BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 610

In the Matter of	)
	)
Rulemaking Regarding the	)
Incremental Cost of Renewable	)
Portfolio Standard Compliance.	)
	)

COMMENTS OF THE

OREGON CITIZENS' UTILITY BOARD

September 14, 2018

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 610

In the Matter of Rulemaking Regarding the Incremental Cost of Renewable Portfolio Standard Compliance.	)))))))	COMMENTS OF THE OREGON CITIZENS' UTILITY BOARD

I. INTRODUCTION

The Oregon Citizens' Utility Board (CUB) appreciates the opportunity to offer comments in this rulemaking. CUB begins our comments with a discussion of the incremental cost of Renewable Portfolio Standard (RPS) compliance and the constraints placed upon the RPS cost cap methodology, and then address the questions that the Staff of the Oregon Public Utility Commission asked stakeholders to review.

II. INCREMENTAL COST OF RPS COMPLIANCE

Oregon's RPS has a 4% cost cap. Ideally, this cap would be implemented by identifying the incremental revenue requirement that would not be incurred but for mandatory RPS compliance and compare that number to the revenue requirement if the RPS did not exist. In this instance, if the revenue requirement associated with compliance is 4% greater than the revenue requirement associated with non-compliance, then the cost cap would be triggered.

When applied to PacifiCorp's recent actions, this would mean that the capital costs associated with their renewable projects would not be considered as an incremental cost because these resources were not acquired to meet the RPS – they grew out of an IRP action plan that was least cost/least risk – and the renewable projects serve all PacifiCorp states, even those that do not have a RPS. Under PacifiCorp's current multi-state protocol for allocating costs between states, if there were incremental costs associated with these projects they would be identified and allocated to Oregon:

> *Portfolio Standards: Costs associated with Resources acquired to comply with a Jurisdiction's Portfolio Standard adopted, either through legislative enactment or a State's Commission, the portion of which exceeds the costs PacifiCorp would have*

otherwise incurred, will be assigned on a situs basis to the Jurisdiction adopting the Portfolio Standard.[1]

Since there are no capital costs associated with PacifiCorp renewable projects that are assigned to Oregon under this standard, there must not be an incremental cost associated with these investments. PacifiCorp does have incremental costs associated with complying with the RPS, but these incremental costs do not include the capital costs of the resources themselves. However, RECs that PacifiCorp purchases solely to comply with Oregon's RPS are clearly incremental costs associated with the RPS, as are the lost revenue associated with retiring rather than selling RECs. But the cost of the renewable projects themselves is not.

PGE is a bit more complicated because it does not serve states without an RPS, making it more difficult to identify what PGE's resource acquisition would be without an RPS. But we know that PGE was acquiring renewable energy before the RPS. PGE acquired Orion Energy's development rights to the Biglow Canyon wind farm in 2006, broke ground on the project in February 2007, and it came online in October 2007.[2] This project was planned and much of its development occurred before the RPS legislation passed. The current rules deem the incremental costs to be zero for facilities that were operational before June 6, 2007. Biglow became operational after June 6, 2007, but was built as a resource action under PGE's 2002 IRP,[3] not to comply with RPS requirements. Therefore, this project were not built to meet the RPS requirements and therefore should not be considered an incremental cost of complying with the RPS, though the lost revenue associated with retiring their RECs should be considered as an incremental cost. PGE, like PacifiCorp, found renewable resources to be part of least cost/least risk portfolios independent of the RPS. The incremental cost question for PGE revolves around identifying the level of renewable investment that would have been made without an RPS in order to compare with the renewable resource investment that was made under the RPS.

III. COST CAP CONSTRAINTS

Unfortunately, Oregon law does not allow us adequate flexibility to evaluate the cost cap based logically on the incremental cost of compliance. Rather than grant the OPUC the flexibility to establish a reasonable cost cap to ensure that a utility's revenue requirement is not greater than 4% more than it would otherwise be due to the RPS, the legislature was very prescriptive as to how that cost cap would be designed. Specifically, the legislature defined the incremental cost of compliance:

> *the incremental cost of compliance with a renewable portfolio standard is the difference between the levelized annual delivered cost of the qualifying electricity and the levelized annual delivered cost of an equivalent amount of reasonably available electricity that is not qualifying electricity*[4]*.*

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[1] OPUC Order No. 16-319, Appendix A, page 6.
[2] https://en.wikipedia.org/wiki/Biglow_Canyon_Wind_Farm.
[3] PGE 2002 IRP Final Action Plan Update, March 2006, page 2
[4] ORS 469A.100(4)

And mandated how to calculate this incremental cost:

> *For the purpose of this subsection, the commission or the governing body of a consumer-owned utility shall use the net present value of delivered cost, including:*
> *(a) Capital, operating and maintenance costs of generating facilities;*
> *(b) Financing costs attributable to capital, operating and maintenance expenditures for generating facilities;*
> *(c) Transmission and substation costs;*
> *(d) Load following and ancillary services costs; and*
> *(e) Costs associated with using other assets, physical or financial, to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs*[5]*.*

And how to calculate the revenue requirement that is multiplied by 4% to identify the cost cap:

> *The annual revenue requirement for an electric utility shall be calculated based only on the operations of the electric utility relating to electricity. The annual revenue requirement does not include any amount expended by the electric utility for energy efficiency programs for customers of the electric utility or for low income energy assistance, the incremental cost of compliance with a renewable portfolio standard, the cost of unbundled renewable energy certificates or the cost of alternative compliance payments under ORS 469A.180. The annual revenue requirement does include:*
> *(a) The operating expenses of the electric utility during the compliance year, including depreciation and taxes; and*
> *(b) For electric companies, an amount equal to the total rate base of the electric company for the compliance year multiplied by the rate of return established by the commission for debt and equity of the electric company*[6]*.*

The focus of this statutory approach is the levelized cost of annual delivered qualifying electricity as compared to non-qualifying electricity. The annual delivered qualifying electricity is the electricity associated with RECs that are retired to meet compliance obligations in a particular year. This does not focus on incremental revenue requirement caused by the RPS and it does not contemplate qualifying electricity existing in a resource portfolio that was developed as a least cost resource independent of the RPS.

It is concerned with the cost of annual qualifying electricity as compared to the capital, operating and maintenance costs of equivalent amounts of delivered energy from generating facilities. However, utility resources alternatives include hydro capacity contracts and demand response programs, neither of which delivers equivalent amounts of electricity.

The revenue requirement definition expressed excludes energy efficiency investments, which are significant resources in the IRP and represent 7% of the bill of a PGE residential customer.[7] In addition, the statue seems to assume that there is an annual determination of revenue

[5] ORS 469A.100(4).
[6] ORS 469A.100 (3).
[7] Calculated from a recent bill.

requirement, rather than recognizing that revenue requirement is established in general rate cases that occur less than annually.

The current methodology used by the Commission focuses on comparing the levelized cost of the renewable projects associated with RECs that are retired each year with the levelized cost of natural gas proxy plants. This grows directly out of the statutory requirements for the cost cap. It may not represent an ideal methodology, but within the constraints of the law, it is reasonable.

IV. STAFF'S QUESTIONS

1. *Is the proxy plant methodology, last examined in Order No. 14-034 in Docket No. UM 1616, and summarily defined in OAR 860-083-0010(30), accurately and appropriately serving as the baseline for the incremental cost of compliance calculation?*

CUB understands how the proxy plant methodology was designed based on the statutory constraints. The statue clearly expects a comparison of a generating plant that qualifies with a generating plant that does not. However, CUB believes that this approach could be modified in order to recognize that some renewables were not built to incrementally comply with the RPS. In the case of renewable resources that were acquired for reasons other than RPS compliance – that are not incremental costs associated with the RPS – CUB believes that the baseline to compare should be those same investments, with a hypothetical sale of the RECs. By modeling the sale of the RECs, the renewable resource would no longer be eligible for RPS compliance and would fit the statutory requirement of comparing an equivalent amount of non-qualifying energy.

2. *Do our incremental cost rules accurately reflect the appropriate categories of cost for the incremental cost of compliance calculation?*

Within the constraints of the law, yes.

3. *Are there any additional components of delivered cost that you would specify must be included in the calculation of incremental cost for long-term or short-term resources? What legal and/or policy justification is there for your position?*

No.

4. *Should the cost of qualifying electricity be included in the incremental cost of compliance in the year the electricity is generated, or in the year the associated RECs are retired? What legal and/or policy justification is there for your position?*

CUB recognizes the discomfort with only counting the cost of the renewable generation that is associated with RECs that are retired for compliance in a year. But the statue requires the cost cap to be based on the annual levelized delivered cost of qualifying electricity. Because we are looking at the annual cost of qualifying electricity, it is necessary to focus on the resources associated with RECs that are retired. Generating a REC does not qualify for RPS compliance, but retiring a REC does. There may be circumstances where a utility wishes to sell RECs out of the REC bank so those REC never become qualifying electricity.

5. *Should the rules be amended to reflect any changes you suggested? Do you have any specific recommendations for changes to the rules?*

See our answer to question 1, above.

6. *What should happen when an electric company reaches the four percent cost limit? What legal and/or policy justification is there for your position?*

Under the statue, utilities are not required to comply during a compliance year if it means that they violate the cost cap. Since compliance means retiring RECs, CUB believes that, at this point, utilities do not have to retire RECs. It may make sense for the RECs to be sold and the revenue provided back to customers or it might make sense to retain the RECs for future compliance which may allow the utility to delay future investment in additional renewables. Both options provide value to customers.

7. *What guidance, if any, should our rules provide about the process for when four percent is reached? Do you have any specific recommendations for changes to the rules?*

CUB has no recommended changes.

8. *Also considering ORS 469A.075, which requires an implementation plan, what should happen if an electric company is forecast to reach the four percent cost limit in a future compliance year? What legal and/or policy justification is there for your position?*

If a utility forecasts that it will reach the cost cap, it has similar options as it has in a compliance year. It could sell RECs out of the REC bank and use these revenues to reduce rates to customers or based on its projection that it will be over the cost cap and will not be required to retire the RECs, it can delay additional renewable investment.

9. *Should utilities include the cost of unbundled REC purchases at the time of purchase or the time of retirement? What legal and/or policy justification is there for your position?*

A purchased REC becomes qualifying when it is retired for compliance, not when it is purchased. The statue is concerned with annual qualifying electricity, which would place the focus on RECs that are retired.

10. *Are there any specific changes you would like to see to the administrative rules regarding any aspect of the ORS 469A.100 cost limit calculation? What legal and/or policy justification is there for your position?*

See our answer to Question 1.

Signed this 24th of September, 2018.

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