BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1662

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY and PACIFICORP dba)
PACIFIC POWER,)
)
Request for Generic Power Cost)
Adjustment Mechanism Investigation)
)

REPLY TESTIMONY
OF THE
CITIZENS' UTILITY BOARD OF OREGON

May 11, 2015

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In the Matter of PORTLAND GENERAL ELECTRIC COMPANY and PACIFICORP dba PACIFIC POWER, Request for Generic Power Cost Adjustment Mechanism Investigation	)	REPLY TESTIMONY OF THE CITIZENS' UTILITY BOARD OF OREGON

Our names are Bob Jenks and Nadine Hanhan, and our qualifications are listed in CUB Exhibit 101.

I. Introduction

In this docket, PGE and PacifiCorp (the Companies) are proposing what they label a Renewable Resource Tracking Mechanism (RRTM), where they are asking for dollar-for-dollar recovery of costs they claim are associated with the Renewable Portfolio Standard. For the utilities, power costs are recovered in two steps: first, they are forecast annually when power cost rates are established; second, an annual Power Cost Adjustment Mechanism (PCAM) allows recovery of variances between the actual costs incurred and the forecasted costs used to set rates subject to a deadband and earnings test. The deadband is designed to recognize the risk that shareholders are already compensated for, and the earnings test is to make sure that customers are charged additional costs when the utilities' earnings are reasonable. This docket is simply the latest attempt by PGE and PacifiCorp to reduce or remove the impact of the deadbands and earnings test and shift additional risk to customers.

CUB fundamentally disagrees with PGE's and PacifiCorp's premise that they should be able to recover dollar-for-dollar variations in power costs, including the variance between forecast and actual renewable generation and market prices that are at issue in this docket. CUB believes that allowing dollar for dollar recovery of forecast errors is poor public policy, improperly shifts risk to customers, has consistently been rejected by the PUC, and is not consistent with the carefully negotiated Renewable Portfolio Standard, SB 838. In addition, CUB believes the proposal by PGE and PacifiCorp is a poorly designed measure that has more to do with recovering the costs of changes in market prices than it does recovering forecasting errors in wind generation. Our testimony is divided into two sections. The first deals with why the Companies' proposal for dollar-for-dollar recovery should be rejected from a policy basis. The second will focus on the specific mechanism that the Companies proposed and CUB's concerns with that mechanism.

II. Policy Arguments: Dollar for Dollar Recovery is Poor Public Policy

In this section, CUB discusses why it opposes dollar for dollar recovery:

- What the Companies are asking for is not consistent with the Renewable Portfolio Standard, SB 838
- Dollar-for-dollar recovery of costs is an inappropriate shift in ratemaking.
- The Commission has consistently rejected similar proposals.

A. The Companies' Proposal is not Consistent with the Renewable Portfolio Standard, SB 838.

This is not the first time that the utilities have proposed something along these lines. PGE sought a "carve-out" of RPS costs from the current PCAM in order to allow for dollar-for-dollar recovery in docket UE 283.[1] PacifiCorp cited the RPS as the reason for seeking a PCAM that allowed for dollar-for-dollar recovery in UE 246.[2] In arguing for dollar-for-dollar recovery of forecasting error, wind integration costs, and market price risk, the Companies have continually misrepresented the carefully constructed agreement behind the RPS.

In the current docket, the Companies again cite to the RPS statute:

> **Q. When the Oregon Legislature enacted SB 838 requiring the Joint Utilities to comply with an RPS, did it also provide for recovery of compliance costs?**
>
> A. Yes. The Joint Utilities' proposal is based on the language of Section 13 of SB 838, Cost Recovery by Electric Companies, codified at ORS 469A.120(1) which states that "all prudently incurred costs associated with the compliance with a renewable portfolio standard are recoverable in the rates of an electric company[.]" SB 838 goes on to elaborate on the types of related costs that should also be recoverable:
>
>> [I]ncluding interconnection costs, costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs and other costs associated with transmission and delivery of qualifying electricity to retail electricity customers.[3]

i. Prudently Incurred Costs are normally recovered through a forecast.

CUB agrees with the utilities on the language of the statute. CUB was a supporter of the RPS and was a key member of the coalition that negotiated most of the language,

[1] UE 283/PGE/100/Piro-Lobdell/19.
[2] Order No. 12-493, page 9.
[3] UM 1662/PGE-PAC/100/Tinker-Dickman/4.

and lobbied the bill through the legislature. CUB fundamentally disagrees that somehow that language was meant to require dollar-for-dollar true-up of these costs. The RPS requires utilities to go out and pursue resources that might not be necessary to meet load and might not be the least-cost resource available (that is why there is a cost cap in the RPS). Utilities wanted to ensure that these costs were allowable for recovery, even if a party could show that the power was not currently needed to meet load or that there was a lower cost resource. So the law said that the costs of complying with the law are recoverable if those costs were prudently-incurred.

The primary tool that the Commission uses to allow recovery of prudently incurred costs is a forecast. Variable power costs are forecasted annually, and other costs are forecasted into a test year in a general rate case. Forecasting a cost and setting rates to a level to recover that cost is how utilities recover fuel costs, capital investments, labor costs, IT costs, and management costs. There is nothing in the RPS that suggests that forecasting these costs is not a legitimate method to ensure that the costs "are recoverable in the rates of an electric company."[4] In fact, every category of costs that the utilities identify in this docket are currently being recovered "in the rates of an electric company," through the use of forecasts.

ii. There was one set of costs that was singled out for alternative ratemaking in the RPS.

The Companies acknowledge that SB 838 did require the Commission to establish a Renewable Adjustment Clause (RAC) but suggest that the law somehow failed to establish a mechanism for the remaining costs:

[4] UM 1662/PGE-PAC/100/Tinker-Dickman/4.

> For the costs to "construct or otherwise acquire" renewable resources and for associated transmission, ORS 469A.120(3) provides that the Commission shall establish an automatic adjustment clause, or another method, that allows for the timely recovery of prudent costs. For the other costs of compliance, the statute did not identify a specific recovery mechanism.[5]

There is a reason behind creating the RAC for construction costs and using traditional regulation for the remaining costs, which the Companies fail to discuss. The reason for establishing the RAC for costs associated with the construction was a belief that those costs could not be handled through tradition ratemaking without causing regulatory lag. Traditional ratemaking (based on forecasting costs) is all that is necessary for the "other costs of compliance" because there was no issue of regulatory lag:

> Renewable energy resources generally come in smaller increments than fossil-based generation resources. We anticipate that, in meeting the SB 838 renewable energy standards, the utilities will be continuously adding modestly-sized investments on an ongoing basis. If the utility were to wait to recover the costs of these resources until a general rate case, either a) there would be a considerable time gap between a utility's investment on behalf of customers in a renewable resource, and the utility's ability to recover the cost of that investment, or b) the utility will have multiple general rate case filings every year. Since a general rate case can last nine to eleven months and requires an enormous expenditure of resources from the utility, the agency and the intervenors, overlapping rate cases from multiple utilities would lead to chaos.
>
> Furthermore, the utilities are currently operating under annual automatic adjustment clauses to pass through variable power costs for fuel and purchased power which were set up to facilitate industrial customer access to non-utility market power. Since adding no-fuel renewable energy resources lowers a utility's variable costs, it seems incongruous to use an automatic adjustment clause to pass through lower variable power costs to customers, but not to allow the utility to recover the costs of the renewable resource that led to the lower power costs.[6]

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[5] UM 1662/PGE-PAC/100/4.
[6] CUB Exhibit 102.

The purpose of the RAC is not dollar-for-dollar recovery, but to avoid regulatory lag of investment costs. The RAC was cited by opponents of the RPS as a reason legislators should vote against it. As the primary customer voice within the RPS coalition, CUB was tasked with writing a memo describing the RAC. CUB's Attorney at the time, Jason Eisdorfer, did just that, explaining that the RAC was like the annual automatic adjustment clauses that pass through variable power costs for fuel and purchased power and the automatic adjustment clause for Purchased Gas Adjustments.[7]

It is ironic that the very automatic adjustment clause that the utilities say is not allowing them adequate recovery of their forecasting error and market price risk is the mechanism that was cited legislatively as the examples of how the RAC would operate when the RAC was proposed.

It is also clear that costs that were not covered under section 13(3) of the RPS (costs other than the costs to construct or acquire), "can only enter rates either through currently existing automatic adjustment clauses or through a general rate case."[8]

B. Dollar-for-dollar Recovery of Costs is an Inappropriate Shift in Ratemaking

The RPS was not trying to guarantee dollar-for-dollar recovery. However, if it is not required, it could still be adopted for policy purposes. But this makes little or no sense from a policy perspective. It would be a significant shift in risk from shareholders to ratepayers and would upset the ratemaking balance.

i. Because Costs Vary, This Does Not Mean They are Not Being Recovered.

Let's begin with CUB's view of the regulatory system. The PUC's primary responsibility is to establish fair, just, and reasonable rates which allow a utility to

[7] CUB Exhibit 102.
[8] CUB Exhibit 102.

recover its costs and earn a reasonable return. While we recognize a specific, forecasted target ROE is used to set rates, a reasonable return is generally considered a range. PGE, in its current rate case recognizes a range of 140 basis points, from 9.8% to 11.2%.[9]

Utility costs fluctuate. Some costs vary by the hour. Rates, on the other hand, are kept steady between rate cases. Under the argument the utilities are making, if costs go up $1 million, rates have to also go up by $1 million, or the utilities are not fully recovering their cost. But, if costs go up $1 million, in all likelihood a utility is still within the reasonable *range* for earnings. If earnings are within this reasonable range, the utility is considered to be fully recovering its costs and earning a reasonable return. So just because a cost changes, and rates are not changed to reflect the new cost, it does not mean that a utility is not fully recovering that particular cost.

This is why Oregon regulation uses earnings tests with most deferrals and automatic adjustment clauses. Without looking at earnings, it is hard to draw any conclusion about whether a cost is being recovered or not.

ii. The Utilities' Proposal Would Shift Normal Business Risk to Customers

As we discussed, costs vary, but as long as earnings are in a reasonable range, a utility is considered to be fully recovering its costs. Managing fluctuating costs is the normal business of a utility. They get compensated for managing this risk. The rate of return includes a risk premium to recognize that returns are not guaranteed. It would be inappropriate to shift normal ratemaking risk from shareholders to customers while retaining the same risk premium to shareholders.

[9] UE 294/PGE/1100/Villadsen/2.

In addition, customers pay utility managers a great sum of money, in terms of salary, benefits and performance incentives to manage the system. Utility managers have more expertise and training to manage the risks of a utility system than do customers.

The risk premium is included when setting the return on equity, which is earned on ratebased capital investments. Renewables that are owned by a utility are ratebased assets, and rate base is what a utility earns a return on equity from. Comparing a wind resource to a natural gas combustion turbine shows that most of the cost of the wind resource is ratebased, and a utility earns equity returns on that rate base. Over the life of the gas plant, the highest cost is the fuel and there is no return paid on fuel. Since the investment risk premium is paid as part of the return on equity, utilities are paid a higher risk premium to manage the risk of renewables then they are with a gas plant.

C. The Commission Has Consistently Rejected Similar Proposals

The utilities are asking to shift the risk of managing the system to customers, but the Commission has regularly rejected this.

i. UE 246, PacifiCorp's Rate Case.

In UE 246, PacifiCorp asked for a PCAM with dollar-for-dollar recovery for all power costs. While that is obviously much more than the utilities are asking for here, it was based on the same set of evidence:

> Pacific Power claims its under-recovery of NPC in Oregon rates is due primarily to the inability to accurately forecast wind generation and factors associated with integrating a new, large fleet of renewable resources whose generation fluctuates widely. Because customers must bear all prudently incurred RPS compliance costs--including the variable NPC impacts associated with integrating renewable energy sources--Pacific Power seeks a PCAM without deadbands, earning bands, sharing

> percentages, or any other feature that would deprive the utility of dollar-for-dollar recovery of any under-recovery of NPC.[10]

No party to the docket supported PacifiCorp's position. The Commission rejected PacifiCorp's proposal and instead adopted the PCAM based on the following principles:

> In adopting a PCAM for PGE, we articulated general principles that form the basis of a well-designed PCAM: (1) any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility; (2) there should be no adjustments if the utility's overall earnings are reasonable; (3) the PCAM's application should result in revenue neutrality; (4) the PCAM should operate in the long-term to balance the interests of the utility shareholder and ratepayer; and, implicitly, (5) the PCAM should provide an incentive to the utility to manage its costs effectively.[11]

ii. UE165 Hydro Only PGA

It should be noted that the RRTM proposed by the two utilities includes a significant amount of their hydro resources: low-impact hydro and hydro upgrades. This isn't the first time the utilities have tried to shift the risk of hydro from a utility to its customers:

> PGE proposed a hydro-specific PCAM in 2004 in docket number UE 165. The proposed mechanism was intended to dampen the fluctuations in PGE's annual power costs that were caused by variations in hydro conditions. PGE described a number of reasons why it was uniquely suited for such a mechanism—roughly 10 percent of that company's generation portfolio is company-owned hydro, which is an inherently unpredictable resource that has significant swings in annual generation.
>
> OPUC Order No. 05-1261 outlines the Commission's four primary design criteria for a hydro-only PCAM. First, a PCAM should only be triggered by extreme and unusual events. Second, adjustments should not be made if earnings are already reasonable. Third, the mechanism should remain revenue neutral over time. And fourth, in order to ensure that the three prior criteria are effective, the mechanism must be intended to remain in place on a long-term basis.

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[10] OPUC Order No. 12-493, page, 9.
[11] OPUC Order No. 12-493, page, 13.

> The Commission ultimately rejected PGE's proposal on the grounds that it failed to fully meet the four criteria described above.[12]

iii. UE 283

In UE 283, PGE proposed a PCAM carve out for any cost that it could associate with renewables claiming that this is required by SB 838:

> PGE's proposal is based on the clear language of SB 838, Section 13, part 1 which states:
>
> > "… all prudently incurred costs associated with the compliance with a renewable portfolio standard are recoverable in the rates of an electric company…"[13]

PGE, like PacifiCorp in UE 246, is arguing that SB 838 required dollar-for-dollar recovery, but as we have shown, that was not the intention of SB 838. No other party supported PGE's position, and the case settled without the dollar-for-dollar recovery.

III. The Mechanism is Poorly Designed

A. The Proposed Mechanism Inappropriately Shifts Market Price Risk onto Customers.

CUB has argued in previous dockets[14] that mechanisms similar to the RRTM go beyond updating and correcting forecasting errors and shifts the risks associated with power price changes onto customers. Customers should not have to bear the risk of errors made in forecasting prices. Quoting from CUB's Opening Testimony in UE 283:

> The problem with this is that even if the forecasted generation and actual generation show no or little variation, (therefore there is no real difference), the mechanism still can result in a significant surcharge or surcredit associated with the change in market prices, essentially passing through the nominal change in values as a real cost to the customer.[15]

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[12] UE 246/CUB/200/Jenks-Feighner/10.
[13] UE 283 / PGE / 500/Niman – Peschka-Hager /43
[14] UE 283, CUB/100/Jenks-McGovern/18.
[15] UE 283, CUB/100/Jenks-McGovern/18.

PacifiCorp filed an attachment to CUB data request 2 showing that the wind forecast variance was 7% in 2011 and -3% in 2012 while the market price variance was -22% and 27%, respectively. The risk associated with market prices seems to overshadow the wind forecasting error. In 2013, the wind forecast error was -1% and the market price error rounded to 0%, suggesting there was no need for a true up.[16] These six data points represent aggregated values, and even they demonstrate that for at least two of those years, there was a notable error in market price forecasting by over 20%. For the three years, the net market value of this market price risk was $39.8 million, $46.4 million, and $6.6 million, for a total of almost $100 million. CUB does not agree that customers should be responsible for bearing this significant risk that is unrelated to wind forecasting error.

The mechanism is less about tracking the changes in wind production and more about tracking the value of wind, which the utilities value at market prices. The price changes under the mechanism would primarily be related to market price forecasting errors, not wind forecasting errors.

B. PGE's AUT Already has an Adjustment for Wind Forecast Error

In the case of PGE, its current power cost case includes an adjustment for wind forecast error:

> **Q. Are there other items that PGE expects will require updates?**
>
> A. Yes. PGE expects to update the cost of wind day-ahead forecast error in the July update filing. Due to the run-time of ROM, the data input process, and the time needed for validation of the inputs and results, we do not anticipate having a final estimate of the updated wind day-ahead forecast error cost in time for the April 1 filing. Consistent with our approach in Docket No. UE 286, we propose to provide the parties of this proceeding with the updated estimate and an

[16] See CUB Exhibit 103.

explanation of input changes via a letter sent by June 1, 2015. The purpose of this letter is to provide parties with adequate time and opportunity to review the updated estimate before we incorporate the estimate in MONET for the July filing.

Q. Please briefly explain the cost of wind day-ahead forecast error.

A. The cost of wind day-ahead forecast error is the cost incurred to re-optimize PGE's portfolio in order to account for the difference between the day-ahead and the hour-ahead forecasts for wind generation. These costs materialize in the form of market transactions (purchases and sales) and the re-dispatch of available generation resources.[17]

If PGE is seeking dollar-for-dollar recovery for wind forecasting errors in this docket, it should not also get recovery for wind forecasting error for its power costs. CUB believes that the two wind forecast error recovery mechanisms will lead to double counting.

In the AUT, there is an adder attached to wind production as a forecast element of the wind forecast error. Currently, this adder is set at $0.65/MWh.[18] In the proposed RRTM, the utilities propose to true up the value of wind from its initial forecast to its actual results. However, the utilities do not propose to remove the adder from the forecast element of the wind forecast error. The RRTM true-up is not between the forecasted wind forecast error and the actual wind forecast error. Customers would be required to pay costs associated with the actual wind forecast error and simultaneously pay the cost associated with a forecast of the wind forecast error.

C. The Mechanism adds Fuel Price Risk to Renewables

When the utilities request recovery of the variance between forecasted and actual market prices, they are valuing renewables based on the market price. In doing this,

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[17] UE 294/PGE/400/Niman-Peschka-Hager/22 &23.
[18] UE 294/PGE/400/Niman-Peschka-Hager/ 23.

utilities are taking away one benefit of renewables: no fuel or variable price risk. When customers invest in a significant resource that is nearly all capital costs, with little variable O&M and no fuel variability, it should be adding rate stability and reduce the risk of fuel cost volatility. In this way, renewables can be thought of as a fixed price hedge. In fact, this is what was supposed to happen with SB 838. Below is a quote from a fact sheet produced by advocates of SB 838 that was used during the 2007 legislative session to describe the RPS:

> STABLE, AFFORDABLE POWER
>
> The price of electricity from renewable resources is stable and reliable because the fuel is free and the cost is predictable – like a dependable 30-year mortgage. In contrast, fuel prices for natural gas more than tripled since 1999 and the price of coal increased 20% between 2003 and 2005.These rising fuel costs cause regular rate increases for utility customers.[19]

Rather than accept this fixed-cost benefit, the Companies' proposal makes renewable generation subject to market price risk and fuel risk, adding an unnecessary burden to customers and incorrectly subjecting renewable energy to two separate risks—market and fuel. It is clear that renewables are subjected to market price risk by virtue of the mechanism that the Companies are proposing—namely, the recovery of the variance of market prices, not just the variance of wind production. The fuel price risk is also present, but implied. Since natural gas combustion turbines are the marginal resource which influences the market price of energy, the Companies are now subjecting customers to natural gas fuel risk by asking for recovery through this mechanism. Under the RRTM, customers could be hit with a surcharge that is primarily related to a change

[19] CUB Exhibit 104.

in market prices caused by a change in natural gas prices, but customers will be told the cost is associated with renewables.

D. The Companies don't just rely on hourly spot market purchases.

Utilities already have several tools to manage risk, and it is unrealistic to assume that the Companies rely on the hourly market to adjust their resource requirement for forecast errors. The utilities are managing a large system of resources and loads and must be proactive—utilities do not sit back and wait to see if the forecast of wind they made last April is correct on January 10th. Utilities are constantly monitoring resources, loads, and expected weather. They update forecasts of loads and resources regularly. While a utility model focuses on the forecast from the power cost case and the actual renewable production, these are only the bookends.

For example, long before a utility gets to a particular day, it reforecast its system for that day. Hydro resources also vary, but over longer periods of time than wind, and utilities will also reforecast their hydro projections. Year-ahead weather forecasts will be replaced by forecasts that are a week or two out, and then a day or two out, and then an hour or two out. If hydro conditions are poor that year, a utility might purchase more power weeks before that day. If weather is getting severe, a utility might purchase power a week beforehand. If weather is mild and hydro is good, a utility may be unconcerned that wind is expected to be lower than forecast. A utility is considering the risks to its system and reacting to the risks. There may be some circumstances where changes in wind availability have no impact. There may be other circumstances where changes in wind availability are concerning, and a utility will reduce its risk in advance with market purchases With PacifiCorp joining the EIM and having access to subhourly markets, utilities are acquiring more tools to manage this problem. Rather than track how the utilities actually manage the risk of wind forecast errors, the RRTM uses the hourly market to value the wind forecast error. While the Companies state that the hourly forecast is the most accurate,[20] it has little to do with the resource actions they take to deal with a forecasting error.

E. The approach relies on information that goes beyond the normal protective order.

In the UM 1662 Joint Testimony, the Companies state:

> **Q. What do the Joint Utilities propose using as a basis for market price?**
>
> A. The Joint Utilities propose using an established, third-party hourly index for their relevant market hubs. The Joint Utilities will use the best available hourly market data. Due to the intra-hour variability of RPS-compliant resources such as wind, this is the most accurate representation of the costs to replace deficit RPS-compliant resources or the value of surplus generation sales.[21]

Both of the Companies originally refused to provide the market price data. They explained that this was because the data was proprietary. After a conversation with the Companies on April 22, 2015, PacifiCorp sent a Supplemental Update to CUB Data Request 2 with the originally requested information.[22] The data response requested that "parties must return or destroy all Powerdex data that the Company provided in responses to data requests in this proceeding, and any extracts thereof, following conclusion of the regulatory matter."[23] This is problematic because not only are customers being asked to recover costs based on market price risk, but it is based on market prices that customer

[20] UM 1662/PGE-PAC/100, Tinker-Dickman/11.
[21] UM 1662/PGE-PAC/100, Tinker-Dickman/11.
[22] See CUB Exhibit 105.
[23] CUB Exhibit 105.

advocates were unable to examine in the first place. This information goes beyond the normal scope of a protective order, and CUB is not comfortable making significant changes in a recovery mechanism using information that the utilities have been reluctant to provide.

IV. Conclusion

In this docket, the Companies have proposed a mechanism that is a derivation of previous proposals. In UE 283, PGE sought out dollar-for-dollar recovery, as did PacifiCorp in UE 264. CUB has testified several times against these proposals. In spite of the claims of the utilities, the RRTM does not align with the spirit of SB 838 because the RPS was never intended to allow dollar-for-dollar recovery. Beyond an issue relating to regulatory lag, SB 838 was not an attempt to change traditional forecasted ratemaking.

CUB believes that the RRTM is poorly designed. It unfairly shifts market price risk and fuel price risk onto customers. CUB is also concerned about the risk of double counting cost recovery and proprietary data that is not readily available to stakeholders. For these reasons, CUB opposes the Companies' proposal.

WITNESS QUALIFICATION STATEMENT

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TITLE: Executive Director

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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 207, UE 208, UE 210, UE 233, UE 246, UE 283, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UM 1633, and UM 1654. 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
Board of Directors (Public Interest Representative), NEEA

WITNESS QUALIFICATION STATEMENT

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Re: A Review of the SB 838 Automatic Adjustment Clause
From: Jason Eisdorfer, attorney, Citizens' Utility Board

Section 13(3) of SB 838 directs the Public Utility Commission to establish an automatic adjustment clause or other mechanism to allow timely recovery of prudently-incurred costs related to the construction or acquisition of renewable energy resources and related transmission. The provision further states that, upon request, the PUC shall grant a hearing and other specified procedural rights.

Why have an automatic adjustment clause at all?
Renewable energy resources generally come in smaller increments than fossil-based generation resources. We anticipate that, in meeting the SB 838 renewable energy standards, the utilities will be continuously adding modestly-sized investments on an ongoing basis. If the utility were to wait to recover the costs of these resources until a general rate case, either a) there would be a considerable time gap between a utility's investment on behalf of customers in a renewable resource, and the utility's ability to recover the cost of that investment, or b) the utility will have multiple general rate case filings every year. Since a general rate case can last nine to eleven months and requires an enormous expenditure of resources from the utility, the agency and the intervenors, overlapping rate cases from multiple utilities would lead to chaos.

Furthermore, the utilities are currently operating under annual automatic adjustment clauses to pass through variable power costs for fuel and purchased power which were set up to facilitate industrial customer access to non-utility market power. Since adding no-fuel renewable energy resources lowers a utility's variable costs, it seems incongruous to use an automatic adjustment clause to pass through lower variable power costs to customers, but not to allow the utility to recover the costs of the renewable resource that led to the lower power costs.

Are the safeguards in SB 838 sufficient to protect ratepayers?
Absolutely. Even without the guaranteed hearing language in Section 13(3), the PUC's automatic adjustment clause process is safe for consumers. CUB tracks the purchased gas adjustment, an automatic adjustment clause currently in use, for the natural gas utilities. When an issue of prudence comes up, the schedule contemplates a full process. (Such a proceeding is currently in progress and the schedule called for five rounds of testimony and a hearing over a six month period.) Since Section 13(3) only applies to prudently-incurred costs, a full process with all procedural rights is assumed. The language in 13(3) states explicitly that a hearing must be held if requested. This explicitly kicks in all the applicable procedures and rights found in the hearing procedure section of the laws relating to the PUC, found in ORS 756.518 to 756.610.

Does the automatic adjustment clause mean the utility will never have another general rate case where other costs can be examined?
Of course not, unless the utility wants to go bankrupt. Section 13(3) allows for the timely recovery of renewable energy sources only. All other costs can only enter rates either through currently existing automatic adjustment clauses or through a general rate case. The fear is that a utility will continue to recover costs through the automatic adjustment clause and never again subject itself to a general rate case where intervenors can examine other costs. A utility that foregoes a general rate case and relies only on the automatic adjustment clause in SB 838 for recovery of costs will very soon find itself significantly under-recovering its costs. A case in point is PacifiCorp's latest draft integrated resource plan. The plan shows that the utility plans to add costly transmission investments to rates in 2010, two natural gas generating units in 2011, and three fossil fuel units in 2012. This does not include hydro relicensing costs and emissions technology investments for its current fleet of resources. The renewable energy investments will be dwarfed by these other costs, and no utility in its right mind would choose to have its shareholders pay these costs by not filing a general rate case.

What does a reference to "a contested case proceeding under ORS chapter 756" mean?
I have no idea. The term contested case does not appear in ORS chapter 756, and ORS chapter 756 includes all kinds of provisions from hearings procedures to PUC general powers to PUC fees. Therefore, this phrase has no clear legal meaning.

Increased Risk from Wind			
	2011 UE-216	**2012 UE-227**	**2013 UE-245**
TAM Forecast			
Wind Generation (MWh) *	4,629,577	4,687,070	4,624,557
Market Price ($/MWh)	33.30	30.60	32.38
Market Value ($m)	154.2	143.4	149.7
Less: PPA Cost ($m)	103.5	107.5	103.8
Net Market Value ($m)	50.7	35.9	45.9
Actual			
Wind Generation (MWh) *	4,946,693	4,553,708	4,557,975
Market Price ($/MWh)	25.94	22.36	32.39
Market Value ($m)	128.3	101.8	147.6
Less: PPA Cost ($m)	117.4	112.3	108.3
Net Market Value ($m)	11.0	(10.5)	39.3
Forecast Variance			
Wind Generation (MWh) *	317,116	(133,362)	(66,581)
Market Price ($/MWh)	(7.37)	(8.23)	0.01
Market Value ($m)	(25.9)	(41.6)	(2.1)
Less: PPA Cost ($m)	13.9	4.8	4.5
Net Market Value ($m)	(39.8)	(46.4)	(6.6)
Forecast Variance %			
Wind Generation (MWh) *	7%	-3%	-1%
Market Price ($/MWh)	-22%	-27%	0%
Market Value ($m)	-17%	-29%	-1%
Less: PPA Cost ($m)	13%	4%	4%
Net Market Value ($m)	-78%	-129%	-14%

* Generation from resources eligible for compliance under S.B. 838

Production Tax Credits			
Owned Wind Variance	196,508	(73,844)	(38,172)
PTC Variance ($m)	6.97	(2.62)	(1.35)

POWERING OREGON'S FUTURE [SB-373]

What a Renewable Energy Standard Means for Oregon

A Renewable Energy Standard ensures that utilities gradually increase the amount of new renewable resources they use to generate electricity. A standard that ensures 25% of Oregon's electricity be renewable by 2025 will build on our legacy of using homegrown resources to provide clean, cost-competitive power to meet our growing energy needs. Expanding the use of Oregon's generous endowment of solar, wind, geothermal, biomass and wave resources can help our state make the transition from fossil fuel dependence to energy independence. Renewable energy also creates new economic development opportunities, protects public health and the environment, and stabilizes electricity rates.

ENERGY INDEPENDENCE

Using our domestic, renewable resources will make Oregon more self-reliant. More than half of the electricity consumed in Oregon comes from volatile and risky fossil fuels and hundreds of millions of dollars leave the state's economy each year to import coal and natural gas. Oregon has excellent wind potential and even the cloudiest areas receive more sunlight than Germany, a world leader in solar power. The state also has abundant biomass and geothermal resources, and areas off the Oregon coast offer some of the world's best wave energy potential.

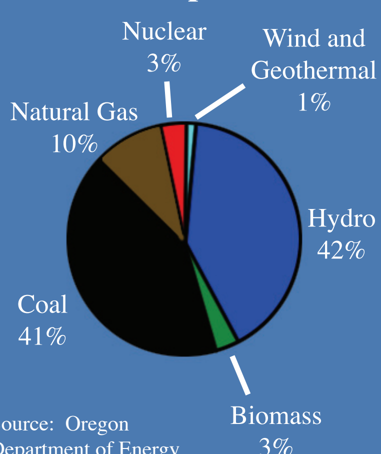
ECONOMIC BENEFITS

Using renewable resources keeps jobs and money in our communities. A Renewable Energy Standard will bring billions of dollars of new economic activity to the state and the region. Wind projects built in the Northwest since October 2005 have already brought $1.38 billion in new capital investment to the region and created nearly 1,400 jobs. These projects will also generate up to $3 million in annual royalty payments to rural landowners and up to $6.8 million each year in property tax revenues. For example, the new property taxes from the relatively small 24 megawatt (MW) Klondike I Wind Farm in Sherman County have increased the county's tax base by 10%. The recent 75 MW expansion is expected increase the county's tax base by an additional 20%, or roughly $750,000 annually.

PROTECTING PUBLIC HEALTH & THE ENVIRONMENT

Global warming has emerged as the most significant threat facing Oregon's environment. Northwest climate experts have already linked global warming to declining snow pack in the Cascades, decreased summer stream flows, rising sea levels on the Oregon coast, and increased incidence of wildfires. A Renewable Energy Standard would be Oregon's most significant step yet to rein in global warming pollution. Renewable energy also generates clean electricity free of the smog, acid rain and mercury emissions that spew from fossil fuel power plants.

2005 Oregon Electricity Consumption Mix



Source: Oregon Department of Energy

STABLE, AFFORDABLE POWER

The price of electricity from renewable resources is stable and reliable because the fuel is free and the cost is predictable – like a dependable 30-year mortgage. In contrast, fuel prices for natural gas more than tripled since 1999 and the price of coal increased 20% between 2003 and 2005.[1] These rising fuel costs cause regular rate increases for utility customers.

Utilities are increasingly reporting significant cost savings from renewable energy. Puget Sound Energy, Washington's largest utility, reports that their investment in two Northwest wind farms will save $170 million over the next 20 years compared to the next cheapest resource.[2] Xcel Energy reports that in 2004 and 2005, the utility saved its Colorado customers $14 million by investing in wind power.[3]

For information call: Gary Conkling, Renewable Northwest Project (503-544-8997) •
Jeremiah Baumann, OSPIRG (503-936-3200) • **Jeff Bissonnette**, Fair & Clean Energy Coalition (503-516-1636)

POWERING OREGON'S FUTURE

HOW IT WORKS...

A Renewable Energy Standard is a proven, flexible policy mechanism that will guarantee a growing percentage of Oregon's electricity comes from new renewable resources. The policy requires utilities to gradually increase the amount of new renewable energy in their electricity supply until 25% of the electricity they sell in Oregon in 2025 comes from new renewable energy sources. It also provides flexibility to electric utilities by allowing them to choose the combination of resources that makes the most sense for their system and their customers.

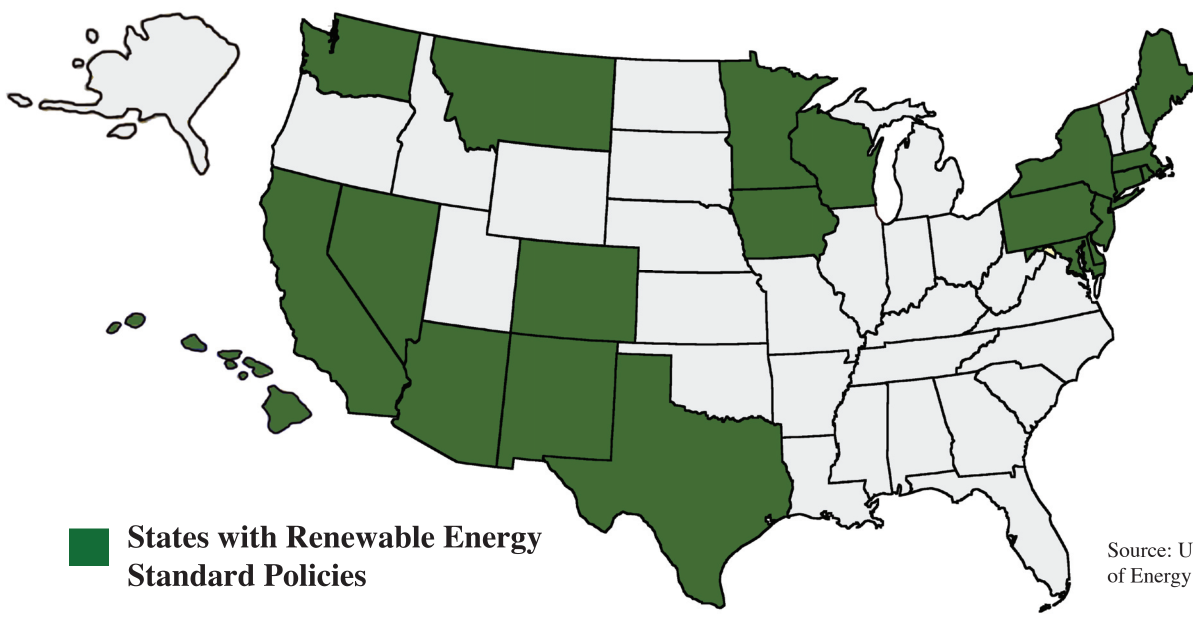
Photo: Leon Werdinger, www.ottertrack.com

EFFECTIVE. PROVEN. NECESSARY.

According to the U.S. Department of Energy, a Renewable Energy Standard is "the most powerful tool a state can use" to promote renewable energy.[4] Experts at Lawrence Berkeley National Laboratory report that these policies are expected to have minimal impacts on electricity rates – generally plus or minus one percent.[5] As a result of Renewable Energy Standards, Texas developed 700 MW of wind power in 2005 alone and Colorado has nearly 800 MW currently under negotiation. By comparison, it has taken nearly a decade to get more than 400 MW installed in Oregon.

DON'T LET OREGON GET LEFT BEHIND

Twenty-one states have enacted Renewable Energy Standards and developers are already exploring renewable energy sites in Oregon to meet other states' requirements. With the right policy, Oregon will benefit significantly from its abundant renewable energy resources. We can't afford to lose this opportunity for greater energy independence, a stronger economy and stable, affordable electricity prices.



Source: U.S. Department of Energy

1. "Behind the Rise in Prices," *Electric Perspectives* (July/August 2006). http://www.eei.org/magazine/editorial_content/2006-07-01-RisingPrices.pdf
2. "2005 Annual Report." Puget Sound Energy (March 2006). http://www.pugetenergy.com/financialreports.html
3. "Xcel Reports Huge Savings from Wind," *Windpower Monthly,* Vol 22, No. 5. (May 2006).
4. "Policies and Market Factors Driving Wind Power Development in the United States." National Renewable Energy Laboratory (July 2003).
5. "Weighing the Costs and Benefits of Renewables Portfolio Standards." Lawrence Berkeley National Laboratory (January 2007).

January 29th, 2007

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PACIFIC POWER
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May 1, 2015

Nadine Hanhan
Citizens' Utility Board of Oregon
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Portland, OR 97205
nadine@oregoncub.org (C)
dockets@oregoncub.org

RE: OR Docket No. UM 1662
CUB Data Request (1-2)

Please find enclosed PacifiCorp's 1st Supplemental Response to CUB Data Request 2. Provided on the enclosed Confidential CD is Confidential Attachment CUB 2 1st Supplemental. The confidential attachment is designated as confidential under Order No. 15-108 and may only be disclosed to qualified persons as defined in that order.

If you have any questions, please call me at (503) 813-6583.

Sincerely,

Natasha Siores

Natasha Siores
Director, Regulatory Affairs & Revenue Requirement

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UM 1662/PacifiCorp
May 1, 2015
CUB Data Request 2 – 1st Supplemental

CUB Data Request 2

Please provide, in electronic form with active spreadsheets, the following information:

(a) Hourly wind generation *forecasts* for PacifiCorp-owned wind generation for the most recent three years with complete data.

(b) Hourly wind *forecasts* for wind generation purchased by PacifiCorp for the most recent three years with complete data.

(c) Hourly wind generation *actuals* for PacifiCorp-owned wind generation for the most recent three years with complete data.

(d) Hourly wind generation *actuals* for wind energy purchased by PacifiCorp through contracts for the most recent three years with complete data.

(e) Hourly forecasted market prices for the most recent three years with complete data.

(f) Hourly actual market prices for the most recent three years with complete data.

1st Supplemental Response to CUB Data Request 2

Further to the Company's response to CUB Data Request 2 dated April 9, 2015, the Company provides the following supplemental information relating to subpart (f):

(f) Please refer to Confidential Attachment CUB 2-2 1st Supplemental, which includes Powerdex actual hourly market prices from January 1, 2007 through December 31, 2013. The markets represented in this data are: Palo Verde (PV) and Mid-Columbia (Mid-C).

Confidential Attachment CUB 2 -2 1st Supplemental contains Powerdex proprietary data and is designated as confidential under Order No. 15-108 and may only be disclosed to qualified persons as defined in that order. Powerdex actual hourly market prices are provided subject to the PacifiCorp Powerdex Subscription Agreement which requires that Powerdex be provided only to persons qualified to receive confidential information under the protective order for this proceeding. Furthermore, parties must return or destroy all Powerdex data that the Company provided in responses to data requests in this proceeding, and any extracts thereof, following conclusion of the regulatory matter.