BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1276

In the Matter of	)
	)
THE PUBLIC UTILITY COMMISSION OF OREGON,	)
	)
Staff request to open an investigation regarding performance-based ratemaking mechanisms to address potential build-vs.-buy bias.	)

COMMENTS ON PARTIES' PROPOSALS

OF THE

CITIZENS' UTILITY BOARD OF OREGON

January 29, 2008

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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I. Introduction

CUB believes that there is a bias on the part of utilities to build their own generating units rather than purchase the output of someone else's. This is not surprising, as monopoly regulation of utilities is designed around financing long-term capital investments through rate-of-return regulation. However, in today's world, where an independent power producer (IPP) can build and operate generating plants, and can share in construction and operational risk, this bias may well be increasing costs to utility customers. This docket was designed to look for a way to design incentive regulation that would overcome this bias.

After months of work on how we could overcome this bias, however, we are left with two primary proposals: a proposal from Staff to pay a utility more if it signs a contract with an IPP, and a proposal from the utilities to pay a utility even more if it signs a contract with an IPP.[1] Neither proposal offers any certainty that utilities would change their behavior by purchasing more from independent power producers. The one thing that is likely from these proposals, on the other hand, is that customers would pay more for power from an IPP than we would otherwise. Whether the incentive would be effective in reducing cost and risk to customers through increased IPP use, however, is not clear, and has not been addressed.

In these Comments we discuss our concerns about the rate impacts of the proposed mechanisms, and propose additional limitations that should be placed on any incentive mechanism to help ensure that it does, in fact, lower rates.

II. Overcoming the Build-Buy Bias Could Raise Customer Rates

We believe there is a problem – a bias – and that this bias leads to customers paying higher rates and taking more risk than we would if such a bias did not exist.

A. Mechanism May Increase Rates, Even If It Changes Utility Behavior

However, this does not mean that either of the primary proposals to reduce the build-buy bias will help provide lower rates or lower risk. If we simply end up paying more for power that would have been purchased anyway, then we would be making a bad circumstance worse. We could overpay for the power that comes from assets built by the utilities due to the build-buy bias, and then we could also overpay for the power that is purchased, which would have been purchased anyway at a lower cost.

If we were to overcome the build-buy bias enough such that utilities entered into additional purchased power contracts, but the cost of the incentive for that power were more expensive than the economic benefit of the contracts, then we would have raised

[1] There are also proposals from NWEC, that would pay a utility significantly less, and PacifiCorp, that would pay a utility significant more. Our Comments focus on the two, middle-ground proposals.

rates by an amount that is greater than the benefit to the customer, and the result would be higher rates. This can be represented by a simple example:

Assume that a utility need 1,000 MWh of power. If it uses its most optimistic capacity projections, it can produce that power for $60/MWh. If it builds, it is more likely to produce the power at $70/MWh. It is bidding against an independent power producer that will guarantee $62/MWh. With no incentive to overcome the build-buy bias, the utility decides that it will build ⅔ of this supply and purchase the rest. It bids ⅔ at $60/MWh which it claims is justified and ⅓ at the more realistic $70/MWh. In the end, the power the utility produces itself costs $70/MWh and what is bought (the remaining third) is bought at the guaranteed price of $62/MWh.The cost to customers for the entire 1,000 MWh will then be $64,333.

Now, what happens if we add an incentive of 10% for purchasing the power, and in this case we know the benefit of purchasing power at $8/MWh is greater than 10%. With this incentive, the utility says that it will now purchase ⅔ of the power and will build ⅓. The cost to customers would now be $67,867. Even though the incentive is economically justified and it changes the utility's behavior, the cost to customers is greater because the incentive is paid on the additional increment that the utility purchased, but also on what was going to be purchased without the incentive.

We should keep this example in mind as we look at the circumstances of PGE and PacifiCorp, and examine the details of the incentive proposals. Our goal should not be simply to create an incentive because we believe there is a bias; instead we should be looking at whether a mechanism is likely to change utility behavior ***and*** lower rates.

B. There Is No Showing That An Incentive, By Itself, Would Lower Rates

The utilities, Staff, and the NW Energy Coalition (NWEC) have all proposed mechanisms to overcome the build-buy bias. All three provide financial incentives to utilities to purchase power under certain circumstances. None of the mechanisms requires a finding that, without the incentive, the utility would not have purchased the power. This means that all three proposals would allow a utility to receive an incentive for purchased power that the utility would have purchased without the incentive, which means that each mechanism could lead to higher rates.

No sponsor of a proposal has argued that its proposal would reduce rates.

In fact, it is not clear that lower rates is a goal of the utilities, or that the utilities are looking to change their behavior. The utilities would like to earn a return on power that is purchased, but to what degree this relates to the build-buy bias is unclear. At the workshop on June 26, 2007, PGE cited the Mid-Columbia (Mid-C) purchase power contracts as an example of where an incentive was needed because of the risk that the company faced in the operation of that contract. That contract, however, was signed without any incentive and without the utility having a self-build option. The result of providing an incentive on the Mid-C contracts would simply be higher rates.

In addition, the utilities propose no cap on the rate impact that would be allowed under such a mechanism, and remove Staff's requirement that the resource be selected under a competitive bidding process and "be in lieu of a utility ownership option." Rather than focus on the narrow set of circumstances where a build-buy bias might come into play, the utilities seem focused on trying to get this incentive paid on as many contracts as possible, regardless of the cost or benefit to customers.

III. The Build-Buy Bias

To place our recommendations in context, it is useful to first discuss the build-buy bias, competitive bidding, utility ratebase, and some other issues that impact a utility's resource choices.

A. The Regulatory System Creates A Bias

A utility bias towards investing money in power plants should not be surprising. This is exactly the behavior that our regulatory system is designed to encourage. Utility service requires a great deal of capital expenditure on infrastructure that will last many years. Our regulatory structure is designed to attract investment in this infrastructure, while keeping utility rates affordable for customers. The mechanism to do this is a utility's ratebase. To finance the critical infrastructure necessary to provide utility service, utilities are called upon to attract capital and repay that capital over the expected life of the utility investment. The utility earns a rate of return each year on the portion of its investment in infrastructure that has not yet been amortized (recovered from ratepayers). One source of capital for a utility is shareholder equity, and for that portion of its financing the utility earns a return on equity.

This return on equity is one of two sources of profit that investor-owned utilities receive under our regulatory system. The other source is the utilities' ability to manage costs. Utilities are generally allowed to retain any net income they produce from operating the utility between general rate cases, whether this comes from reducing costs below what was projected or increasing revenues above what was forecast.

Owning and operating a power plant provides opportunities for both kinds of profits. The utility finances the plant and earns a rate of return on the unamortized investment. The utility also manages the plant and can retain any cost savings from operating the plant more efficiently than forecast. Obviously this second part can be limited by the impact of a power cost adjustment mechanism.

A purchased power agreement (PPA) provides few opportunities for a utility to profit. The utility is not the one financing the plant, so it does not receive a rate of return, and the utility is not operating the plant so any operational efficiencies generally fall to the owner of the plant.

It is not unreasonable that the profit-making potential of building a power plant would result in a utility preference to build and own plants rather than purchase the output from an IPP-owned plant. Purchased power agreements can reduce costs to customers due to the fact that the risk of cost overruns, plant failure, reduced capacity, and other risks are taken by the IPP. Thus the utility bias toward owning and operating plants may be causing customers' rates to be higher than necessary.

B. This Bias Increases Costs & Risks For Customers

In comments last May, the Northwest & Intermountain Power Producers Coalition (NIPPC) did a good job of laying out the potential benefits of a PPA in terms of risk reduction to customers. CUB agrees that purchased power agreements can lead to lower overall costs to customers, because of the financial impact of these risks:[2]

1. The IPP assumes the risk of construction cost overruns.
2. The IPP assumes the technology risk (heat rates, capacity factors, *etc.*).
3. The IPP assumes the risk of O&M increases.
4. The IPP assumes the plant availability risk.
5. The IPP may offer a lower cost-of-capital due to greater debt financing.
6. The IPP assumes decommissioning costs.

[2] UM 1276 NIPPC Opening Comments, May 31, 2007, at 3-4.

C. Competitive Bidding Is Limited In Its Ability To Overcome This Bias

Within our regulatory environment, we have attempted to deal with the build-buy bias by requiring utilities to use competitive bidding in order to compare the cost of building a resource to the cost of purchasing power from an IPP. Unfortunately, there are real limitations to relying on competitive bidding to protect customers from higher costs associated with building plants, for several reasons: First, because cost overruns on a utility-built plant are often placed on customers, while independent power producers are required to absorb cost overruns, a utility can take the risk of low-balling its cost estimates. Second, if a utility-owned power plant is less efficient than expected, this lower performance will be updated through an annual power cost update, thus passing the additional cost of the lower efficiency to customers.

An IPP, on the other hand, is usually expected to meet the efficiency contained in its bid. This means that a utility can high-ball its expected efficiency, whereas an IPP cannot afford to do this. This is particularly problematic with regard to wind resources. The availability of a wind project (30%, 35%, 37%) has a very significant impact on its cost. If a wind project is expected to have a capacity factor between 32% and 35%, a prudent independent bidder would likely bid based on the 32% number, while a utility can afford to bid at the 35% number. Third, a utility can be less concerned in the bidding process about preparing for contingencies. Generating plants can fail, they can shut down at critical times, they can close before the end of their useful life, and they can require significant additional investment. They can also be subject to new environmental regulation. Power plants last a long time, and a lot can happen during that time. This is not much of a problem for a utility, because customers can act as insurance against these contingencies. An IPP, however, must plan for such contingencies, and include the costs in its bids.

D. Front-Loading A Utility's Ratebase

It needs to be recognized as we discuss ratebase, that the costs are front-loaded. An asset in a utility's ratebase will almost always increase rates when it comes online, but over time, as we amortize the capital investment and therefore reduce the annual cost of return on unamortized plant, its costs decline relative to the market. This is a different pricing strategy than independent power producers use. An IPP is more likely to levelize the capital portion of what it charges a utility, so the cost is not front-loaded.

E. Uncertain Regulatory Environment Of The 1990s

The bias a utility has towards investing in power plants was not enough in the 1990s to motivate utilities to invest. Utilities were concerned about deregulation and stranded costs. Without the assurance that regulation would protect them for the decades-long life of new generating units, utilities were unwilling to invest in new generation, and were, instead, content to purchase additional power supply in the market.

For PGE this presented a particular problem. PGE shut down its largest generating asset, Trojan, and later removed it from ratebase. The Company added one small gas-fired plant, Coyote Springs, but overall saw its generation ratebase decline significantly. This created a 20-year hole in PGE's ratebase where there was little additional investment. By the time of the Western Energy Crisis, PGE had little new generation ratebase, and much of its ratebase was largely amortized. This meant that the Company's generation ratebase was relatively low, it had to purchase a great deal of power from the market, and, therefore, had limited profit-making opportunities.

F. Purchased Power Has An Important Role In A Utility's Resource Portfolio

While there is a certain us-vs.-them dichotomy presented in this docket between utility-built supply and purchasing power, the reality is a bit more nuanced. All utilities purchase power, because purchased power has advantages in certain circumstances. It has flexibility that allows the utility to adjust to load variation both short-term and long-term. Building a resource takes several years of lead time (planning, permitting, negotiating contracts, building, testing, *etc.*), but purchased power can come online quickly.

This means that our utilities will be purchasing power in the future no matter what results from this docket.

IV. PGE's Current Situation

During the 1990s, PGE closed its largest asset, and within a few years removed it from ratebase. Due to concerns about stranded assets and a corporate parent that opposed utilities owning generating assets, PGE did not invest much in new generation supply. This created a situation where PGE entered this decade with a ratebase that was relatively small compared to the Company's revenue requirement.

A. PGE Is In A Capital Investment Period That Will Increase Its Ratebase

PGE has responded by trying to nearly double its ratebase in a short period of time. PGE's rates are already high due to its reliance on the wholesale market. As building and ratebasing a generating plant is front-loaded, PGE's drive to build its way out of its generation deficit will only take the Company's already high rates and increase them considerably. Currently, PGE has plans to increase its ratebase by 80% over the next few years.

The Company just got approval to add Phase I of Biglow Canyon to its ratebase to the tune of $255-$265 million.[3] Port Westward added $279 million to the Company's ratebase.[4] The Company projects Phase II and III of Biglow Canyon to add another $600 to $700 million to its ratebase.[5] Over the next 4 years, PGE plans several other large capital projects including Boardman emissions control and hydro relicensing. PGE's past and projected future capital expenditures are:

PGE Capital Expenditures

2003	$ 167 million
2004	$ 194 million
2005	$ 255 million
2006	$ 371 million
2007	$ 471 million
2008	$ 541 million
2009	$ 541 million
2010	$ 571 million
2011	$ 312 million

After adjusting for annual depreciation of approximately $210 million per year, this shows that PGE's ratebase will grow 79% between 2006 and 2011.[6]

i. With PGE's Small Ratebase, Would New Incentives Have Made A Difference?

PGE entered this decade woefully short of ratebase, because it had invested so little new capital in its system since the mid 1980s. Once the Western Energy Crisis stopped the movement towards deregulation, thereby removing the threat of stranded costs, the Company may have felt compelled to significantly rebuild its ratebase. Regulation is built around providing a return on invested capital, so investing capital in new generating resources and expanding ratebase was the primary way the Company

[3] PGE Presentation at Edison Electric Institute, November 2007. See UE 189 CUB/100/Jenks/104/1-2.
[4] UE 180 OPUC Order No. 07-015 at 50.
[5] PGE Presentation at Edison Electric Institute, November 2007. See UE 189 CUB/100/Jenks/104/1-2.
[6] *Ibid.*

could improve its ability to generate profits. The ratebase system has been in place for decades, while regulatory incentive mechanisms change as regulatory priorities change. It is doubtful whether having an incentive mechanism, such as those proposed here, would have made much difference in PGE's choices. A utility that feels a need to expand ratebase may do so with or without an incentive to purchase power.

ii. Practically Speaking, PGE Approaching Short-Term Limit On Ratebase Additions

PGE's 80% increase in ratebase will put considerable upward pressure on rates, especially given that the costs are front-loaded. While it will close some of the gap between PGE's load and its electric supply, it will still leave PGE well short of load-resource balance. With PGE's capital costs, and its associated ratebase, growing so rapidly, and with any new ratebase also front-loaded, PGE is likely nearing the limit of the amount of investment it can add to ratebase over a short period without facing a customer backlash.

B. PGE Already Plans To Invest Significantly In Purchased Power Agreements

PGE's recent resource plans and the plan that it presented to investors in November show that the Company plans to sign a number of contracts to purchase power. PGE is 818 aMW short of the capacity it needs in 2012. It plans to meet this through building Biglow II and III, but also through purchased power. PGE plans to acquire 192 aMW from PPAs of 6 to 10 years' duration, 180 aMW from PPAs of up to 5 years, and 218 aMW of additional renewable resources.[7]

PGE is doing this under the existing regulatory structure with its build-buy bias, which suggests that there is a limit to PGE's ability to build its way out of its resource

[7] PGE Presentation at Edison Electric Institute, November 2007. See UE 189 CUB/100/Jenks/104/1-2.

deficit in the short-term. Customers have to absorb and pay-off some of the new ratebase before the Company can reasonably add more to it, and PPAs of less than 5 years and PPAs of 6 to 10 years will allow PGE and its customers to absorb the capital expenditures that are currently planned.

C. PGE Has Already Launched An RFP To Begin Securing These Resources

Last week PGE published a request for proposals (RFP) to begin implementing these plans. This RFP lists the resource targets as: up to 192 aMW of power purchase agreements of 6-10 years terms; and up to 218 aMW of renewable energy resources.

PGE is clearly moving forward to secure additional power supply beyond what is included in capital expenditure plans, and is looking to acquire PPAs which would be eligible for an incentive under the Staff and Joint Utility proposals. PGE's plans, however, have grown out of the Company's IRP process, and were developed independently from any incentive that may be established as a result of this proceeding.

D. How An Incentive Mechanism Would Affect PGE's Plans

Staff's proposed mechanism would allow a utility to earn a 10% margin on a PPA that came from a competitive bidding process and was more than 3 years in length. The Joint Utility proposal would provide a larger incentive, approximately 14%, to a wider range of contracts. How would this impact PGE's plans?

PGE is already planning on acquiring 192 aMW of power from PPAs that would be eligible for Staff's and the Joint Utilities' proposed incentives, and another 180 aMW that might be eligible, depending upon the length of the contracts. While we do not know what the price of these contracts will be, if the contract were for $65/MWh and we only consider the contracts that are 6 years or longer, the cost of the incentive from Staff's proposal would be $11 million and $15 million from the Joint Utility proposal.[8] If we include the additional 180 aMW that might be eligible, the cost to customers would be $21 million from the Staff proposal and $30 million from the Joint Utility proposal.[9] At this point we would be above the rate cap that Staff proposed (1% of revenue requirement),[10] yet no new PPA would have been signed beyond what PGE has already planned for without an incentive.

This result is not reasonable. Customers would provide PGE with additional dollars – additional profit above their authorized ROE – and the Company would do what it was going to do anyway. Thus, while the result is the least-cost and least-risk approach based on the Company's IRP, we would have made it more costly for customers without improving it. No behavior on the part of the Company would have changed. There would be no reduction in risk placed on customers. The only effect would be increased retail rates and increased shareholder profits. Paying more to get the same utility behavior is terrible regulatory policy.

V. PacifiCorp's Current Situation

Oregon's ability to influence PacifiCorp's decision-making is limited because Oregon is a declining percentage of PacifiCorp's load.

A. PacifiCorp's Multi-State Resource Allocation Dilutes Any Incentive

Oregon currently represents 25% of PacifiCorp's load, and that figure is declining. PacifiCorp operates as an integrated multi-state utility with power costs

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[8] (10%) x ($65/MWh) x (192 aMW) x (8,760 hours/year) = $10,932,480.
(14%) x ($65/MWh) x (192 aMW) x (8,760 hours/year) = $15,305,472.

[9] (10%) x ($65/MWh) x (372 aMW) x (8,760 hours/year) = $21,181,680.
(14%) x ($65/MWh) x (372 aMW) x (8,760 hours/year) = $29,654,352.

[10] PGE opposes the cap.

(whether resources are in ratebase or are purchased power) that are divided between the states based on each state's load (demand and energy). This means that Oregon remains a significant part of PacifiCorp's load and PacifiCorp must listen to Oregon. The risk of disallowance of 25% of the cost (or profit) on a new resource gives Oregon a great deal of clout on resource decisions. At the same time, being 25% of the system means that the incentive Oregon provides will do little to influence the utility unless other states adopt similar incentives.

In the case of Staff's 10% incentive, for PacifiCorp in Oregon this is reduced to an incentive of 2.5%, since it is only applied to ¼ of the purchase contract. If this is enough to change the utility's behavior then we are significantly overpaying PGE, since in order to minimize rates, incentives should be no greater than necessary. If this is not enough to influence behavior, then it is simply adding costs to rates, since PacifiCorp will likely make some purchases that would be eligible for the proposed incentives.

VI. What Limits Should We Place On A Mechanism?

At this point, after evaluating the various proposals and applying them to the current situation of each utility, we have concluded that the Commission should reject both the two main proposals unless the Commission places additional constraints upon the mechanism. With some additional constraints and with a sunset provision so the mechanism does not become permanent if it does not add value, we believe that a modified proposal is reasonable.

A. Incentives Should Be Awarded On A Case-By-Case Basis

First, we think that it is important to recognize that the incentive should only apply in circumstances where it adds value to customers. This means that each PPA would have to be considered separately, and the Commission would have to affirmatively find that paying an incentive is appropriate for that particular PPA. Where it cannot be demonstrated that a PPA provides a benefit to customers, then an incentive should not be paid.

B. Incentives Should Only Be Paid On Contracts Of 10 Years Or Longer

The utilities and Staff are proposing their mechanism apply to PPAs that are 3 years or longer in length, but utilities do not build such short-term resources and the customer benefits of PPAs do not flow from these short-term purchases. Earlier, we discussed the benefits that NIPPC identified from PPAs. Most of these benefits come from choosing a long-term PPA instead of building a new plant. A 3-year PPA simply may delay a utility building a power plant, but it doesn't necessary change the risk associated with the utility building that plant. If after the 3-year delay, the utility goes forward with a self-build option, there is little risk reduction. The risk reduction benefits (cost overruns in construction, technology risk of the heat rate or capacity factor, O&M costs, costs of capital benefits, and decommissioning costs) come when the utility avoids building a plant altogether by purchasing power from an IPP. However, when the utility simply delays a decision to build, but then builds the plant, there is little risk reduction.

Contracts of 3 years which delay but do not avoid a utility self-build option should not be eligible for an incentive. CUB would encourage the Commission to reject both the Staff and the utilities' proposal for the length of time of a contract eligible for incentive. The real goal should be to create an incentive for long-term purchases of output from dedicated facilities which allow the utility to avoid building a generating plant. We recommend that the incentive be limited to contracts of 10 years or more.

C. Incentives Should Only Be Paid Where There is a Real Benefit

In order to receive an incentive, a linkage to these risk reductions must be found. The Staff recommends that an independent evaluator provide a formal recommendation on the eligibility of a PPA for the incentive, based on an evaluation of costs and benefits compared to the utility ownership options. We think this is a reasonable proposal.

The Staff goes on to say, however, that the utility may use FASB Interpretation 46(R), to show that the PPA absorbs ownership risks and does not require consolidation on the utility's balance sheet. The Joint Utilities go even farther, eliminating any role for the independent evaluator and leaving the evaluation of whether the PPA absorbs risks, solely to FASB accounting. We oppose linking this issue to FASB accounting. FASB accounting does not look at these risks from a perspective of customer benefit and is not evaluating whether the level of risk reduction justifies charging customers higher rates. While it may be true that, if FASB accounting requires a PPA to be consolidated on the utility's balance sheet, then the PPA does not offer the risk reduction necessary to qualify for an incentive, the reverse cannot be assumed. If FASB does not require consolidation, it does not mean that a PPA offers enough risk reduction that it should qualify for an incentive.

CUB believes that the proper process is to have the independent evaluator make a recommendation to the Commission regarding the level of risk reduction and whether a contract should be eligible for an incentive. The Commission would, after receiving input from parties, make the final decision.

D. Incentives Should Only Be Paid For Incremental Increases In Purchased Power

We cannot find any justification for providing an incentive to utilities to purchase power that the utilities would have purchased without the incentive. As we have demonstrated, utilities are currently moving forward, without any incentive, to sign PPAs. There is no reason to raise rates to pay for an incentive that is not necessary. Power purchase agreements that come from RFPs that are already announced, or that are included in a utility's Least Cost Plan that has been filed with the Commission should not be eligible.

If a utility is currently planning to pursue a PPA in spite of its build-buy bias, then it is not in customers' interest to increase the cost of that PPA. Only PPAs that go beyond what utilities are already planning should be eligible for incentives.

E. There Should Be A Cap On Incentive Payments

We support the Staff's proposal to cap the incentive at 1% of revenue requirement. We should be very careful about raising rates at this time. In the case of PGE, rates will be going up significantly because of the Company's capital expenditures and additions to ratebase. Regulatory policy should be careful about adding costs to customers' rates. Until we are sure that customers are getting real value from this incentive program we should place very real limits on it.

In addition, if we only apply an incentive to incremental PPAs that go beyond what is already planned, and limit the incentive to contracts that really compete with utility self-build options (10 years or longer), then the 1% cap should be adequate. The cap only becomes a problem if we are providing the incentive to a lot of contracts that have little to do with the build-buy bias.

F. The Level Of An Incentive

There are four proposals for the level of an incentive. The Staff proposes 10% before taxes and the Joint Utilities proposed 10% after taxes (about 14% pretax). PacifiCorp also submitted a proposal to, in effect, ratebase a PPA which, because of compound interest, would produce an incentive well above the other proposals. NWEC proposes an incentive of 2-3% after taxes.

Even though this docket has been going on for a long time, there is no real basis for determining what an incentive should be. Utilities earn a rate of return on dollars that they have are invested in the system but that have not yet been amortized. PPAs do not require any investment of up-front capital. The return that is needed on expenses in order to overcome a bias caused by a rate of return on investments, does not appear from a simple mathematical formula. Someone in this docket suggested the problem was we are comparing apples to oranges; it is more like comparing apples to pork chops.

Generally, the incentive should be the smallest incentive necessary to produce the result we want, as long as the benefit created is greater than the incentive given. But we know neither the level of incentive that would be necessary to produce the result we want, nor the level of incentive that would be greater than the resulting benefit.

The level of incentive also is related to how broadly we apply the incentive. If the incentive is applied to contracts that would have happened without the incentive or to contracts with little risk reduction, then the incentive level would have to be small or we would end up in a situation where the total incentive paid is greater than the total benefit received by customers.

If the Commission rejects our restrictions and allows an incentive to be paid on contracts of 3 years and contracts that are already planned for, then the incentive would have to be well below Staff's and the Joint Utilities' proposals in order to provide an overall customer benefit. If the Commission accepts our recommended limits, such that the incentive is narrowly targeted towards situations where the build-buy bias exists, and if we do not pay an incentive for contracts that have already been planned for, then it may be reasonable to set an incentive at 10% pretax, as Staff has recommended.

G. The Incentive Should Sunset In Three Years

Most of the proposals allow for some sort of review in a few years, but CUB believes that, without much evidence that a build-buy incentive would produce lower costs and lower risks, and with some evidence that an incentive would produce higher rates, a sunset provision makes more sense.

We propose that an incentive sunset in 3 years, unless the Commission takes action to reauthorize it. This places the burden on the advocates of the incentive to demonstrate that it has produced positive results for customers. If such a demonstration can be made, we would expect that the Commission would reauthorize it. If such a demonstration cannot be made, the incentive would be discontinued.

Respectfully Submitted,

Bob Jenks
Executive Director

CERTIFICATE OF SERVICE

I hereby certify that on this 29th day of January, 2008, I served the foregoing Comments on Parties' Proposals of the Citizens' Utility Board of Oregon in docket UM 1276 upon each party listed below, by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending 6 copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

Respectfully submitted,

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W=Waive Paper service, C=Confidential, HC=Highly Confidential

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