net variable power costs (NVPC) annually under an adjustment to the RVM in Schedule 125. The annual adjustment allows PGE to update costs related to applicable resources; company market power purchases; costs of fuel and transportation; hydro operating

---

[1] ORS 757.259(2)(e) provides:

> (2) Upon application of a utility or ratepayer or upon the commission's own motion and after public notice, opportunity for comment and a hearing if any party requests a hearing, the commission by order may authorize deferral of the following amounts for later incorporation in rates:
>
> * * * * *
>
> (e) Identifiable utility expenses or revenues, the recovery or refund of which the commission finds should be deferred in order to minimize the frequency of rate changes or the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers.

constraints imposed by governmental agencies; market power prices including transmission; transmission and ancillary services; and retail load forecast.

The RVM does not adjust for forecast hydro generation. Instead, PGE's NVPC include normalized hydro conditions. In UE 139, PGE's base energy rates were set using the NVPC associated with the 59-year average of simulated hydro generation.

PGE states that for the entire year 2003 it incurred $31.6 million in excess NVPC, or about 172 basis points of return on equity. PGE proposes a sharing mechanism that, when applied to the amount for the deferral period (February 11, 2003 to December 31, 2003), yields a deferral amount of about $26 million. Without deferral, PGE's return on equity for 2003 would be about 8%. With the deferral and associated amortization of deferred costs, its return on equity for 2003 would be about 9.75%.

Positions of the Parties. The parties (PGE; Industrial Customers of Northwest Utilities, ICNU; Citizens' Utility Board, CUB; Commission Staff, Staff) filed initial and reply comments and presented oral argument to the Commission on January 27, 2004. The following summarizes their arguments.

PGE proposes to defer the difference between its baseline unit NVPC set in UE 139 and its actual NVPC. PGE proposes use of a sharing mechanism that would enable it to defer about $26 million, which represents a reduction of 18 percent from its excess NVPC for the whole of 2003. PGE contends that the Commission should authorize its deferral application for several reasons. First, the application meets the requirements of ORS 757.259. Second, the application is supported by Commission decisions granting deferrals in the past. Third, a grant of the application would be sound regulatory policy, because it recognizes that PGE cannot control the weather or hydro conditions but still needs an opportunity to recover the costs it incurs. Further, authorizing a deferral keeps PGE's cost of capital, and hence rates lower over time.

PGE argues that deferred accounting relief is particularly appropriate, and interim relief inappropriate, where the magnitude of the financial impact of poor hydro conditions is difficult to estimate in advance. PGE notes that without recourse to deferred accounting it would have filed for immediate interim rate relief in February 2003. Given the uncertainty about hydro conditions, PGE might have filed new rate cases several times during 2003 to track the rate effects of changing hydro and power cost forecasts. Granting PGE's deferred accounting application would serve to minimize the number of rate changes, PGE contends, and thus fits under the deferred accounting statute.

PGE cites a number of Commission decisions granting deferred accounting applications. PGE argues that these decisions (UF 3518, Order No. 79-830; UM 445, Order No. 91-1781; UM 529, Order No. 93-309; UM 480, Order No. 92-1130; UM 673, Order No. 94-1111) are similar to its own application. In support of its application, PGE points out that it has no control over poor hydro conditions, and that hydro generation is very low cost, while the hydro shortfall also causes the cost of replacement power in the wholesale market to increase.

PGE also argues that its proposed sharing mechanism is similar to other mechanisms the Commission has approved over the years.

Finally, PGE argues that granting the application is good regulatory policy. First, PGE maintains that hydro generation is an appropriate subject for deferred accounting treatment because it is not within the utility's power to control, does not implicate any incentive structure, is not expected to recur, and does not qualify as a minor variation in cost or revenues that would not justify an adjustment.

Second, PGE points out that granting its application will also provide a tangible benefit to customers by keeping the cost of capital lower. According to PGE, if the Commission signals that Oregon utilities will not substantially underearn because of events beyond their control, the financial markets will use that signal to keep the cost of capital down. Ultimately, PGE contends, this will keep rates lower as well.

PGE's third policy argument is that customers benefit from the Commission's deferred accounting policy. The Commission has used this tool to lower customer rates on many occasions (UF 3518; UM 815; UM 878; UE 115; UE 149). Moreover, according to PGE, the rate increases that deferred accounting prevents benefit customers as well. PGE contends that the proper comparison is not deferred accounting treatment versus no recovery of costs, but deferred accounting treatment versus interim rate relief. PGE believes that, in this case, deferred accounting provides a better mechanism than interim rate relief.

In response to arguments by opponents to its application, PGE argues that its RVM does not mitigate its hydro risk. The RVM allows PGE to update its wholesale market purchases, fuel and transportation costs, and retail load, among other factors. PGE argues that there is no way to predict what the hydro conditions will be for the next calendar year when PGE makes its final RVM on November 15 of each year. PGE asserts that the RVM does not address hydro risk and, in fact, amplifies that risk by annually updating factors that otherwise might provide a buffer against wide swings in hydro generation.

Commission Staff, ICNU, and CUB. These entities oppose PGE's application. All three argue that replacement costs for hydro generation are not a proper subject for deferred accounting, because PGE's RVM is already based on NVPC that include a 59 year average of hydro conditions. In some years there is a hydro shortfall; in others, there is more than the projected amount of hydro. Over time, shortfalls and surpluses average out; that is the significance of normalized hydro conditions included in PGE's NVPC. Granting an adjustment for one relatively poor year (which is still well within the parameters of the 59 hydro years) would create an imbalance and defy the concept of averaging on which PGE's normalized hydro is based.[2]

[2] PGE responds that the 59-year average in the past is not necessarily a predictor of future hydro generation. For one thing, the average does not capture climate changes such as global warming. For another, PGE's contracts for hydro at the Mid-Columbia Projects will expire in the next decade and it is presently unclear what volume of hydro will be available then. PGE argues it may be unable to recover from large hydro variations in early years if it loses a significant part of its hydro resources.

These entities also point out that although PGE has asked for deferral of its hydro related excess NVPC, its formula for determining its NVPC includes a substantial amount (ICNU estimates $19.8 million) for higher than forecast coal and natural gas costs. These parties argue that PGE has supplied no justification for inclusion of these costs in its deferral application.

Staff first argues that PGE's application does not fit under the statute. Staff notes that PGE has an RVM that adjusts its rates annually. Therefore, according to Staff, it is unclear how rates would change more frequently without the proposed hydro deferral. PGE implies that it could have used interim rate relief to address the hydro shortfall of 2003 and that ratepayers would have seen one or more rate changes during 2003 as a result. Staff contends that interim rate relief was not a real possibility for PGE during 2003. Interim rate relief, codified at ORS 757.215(5), is rarely used. According to Staff, the Commission prefers to increase rates after completion of a hearing to determine the propriety and reasonableness of the proposed rates. Interim rate relief is meant to address dire financial circumstances. Staff contends that PGE's alleged 8 percent rate of return on equity for 2003, assuming no deferral, does not constitute dire circumstances and thus does not justify interim rate relief.

Staff also believes that the Commission would have suspended any proposed rate increase from PGE in 2003. Thus, PGE's proposed use of deferred accounting eliminates one rate change, at best. However, the Commission uses average hydro conditions to forecast power costs, and hydro conditions in 2003 fall within the range considered when rates were calculated and set in UE 139. Therefore, Staff contends that it is unclear how PGE would have received rate relief for poor hydro through a general rate case filing.

As to the match between ratepayer costs and benefits, Staff argues that this depends on the pattern of actual hydro variation over time. A mismatch at a particular point in time is not necessarily a problem. Staff contends that a mismatch becomes a problem only if it grows so large that we expect it to persist for a prolonged period. A one time deferral to improve the matching of the hydro costs borne by ratepayers and the hydro benefits received by ratepayers creates the need for more deferred accounting or the need for a future adjustment to the method of reflecting hydro benefits and costs in base rates, Staff argues.

Staff further disagrees with PGE's assertion that its application should be granted because the adverse hydro conditions have resulted in unexpected and extraordinary replacement power costs. According to Staff, hydro variability is well known and well understood in the Northwest. Staff classifies hydro variability as a stochastic risk: a risk that is quantifiable and can be represented by a known statistical distribution. As such, its impacts on NVPC can be simulated in advance and have been included in the NVPC underlying PGE's RVM. Staff believes it is inappropriate to use deferred accounting to mitigate stochastic risks that are reflected in base rates. Deferred accounting should be used only to address scenario or paradigm risks, which are not quantifiable and often represent abrupt changes in business factors or practices (the unexpected shutdown of the Trojan nuclear plant is an example).

Staff acknowledges that PGE had no control over hydro conditions. However, according to Staff, utility control over the cost driver is not the primary issue here. Hydro variability is a stochastic risk, that is, it is quantifiable and expected to persist through time. Such risks should be addressed in a general rate case or in a power cost adjustment (PCA).

Staff estimates PGE's excess NVPC attributable to poor hydro conditions at $17.5 million and believes that under the current rate regime, without deferred accounting, PGE will recover that amount over time. In its opening comments, PGE estimated that poor hydro conditions caused $31.6 million in excess power costs during 2003. Staff contends that $27.3 million of this total reflects the company's proposed Hydro Cost Adjustment Account (HCAA) balance for the deferral period prior to application of 95 percent sharing that PGE proposes. The HCAA calculation captures all changes in unit NVPC, regardless of cause. It is unclear how much of the $27.3 million, and, in turn, of the $31.6 million, should actually be attributed to poor hydro conditions.

Staff and intervenors have not had a chance to review PGE's claims about 2003 earnings. Staff argues that the company's earnings are properly addressed at the time of amortization. Poor earnings themselves are not a reason to defer.

As an alternative solution to hydro variation, Staff proposes a permanent hydro only PCA. Staff believes that Order No. 79-830 and the Commission's current purchased gas cost adjustment (PGA) policy, adopted in Order No. 89-1046, support a permanent ongoing allocation of risk, not a temporary allocation based on the timing of requests for deferred accounting.

The purpose of a PCA is to protect the company from extreme events. An extreme event hydro only PCA may be acceptable if it is implemented in a fair way. Instead of calculating base energy rates using the NVPC associated with the average of 59 years of simulated hydro generation, Staff believes that base rates could be calculated using the average of the 48 years of simulated NVPC that fall below the 80th percentile (the 90th and 95th percentiles represent other possible cutoffs). This change would result in the reduction of base energy rates by removing the 11 highest cost water years from the calculated average. In exchange for lower base rates, PGE would be assured of deferral and recovery of excess NVPC attributable to poor hydro (the difference between actual NVPC and the 48 year average NVPC that is attributable to poor hydro) whenever the NVPC deviation fell above the 80th percentile (that is, was an extreme event). The Commission could allow the utility to choose its level of extreme hydro protection. The tradeoff the utility faces, however, is that coverage for the highest 20 percent of the hydro related NVPC distribution comes with a higher price (i.e., a larger reduction in base rates) than coverage for the highest 10 percent of the hydro related NVPC distribution.

The administration of the hydro only PCA would occur in two phases. First, the calculation of the base energy rate reduction (i.e., the price of the hydro protection) would be made annually, prior to the calendar year in which the base rates would be in effect. The base rate reduction would depend on the utility's resource portfolio and expected market conditions. Second, the calculation of the difference between actual NVPC and the 48 year average NVPC that is attributable to poor hydro would occur annually after the calendar year in which the base rates were in effect. Staff believes this calculation should be made using a MONET backcast approach.

These are the general outlines of a PCA framework that Staff believes has promise as a permanent solution. The details, such as use of a sharing percentage or a cap on the amount of the payout when extreme conditions occur, would have to be worked out. This approach would result in a PCA adjustment charge whenever extreme hydro events occur. However, it also retains a long run intertemporal matching of ratepayer benefits and costs and actual benefits and costs. This approach also has the potential to ensure that the company will not bear the cumulative impact of successive mismatches between actual hydro related costs and those reflected in rates for a prolonged period.

In summary, Staff recommends that authorization for PGE to defer replacement power costs associated with the 2003 shortfall in hydro based energy generation be denied, because PGE's stated reasons for deferred accounting are not persuasive. If the Commission does decide to grant PGE's application, Staff recommends that the Commission limit the deferral to costs attributable to the poor hydro conditions of 2003, which Staff estimates at $17.5 million, and that the Commission apply the deadband and sharing bands that Staff proposed in testimony regarding PGE's application for a power cost adjustment in UE 137. This would likely produce a deadband result (no monies deferred).

CUB argues, in addition to its contention that the 2003 hydro year is within the NVPC parameters for average hydro, that PGE's application fails the fair and reasonable test. Over time, on average, CUB argues, PGE will recover its revenue requirement associated with hydro variation. Granting this application would give PGE an unreasonable opportunity to recover costs.

CUB notes that the hydro conditions that cause PGE to file its application happen once every 4.5 years, based on the 59-year average of hydro conditions on which normalized rates are based. If we then give a deferral for good hydro conditions to distribute benefits to customers, CUB contends that we should have a deferral of hydro costs or benefits nearly every other year.

CUB maintains that five of the last 10 years were within the 1 in 4.5 range, good or bad. Two of the five represent bad hydro years, in which PGE would have benefited from a deferral; three years represent good hydro years, in which customers would have benefited. CUB points out that the benefits of good water years have already flowed to the utility. Customers received no benefits from the good hydro year through a deferral.

CUB takes issue with PGE's contention that its deferral will minimize the frequency of rate changes. PGE asserts that it would have filed for interim rate relief last year. Any new rate case PGE would have filed would also have been based on average hydro, CUB contends; therefore, PGE would not have gained an increase in rates based on this hydro variation. Also, CUB notes that PGE gets to file a new power cost rate case every year.

CUB supports a PCA for PGE because PCAs provide a forum for full investigation of the historic risks and benefits that exist between rate cases, how those have historically been allocated, how to ensure any change in such an allocation is fair to customers and shareholders, and how reducing the risk allocated to the utility reduces the utility's return on equity.

In response to PGE's argument that a deferral will help keep the cost of capital lower, CUB discusses the Moody's Investor Service report that PGE referenced in its comments ("Improving Liquidity for Pacific Northwest Utilities" (Moody's report)). According to CUB, PGE makes no showing that financial markets require the Commission to allow recovery of costs associated with normal variation in hydro conditions. The Moody's report does not suggest that a downgrade in PGE's credit rating is riding on this docket. Instead, CUB argues, Moody's concern was primarily the high wholesale power prices in 2000-2001, not the normal variation in hydro conditions of 2003. The forward looking concern that Moody's had about PGE was PGE's ability to remain insulated from the bankruptcy proceedings of its parent, Enron Corp., and to clarify uncertainties about the outcome of ongoing federal investigations into its role in the western power markets.[3]

CUB notes that the alleged drop in PGE's return on equity is not a legal justification for this deferral. Even if this deferral is granted, CUB contends that PGE's return on equity will still be significantly below its authorized rate of return. CUB urges that PGE can file a general rate case to correct that situation.

ICNU contends that PGE's application does not meet the deferred accounting statute's requirements and should be denied. Deferred accounting, according to ICNU, is designed to be used in a limited manner to allow recovery of unanticipated discrete costs incurred in extraordinary circumstances between rate cases. Here, PGE obtained 89 percent of its normal hydro generation for the deferral period. Moreover, ICNU argues that PGE is protected by having normalized hydro generation included in its NVPC, which are updated annually through the annual adjustment to its RVM. ICNU argues that PGE proposes to shift all risk of power cost variation to its customers.

ICNU claims that PGE's application covers more than just hydro replacement costs. PGE failed to provide evidence of extraordinary or unanticipated events that would justify deferral of any non hydro related costs. According to ICNU, granting the application would not minimize the frequency of rate changes or fluctuations of rate levels. Power costs used to establish normalized rates assume average hydro conditions. Below normal hydro would never be a legitimate basis for filing a general rate case, so, ICNU argues, hydro generation would not be adjusted to any significant degree. Authorizing deferral of these costs will not reduce the frequency of rate changes because there is no nexus between filing a rate case to update the level of hydro generation assumed in rates and the frequency of rate changes.

ICNU notes that PGE's rates also include many adjustment schedules, including two related to deferred power costs. Approval of a deferral here would result in another adjustment schedule, likely increasing rate fluctuations in the future. To balance PGE's recovery of hydro costs, ICNU argues that future rate changes to reflect amortization of costs deferred and future deferrals will be necessary.

[3] ICNU makes the same point about the Moody's report.

ICNU also argues that the hydro conditions have been better than the average assumed in rates for 6 of the last 9 years. ICNU contends that a deferral would overcompensate PGE at the expense of customers.

If the Commission grants a limited deferral (for PGE's hydro generation related costs only), ICNU recommends that the Commission develop an appropriate sharing mechanism that removes load fluctuations from the deferral using peak prices as well as flat market prices.

Commission Discussion and Resolution. The deferral statute sets out a two stage decision process. One stage entails an exercise of Commission discretion ("the commission by order *may* authorize . . . "). The other stage, delineated in subsections (a) to (e) of ORS 757.259, requires that we determine that the proposed deferral is authorized by law. In this proceeding, PGE has proposed a deferral under subsection (e). Therefore, to grant PGE's request, we must determine whether the application either minimizes the frequency of rate changes or the fluctuation of rate levels or appropriately matches the costs borne by and benefits received by ratepayers.[4]

Depending on the facts of a case, we may decide a case in the negative at either stage. If we conclude that a case does not warrant a deferral, we can elect not to exercise our discretion without further inquiry. Similarly, if a case does not meet any of the criteria set forth in subsections (a) to (e), we can elect not to discuss the conditions under which we exercise our discretion to grant deferrals. On the other hand, if we find that a case meets our standards for granting deferral, we cannot authorize deferral unless the case also meets one of the subsection (a) to (e) criteria. Thus, meeting one of the subsection (a) to (e) criteria is a necessary but not a sufficient condition for granting a deferred accounting application.

Our previous deferred accounting orders do not discuss the exercise of our discretion. Therefore, we raise the question here: Under what circumstances do we elect to consider a deferral? We note first that our discretion is constrained by the statutory scheme that creates and governs the Commission. That is, the deferral statute must be read to grant us a sphere of discretion that does not conflict with regulatory practice. The deferral statute is a specific grant of authority to make rates retroactively. It must be read so as to avoid conflict with the other statutory provisions governing ratemaking.

We look at two interrelated considerations for our initial determination whether to exercise our discretion. We consider both the type of event that caused the request for deferral and the magnitude of the event's effect. These considerations interact with each other such that neither one is dispositive without the other.

Staff has established a distinction between the risks that can be predicted as part of the normal course of events and those that are not susceptible to prediction and quantification. Staff calls the former stochastic risks and the latter, paradigm or scenario risks. An example of a stochastic risk is variation in hydro availability over time. An example of a scenario risk is the "perfect storm" of 2000-2001, a cascade of effects that included poor hydro conditions, cold

[4] We note that we will soon be opening a docket to investigate deferred accounting in general.

weather, and extremely volatile power markets (UM 995).[5] We find this distinction useful to characterize the type of risk we consider appropriate for deferral.[6]

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.

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.[7] 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.

We believe that deferred accounting treatment is appropriate for scenario or paradigm risks, extraordinary events that fall outside the predictable and quantifiable. For such risks to qualify for deferred accounting, the financial impact on the utility need be only material. The financial threshold for deferred accounting is lower for the scenario or paradigm risk because the effect of that type of risk is not likely to fluctuate as the stochastic risks do. Hydro variability, for example, causes costs to swing above and below the average included in rates, so the effect should average out. For paradigm or scenario risks, there is no likelihood that a cost swing will be balanced out over time.

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. Moreover, Staff estimates the hydro related excess NVPC to be about $17.5 million, which, by extension, amounts to about 95 basis points of return on equity. That figure is about 55 percent of PGE's $31.6 million. Finally, we note that PGE claims that without deferral, its return on equity will drop to 8 percent. That is far from a dire figure. We find that the impact of excess hydro costs is not significant enough in this case to warrant a deferral.

[5] In its reply comments, PGE argues that the second type of event *can* be predicted and included in models. The point is that such events would not normally be included because they are outside the usual course of events.
[6] PGE argues that this docket is not the place to introduce a new theory of deferrals. We note that the terminology is new but the practice the terms describe is not.
[7] We approved the same deadband for recovery of 2001 excess net variable power costs for both PGE (UM 1008/UM 1009) and Idaho Power (UM 1007).

PGE argues that in a number of cases, we have granted deferrals under circumstances similar to what it alleges here.[8] We disagree. In the Trojan deferral cases, UM 445 and UM 529, we were dealing with a paradigm or scenario risk. While rates are typically set using four year average forced outage rates to forecast NVPC, the duration and cost of the Trojan outages were not within the range considered when we set base energy rates. The Trojan shutdown was not a normal forced outage, and the risk of premature decommissioning was not reflected in base energy rates. By contrast, the 2003 hydro year at issue here is within the range considered in normalizing hydro availability.

In the Idaho Power cases, UM 480 and UM 673, the Commission understood that Idaho Power's base energy rates were calculated using 63 years of historic hydro conditions. We authorized the deferral of a cost variation that had been included in base rates. In those cases, however, the utility had endured a multiyear drought, to which the Commission explicitly referred as a deciding factor. PGE does not face a multiyear drought in this application. Moreover, Idaho Power was much more dependent on hydro generation than is PGE. Idaho Power relies on hydro for about two thirds of its generation, whereas hydro accounts for only about a fourth of PGE's generation.

Finally, the impact of the hydro conditions was much more serious on Idaho Power than on PGE. In UM 480, Idaho Power was allowed to recover 33.5 percent of its excess power costs; the amount of recovery excluding interest was $949,876. This translates to an annual excess power cost of about $3.64 million, equal to approximately 725 basis points of return on equity. In UM 673, the company was allowed to recover 60 percent of its excess power costs; the amount of recovery, excluding interest, was $1,294,847. This equals annual excess power costs of about $3.38 million, or approximately 675 basis points of return on equity.[9]

PGE argues that the hydro variability reflected in the 59-year average does not necessarily predict hydro variability going forward. For instance, PGE points out that many of its mid-Columbia contracts for hydro must be renegotiated soon. PGE also points out that the 59-year average does not take into account climate changes such as those brought about by global warming. Given sufficient variation in hydro patterns, PGE contends, it will not recover its losses for 2003.

We are aware of climate changes and other factors, such as hydro availability, that may affect PGE's ability to recover its hydro losses. Therefore, although we do not find that this case is appropriate for deferred accounting, we encourage the parties to this docket or other interested persons to present alternatives to deal with hydro variability. For instance, parties

---

[8] PGE cites to UF 3518 as well. That was the case in which we approved the PCA under which PGE operated until 1987.

[9] Orders No. 93-966 (UE 84) and 95-690 (UE 91) show the amount of recovery, excluding interest, on Appendix A, Page 5 for the 1992 and 1994 deferrals ($949,875 and $1,294,847). Those orders also report the deferral periods (3/23/92 through 12/31/92 and 5/13/94 through 12/31/94) and the shares of excess power costs allowed to be deferred and amortized (33.5 percent and 60 percent) for the two deferrals. Data from Idaho Power's general rate case (UE 92) were used to determine that 100 basis points was equivalent to about $500,000 in revenue requirement for the company's Oregon operations. We take official notice of the record in UE 92, pursuant to OAR 860-014-0050.

might present a PCA proposal similar to the one Staff has outlined here. For the reasons that Staff provides, and that CUB has cited as well, we believe a PCA may be an appropriate way of permanently allocating risks and benefits of hydro variability between shareholders and ratepayers.

We find that the cause of PGE's request is not extraordinary enough to justify deferred accounting. We further find that the financial impact to PGE of excess hydro costs is not significant enough to warrant a deferral. Accordingly, we conclude that PGE's application for deferred accounting should be denied. Given our conclusion, we need not address whether PGE's application meets the criteria of ORS 759.259(e).

ORDER

IT IS ORDERED that the application of Portland General Electric Company for an order approving the deferral of hydro replacement power costs is denied.

Made, entered, and effective MAR 02 2004.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.