BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1050

	)
In the Matter of PACIFICORP	)
Request to Initiate an Investigation of	)
Multi-Jurisdictional Issues and Approve an	)
Inter-Jurisdictional Cost Allocation	)
Protocol.	)
	)

DIRECT TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

January 27, 2010

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

I. Introduction

As someone who helped negotiate the Revised Protocol, I was a strong proponent of the "bargain" that was the basis of Oregon's support for that allocation methodology. As such, the new 2010 Protocol being proposed for use in states other than Utah[1] will largely be viewed by CUB based upon whether it is consistent with that bargain. Because our analysis finds that it is not consistent, CUB has concluded that the 2010 Protocol should not be adopted in Oregon.

II. The Bargain That Was the Revised Protocol

Since the merger of low-cost, hydro-based Pacific Power and high-cost, coal-based Utah Power in the 1980s which formed PacifiCorp, resource cost allocation

[1] Utah is moving to a Rolled-In methodology not contemplated by the 2010 Protocol as part of a "side deal." UM 1050/ PPL / 100 / Kelly / 11.

between the PacifiCorp states has been a difficult issue, made more difficult by the Company cutting different deals and agreements with various states.

During the original merger, Utah believed it was promised that power supply costs would be merged and Utah's rates would fall. The Pacific Power states believed, and continue to believe, that they were promised that the benefits of the cheap hydropower would stay with the Northwest and not be shared. Nine years ago, PacifiCorp and stakeholders from the states in its service territory undertook a new effort to reach agreement on cost allocation, resulting in the current methodology.[2] It became clear during these negotiations that the states were negotiating different deals. Utah was focused on forecasts of rates and trying to ensure that its rates were as close as possible to "Rolled –In" (Utah's term for allocating hydro, clean air, and peaking costs equally across all states). Utah reserved the right to blow up any agreement that varied too greatly from its preferred rates. Oregon stakeholders, including CUB, were focused on securing the benefits of the Northwest hydro system for Northwest ratepayers. Oregon's goal was a long-term agreement, whereby Northwest residents would pay for the early front-loaded costs of hydro relicensing in exchange for receiving the benefits of the hydro resources for the life of those licenses. In order to secure this agreement, Oregon stakeholders were willing to absorb the large costs associated with relicensing, and had to pay an additional $97 million associated with in-state QF's, in order to receive our benefits[3]:

> The parties to this Stipulation recognize that there is uncertainty regarding the future value of the Mid-Columbia Contracts and that it is possible that, during the remaining term of the Existing QF Contracts, the costs to

[2] UM 1050, PacifiCorp Petition for Approval of Amendments to Revised Protocol Allocation Methodology, page 3.
[3] CUB Exhibit 102.

> Oregon customers associated with the contemplated allocation of Existing QF Contracts will exceed the benefits of the contemplated allocation of Mid-Columbia Contracts. However, the Oregon Parties are prepared to assume this risk because they expect that the contemplated allocation of Mid-Columbia Contracts will continue to provide long-term benefits to Oregon customers after the expiration of the Existing QF Contracts. Similarly, the parties to this Stipulation recognize that the addition of relicensing costs to the Company's ratebase may cause the Hydro-Electric Resources to be more costly than other market opportunities in the near term, but Oregon Parties are willing to accept responsibility for these higher near-term costs in the expectation that, as the relicensing costs are depreciated, Hydro-Electric Resources will yield long-term benefits to Oregon customers. For the foregoing reasons, it is critical to Oregon Parties that their entitlement to Hydro-Electric Resources and Mid-Columbia Contracts not be abridged at any time in the future.[4]

Obviously these two approaches were problematic. Utah was focused on the short-term rate impacts and refused to accept the deal as a long-term agreement. Oregon stakeholders were willing to absorb large costs in exchange for a long-term stream of benefits, but this required a long-term agreement. In the end, these approaches seemed incompatible, but PacifiCorp was willing to step up to the plate and take the risk of incompatibility. In Utah, the Company agreed to insure that the rates approached the "Rolled-In" requirements of Utah parties. In Oregon, the Company was willing to agree that as long as the Revised Protocol "is relied upon by the OPUC for purposes of inter-jurisdictional allocation of the Company's costs, all PacifiCorp's general rate case filings in Oregon will be based upon same."[5]

Today, PacifiCorp is asking the Commission to adopt a different methodology and to order the Company to use it in future rate cases, because the Company is no longer willing to absorb the risk that Utah's and Oregon's approaches to cost allocation are not compatible. However, CUB analysis finds that the PacifiCorp proposal is incompatible

[4] CUB Exhibit 103, page 2.
[5] *Ibid*., page 4.

with the earlier agreement. First, rather than recognize the long-term stream of hydro benefits which Oregon customers paid for in the Revised Protocol, the 2010 Protocol removes any expectation that Oregon has long-term rights to Northwest hydro resources, and replaces it with an expectation that every 5 years the states will renegotiate hydro benefits. It is based on unreliable forecasts which cannot be verified and likely underestimates Oregon's share of hydro benefits. It guarantees that Oregon customers do not get the hydro endowment for the life of the hydro licenses, even though we paid the front-loaded costs associated with hydro relicensing. Finally, it violates the used and useful principle of ratemaking.

CUB recommends that the Commission reject this proposal. Instead, the Oregon PUC should seriously consider a structural separation which follows the principle of cost causation and brings real benefits to Oregon customers.

III. Oregon Principles from MSP

A. Regional Preference

During the MSP negotiations, CUB strongly articulated our belief that a regional preference was a critical piece of allocating the benefits of hydro facilities. Regional preference to hydro is a long-standing tradition in the Northwest as it applies to federal hydro power, and CUB believes it is an important principle for all hydro facilities.

The basis of regional preference comes from the fact that a hydroelectric dam is not simply a power production facility. A hydroelectric dam has important impacts on the river and the watershed, on the communities near the facility, on communities upriver and downriver from the facility, on the economic interests associated with the river, on transportation, recreation, and fish and wildlife. These impacts are regional impacts. The dam completely changes the river, which impacts fish and wildlife and its scenic quality. The dam also affects flood control, irrigation, transportation, fishing and other economic uses of the river. How the dam is operated often involves trade-offs between these various uses and electricity production.

How this trade-off is managed is influenced by regional preference. If there is no regional preference for the hydropower benefits, but the other effects of the dam are primarily or entirely regional, then the balancing of these trade-offs becomes more difficult. If all the economic and environmental costs of a facility are contained within one state, but most of the economic benefits flow out of state, then that state's interest will likely be to curtail hydro production. However, this is difficult to assess, because the people who benefit from the power production have no reason to agree to any curtailments since they see none of the costs. The Klamath Agreement is a great example of this type of negotiation. Oregon and California have a strong interest in the impact of the dams on fish and wildlife. The Klamath River dams have a significant impact on salmon runs in California's Sacramento River, which is critical to Oregon's off-shore fishing industry. Utah and Wyoming, on the other hand, are not impacted by the effects that the Klamath dams have on fish and wildlife.[6] If Klamath dam removal had required approval by all PacifiCorp states, it is not clear that dam removal would be moving forward.

CUB's position on a regional preference for hydro facilities is not limited to this case and the federal system. When Enron proposed divesting PGE of all electric generation, including hydro facilities, CUB raised opposition both for economic reasons and because out-of-region ownership would not have had an interest in the environmental

[6] UE 219 / CUB / 100 / Feighner / 5.

impacts of the facilities.[7] Theoretically, since the value of the sale would have been used to reduce rates to customers, customers would still get the value of the hydro assets. However, CUB strongly opposed the sale of hydro facilities because of regional preference. In our spring 1998 newsletter, we described the issue this way:

> Access to the Northwest's cheap hydro power is being threatened. Enron is proposing to sell off PGE's hydro assets to the highest bidder…Under the Fair and Clean Plan, residential customers of Oregon would be allowed to purchase power from the region's hydro system. This will keep rates down and provide for rate stability. In addition, Northwest residential customers are more likely to support salmon recovery efforts and understand the connection between hydroelectric power and endangered species.[8]

B. Hydro Endowment in Place for Long Term

Before the Revised Protocol, costs were divided up based on the Modified Accord. CUB disagreed with how the Modified Accord treated hydro investments and CUB's highest priority in the Multi-State Process (MSP) negotiations was to restore the long-term hydro benefits that were given away in the Modified Accord.

The Modified Accord included a hydro endowment, but the endowment only applied to the current investment in hydro and did not include the Mid-Columbia hydroelectric contracts. All new investment would be Rolled-In, and as the hydro facilities were relicensed over time, the hydro endowment would disappear.

Because of our belief in a regional preference to hydro, CUB worked to establish a long-term hydro endowment in MSP. Achieving this agreement required Oregon customers to agree to pay significant costs.

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[7] UE 102, CUB Opening Brief, page 20.
[8] CUB Exhibit 104, page 3.

i. The Cost of Hydro Relicensing.

CUB was clear that Northwest regional customers – if we wanted to retain the benefits of the hydro facilities – had a responsibility to pay the costs associated with these facilities. These were not small costs; PacifiCorp's forecasts of relicensing costs were significant.[9] While CUB was skeptical of these forecasts, hydro relicensing costs were a significant risk and had the potential to be greater than market costs in the short term. When we evaluate hydro relicensing costs versus other alternatives (dam removal with replacement resources, for example), we favor relicensing if it has a lower net present value than the alternatives. However, because there is no fuel involved in hydro facilities, the cost associated with dams is nearly all capital investment, which is ratebased. This cost is front-loaded and declines each year, as compared to a natural gas plant, which has fuel prices that are expected to increase each year, or market purchase prices, which are expected to increase over time. Agreeing to take on the cost of hydro relicensing regardless of the ultimate cost, involved taking on the risk that short-term prices could be higher than if those relicensing costs were Rolled-In as they were under the Modified Accord.

CUB was willing to see Oregon customers take the risk of higher short-term costs from hydro relicensing, but that was only a rational decision if those same customers then benefited from the resource when it became cheaper. This decision would have made no sense if the Revised Protocol had been designed to be in place for only 5 years.

The Commission recognized this in the order accepting the Revised Protocol:

[9] CUB Exhibit 105.

> The Stipulation states that Staff and CUB want to retain PacifiCorp's hydroelectric resources and Mid-Columbia contracts for Northwest citizens. As part of the negotiations, Staff and CUB accepted the Revised Protocol cost allocation for the existing qualifying facilities contracts. Staff and CUB also wanted to make certain that if Oregon customers were responsible for near-term costs and risks of the hydro resources, such as relicensing costs, then Oregon customers should also expect to receive the long-term benefits of these resources.[10]

IV. The Revised Protocol and Oregon Protections

A. The Revised Protocol Was a Compromise

The Revised Protocol was a compromise. Oregon parties wanted structural separation between the Western Control Area and the Eastern Control Area through a mechanism referred to as the Hybrid Method. This is summed up by Commissioner Savage in his concurring opinion:

> I believe, however, that the Hybrid Method of cost allocation (Staff/102, Hellman/62-66) is superior to the Revised Protocol in some ways. The Hybrid Method retains the Hydro Endowment without the need for offsetting adjustments through the state-situs allocation of Qualifying Facility costs. The Hybrid Method assigns costs that are more closely aligned with the principle of cost-causation than does the Revised Protocol (for example, Oregon is not as exposed to the costs of meeting load growth in other states under the Hybrid Method). And it would result in lower costs to Oregon ratepayers (Staff/202, Wordley/31and 44).[11]

The Hybrid Method did assign costs in a manner consistent with cost causation. The fast-growing Eastern states would have to pay for the costs of growth and the Western hydro would naturally be allocated to the Western states without the need to offset the hydro value by an artificial assignment of QFs on a situs basis.

[10] OPUC Order No: 05-021, page 4.
[11] OPUC Order No: 05-021, page 13.

B. How the Oregon Stipulation Added Protections to the Revised Protocol

It was clear that Oregon parties and Utah parties viewed the Revised Protocol compromise differently. Utah supported it only to the degree that it would establish rates that are close to its preferred method, Rolled-In. Utah retained the right to abandon it if rates were not sufficiently close to Rolled-In. Oregon customers supported it because we were trying to establish a permanent hydro endowment. These two goals, however, were not compatible.

CUB supported the Revised Protocol only because PacifiCorp agreed to an Oregon stipulation that gave Oregon customers protection and transferred the risk of Utah abandoning the Revised Protocol to PacifiCorp. Specifically, PacifiCorp agreed that it would use the Revised Protocol in rate filings as long as it "is relied upon by the OPUC for purposes of inter-jurisdictional allocation of the Company's costs."[12] CUB believed this provided Oregon customers significant protection, because it allowed Oregon to maintain the hydro endowment as contemplated in the Revised Protocol in all rate cases until we decided to do something else.

This stipulation is attached to this testimony as Exhibit 103. It has other terms that were critical for CUB to support the Protocol.

i. The Oregon Stipulation Established the Importance of the Hydro Endowment and Made Clear That the Situs Assignment of QFs Was the Price Oregon Paid For the Hydro Endowment.

> Throughout this proceeding, Oregon Parties have made clear the importance of maintaining the Hydro-Electric Resources and Mid-Columbia Contracts for Northwest citizens. An allocation of these Resources to Oregon that is less than that contemplated by the Revised Protocol is not acceptable to Oregon Parties. In order to secure the

[12] CUB Exhibit 103, page 7.

> allocation of the Mid-Columbia Contracts that is contemplated in the Revised Protocol, Oregon Parties have accepted the allocation of the costs of Existing QF Contracts that is contemplated in the Revised Protocol.[13]

ii. The Oregon Stipulation Established Very Clearly That Oregon Customers Were Taking the Risk That Prices Could Be Higher in the Short Term, but We Were Taking This Risk Because We Believed That We Were Gaining the Long-Term Value Associated with the Hydro Resources.

> The parties to this Stipulation recognize that there is uncertainty regarding the future value of the Mid-Columbia Contracts and that it is possible that, during the remaining term of the Existing QF Contracts, the costs to Oregon customers associated with the contemplated allocation of Existing QF Contracts will exceed the benefits of the contemplated allocation of Mid-Columbia Contracts. However, the Oregon Parties are prepared to assume this risk because they expect that the contemplated allocation of Mid-Columbia Contracts will continue to provide long-term benefits to Oregon customers after the expiration of the Existing QF Contracts. Similarly, the parties to this Stipulation recognize that the addition of relicensing costs to the Company's ratebase may cause the Hydro-Electric Resources to be more costly than other market opportunities in the near term, but Oregon Parties are willing to accept responsibility for these higher near-term costs in the expectation that, as the relicensing costs are depreciated, Hydro-Electric Resources will yield long-term benefits to Oregon customers. For the foregoing reasons, it is critical to Oregon Parties that their entitlement to Hydro-Electric Resources and Mid-Columbia Contracts not be abridged at any time in the future.[14]

iii. The Oregon Stipulation Established that PacifiCorp Could Not Materially Change the Hydro Endowment Bargain.

> Notwithstanding the status of the Revised Protocol as an inter-jurisdictional cost allocation method, if any party to this Stipulation proposes a material change to the allocation methodology for Hydro-Electric Resources, Mid-Columbia Contracts or Existing QF Contracts as specified in the Revised Protocol, the proposed change should be consistent with the trade-off between near-term negative impacts of Existing QF Contracts and long-term positive impacts of Mid-Columbia Contracts and the potential near-term costs and long-term benefits of

[13] *Ibid.*, page 2.
[14] *Ibid.*, page 2.

Hydro-Electric Resources as described in Sections 4 and 5 of this Stipulation.[15].

V. The *2*010 Protocol Harms Oregon

CUB believes the 2010 Protocol makes material changes to the hydro endowment and fails to retain the trade-off between short-term costs and long-term benefits. As such, it violates the existing stipulation between PacifiCorp, Staff, CUB, and AARP.

Second, the shift from using firm rate case-tested numbers for the hydro endowment to a forecast is a material change that allows PacifiCorp to reduce the value of the hydro endowment by inflating hydro investment forecasts.

Below, I describe more fully how the 2010 Protocol materially deviates from the bargain that was struck in the Revised Protocol, and should therefore be rejected.

A. Incorporating Pre-2005 Resources Changes the Hydro Endowment in a Manner That Guarantees That Oregon customers Will Not See the Long-Term Benefits of Hydro

The bargain in the Revised Protocol was that Oregon would pay the front-loaded costs of hydro relicensing, even if that resulted in higher rates than under other methods, in exchange for the value of these hydro assets over the life of those relicensed hydro projects. This was a change from the Modified Accord, which sunset the hydro endowment as hydro facilities were relicensed.

For a hydro license, the long term is often 50 years. But the 2010 Protocol links the hydro endowment to the pre-2005 resources, which are primarily coal facilities. This means the hydro endowment will sunset based on the operating life of the pre-2005 resources. Once those plants are retired, there will no longer be a hydro endowment.

[15] *Ibid.*, page 4-5.

Linking the hydro endowment to the life expectancy of thermal units (primarily coal) in the face of climate change is a material change in the fundamental bargain that Oregon struck in the Revised Protocol. In addition, this provision creates a "poison pill" for Oregon customers who might want to advocate closing coal plants, since doing so will eliminate hydro benefits.

B. The Agreement to Use Rolled-In In Utah Is Not Compatible with the Bargain for Paying for Short-Term Resources

PacifiCorp has agreed not to use the 2010 Protocol in Utah, but instead to use Rolled-In:

> In Utah this cost allocation methodology produces results close to Rolled-In so a side agreement between the Company and Utah parties will allow Utah to utilize Rolled-In cost allocation methodology for its ratemaking purposes.[16]

Because Rolled-In allocation to Utah is not compatible with the long-term benefits that Oregon bargained for in the Revised Protocol, the 2010 Protocol with its side agreements is not designed to be consistent with this bargain. Again, this is a material change from the bargain that was negotiated as part of the Revised Protocol. The Oregon stipulation stated that if any party proposed a material change to the allocation methodology for hydroelectric resources, Mid-C contracts or existing QF contracts, that change had to be consistent with the bargain that Oregon was taking higher short-term costs in exchange for a robust hydro endowment in the long run. By agreeing to use Rolled-In as the allocation method in Utah as part of the 2010 Protocol, PacifiCorp is proposing a change in allocation to the hydro-electric resources and the Mid-C contracts that is not consistent with that bargain. For example, under that bargain the

[16] UM 1050 / PPL / 100 / Kelly / 11.

Revised Protocol allocated 100% of Priest Rapids (a Mid-C contract) to Oregon. Under Rolled-In, 40% of that contract will now be allocated to Utah.

It is also important to note that Utah's definition of Rolled-In does not apply to all resources. In the context of this case, "Rolled-In" means that Northwest Hydro-electric resources, Mid-C contracts (which were granted to the old Pacific Power based on regional preference), clean air investment (on the old Utah Power coal plants), and the costs of peakers (to meet Utah summer load) will be divided equally between the states. The cost of wind and energy efficiency, on the other hand, is largely considered a state resource. So, if Oregon requires additional investment in wind or energy efficiency, those will be Oregon's responsibility. But if Utah requires clean air investment in its coal plants, or peakers to meet summer load, that is part of our shared responsibility.

Finally, we note that according to the 2010 Protocol, it must be accepted by Utah without material changes or it will not be valid:

> The 2010 Protocol has been developed by the parties as an integrated, inter-dependent, organic whole. Therefore, final ratification of the 2010 Protocol by any of the Commissions of Oregon, Utah, Wyoming and Idaho, is expressly conditioned upon similar ratification of the 2010 Protocol by the other mentioned Commissions, without any deletion or alteration of a material term, or the addition of other material terms or conditions. Upon any rejection of the 2010 Protocol, or any deletion, alteration, or addition to its terms, by anyone or more of the four Commissions, the Commissions who have previously conditionally adopted the 2010 Protocol shall initiate proceedings to determine whether they should reaffirm their prior ratification of the 2010 Protocol, notwithstanding the action of the other Commission or Commissions. The 2010 Protocol shall only be in effect for a State upon final ratification by its Commission. The Company will continue to bear the risk of inconsistent allocation methods among the States.[17]

CUB believes that the decision by Utah to ignore the 2010 Protocol and instead use a Rolled-In methodology to set rates is a material change to the terms of the

[17] UM 1050 / PPL / 101 / Kelly / 14.

agreement. The 2010 Protocol does not allocate costs in a Rolled-In manner. CUB disagrees with PacifiCorp's claim that the Utah side deal of Rolled In is close enough to the 2010 Protocol that it does not constitute a material change. PacifiCorp's forecast of the difference between the 2010 Protocol and a Rolled-In methodology is just that, it is a forecast. And, as a forecast, it is wrong. Whether Utah's rates will be greater or lower than provided under the 2010 Protocol may be unclear, but what is clear is that Utah's rates will not be based on the 2010 Protocol. The costs associated with Hydro-electric resources, and Mid-Columbia contracts will not be allocated to Utah in a manner that is consistent with the 2010 Protocol. This is therefore a material change to the Protocol.

C. After 5 Years, Oregon Will Have to Repurchase Hydro Endowment

The 2010 Protocol is not intended to be the basis of a long-term commitment to the allocation of hydro benefits. It is simply a short term allocation of costs that tells us nothing about how costs will be allocated after 2016:

> **What does the Company envision as a process to address allocation issues post-2016?**
>
> The process would likely be similar to the one just followed. For example, the post-2016 issues would likely first be reviewed at the 2015 Standing Committee annual meeting. From that review, the Standing Committee would agree on appropriate next steps as far as issue identification and analysis. Standing Committee efforts would need to be designed to culminate in time for formal commission proceedings to occur with decisions well in advance of January 1, 2017. It is also possible that the states would agree to extend the terms of the 2010 Protocol to apply beyond calendar year 2016.[18]

The Oregon Stipulation contained a bargain that requires Oregon to receive long-term hydro benefits. The 2010 Protocol is a significant change, because it does not contain any basis for long term allocation. It is simply runs out in 5 years and any hydro benefits received after that will have to come from Oregon negotiating with other states.

[18] UM 1050 / PPL / 100 / Kelly / 14.

The negotiations at the end of 2010 Protocol would, however, be different than the current negotiations. Utah will be coming off of 5 years of using Rolled-In as its calculation of costs. Any post-2016 agreement will be built upon a base that allows Utah to continue using Rolled-In, and this will require either reducing hydro benefits to Oregon, offsetting hydro benefits to Oregon, or simply eliminating the hydro endowment altogether.

The bargain that Oregon struck in the Revised Protocol involved short-term costs and long-term benefits. Over time the benefits of that bargain will grow and it will increasingly become incompatible with Utah's version of "Rolled-In" assignment of costs. Over time Oregon will be asked again and again to agree to off-sets that are designed to prevent the real benefits of this bargain from flowing through to Oregon customers.

D. In the Short Term, Oregon Loses Some of the Value of the Hydro Endowment

The 2010 Protocol makes several changes to the hydro endowment which will likely reduce its value to Oregon:

> Besides using a Rolled-In allocation methodology as the starting point, a significant change relates to the Embedded Cost Differential (ECD). The scope of the ECD has been reduced and limited, using a comparison of embedded costs based on resources in place on the Company's system prior to 2005. The ECD calculation has been based on projected pre-2005 resource costs and the value allocated to each state is fixed and levelized over the term of the 2010 Protocol. For the duration of the 2010 Protocol a fixed dollar amount per year deviation would be applied to each state's revenue requirement under the Rolled-In allocation methodology. The deviation is composed of two parts; a situs adjustment associated with the surcharge imposed under the Klamath Hydroelectric Settlement Agreement to Oregon and California with a corresponding credit to the other states, and the fixed levelized ECD.[19]

While PacifiCorp's analysis claims this will only reduce the value of the hydro endowment a little (rates will be about ½ of 1% higher by 2016) as compared to the Revised Protocol, this claim is not reliable. The unreliability arises because the 2010 Protocol is based on a fixed 5 year forecast of the value of the hydro endowment whereas the Revised Protocol uses actual data from ratecases to adjust the value of the hydro endowment in each rate case. The real difference between the two methods is unknown.

CUB has already shown that the change to using pre-2005 resources will eliminate the hydro endowment over the long term. In the short term this also will likely reduce the value of the hydro endowment, as the pre-2005 resources are generally cheaper than the post-2005 resources. Pre-2005 resources have been further depreciated and are largely coal-fired. Post-2005 resources are largely undepreciated and are largely natural gas and wind resources. The switch to pre-2005 resources is designed to reduce the value of the hydro endowment.

[19] UM 1050, PETITION FOR APPROVAL OF AMENDMENTS TO REVISED PROTOCOL ALLOCATION METHODOLOGY, page 5.

E. The Use of a Fixed Allocation Based On a Forecast Is a Terrible Idea

During the negotiations over the Revised Protocol, CUB largely ignored most of the Company's forecasts and modeling, after we concluded that the forecasts were not reliable. The modeling that was done during the MSP negotiations contained huge costs associated with hydro relicensing which had a significant impact on the forecasted value of the hydro endowment, but could not be verified.

During those negotiations, CUB concluded that hydro relicensing costs were likely being overestimated and that the value of the hydro endowment was likely greater than PacifiCorp forecasted. CUB was proved correct in that the hydro relicensing costs were overestimated, though that benefit was partially offset by lower gas costs.

CUB Exhibit 105 shows the hydro relicensing costs that were used in the MSP forecast study that was the basis for the Revised Protocol versus actual costs based on the Company's Results of Operations Reports.

Year[20]	MSP Forecast	Actual Results	Variance
2005	12,687,741	10,252,812	24%
2006	14,560,192	9,323,327	56%
2006/2007	14,136,849	11,807,181	20%
2007/2008	24,355,166	13,499,557	80%
2008/2009	41,400,634	15,326,494	170%
2009/2010	63,954,293	17,600,671	263%
Total	**171,094,874**	**77,810,042**	**120%**

[20] We note that PacifiCorp changed fiscal years during this time, so the years do not perfectly line up.

This shows that PacifiCorp systematically overestimated the cost of hydro relicensing. Over the course of the 6 years, the forecast became increasingly inaccurate and the total variation was nearly $100 million of revenue requirement. If the 2010 Protocol methodology had been in place during the last 6 years, the overblown estimate of hydro relicensing costs would have caused Oregon rates to be significantly greater than the rates that we did pay.

One problem with forecasts is that the goal of the Company during MSP negotiations is to come up with a forecast that will please Utah by being close to Rolled-In and, at the same time, maintain the robust hydro endowment to please Oregon. Because Oregon agreed to pick up hydro relicensing costs, even if those costs caused rates to be higher, inflating hydro relicensing costs makes a compromise solution easier for PacifiCorp. It reduces the value of the hydro endowment so Utah is closer to Rolled-In rates, and it does so in a manner to which Oregon cannot object. Finally, because hydro relicensing negotiations are highly confidential,[21] there is no way to find publicly-available numbers to verify PacifiCorp's projections.

PacifiCorp has an incentive to overestimate hydro relicensing costs because it helps lead to an agreement. Using these unverified numbers as the basis for setting rates, as the 2010 Protocol proposes, would be irresponsible.

F. The Company Has Under Estimated Cost of MACT Standards

The other side to the incentive to overestimate the cost of hydro relicensing is an incentive to underestimate the cost of capital investment on the pre-2005 thermal plants. CUB believes that PacifiCorp is underestimating these costs in its 2010 Protocol.

[21] See UE 219.

In LC 48 there was a great deal of discussion of the pending Maximum Achievable Control Technology (MACT) standards that will be issued later this year by the EPA. A good summary of what is expected was provided by David Schlissel, a consultant working for the Sierra Club in that docket:

> *New Jersey v. EPA* (Feb. 8, 2008), the U.S. Court of Appeals for the DC Circuit vacated CAMR and told EPA that it must promulgate a standard for electric generating units under the more stringent air toxics provisions of the Clean Air Act, and that such rule must cover all toxic air pollutants emitted in significant amounts by coal fired power plants - not just mercury.
>
> EPA was sued when it failed to satisfy this requirement by the deadline set in the statute.[41] The binding settlement of that suit requires EPA to promulgate a new air toxics rule for coal-fired power plants by November 16, 2011**.**
>
> Existing sources at the time that an applicable MACT standard is made effective are required to comply with the standard by an EPA-set compliance date that is "as expeditiously as practicable, but … no … later than 3 years after the effective date of such standard."[42] After that date, it is illegal to operate out of compliance with the federal standard. The law does not allow exemptions from these requirements. There are some compliance extensions available for very specific grounds and for very limited time periods (i.e. one year). The law is clear that extensions outside these narrow circumstances are illegal. In *Natural Resources Defense Council v. EPA*, the D.C. Circuit rejected EPA's argument that it could grant sources additional time to comply, finding that "Congress has … not provided EPA with authority … to extend the compliance date [beyond specific circumstances enumerated in the statute] …."
>
> When EPA issues the air toxics rule, it is reasonable to expect that it will require installation and operation of a sulfur dioxide scrubber that will reduce hydrochloric acid (HCL) and hydrogen fluoride (HF). The rule could require installation and operation of a Selective Catalytic Reduction (SCR) unit to control dioxin, furans, volatile organic compounds, organic hazardous air pollutants, and ammonia. An SCR can also maximize oxidation of mercury, a significant co-benefit for mercury reduction through scrubbing. Thus, the new air toxics rule should not be viewed as just pushing limits lower, but rather as an opportunity for EPA to mandate other technology options currently in use, either alone or in combination with sorbent injection. These other options are available and deployed on many coal-fired power plants, and can achieve higher removal efficiencies for a wider range of air toxics than sorbent injection alone. The costs for

> compliance with these new air toxics standards either equal or exceed the costs now contemplated for compliance with the BART rule and the reasonable further progress requirements, but speed up the required investments significantly.
>
> 41 *American Nurses Association v. EPA,* No. 1:08-cv-02198 (D.D.C.).
> 42 42 U.S.C. § 7412(i)(3)(A).[22]

The expectation that the MACT standards will be far-reaching and expensive is not limited to Sierra Club. During LC 48, CUB submitted an analysis of MACT standards by BernsteinResearch which has similar conclusions.

> Within three years of issuance of the final rule (i.e., by November 2014), the Clean Air Act stipulates that sources of hazardous air pollutants must comply with MACT standards. While one-year extensions may be granted on a case-by-case basis, 2015 may be thought as the year by which all U.S. coal fired fleet power plants must have installed maximum achievable control technology for hazardous air pollutants.
>
> --Referred to as "air toxics," these hazardous air pollutants include mercury and other toxic metals, such as arsenic, lead, and selenium; acid gases such as hydrogen chloride, hydrogen fluoride, and hydrogen cyanide; and organic air pollutants including organic hydrocarbons and volatile organic compounds. [23]

In its study that is the basis for the hydro endowment, PacifiCorp includes additional clean air investments in pre-2005 power plants. CUB asked PacifiCorp for its forecast of these costs. The answer is supplied as Confidential Exhibit 106.

What is striking about these forecasts is that the largest amount of costs being forecast occurs in 2012, even though the Company won't know the requirements of MACT until late 2011. In addition, the investments go down in 2015, which is the year of compliance when the MACT investments would need to be used and useful.

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[22] LC 48, Comments on PGE 2009 Integrated Resource Plan, Schlissel Technical Consulting, Inc. Page 31
[23] LC 48 Comments of the Citizens' Utility Board of Oregon, Attachment B.

CUB asked PacifiCorp about its view of the MACT standards and found that PacifiCorp's projections of costs related to clean air are based on an assumption that MACT will only impact mercury emissions. CUB believes that it is not that PacifiCorp does not expect MACT to apply to other pollutants, but rather that PacifiCorp does not have insight into what other pollutants should be modeled. [24]

> In line with current industry information, the Company's current expectations for reduction requirements under mercury MACT are between 85 to 95% removal and/or the establishment of Hg emission limits between 0.5 and 1.3 lb/TBtu. There is little, if any, industry information available to provide insight into the EPA's intentions regarding MACT levels for other HAPS, including acid gases. Certain industry groups have surmised that EPA may ultimately require scrubber technology as a surrogate control mechanism for HAPS MACT compliance. The Company's current projections for incremental control technology installations are limited to mercury MACT compliance, at this point in time.

Therefore, PacifiCorp's cost projections do not assume that scrubbers, baghouses, or any other non-mercury control technologies will be required under MACT. CUB did ask PacifiCorp about the cost of adding scrubbers to its fleet. For Dave Johnston Units 1 and 2, the Company has no detailed estimates, but instead supplied "order of magnitude" estimates.[25] Without reliable analysis of the investments that will likely be required under MACT for gases other than mercury, it is likely that PacifiCorp is underforecasting the investments that will be necessary to its pre-2005 coal fleet.

When forecasting capital investments as part of MSP, PacifiCorp has an incentive to inflate the cost of hydro relicensing, as CUB has demonstrated that the Company has done, and underestimate the cost of clean air investment on coal plants, as the Company

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[24] CUB Exhibit 107, page 2.
[25] *Ibid.*, page 1.

also seems to be doing. Using this fixed forecast to set rates for the next five years is therefore not reasonable.

G. The 2010 Protocol Violates the Used and Useful Principle

This use of forecasting and fixing the hydro endowment violates the established principle of used and useful ratemaking. When hydro investments are forecasted, they function very much like ratebase resources. The capital investment is assigned a pre-tax ROR and assumed to be amortized over its useful life, with the year-by-year revenue requirement added to the ECD as an expense. This hydro relicensing expense has a "one-to-one impact on the value of the hydro differential."[26]

This creates two serious problems with the used and useful principle. First, by forecasting these costs over the next five years and then adding them to rates today, PacifiCorp intends to charge Oregon customers for their share of hydro investment before that investment becomes used and useful. Secondly, because this forecast has been demonstrated to be inflated, PacifiCorp intends to charge customers for investments that will never be used and useful.

Undoubtedly, PacifiCorp will argue that because the expense derived from this investment is not included in the Company's revenue requirement, it is not a violation of the used and useful principle. Instead of adding this cost to PacifiCorp's revenue requirement, this cost is used to shift money from one state to another. But CUB believes the used and useful principle applies because this proceeding is about rates. Customers

[26] CUB Exhibit 108.

are, on a dollar-for-dollar basis, seeing the rate effects of capital investments that are not used and useful.[27]

H. What Happens When Rate Case Forecasts Have Significant Variations From 2010 Protocol?

If the Commission approves the 2010 Protocol, it is inevitable that Oregon will face a rate case in the future that contains costs and benefits that are not included in the five year fixed assignment of hydro endowment benefits. What happens in 2014 if a rate case shows that the capital investment in hydro relicensing that was forecast by PacifiCorp did not materialize? What happens if the rate case includes a significant capital investment in clean air compliance that was not included in the calculation of the hydro endowment? The evidence necessary for the revenue requirement would show that the hydro endowment was flawed and undervalued. But, under the 2010 Protocol, the Commission would have to ignore this evidence because the hydro endowment if fixed.

I. Loss of Value of the Oregon Stipulation

CUB only supported the Revised Protocol because it was accompanied by an Oregon stipulation with PacifiCorp that described the bargain of the Revised Protocol from an Oregon perspective and made clear that the Company could not abandon the Revised Protocol. In effect, the Company was taking the risk that Utah would not be willing to continue to operate under the Revised Protocol.

But the 2010 Protocol is different. It does not even pretend to retain long-term benefits for Oregon customers. It does not even pretend to be the basis of a long-term

[27] We note that ORS 757.355, the codification of the "used and useful doctrine" in Oregon statues clearly applies to rates not revenue requirement and states that customers cannot be charged "directly or indirectly" for investments "not presently used for providing service to the customer." CUB intends to address the legal status of this forecasting in its Opening Brief.

allocation methodology. Adoption of the 2010 Protocol means Oregon loses the long-term bargain contained in the Oregon Stipulation.

While CUB believes that PacifiCorp is violating the Oregon Stipulation by proposing the 2010 Protocol that materially changes the bargain that was the Revised Protocol, we still believe there is value in the Oregon Stipulation. However, if Oregon were to adopt the 2010 Protocol, the protections in the Oregon Stipulation would be lost and PacifiCorp would be free to work to undermine the hydro endowment bargain even more than the 2010 Protocol has done.

J. Different Treatment between Pre-2005 and Post-2005 Resources Will Impair Resource Planning

In its filing PacifiCorp claims that the 2010 Protocol was supposed to prevent the "Utah issue" from impairing "integrated system planning." Unfortunately, CUB believes that the 2010 Protocol will in fact significantly impair system planning.

One of the primary issues PacifiCorp will have to address in future IRPs is the future of coal-fired generation as this country faces up to addressing climate change. How much will the Company need to invest in pollution controls at coal plants? Should the Company's coal-fired plants be shut down in favor of investment in cleaner alternatives? This issue is hanging over PacifiCorp's coal fleet and will be a significant issue in future IRPs. For those of us who participated in PGE's recent IRP, this is a serious undertaking. Under the 2010 Protocol, this analysis will be impaired. Because the 2010 Protocol treats investments in pre-2005 plants differently from new facilities, PacifiCorp states will not all be aligned in their interests in least cost planning. For Oregon, shutting down coal plants that are expensive due to clean air and carbon regulatory costs may not make financial sense because that can cause a devaluation of the hydro endowment, whereas the replacement power resource will be post-

2005 and considered Rolled-In. For Utah, the consideration would be reversed if rates were set on the basis of the 2010 Protocol rather than a side agreement. Idaho will be in the position that Utah would be if Utah did not have a side agreement.

It is likely that there will be carbon regulatory costs in the future. As these costs grow, it will be necessary for IRPs to compare the cost of carbon regulation with the cost of closing coal facilities and replacing them with cleaner resources. This analysis will be impaired because the two choices are allocated differently among states, so there may be a difference between which option is least cost to a particular state and which option is least cost to the system as a whole.

VI. MEHC's Inability to Control PacifiCorp's Costs

It is not surprising that Utah is pushing to change cost allocation as a way to offset the upward pressure that is resulting from Mid-American Energy Holding Company's (MEHC) inability to control costs and meet the expectation that MEHC created when it purchased PacifiCorp.

A. MEHC claimed that it would control costs.

When MEHC was applying for OPUC approval to purchase PacifiCorp, it stated that rates were expected to increase by 4%/year under ScottishPower control.[28] MEHC claimed that it could reduce PacifiCorp's revenue requirement by $201 million between 2006 and 2015. Year by year projections had the following revenue requirement benefits for Oregon[29]:

[28] UM 1209 / PPL / 312 / Gale / 6.
[29] UM 1209 / PPL / Exhibit 313.

Year	Oregon Revenue Requirement Reduction
2007	3.4 million
2008	7.6 million
2009	4.8 million
2010	14.1 million

This promise came in response to CUB's concern that MEHC had plans to invest a great deal of money in PacifiCorp but seemed unconcerned about the rate increases associated with that investment:

> **Mr. Jenks claims that MEHC hasn't analyzed the effect of its plans on customer rates and has generally not addressed the issue of rates. Mr. Jenks provides an excerpt of an exhibit that he claims demonstrates this lack of attention to the impact on rates. How do you respond?**
>
> A. Prior to the filing of the Joint Application, MEHC performed a high-level estimate of changes to overall revenue requirements to ensure there would not be a negative impact on rates. This was the basis for the statement in my revised direct testimony at pages 28, line 23, "We do not expect that the commitments we are offering will cause an increase in the percentage discussed in PacifiCorp witness Johansen's testimony." In response to issues raised by Mr. Jenks and others in their testimony, MEHC has continued to refine that analysis, the results of which are included in Exhibit PPL/313.
>
> **Q. Please describe Exhibit PPL/313.**
>
> A. This exhibit demonstrates that the implementation of MEHC's commitments will result in an overall reduction in PacifiCorp's projected revenue requirement of approximately $201 million on a net present value basis, measured over the period of 2006-2015. These savings, which are MEHC's best current estimate, are presented both in annual form and as a net present value and are derived by comparison to the confidential PacifiCorp business plan ScottishPower provided to MEHC in due diligence.[30]

[30] UM 1209 / PPL / 312 / Gale / 2.

Both CUB witness Jenks and CADO-OECA witness Abrahamson express apprehension about the impact of MEHC's investment commitments on rates, implying an ominous lack of concern on MEHC's part regarding customer rate levels. Mr. Abrahamson at page 9, lines 12-14, also attributes PacifiCorp's planned average 4% annual rate increases to MEHC's investment commitments. Please explain.

We understand customers' concerns about incremental rate increases and prepared Exhibit PPL/313 to address and dispel these concerns. In this regard, it is important to clarify that the average annual 4% rate increase mentioned by Mr. Abrahamson is not the result of MEHC commitments but instead reflects PacifiCorp's preexisting need for annual rate increases averaging around 4% total company over ten years based, regardless of whether this transaction is approved. As witness Johansen testifies, these projected increases, which are based upon then-current market prices, are part of the plan by ScottishPower and PacifiCorp to enable PacifiCorp to meet its capital investments needs and earn its authorized return. The investments proposed by MEHC are not projected to increase the net revenue requirements of PacifiCorp; rather, as indicated 1 by Exhibit PPL/313, MEHC's investments are projected to reduce net revenue requirements over time.[31]

B. Rates Are Going Up Much Faster Than Was Promised

CUB was concerned that MEHC was purchasing PacifiCorp as an investment vehicle; the investments it intended to make would push rates up significantly, and MEHC had done little analysis and showed little concern about the rate impact of its investments.[32]

MEHC claimed that while ScottishPower expected rates to go up 4% per year, and that between 2006 and 2015 it would keep rates $201 million less than rates would be under ScottishPower ownership. In reality, however, rates since 2005 for Oregon have gone up considerably more than the 4% that ScottishPower forecasted.[33]

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[31] UM 1209/PPL/312/Gale/6.

[32] UM 1209, Comments of the Citizens' Utility Board, pages 2-12.

[33] The residential rates list are from http://www.eia.gov/cneaf/electricity/esr/backissues.html, except the 2010, which come from the OPUC webside (http://www.puc.state.or.us/PUC/news/2010/2010029.shtml) listing a 11.5 % residential increase for PacifiCorp in 2010 and the Utah PSC website

	Oregon Residential Rates	% increase	Utah Residential Rates	% increase
2005	6.31		7.41	
2006	6.83	8.24%	7.48	0.94%
2007	7.84	14.79%	8.22	9.89%
2008	8.38	6.89%	8.3	0.97%
2009	8.39	0.12%	8.56	3.13%
2010	9.35	11.50%	8.75	2.26%
Total		48.25%		18.13%

These figures represent actual retail rates, not forecasts of power supply costs. As such, they should include credits Oregon residential customers receive from BPA for the Residential Exchange. Today, Oregon customers pay higher rates than Utah. It is clear that Oregon customers have been hit hard by MEHC ownership of PacifiCorp, while Utah has fared considerably better.

To the degree that these rate increases represent Oregon agreeing in the Revised Protocol to take on higher costs of situs assignment of QFs and front-loaded costs of hydro relicensing, then it is clear that Oregon has paid considerably for the right to have long term hydro benefits and will be significantly harmed by reductions in that long-term flow of hydro benefits. To the degree that these costs represent the response of the Company to Utah's complaining about rates and threatening to withdraw from the Revised Protocol, then it is clear that Oregon should also be making noise.

Regardless of the cause, this disparity in rates shows that Oregon is not in any position to take on higher rates in order to allow PacifiCorp to offer Utah lower rates.

(http://www.psc.utah.gov/utilities/electric/Rate%20Changes%20Electric%201-11-11.pdf) showing a 3.07% increase and a 0.81% decrease for Utah customers.

VII. Oregon's Options

Five years ago, the Revised Protocol was a compromise between Utah, which wanted to have an allocation method based on Rolled-In methodology, giving it a large share of Northwest hydro resources, and Oregon, which wanted structural separation of the East and West Control Areas.

That compromise has failed to satisfy Utah, which has won an agreement from PacifiCorp to use a Rolled-In methodology. It seems that Oregon now has three options:

i. Agree To the 2010 Protocol

This means a small rate hike to help fund Utah's Rolled-In methodology. More importantly, it means more significant rate hikes in the future. Oregon took on front-loaded hydro relicensing costs and costs associated with situs assignment of QFs in order to secure a long term hydro endowment. As the front-loaded costs are depreciated, the benefit of this bargain will grow. In order to allow Utah to proceed with a Rolled-In methodology, larger and larger costs will have to be found and allocated to Oregon to offset this growing hydro benefit. The cost of funding Rolled-In for Utah will only increase for Oregon as compared to the Revised Protocol or Structural Separation.

If Oregon adopts the 2010 Protocol, there is little doubt that Oregon customers will be asked to make larger concessions in 5 years. By that time Utah will have experienced five years of using the Rolled-In methodology and will be assured that, as PacifiCorp's largest state, it has the power to impose its preferred cost allocation methodology on the Company's other states. PacifiCorp will know from experience that when push comes to shove, Oregon will make the necessary concessions to be part of the team. Under this scenario, the fundamental bargain of the Revised Protocol is dead.

ii. Continue To Use the Revised Protocol

If the Commission does not recognize an alternative approach, the Company will continue to use the Revised Protocol. Under the Revised Protocol and the 2010 Protocol, the Company takes the risk that different jurisdictions choose different methods. If Oregon does not believe that using the 2010 Protocol in Oregon, California, Wyoming, and Idaho, with Utah using Rolled-In and Washington using its own methodology, is in the best interest of Oregon customers, Oregon can simply reject the 2010 Protocol and continue to support the Revised Protocol. In other words, Oregon customers can stick to the compromise we agreed to support.

iii. Move towards Structural Separation

As an alternative to being the last state clinging to a compromise that no other state supports, Oregon can implement its preferred methodology: Structural Separation. While PacifiCorp dismisses this in its testimony, noting that no state is advocating for it, that it would have greater costs overall, and that its results are based on assumptions (as if the 2010 Protocol isn't based on assumptions about hydro relicensing, clean air investment, and other major issues), Structural Separation should not be dismissed. Structural Separation has been Oregon's preferred method; just as Rolled-In is Utah's preferred method. As Commissioner Savage stated in his concurring opinion five year ago, it is the method that is most consistent with cost causality. It will reduce rates for Oregon customers and it will improve Oregon's ability to address climate change.

1. Cost causality.

Oregon, more than other states, has lived up to the principle of cost causality. We recognize that if Oregon wanted the benefits of Northwest regional preference, Oregon had to pay the costs of relicensing and the cost of Klamath Dam removal. Oregon passed a Renewable Energy Standard (RES) and Oregon agreed that its customers should pay the above market costs of the renewables that it is forcing PacifiCorp to build.

The problem is that other states are not taking their share of the costs that they place upon the system and Oregon, while agreeing to take on the costs it is placing on the system, is not getting full credit for those costs or the power generated with those costs.

Oregon has agreed to pay for the costs of hydro relicensing and for the costs of the renewable energy required to meet the RES. But Oregon is not getting full credit for paying for these costs. As Oregon adds renewables and reaches a level of 25% of our energy being provided by eligible renewables, our share of the coal plants and their costs associated with clean air compliance and carbon regulation should decline. Under the 2010 Protocol, however, those costs are Rolled-In. Oregon is paying for a cleaner portfolio of resources, but is still being allocated a Rolled-In share of the old dirty resources. In theory the clean air and carbon costs should be somewhat offset by the hydro endowment (those costs are compared to hydro costs with a credit flowing to customers through the ECD), but that does not happen in a system where those costs are underforecasted for the purpose of the ECD, but not for the purpose of setting rates.

While Oregon has agreed to pay for the cost of the RES and the costs of our energy efficiency programs, the 2010 Protocol shifts responsibility for seasonal resources, which are needed to serve summer loads in the Southwest, to all states. The theory behind Oregon picking up the costs of the RES and energy efficiency was that a state should pick up the costs that its public policy decisions place on the utility. The need for summer peaking resources is not unrelated to public policy, to land use planning, to housing and appliance codes, or to energy efficiency requirements, and it should be borne by each state individually.

Pursuing the path of structural separation will allow Oregon to work with PacifiCorp to find a method to allocate costs that truly follows the principle of cost causation.

2. Lower Rates for Oregon Customers

Begin Confidential Information

PacifiCorp's confidential workpapers show that structural separation would lower Oregon's rates by [redacted] in 2011 and [redacted] by 2015.[34]

End Confidential Information

Oregon customers of PacifiCorp have suffered through a series of significant rate hikes in the last few years. Any approach that offers rate relief while sticking to the principles of cost causality should be considered.

3. Carbon Planning

It is increasingly clear that sharing coal-fired power plants with the states in the Eastern Control Area will inhibit Oregon's ability to address carbon and climate change. Structural Separation would allow Oregon, Washington, and California to pursue a different climate policy towards coal generation than that pursued by the states of Idaho, Wyoming, and Utah.

VIII. CUB's Recommendations

CUB recommends that the PUC take the following actions in this docket:

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[34] CUB Exhibit 109.

A. Reject the 2010 Protocol as an Allocation Methodology

It is clear that the 2010 Protocol, which is being proposed for Oregon, Idaho, California, and Wyoming, represents a material change to the bargain that was struck by Oregon parties with regards to long term hydro benefits. As such, it should be rejected.

B. Adopt Structural Separation as Oregon's Approach to Allocation

CUB recognizes that adopting Structural Separation, while benefiting Oregon ratepayers, will be seen by other states as provocative. But since the Revised Protocol, which Oregon adopted as a compromise, is no longer the basis for cost allocation across the system, Oregon, like Utah, should implement its own preferred approach. Structural Separation has been, and remains, Oregon's preferred approach. The Commission should order PacifiCorp to begin work with Oregon stakeholders to develop a structural separation methodology that can be implemented in its next general rate case.

C. If The PUC Is Unwilling to Adopt Structural Separation, Oregon Should Stick to Using the Revised Protocol

The only reasonable alternative to Structural Separation is to continue to stick to the compromise that was struck five years ago. While the bargain the parties struck then is threatened by the 2010 Protocol, Oregon can continue to stick to that bargain and give Oregon customers the long term benefits associated with regional hydro facilities.

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 400
Portland, OR 97205

EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 196, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, and UM 1209. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

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

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

Attachment CUB 28

Actual Oregon Existing QF Contracts ECD	Mar-05	Mar-06	Dec-06	Dec-07	Dec-08	Dec-09
Situs	32,092,841	28,601,279	24,939,126	27,011,777	27,136,376	27,626,514
SG	(14,117,152)	(14,408,005)	(12,425,721)	(12,003,806)	(11,474,153)	(11,596,399)
	17,975,689	14,193,273	12,513,404	15,007,971	15,662,223	16,030,115

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1050

In the Matter of PACIFICORP Requesting to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol

STIPULATION

PARTIES

1. The parties to this Stipulation are PacifiCorp (or the "Company"), the Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB") (collectively "Oregon Parties"), and AARP.

BACKGROUND

2. As a result of discussions among representatives of PacifiCorp, Oregon, Utah, Washington, Idaho, and Wyoming regarding issues arising from PacifiCorp's status as a multi-jurisdictional utility, the Company has proposed interjurisdictional cost allocation methods that are embodied in a document titled the "Revised PacifiCorp Inter-Jurisdictional Cost Allocation Protocol" (the "Revised Protocol"). PacifiCorp has asked that the Public Utility Commission of Oregon (the "OPUC") and the utility commissions of the other jurisdictions in which it operates, ratify the Revised Protocol and use its allocation methodology in future regulatory proceedings. A copy of the Revised Protocol is attached as Exhibit A to this Stipulation. Capitalized terms used in this Stipulation are to have the same meaning as those used in the Revised Protocol and as set forth in its Appendix A.

3. Included in the provisions of the Revised Protocol are those specifying how PacifiCorp's Hydro-Electric Resources, Mid-Columbia Contracts, and Existing QF Contracts will be allocated among the States.

4. Throughout this proceeding, Oregon Parties have made clear the importance of maintaining the Hydro-Electric Resources and Mid-Columbia Contracts for Northwest citizens. An allocation of these Resources to Oregon that is less than that contemplated by the Revised Protocol is not acceptable to Oregon Parties. In order to secure the allocation of the Mid-Columbia Contracts that is contemplated in the Revised Protocol, Oregon Parties have accepted the allocation of the costs of Existing QF Contracts that is contemplated in the Revised Protocol.

5. The parties to this Stipulation recognize that there is uncertainty regarding the future value of the Mid-Columbia Contracts and that it is possible that, during the remaining term of the Existing QF Contracts, the costs to Oregon customers associated with the contemplated allocation of Existing QF Contracts will exceed the benefits of the contemplated allocation of Mid-Columbia Contracts. However, the Oregon Parties are prepared to assume this risk because they expect that the contemplated allocation of Mid-Columbia Contracts will continue to provide long-term benefits to Oregon customers after the expiration of the Existing QF Contracts. Similarly, the parties to this Stipulation recognize that the addition of relicensing costs to the Company's ratebase may cause the Hydro-Electric Resources to be more costly than other market opportunities in the near term, but Oregon Parties are willing to accept responsibility for these higher near-term costs in the expectation that, as the relicensing costs are depreciated, Hydro-Electric Resources will yield long-term benefits to Oregon customers. For the foregoing reasons, it is critical to Oregon Parties that their entitlement to Hydro-Electric Resources and Mid-Columbia Contracts not be abridged at any time in the future.

6. Oregon Parties have been concerned that relatively faster-growing States cause other States to unreasonably support the costs associated with that faster load growth. Load-Based Dynamic Allocation Factors cause costs to be shifted to relatively faster-growing States. However, in order to insulate slower-growing States from the consequences

of faster load growth in other States, rates in relatively slower-growing States should incorporate relatively current Load-Based Dynamic Allocation Factors, which reflect an appropriate level of relative cost responsibility.

AGREEMENT

7. The undersigned parties hereby stipulate and agree that they will support the ratification of the Revised Protocol by the OPUC and that they will file and defend testimony supporting the use of the Revised Protocol as appropriate. Except as otherwise provided below, PacifiCorp agrees that, as long as the Revised Protocol, or any amended version of the Revised Protocol recommended by the MSP Standing Committee, is relied upon by the OPUC for purposes of inter-jurisdictional allocation of the Company's costs, all PacifiCorp's general rate case filings in Oregon will be based upon same. Except as otherwise provided below, the Oregon Parties agree that, until such time as the Revised Protocol is amended in accordance with its terms, they will support the use of the Revised Protocol for allocating costs among PacifiCorp's jurisdictions.

8. Should the benefits or detriments to Oregon customers of the contemplated allocations as specified in the Revised Protocol, or any amended version of the Revised Protocol recommended by the MSP Standing Committee, no longer produce results that are just, reasonable and in the public interest, any party to this Stipulation may propose amendments to the Revised Protocol or propose to the OPUC that the OPUC depart from its terms, so as to produce results that are just, reasonable and in the public interest.

9. Notwithstanding the status of the Revised Protocol as an inter-jurisdictional cost allocation method, if any party to this Stipulation proposes a material change to the allocation methodology for Hydro-Electric Resources, Mid-Columbia Contracts or Existing QF Contracts as specified in the Revised Protocol, the proposed change should be consistent with the trade-off between near-term negative impacts of Existing QF Contracts and long-term positive impacts of Mid-Columbia Contracts and the potential near-term costs and long-

term benefits of Hydro-Electric Resources as described in Sections 4 and 5 of this Stipulation.

10. As provided for in Section XIII C of the Revised Protocol, a party's initial support of the Revised Protocol will not bind that party in the event that unforeseen circumstances cause that party to conclude that the Revised Protocol no longer produces just and reasonable results. To allow Oregon Parties to monitor the impacts of the Revised Protocol, the Company's annual reports of operation, and general rate case filings filed with the OPUC for the ten years following the OPUC's ratification of the Revised Protocol shall include calculations of the Company's Oregon revenue requirement under both the Revised Protocol and the Modified Accord methods, and shall include and adequately explain all adjustments, assumptions, work papers and spreadsheet models used by the Company in making such calculations. Such annual reports shall also include forecasts of Load-Based Dynamic Allocation Factors for the Company fiscal year subsequent to the reporting period.

11. In consideration of the concerns set forth in Section 6, the parties to this Stipulation agree that following Commission ratification of the Revised Protocol, and as long as Load Based Dynamic Allocation Factors are relied upon by the OPUC for allocating costs of New Resources:

(a) If the Company's annual report of operations demonstrates that the Company's return on equity for its Oregon operations, including Type I and Type II adjustments, is 200 basis points or more above the most recently authorized rate of return in Oregon, and

(b) Oregon's Load-Based Dynamic Allocation Factors are forecasted to decline in the fiscal year subsequent to the reporting period, then:

(c) The Company will file within 90 days to establish a tariff rider that credits to Oregon customers the difference between the results of operations as filed and the results of operations restated using the forecasted Load-Based Dynamic Allocation Factors for the fiscal year subsequent to the reporting period.

(d) The tariff rider will remain in effect until the earlier of:

(i) the effective date of a rate change from a general rate proceeding, or

(ii) one year from the effective date of the tariff rider.

(e) The Company's annual report of operations as provided for in subsection (a) shall not include the effects of any tariff rider pursuant to this section.

12. Within 30 days following the date that the Revised Protocol is finally ratified, as contemplated in Section XIII D of the Revised Protocol, the Company shall initiate efforts with each Commission that has finally ratified the Revised Protocol to organize the MSP Standing Committee. Within 90 days of such final ratification of the Revised Protocol, the Company shall file with each Commission that has finally ratified the Revised Protocol a proposed budget sufficient to reasonably fund the appointment of the Standing Neutral and the activities described in Section XIII B of the Revised Protocol for a 12-month period.

13. If the Revised Protocol is ratified by the Commission, if so requested by the Commission within 90 days of such ratification, PacifiCorp will make a filing in Oregon for the purpose of changing rates so as to implement the Revised Protocol. Nothing in this Stipulation shall otherwise alter or abridge PacifiCorp's right to initiate Oregon rate proceedings when it deems appropriate to do so.

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CUB
Spring 1998
THE BEAR FACTS
Citizens' Utility Board of Oregon...because the utilities bear watching

Electric Deregulation Threatens Northwest Consumers

Deregulation of the electric industry—it's happening all around us:

- California launches a bold experiment in energy deregulation later this year.
- Several other states have recently passed laws committing them to electric deregulation.
- Large energy companies are lobbying Congress to require all states to deregulate their electric utilities.
- Enron, the parent company of PGE, wants broad deregulation in Oregon by August of this year.
- Hillsboro, Sandy, Oregon City and St. Helens are already participating in a deregulated electric marketplace as part of an Enron/PGE test in Oregon.

What's going on and who's going to benefit?

The answer to either question depends on where you live. In the states with high energy rates (per kilowatt hour):

- California—11.6¢
- New Hampshire—13.5¢
- Maine—12.5¢
- Rhode Island—11.5¢

advocates of electric deregulation hope that competition will lower electric rates. In some states (California, Massachusetts, Pennsylvania), utility companies are even guaranteeing at 10% rate reduction after deregulation goes into effect.

But if you live in the cheap energy states of the Northwest:

- Oregon—5.5¢
- Washington—5.0¢
- Idaho—5.3¢

there really is no financial benefit to deregulation for most consumers. In fact, electric rates are projected to rise 20-30%, according to a new study by the Federal Energy Information Agency.

So why are we considering a plan that will raise our rates?

CUB believes that the real agenda behind deregulation is deregulation of utility profits. For example, under deregulation, a Northwest utility can take low-cost (hydro) resources currently used to serve Oregon customers and can sell that power at a much higher rate in California. In fact, they can label the power "clean, green and renewable" and sell it for a premium.

This issue of The Bear Facts is dedicated to examining the details and the implications of electric deregulation for ratepayers in the Northwest. Find out what's going on and what you can do about it.

The alternative to deregulation

The Fair and Clean Energy Plan

So what's the alternative to Enron's deregulation plan, a proposal that will throw out consumer protection and could raise our electric rates? The Fair and Clean Energy Plan, developed by CUB and other public interest groups, will protect consumers, the environment, and universal electric service.

The Fair and Clean Energy Plan grew out of the work of the Fair and Clean Energy Coalition, a group formed by CUB and other public interest groups to lobby during the 1997 legislative session for fair and equitable utility policies.

Consumer activists have become aware that some problems do, indeed, exist in the current electric utility industry. That residential rates are too low was not one of those revelations:

continued on p. 3

The Alternative

The Fair and Clean Energy Plan

continued from p. 1

1. Large industrial customers have seen their rates drop as the wholesale price of electricity has decreased, but residential customers have seen none of those savings.

2. Utilities have slashed spending on weatherization programs and renewable energy.

3. Access to the Northwest's cheap hydro power is being threatened. Enron is proposing to sell off PGE's hydro assets to the highest bidder, and residential customers of Oregon have lost their access to the federally-owned dams.

4. As rates increase—and federally funded energy assistance programs are cut—many low-income families are finding it difficult to heat their homes.

The Fair and Clean Energy Plan is based on four principles:

- protecting customers
- protecting the environment
- preserving low-cost hydro
- providing universal service

Protecting customers

The Fair and Clean Energy Plan is based on the concept of affordable electricity rates for everyone—not just the aluminum companies that buy huge quantities of electricity, but the elderly couple in rural Eastern Oregon who only need a small amount of power.

The Fair and Clean Energy Plan proposes capping rates for residential customers and lowering them, if necessary, to guarantee that any reduction in electric rates are enjoyed by all customers.

Protecting the environment

The electric industry causes significant harm to the environment, from endangered salmon to nuclear waste; from global warming to acid rain. The Fair and Clean Energy Plan would require the electric industry to invest at least 3% of total retail revenue in programs designed to reduce the demand for electric power, such as weatherizing older homes and promoting renewable sources of energy, such as wind power.

The Fair and Clean Energy Plan would also allow customers to buy their electricity directly from clean, renewable resources, such as wind and geothermal generation.

Preserving low-cost hydro

Under the Fair and Clean Plan, residential customers of Oregon would be allowed to purchase power from the region's hydro system. This will keep rates down and provide for rate stability. In addition, Northwest residential customers are more likely to support salmon recovery efforts and understand the connection between hydroelectric power and endangered species.

Providing for universal service

The Fair and Clean Energy Plan would establish a universal service fund to guarantee everyone affordable electric service, even those with impaired credit, special needs or rural locations. The need for this guarantee has become ever more evident as Congress cuts heating assistance programs and electric companies set rates based on cost of service.

Electric Deregulation Pilot Program Fails in Northwest

So, just how well would electric deregulation work in the Northwest?

Not too well, if the pilot programs conducted in 1997 are any indication. All three of these tests proved that electric deregulation, by itself, does not create a competitive market.

- Washington Water Power (serving Spokane) opened up part of their territory to competition. No company, however, was willing to come in and sell to residential customers.

- Puget Power (serving Western Washington) did the same thing and also found no takers.

- Enron had a little bit more luck when they opened up part of PGE's territory in Oregon to competition—one small company from South Carolina was willing to sell to residential customers.

A deregulated marketplace needs multiple competitors so customers can have a true choice of electric service providers. One company willing to compete for service in only one of three test markets does not indicate that a competitive marketplace exists at this time.

And why is this so? Perhaps it's because the Northwest already has the lowest electric rates in the country. New companies cannot enter the market, absorb the start-up costs, invest in marketing services, and still beat the current, established electric rates.

So, despite all the free-market theories, competition in the electric industry in the Northwest has proved a failure. The one ingredient needed to make competition work here—substantially higher rates—is not likely to happen as long as Oregon maintains state regulation. If Oregon does deregulate the electric industry and rates do rise substantially, we'll probably have plenty of companies competing to sell us power. **Which scenario do you prefer?**

Attachment CUB 23

Results of Operations Actual Results	Mar-05	Mar-06	Dec-06	Dec-07	Dec-08	Dec-09
Hydro Relicensing Amortization Expense	2,978,960	2,191,860	3,239,131	5,094,312	5,289,321	7,378,043
Hydro Relicensing Rate Base	67,753,100	67,890,889	86,597,942	86,082,833	99,750,992	99,337,652
Hydro Relicensing Accumulated Reserve	(5,459,698)	(10,716,813)	(13,026,175)	(11,416,592)	(9,991,543)	(10,146,980)
Net Rate Base	62,293,402	57,174,075	73,571,766	74,666,241	89,759,449	89,190,672
Pre-tax Return	11.68%	12.47%	11.65%	11.26%	11.18%	11.46%
Rate Base Revenue Requirement	7,273,853	7,131,467	8,568,050	8,405,245	10,037,173	10,222,628
Actual Results of Operations Revenue Requirement	**10,252,812**	**9,323,327**	**11,807,181**	**13,499,557**	**15,326,494**	**17,600,671**

West Hydro Relicensing in Original MSP Study	Mar-05	Mar-06	Mar-07	Mar-08	Mar-09	Mar-10
MSP 2004 Study Forecast Revenue Requirement	**12,687,741**	**14,560,192**	**14,136,849**	**24,355,166**	**41,400,634**	**63,954,293**

CUB Exhibit 106 is Confidential
and Subject to Protective Order No. 03-638

UM-1050 / PacifiCorp
December 22, 2010
CUB Data Request 35

CUB Data Request 35

For each coal unit that is part of PacifiCorp's system, please provide the following:

a. Whether the unit includes a scrubber.
   i. If the unit has a scrubber, the unit cost of installing it.
   ii. If the unit does not have a scrubber, the projected cost of installing one and the projected year of installation.

b. The Company's projections as to how the unit will be affected by EPA MACT rules that are expected to be released in 2011.

c. The forecasted cost and timing of investments expected to be necessary to comply with the forthcoming EPA MACT rules.

Response to CUB Data Request 35

a. Please refer to Confidential Attachment CUB 35a for items i and ii. For the scrubbers installed with the initial unit installation, the cost estimates provided are only approximate because a proportion of the total plant costs must be added to the bare equipment costs to reflect a cost consistent with later scrubber installations which include all the costs necessary to retrofit a complete system. The estimates given are best effort approximations to demonstrate the magnitude of the costs relative to current costs. The estimated costs for Dave Johnston Units 1 and 2 are order-of-magnitude estimates and are not based on detailed estimates. The estimates provided for those units are reflections of other recent similarly sized projects with consideration given to unit specific constraints that could reasonably be expected.

   The units for which PacifiCorp has an ownership share at Colstrip, Craig, and Hayden all have existing scrubbers that are capable of 90%+ removal efficiencies. Future scrubber costs at these units are not anticipated.

b. After the vacatur of the Clean Air Mercury Rule by the District of Columbia Circuit Court of Appeals, the EPA has focused its efforts on establishing a maximum achievable control technology (MACT) standard for mercury and possibly acid gases. Pursuant to a court-ordered consent decree, EPA has committed to issuing a proposed MACT by March 2011 and a final rule by November 2011. The Clean Air Act defines MACT as the emission rate based on the "best performing 12% of sources in a source category." The recent issuance of an information collection request for mercury monitoring and related hazardous air pollutants (HAPS) data to all coal-fueled power plants in the U.S. will inform EPA regarding what sources are the "best performing 12%." The best performing sources are not necessarily those with specific emission control technologies installed—for example mercury emissions may vary dramatically based on coal characteristics, power generating unit operating characteristics and equipment configurations, and other factors. In line with current industry information, the Company's current expectations for reduction requirements under mercury MACT are between 85 to 95% removal and/or the establishment of Hg emission limits between 0.5 and 1.3 lb/TBtu. There is little, if any, industry information available to provide insight into the EPA's intentions regarding MACT levels for other HAPS, including acid gases. Certain industry groups have surmised that EPA may ultimately require scrubber technology as a surrogate control mechanism for HAPS MACT compliance. The Company's current projections for incremental control technology installations are limited to mercury MACT compliance, at this point in time.

From a timing perspective, the Clean Air Act is prescriptive regarding the effective date for compliance with emission reduction requirements. Clean Air Act Section 112(i)(3)(A) provides that existing sources are required to comply "as expeditiously as practicable, but in no event later than 3 years after the effective date" of the standard (i.e., in this case by November 2014). However, the EPA Administrator or a state with an approved program may issue a permit that grants an extension of 1 additional year to comply if the additional period is necessary for the installation of controls (see 42 U.S.C.A. §7412(i)(3)(B)).

c. Please refer to Confidential Attachment CUB 35c.

The confidential information is provided subject to the terms and conditions of the general protective order dated September 20, 2010 (Order No. 10-365) applicable in this proceeding.

UM-1050 / PacifiCorp
December 22, 2010
CUB Data Request 34

CUB Data Request 34

According to DR 23, PacifiCorp's Revised Protocol projected Westside hydro relicensing costs of $63.9 million in 2010, while such costs were actually $17.6 million, yielding a difference between forecast and actual costs of $46.3 million. If the 2010 ECD included $46.3 million in additional hydro revenue requirement, how much would that reduce the hydro endowment value that year? Please provide the answer in both dollars and percentage terms.

Response to CUB Data Request 34

To clarify, PacifiCorp's response to CUB Data Request 23 showed projected Westside hydro relicensing costs of $63.9 million for fiscal year March 2010, which was the fiscal year basis under Scottish Power, and actual $17.6 million for the 12 months ended December 2009. Therefore, the $43.6 million referenced in the request represents the difference between projected costs for fiscal year March 2010 and actual costs for the 12 months ended December 2009.

Notwithstanding this clarification, any change to hydro related expenses has a one-to-one impact on the value of the hydro differential if all other ECD components are held constant. For example, if hydro related expenses increased by $1 million in a given year, the amount of the hydro differential would decrease by $1 million. To assess the cost impact to a jurisdiction, the change in the differential is allocated by the jurisdiction's DGP factor and the inverse amount is allocated using the jurisdiction's SG factor.

CUB Exhibit 109 is Confidential
and Subject to Protective Order No. 03-638

UM 1050– CERTIFICATE OF SERVICE

I hereby certify that, on this 27th day of January, 2011, I served the foregoing DIRECT TESTIMONY OF THE CITIZENS' UTILITY BOARD in docket UM 1050 upon each party listed in the UM 1050 PUC Service List by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending one (1) original and five (5) copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

(W denotes waiver of paper service)

(C denotes service of Confidential material authorized)

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