BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

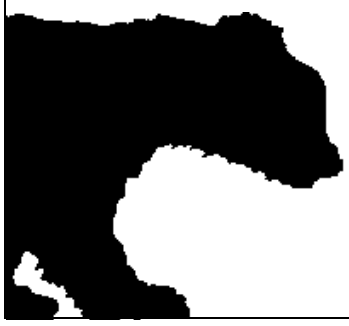
UE 294

In the Matter of	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
Request for a General Rate Revision	)

NVPC OPENING TESTIMONY OF THE

CITIZENS' UTILITY BOARD OF OREGON

May 28, 2015



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In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision	)	NVPC OPENING TESTIMONY OF THE CITIZENS' UTILITY BOARD OF OREGON

Our names are Bob Jenks and Jaime McGovern, and our qualifications are listed in CUB Exhibit 101.

I. Introduction

While UE 294 is a General Rate Case (GRC), this testimony concerns only net variable power costs (NVPC). NVPC, which are normally reviewed through an automatic adjustment clause called the Annual Update Tariff (AUT), are rolled into 2015 PGE's General Rate Case but are operating on a separate schedule.

CUB is happy to see a NVPC filing that shows power costs declining, but CUB still has a few issues that need to be addressed:

- The timing of Carty, PGE's new natural gas resource.
- The double counting of wind forecasting error costs in this docket and UM 1662, the generic PCAM investigation.

- The changes to PGE's system as it adds resources and the effect on needed capacity.

II. CUB Concerns About PGE's NVPC.

A. The Timing of Carty, PGE's New Natural Gas Resource

PGE's new generating resource, the Carty Generating Station, will come online during 2016. A new generating resource will increase the fixed costs in a general rate case due to the added rate base associated with the capital investment while simultaneously reducing Net Variable Power Costs (NVPC) by displacing market purchases or adding sales for resale revenue.

PGE's rate case is designed in a way as to minimize the risk that the Company might suffer regulatory lag on the fixed cost recovery. At the same time, it creates a lag in recognizing the NVPC benefits of the plant. This means that while shareholders will get full recovery of their capital investment, customers will not fully benefit from the offset from reduced NVPC.

i. Two Stage Rate Case Eliminates Regulatory Lag

PGE filed this GRC with a rate effective date of January 1, 2016. But PGE does not need a rate change on January 1, 2016. According to PGE, without the January increase, PGE's ROE would be 8.8% before Carty comes online.[1] While the PUC will authorize a specific target for ROE, it is generally accepted that there is a range of reasonableness -- just because an ROE is above or below the authorized level does not mean that a utility is not earning a reasonable return. And according to the Staff analysis in PGE's last GRC, an 8.8% ROE is still within the range of reasonableness.[2]

[1] UE 294 - PGE/200/Tooman - Brown/3.
[2] UE 283 - Staff/200/Muldoon/24.

If PGE does not need a rate increase in January 2016 in order to ensure reasonable earnings, why did PGE file this case? The answer is clear. PGE has consistently filed a general rate case to conclude 4 to 6 months before a major new generating investment comes online. It has been true for Tucannon and Port Westward 2 and it was true for Port Westward 1. The only exception is Coyote Springs, which came on line 9 months after the last general rate case ended, but PGE had an agreement with OPUC Staff to allow it to bring on Coyote Springs with a tracker filed 90 days before the expect in-service date and an "attestation by a corporate officer" that the plant was operational.[3]

PGE has found a way to manage the regulatory system to ensure that it bears no regulatory lag for its capital investments in new generating plants like Carty: file a two stage rate case with the first stage ending within 6 months of the new plant. This allows it to get the second plant approved as a second stage to that rate case. This means that approval and a tariff are in place before the plant is operational, so there will not be a single day of regulatory lag.

ii. Allowing Lag for NVPC

Unlike capital costs which increase when a new plant comes on line, NVPC are reduced. Therefore, the utility does not have the same need to prevent any lag on the NVPC side.

In Monet, PGE models Carty as being shut down for maintenance from January 1, 2015 through May 15, 2015[4] and its NVPC forecasts reduce costs associated with Carty from that date forward. According to PGE, May 15, 2016 is the deadline for the project to be completed and operational or its contractor "will be liable for liquidated damages."[5] Therefore May 15, 2016 is the deadline for completing the plant, but it is not a forecast of when the plant is likely to be operational -- it is an upper bound on the timeline, not a reasonable expectation.

[3] OPUC Order No. 95-322, Appendix D, page 3.
[4] UE 294 - CUB Exhibit 102.
[5] UE 294 - PGE/300/Pope – Lobdell/14.

Tucannon and Port Westward 2 were both finished well before their deadlines. The Tucannon attestation was filed on December 15, 2014,[6] and the Port Westward attestation was filed on January 26, 2015.[7] In both cases, this was well before they were expected to come online.[8] Tucannon was scheduled to come online as late as June 2015,[9] but came online in December 2014.

There is no reason to believe that PGE has accurately forecasted the date that Carty will come online for NVPC purposes. This creates a lack of symmetry. Shareholders are fully protected from any sort of regulatory lag and will recover their capital investment whether the plant is early or late.

If the plant comes online early, then the shareholders will get to keep the benefit of reduced NVPC prior to May 15, 2016. If the plant is tardy, then the shareholders will receive compensation from the contractor, and immediately, upon the plant going into service, will start receiving a return on the investment from ratepayers.

Customers, who ultimately pay for Carty and who should see offsetting benefits through the NVPC, will likely not see the full benefits of the reduction in NVPC because the benefits are subject to a forecast of when the plant comes online and that forecast assumes worst case.

iii. CUB's Recommendation.

There are a couple ways to address this. The Commission could establish a deferral and require the Company to defer the NVPC benefits between the time the plant comes online and the time it is projected to come online in Monet. This would capture the benefits and allow them to be passed through to customers. CUB does not recommend this for three reasons. First, filing

[6] UE 283 - Attestation of Stephen Quennoz filed December 15, 2014.
[7] UE 283 - Attestation of Stephen Quennoz filed January 26, 2015.
[8] UE 283 - CUB/100/Jenks-McGovern/5-4.
[9] *Ibid*.

a deferral under the circumstances in this case for a cost that is not very significant seems like overkill. PGE projects the dispatch benefits of Carty's "partial year operations in 2016 will decrease PGE's initial 2016 NVPC forecast by approximately $0.98 million."[10] CUB estimates that the NVPC benefit of forecasting Carty online for the entire year would reduce PGE's rates by an additional $600,000 from its filed case. Second, these costs are subject to the PCAM, with its deadband and earnings test, which will only become more complicated if we have to adjust the PCAM for the results of a deferral. Third, CUB believes that setting rates through forecasts is generally preferable to establishing more mechanism to ensure dollar-for-dollar recovery.

To be clear, our concern is not that forecasting is being used, but that the forecast is not based on the most likely outcome. PGE assumes the contractor risks will risk liquidated damages by taking until the very last day to complete the project. It makes more sense to expect that the project will be completed well before the deadline in order to minimize the risk of liquidated damages. This has been demonstrated by PGE's recent history with large capital projects. However, PGE has very little information on the record which allows a good estimate of the in-service date – this is not surprising since capital cost recovery is no longer subject to regulatory lag. Based on the recent history with Port Westward 2 and Tucannon, however, CUB believes that there should be an expectation that the plant will come online 3 to 6 months ahead of schedule. CUB therefore recommends that the NVPC benefits of Carty be forecast beginning January 1, 2016. This will reduce NVPC by approximately $600,000.

[10] UE 294 – PGE/400/Niman - Peschka – Hager/11.

B. The double counting of wind forecasting error costs in this docket and UM 1662, the generic PCAM investigation.

In CUB's recent testimony in UM 1662, we discussed the double counting between that docket and PGE's AUT (NVPC):

> 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.[11] 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.[12]

Because UE 294 includes this year's AUT, the 65 cents/MWh wind forecast error adder is in this case. CUB does not propose eliminating this adder because CUB opposes the creation of the Renewable Resource Tracking Mechanism proposed in UM 1662. PGE, on the other hand, is supporting the adder here and supporting dollar-for-dollar recovery of wind forecast errors in the generic PCAM docket. CUB believes that PGE's position, if approved in both dockets, will lead to overcharging customers by double counting a cost.

C. The changes to PGE's system as it adds resources and the effect on needed capacity.

CUB believes that it is time for a review of and/or revision to the way the Company approaches capacity adders, specifically those employed for peak serving. In CUB's review, we find several practices and contracts that have been in place while the Company and its customers have changed. Therefore, status quo is not a sufficient demonstration of prudency. The significant changes in the Company's customer base (and load) include an increasing component of energy efficiency (EE) and renewables, and more recently, storage. In addition, the Company

[11] UE 294 - PGE/400/Niman-Peschka-Hager/ 23.
[12] UM 1662 - CUB/100/Jenks-Hanhan/6.

has moved away from market purchases to serve load and almost entirely relies on its own fleet for energy supply.[13] The significant changes in the Company's serving resources include expanding generation with ever more flexible capacity. In addition, the Company is committing resources to near-term involvement in the energy imbalance market (EIM), which will have an impact on resource needs. However, the Company maintains the same super-peak contract that it has had in place for several years.

i. Energy Efficiency has peak shaving effects.

CUB has already demonstrated that at least 100 MWa of EE is embedded into PGE's service territory.[14] This has the effect of making customers less sensitive to weather changes, thereby reducing the need for capacity. Given that PGE models EE as load reduction and not a load serving resource, the Company does provide shaping modeling for energy efficiency.

ii. The Super-Peak Contract is not a vital resource.

When the Super-Peak Contract was implemented, the Company owned only 3019 MW of resource capacity (4,168 MW -1,149 MW):[15]

[13] http://files.shareholder.com/downloads/POR/11173558x0x815699/C9E3CFDB-6CFD-4BDB-A8DC-C5D40E309FF1/PGE_Investor_Presentation_March_2015_FINAL.pdf at page 28.
[14].UM 1713 - CUB Opening Comments.
[15] *See* PGE's August 2012 Form 8-k, accessed at: http://investors.portlandgeneral.com/secfiling.cfm?filingID=784977-12-94.

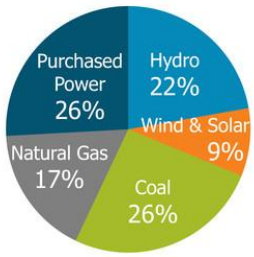
Resource Mix

Resource Capacity (at 12/31/11)(1)

	Capacity	% of Total Capacity
Hydro		
Deschutes River Projects	298 MW	7.1%
Clackamas/Willamette River Projects	191	4.6
Hydro Contracts	485	11.6
	974	**23.3**
Natural Gas/Oil		
Beaver Units 1-8	516 MW	12.4%
Coyote Springs	246	5.9
Port Westward	410	9.8
	1,172	**28.1**
Coal		
Boardman	374 MW	9.0%
Colstrip	296	7.1
	670	**16.1**
Wind(2)		
Wind Contracts	44 MWa	1.1%
Biglow Canyon	159	3.8
	203	**4.9**
Purchased Power	**1,149**	**27.6%**
Total	**4,168 MW**	**100.0%**

Power Sources as a Percent of Retail Load
Per the 2012 AUT

Total = 2,217 MWa



1) Capacity of a given plant represents the megawatts the plant is capable of generating under normal operating conditions, net of electricity used in the operation of the plant
2) Wind generation from contracts and Biglow Canyon is expressed in average megawatts; Biglow's capacity reflects the weighted average capacity factor for all three phases of the project

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Fast-forward to today, when the Company owns 4048 MW of resource capacity (4,910 MW-862 MW):[16]

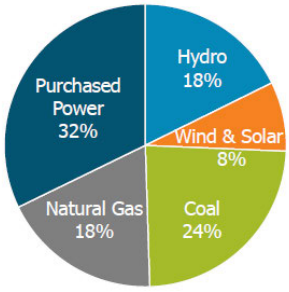
Diversified Resource Mix

Resource Capacity (at 12/31/14)(1)

	Capacity in MW	% of Total Capacity
Hydro(1)		
Deschutes River Projects	303	6%
Clackamas/Willamette River Projects	191	4%
Hydro Contracts	595	12%
	1,089	**22%**
Natural Gas/Oil(1)		
Beaver Units 1-8	516	11%
Coyote Springs	248	5%
Port Westward Unit 1	401	8%
Port Westward Unit 2	224	5%
	1,389	**28%**
Coal(1)		
Boardman	518	11%
Colstrip	296	6%
	814	**17%**
Wind		
Biglow Canyon(2)	450	9%
Tucannon River(3)	267	5%
Wind Contracts	39	1%
	756	**15%**
Purchased Power	**862**	**18%**
Total	**4,910**	**100%**

Power Sources as a Percent of Retail Load
(2014 Actuals)

Total = 18,734 MWh



1) Capacity of a given plant represents the megawatts the plant is capable of generating under normal operating conditions, net of electricity used in the operation of the plant
2) With respect to Biglow Canyon, capacity represents nameplate and differs from expected energy to be generated, which is based on a 30% capacity factor
3) With respect to Tucannon River Wind Farm, capacity represents nameplate and differs from expected energy to be generated, which is based on a 38% capacity factor

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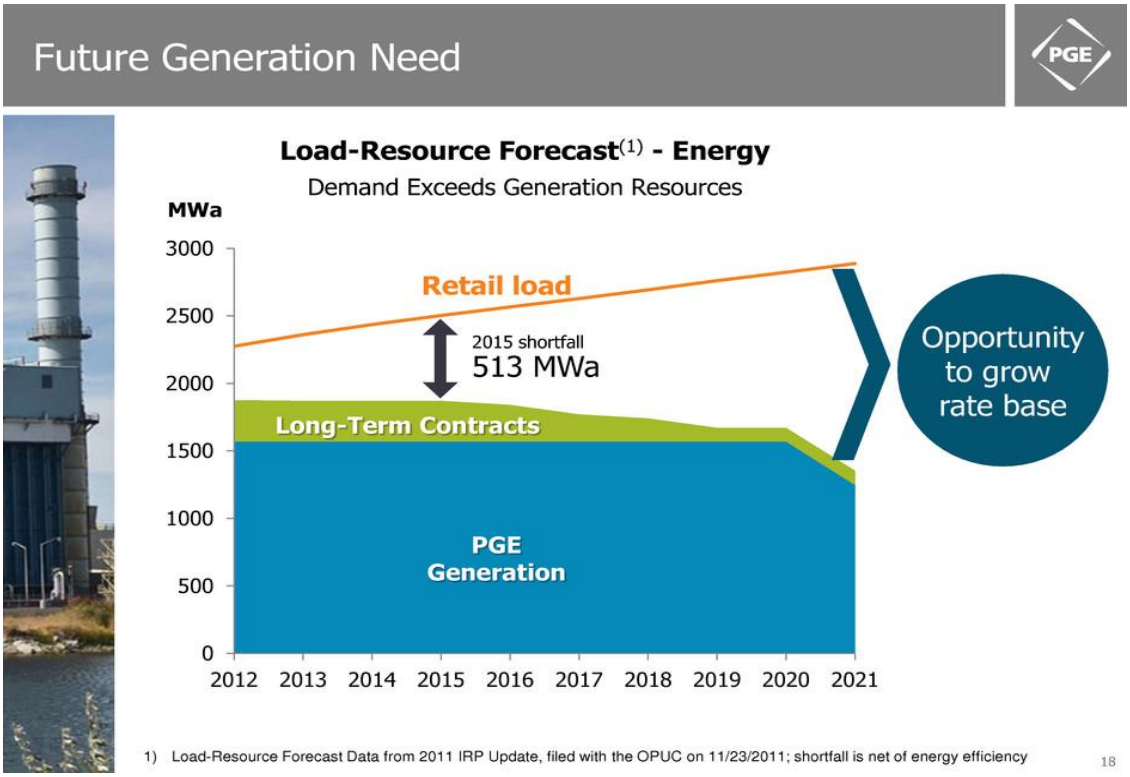
[16] PGE's August 2012 Form 8-k, accessed at: http://investors.portlandgeneral.com/secfiling.cfm?filingID=784977-12-94

The Company has replaced market purchases with rate base resources. This has the effect of increasing base rates, and with economic dispatch of Company owned generation, hopefully decreasing NVPC. The power plants are meant to dispatch economically, but the economic dispatch and therefore the NVPC are entirely dependent on the parameters that are fixed in the model. The Super-Peak Contract may be an uneconomic parameter.

That is, when the Super-Peak Contract was implemented, the Company's customers were exposed to the market for 27.5% of their capacity needs, and now, through the Company's continued increase in rate base, customers self-serve all but 17.5% of their capacity needs. This was clearly not accidental:



With the pending retirement of Boardman and the expiration of long-term contracts, the Company had a vision to grow rate base through generation resources.[17] The benefit for

[17] PGE's August 2012 Form 8-k, accessed at: http://investors.portlandgeneral.com/secfiling.cfm?filingID=784977-12-94.

shareholders is, of course, increased returns. One of the benefits for ratepayers should be increased security. The Company has continually touted the flexibility of its new fleet of gas-fired power plants. With this 34% increase in investor owned capacity in just three years, CUB believes that the Company's new, more flexible resource stack may be well situated to absorb load spikes without the addition of a super-peak contract. CUB understands that the Company is currently performing a study on ramp rates, and that more informed dispatching may soon be available. However, the Super-Peak Contract should not be presumed prudent in light of all the structural changes, and in the absence of compelling evidence. Moreover, given that the Company gives up power and pays a significant premium for the super-peak purchases, CUB thinks that the Company must do more to demonstrate its prudence.

iii. Sales for Resale could benefit customers more

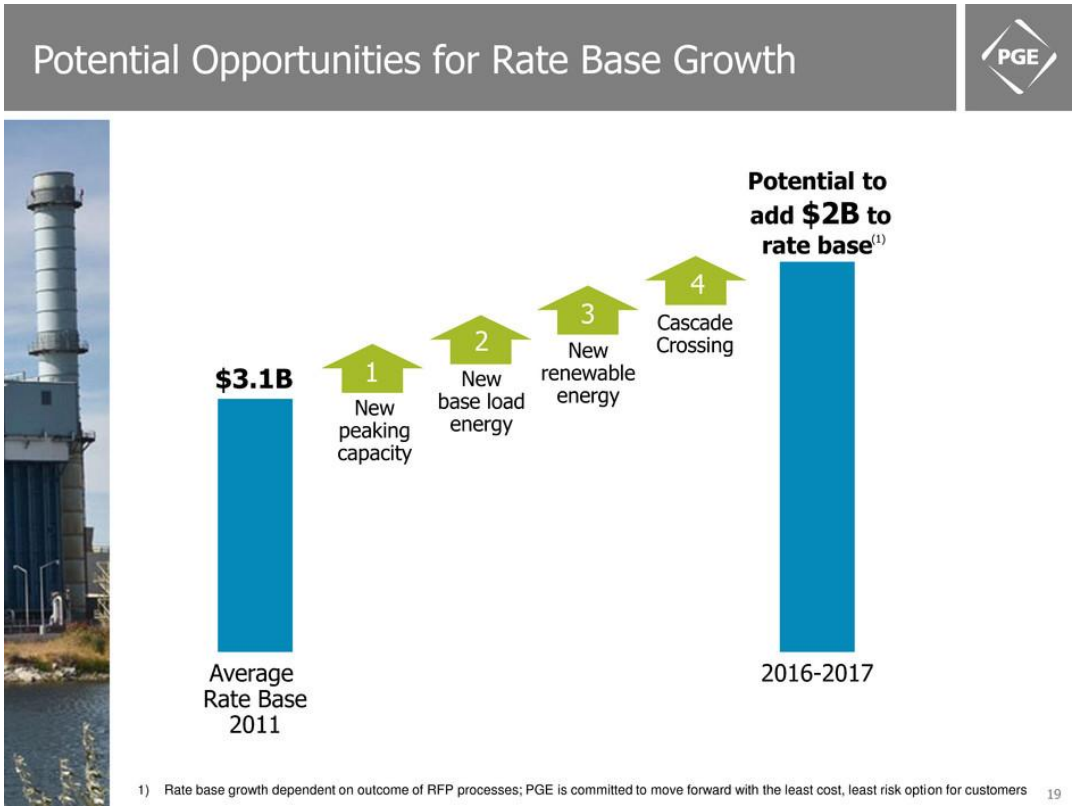
In 2013, the Company had more than $115 million in sales-for-resale.[18] In 2014, this rose to more than $125 million.[19] Two important things are evident here. First, the Company has a large amount of generating resource available and it dispatches into the marketplace significantly. Second, the way that these revenues are treated may not be in the best interest of the customers. Currently, the Company uses these revenues to lower NVPC. However, in unregulated industries, revenues above variable costs are applied to fixed costs. Carty has a projected annualized cost of $83.6 million.[20] In the interest of providing service to customers in the least cost, least risk manner, CUB believes that the Company should analyze whether some or all of sales for resale should be used reduce fixed costs by offsetting rate base.

[18] PGE 2013 Results of Operation, page 2, http://edocs.puc.state.or.us/efdocs/HAQ/re119haq16313.pdf.
[19] PGE 2014 Results of Operation, page 1, http://edocs.puc.state.or.us/efdocs/HAQ/re119haq141752.pdf.
[20] UE 294 – Executive Summary of PGE at page 2.

iv. Shareholders may be well situated to absorb some spikes in NVPC

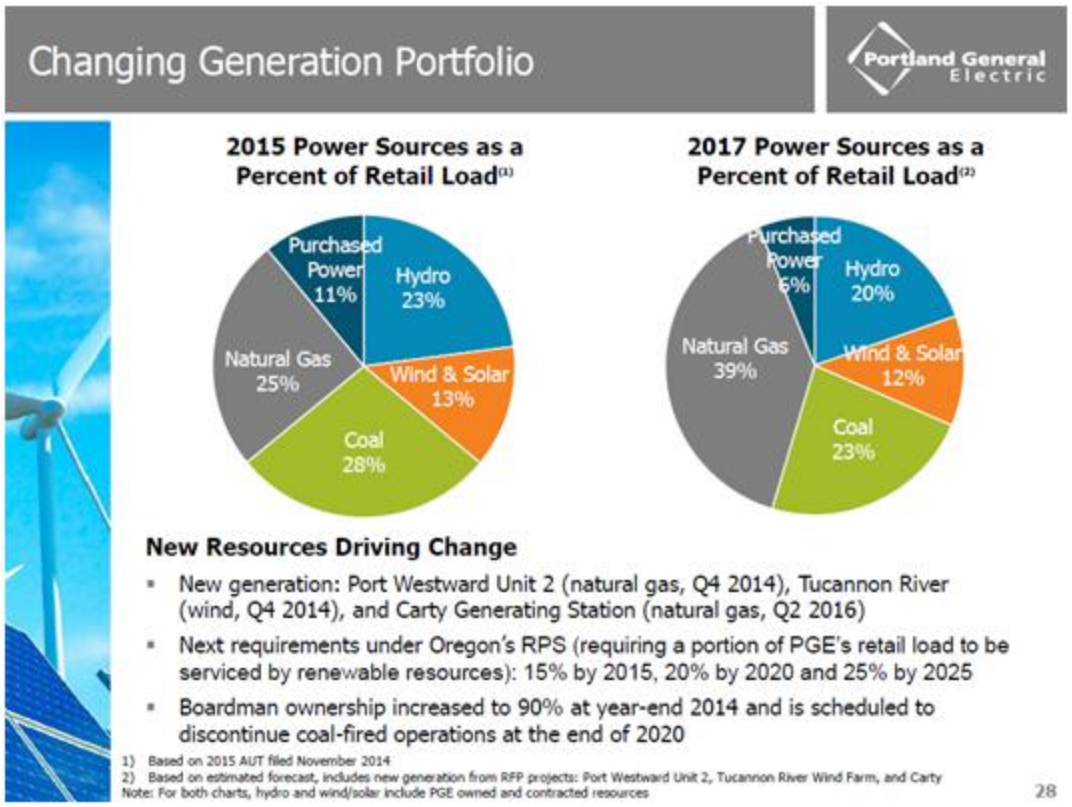
CUB has discussed some reasons why the Company's physical system may be able to absorb fluctuations in load without compromise. In addition, the shareholders may also now have the cushion of additional rate base to weather fluctuations in the NVPC.

The Company is clear, with its investors, in its intent to grow rate base by approximately half:



By 2017, less than a year after the order in this case, the Company will have nearly 95% of its load served by Company owned resources.[21]

[21] PGE investor presentation, March 2015, accessed at: .http://investors.portlandgeneral.com/eventdetail.cfm?eventid=157935.



Those power sources make up a significant increase in rate base. As a matter of simple math, the impact of changes to NVPC has significantly less impact on earnings. CUB sees very little necessity to protect the shareholders from the impact of possible swings in fuel costs, as the Company has been deft in eliminating other power costs.

It can be argued that the Company is well situated against upward market pressure, and therefore protects the customers against increasing trends or swings in power costs. However, the Company is now heavily dependent on natural gas, much more rigidly than it was 5 years ago, and also earns a return on a much higher level of capacity resources. The Company may be well situated to absorb load spikes and the shareholders may be well situated to absorb power cost spikes.

III. Conclusion.

CUB recommends that in the absence of more rigorous analysis, the super-peak contract be removed from rates. CUB also recommends that the Company reduce NVPC by $600,000 by assuming that Carty comes on line on January 1, 2016, consistent with recent PGE experience. Finally, CUB recommends the PUC not adopt both of the PGE wind forecasting error proposals – (1) the adder in this docket and (2) the RRTM in UM 1662 – because this would cause double-counting of costs.

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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
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Electricity Policy Committee, Consumer Federation of America
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Economics professor at Mesa Community College and the State University of New York from 2004–2010.

2016 GRC – February 12, 2015 Initial Filing

Carty Schedule and Maintenance

For the initial filing of the 2016 GRC, Carty's maintenance is based on information provided by the plant manager, Scott DeGeeter (Doc #1). The current schedule is for a four-day outage in October for water washing and warrantee work.

Carty's maintenance may be updated in a later filing.

The maintenance logic in Monet is also used to adjust the costs and benefits to reflect a May 16, 2016 in-service date. When Carty is activated ("PC Input" worksheet, cell AC18 set to "1"), the plant is modeled as if on 100% maintenance for January-April and fifteen days of maintenance for May. The maintenance deration in May reduces the plant's generation (and fuel cost). The fixed gas transportation and transmission costs are adjusted to show no cost for January-April and 16/31 of the total cost for May.

Source Documents

1. "EM_CartyMaint2016_DeGeeterS20150121.xps", email from Scott DeGeeter confirming Carty's maintenance schedule.

Monet Inputs

On the "PC Input" worksheet:

- Carty Maintenance Description is in cell K604.
- Carty Maintenance Days are in row 617.
- Carty In-Service Date is in cell AL18.
- Carty days prior to commercial operations are calculated in cells K619:P619.
- Carty's combined days of maintenance and days prior to commercial operations are in cells K615:V615.
- Carty Maintenance Derations are calculated in row 631.