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June 15, 2015

Via Electronic Filing and Federal Express

Public Utility Commission of Oregon
Attn: Filing Center
3930 Fairview Industrial Drive SE
Salem OR 97302

Re: PORTLAND GENERAL ELECTRIC
2015 General Rate Case
Docket No. UE 294

Dear Filing Center:

Enclosed for filing in the above-referenced docket, please find the Opening Testimony and Exhibits of Michael P. Gorman, Bradley G. Mullins, and James W. Daniel on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Pursuant to the protective order in this proceeding, the sealed confidential portions of Mr. Mullins' testimony and exhibits will follow to the Commission via Federal Express, and to the parties that have signed the protective order via First Class U.S. Mail.

Because this filing exceeds 100 pages, ICNU is also providing complete hard copies to the Commission and to PGE. The other parties to this proceeding have waived paper service of ICNU's testimony and exhibits.

Thank you for your assistance. If you have any questions, please do not hesitate to contact our office.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the confidential portions of the **Opening Testimony and Exhibits of ICNU** upon the parties shown below by sending copies via First Class U.S. Mail, postage prepaid.

Dated at Portland, Oregon, this 15th day of June, 2015.

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

REDACTED OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 15, 2015

TABLE OF CONTENTS TO THE OPENING TESTIMONY OF BRADLEY G. MULLINS

EXHIBIT LIST

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

Q. ARE YOU THE SAME BRADLEY G. MULLINS WHO FILED OPENING POWER COST TESTIMONY IN THIS PROCEEDING?

A. Yes. I previously filed Opening Power Cost Testimony on behalf of the Industrial Customers of Northwest Utilities ("ICNU") in this proceeding. ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including customers of Portland General Electric Company ("PGE" or the "Company"). A summary of my education and work experience can be found at Exhibit No. ICNU/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Pursuant to the Prehearing Conference Memorandum issued on March 6, 2015, the procedure for this rate proceeding includes two parallel schedules—one for general rate case issues and the other for power cost issues. My testimony addresses several issues pertinent to the general rate case portion of this proceeding. Specifically, my testimony discusses issues surrounding the generation marginal cost study, capital additions, and aspects of the Company's rate schedules. In addition to my testimony, Michael P. Gorman will be providing testimony on behalf of ICNU on cost of capital and James W. Daniel will be providing testimony on behalf of ICNU on rate spread and rate design issues, other than generation marginal costs.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The following is a summary of my testimony, which is organized respectively:

(1) **Generation Marginal Costs Study:**

(a) Marginal Capacity Resource. I recommend that Port Westward II be used as the marginal capacity resource. Unlike the Company's proposal to use an F-Class Combustion Turbine ("Frame CT"), Port Westward II represents a peaker resource that the Company would actually build and is consistent with the Company's proposal to use the Carty Generating Station as the marginal energy resource.

(b) Dispatchability Credit. The Company calculates the variable energy cost portion of the marginal cost of energy based solely on the fuel cost of the marginal energy resource. This calculation, however, understates the true energy cost of the marginal energy resource as it does not account for dispatch benefits, which I propose to include in the marginal cost of energy.

(c) Capitalized Energy. When calculating the capitalized energy component of the marginal cost of energy, the Company included fixed pipeline costs for the marginal energy resource but did not include fixed pipeline costs for the marginal capacity resource. I recommend including fixed pipeline costs for both resources, which will reduce the capitalized energy cost assigned to the marginal cost of energy.

(2) **Load Following Credit:** The Company has changed the methodology used to allocate the load following credit applicable to Schedule 90. I propose to use the same methodology approved in Docket No. UE 283, allocating the load following credit to all customers based on the generation allocation factor of each rate class.

(3) **Capital Additions:** I have performed an audit of the capital forecast proposed by the Company in this proceeding. Based on my review, I recommend a $[redacted] million reduction to the Company's capital forecast, resulting in a revenue requirement reduction of $9.5 million.

(4) **Rate Schedule Issues:**

(a) Schedule 75 & 76R. The Company's proposed changes to Schedule 75 should be rejected. The proposed changes are unfair to customers and are inconsistent with the purpose of Schedule 76R, which allows the self-generating customer to purchase at market prices when it is uneconomic to dispatch the customer-owned generator.

(b) Schedule 77. The Reservation Price offered under the firm load reduction program should be increased to be consistent with the marginal cost of capacity calculated in the generation marginal cost study. In addition, for customers that participate in the program for the entire year, the Reservation Price should apply in all months of the year, not limited solely to participation months.

Q. HAVE YOU PREPARED A SUMMARY TABLE DETAILING THE IMPACT OF ICNU'S REVENUE REQUIREMENT RECOMMENDATIONS?

A. On May 29, 2015 parties reached a settlement in principle resolving a number of revenue requirement issues in this proceeding. Table 1, below, details the impact of ICNU's remaining revenue requirement recommendations relative to the revenue requirement included in the Company's initial filing. The calculation of these revenue requirement calculations has been detailed in Exhibit ICNU/201.

TABLE 1
Summary of Remaining Revenue Requirement Recommendations ($000)

ln		Base	Base w/ Carty
1	**Company Proposed Rate Increase**	**$ 38,752**	**$ 122,335**
2	Cost of Capital (Gorman)	(22,264)	(24,966)
3	Capital Additions	(9,455)	(9,455)
4	**Adjusted Rate Increase**	**$ 7,033**	**$ 87,915**

II. GENERATION MARGINAL COST STUDY

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR RECOMMENDATION ON THE GENERATION MARGINAL COST STUDY.

A. I recommend three changes to the generation marginal cost study. First, consistent with the Company's use of the Carty Generating Station as the marginal energy resource, Port Westward II should be used as the marginal capacity resource. Second, the marginal cost of energy should reflect the dispatchability of the marginal energy resource, which results in lower energy costs as a result of the option to generate in some hours and purchase from the market in others. Third, the calculation of capitalized energy costs should reflect fixed fuel transportation costs for both the marginal energy and capacity resources, as those costs are currently excluded from the marginal capacity resource in the Company's calculation. The combined rate spread impact of all of these changes, as well as the generation marginal cost calculations, have been detailed in Exhibit ICNU/202. In addition, Table 2, below, summarizes the rate spread impact of these three adjustments, along with an alternative adjustment for the marginal capacity resource. These percentages are based on the revenue requirement proposed in the Company's initial filing and do not reflect the partial stipulation, ICNU's remaining revenue requirement adjustments, nor the adjustments proposed in Mr. Daniel's Opening Testimony.

TABLE 2
Rate Spread Impacts of Generation Marginal Cost Recommendations
Percent Rate Adjustment, Including the Carty Generating Station

ln	(a) **Rate Class**	(b) **Company Proposed (Table 5)**	(c) Capacity Resource PWII	(d) Dispatch-ability Credit	(e) Capitalized Energy	(f)=∑(b):(e) **Adjusted Total**	(g) *Alt. Capacity Resource LMS100*	(h)=(f)-(c)+(g) ***Alt. Adjusted Total***
1	7	3.1%	0.8%	0.1%	0.2%	4.1%	*0.5%*	*3.9%*
2	15	-4.2%	-0.5%	0.0%	-0.1%	-4.8%	*-0.3%*	*-4.7%*
3	32	6.0%	-0.1%	0.0%	0.0%	5.9%	*-0.1%*	*5.9%*
4	38	12.7%	0.0%	0.0%	0.0%	12.8%	*0.0%*	*12.7%*
5	47	0.6%	-0.1%	0.0%	0.0%	0.5%	*0.0%*	*0.6%*
6	49	13.5%	0.0%	0.0%	0.0%	13.6%	*0.0%*	*13.6%*
7	83	5.3%	-0.4%	0.0%	-0.1%	4.9%	*-0.3%*	*5.0%*
8	85	3.9%	-0.9%	-0.1%	-0.2%	2.7%	*-0.6%*	*3.0%*
9	89	4.0%	-1.9%	-0.2%	-0.4%	1.5%	*-1.4%*	*2.1%*
10	90	4.9%	-2.3%	-0.2%	-0.5%	1.9%	*-1.6%*	*2.6%*
11	91/95	-2.4%	-0.6%	0.0%	-0.1%	-3.1%	*-0.4%*	*-2.9%*
12	92	5.7%	-2.1%	-0.1%	-0.5%	3.0%	*-1.4%*	*3.6%*

a. Marginal Capacity Resource

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR RECOMMENDATION RELATED TO THE MARGINAL CAPACITY RESOURCE.

A. The marginal capacity resource proposed by the Company is an F-Class Combustion Turbine ("Frame CT"), a type of Simple Cycle Combustion Turbine ("SCCT") that is characterized by its inflexibility and low capital cost. The use of the proposed Frame CT, based on an Energy Information Administration ("EIA") report, produces a real levelized marginal capacity cost of $127.44/kW-yr.[1/] I disagree with using a Frame CT in the generation marginal cost study. Because of its inflexibility, it is not consistent with the type of capacity resource that the Company would actually build to meet incremental peak loads. In addition, it is based on EIA cost data that is inconsistent with the use of the Carty Generating Station as the marginal energy resource, the cost of which was established in a request for proposal ("RFP") process. Rather, my recommendation is that the marginal capacity costs should be based on Port Westward II, which was selected in the same RFP process as the Carty Generating Station. This recommendation will produce a real levelized marginal capacity cost of $[redacted]/kW-yr.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?

A. Yes. In the alternative, my recommendation is to use an LMS100 as the marginal capacity resource based on EIA cost data. For consistency purposes, however, my alternative proposal is to couple the LMS100 with a Combined Cycle Combustion Turbine ("CCCT") as the marginal energy resource based on the same EIA cost data, rather than using the Carty Generating Station. This alternative recommendation will produce a real levelized marginal capacity cost of $[redacted]/kW-yr, as well as an approximate $4.70/MWH reduction to the marginal cost of energy.

Q. WHAT ARE THE TRADITIONAL CAPACITY TECHNOLOGIES CONSIDERED BY UTILITIES IN RESOURCE PLANNING TODAY?

A. There are four primary resource types considered by utilities in resource planning today. These resources are detailed in Table 3, below, along with a brief description of each.

[1/] PGE/1301 at 2 (See footing in column titled "Weighted Capacity Costs $/kW-year").

TABLE 3
Characteristics of Peaker Resources

	Frame GE 7F	Aeroderivative LM6000	Hybrid LMS 100	Reciprocating Wärtsilä
Description	Stationary industrial gas turbine	Designed from aircraft engine; lighter, more delicate than frame	Hybrid of frame and aeroderivative – intercooled equipment required	Large natural gas reciprocating engines
Characteristics	Slower response time; higher heat rate; higher exhaust temperatures/difficult air quality control	Rapid response time; lower heat rate than frame; easy maintenance; smaller unit size	Rapid response; lowest GT heat rate; Especially useful in summer peaking; requires continuous source of cooling water	Highly modular; very rapid response, low heat rate, duel fuel capability, not sensitive to temps and elevation
Capital Cost ($/kW)	800	1,100	1,000	1,300
Fixed O&M ($/MWh)	7.00	25.00	11.00	10.00
Variable O&M ($/MWh)	10.00	5.00	7.00	9.00
Heat Rate (btu/kWh)	9,801	9,048	8,541	8,370
Quick Start (10 min)	No	Yes	Yes	Yes
Ramp Rate (MW/min)	40	50+	50+	250
Recent PNW Additions (Since 2010):	None	Culbertson (2010) Dave Gates (2011) Highwood (2011)	None	Port Westward II (2014)

Table 3 is based largely on the preliminary resource assumptions the Northwest Power and Conservation Council ("Planning Council") is using for the Seventh Power Plan.[2/] The source documents for most of this data have been attached as Exhibit ICNU/203. As can be noted from the figure, the Frame CT is the least flexible and has the highest heat rate of any of the peaker resource options. No Frame CT has been constructed in the Northwest since at least 2010.

[2/] See Exhibit ICNU/203; Draft Seventh Plan Generating Resource Characteristics for use in the Regional Portfolio Model Planning Council (Feb 2015). http://www.nwcouncil.org/media/7148827/p3.pdf; Preliminary Assumptions for Natural Gas Peaking Technologies ("Natural Gas Technologies"), Planning Council (May 2014). https://www.nwcouncil.org/media/7089901/WEB_Ver-5-Preliminary-Assumptions-for-Natural-Gas-Peaking-Technologies_052614.pdf

Q. WHAT IS THE PURPOSE OF A MARGINAL COST STUDY?

A. As the Commission has cited, "[a] marginal cost study should answer the question: How would the utility's costs change if it were to supply an additional kWh or kW at a particular time or service an additional customer? The study is forward looking and must take into account the practices and planning standards *of the particular utility* …."[3/]

Q. UNDER THIS STANDARD, WHAT CRITERIA SHOULD BE USED TO SELECT THE COMPANY'S MARGINAL CAPACITY RESOURCE?

A. Foremost, the capacity resource used in the marginal generation cost study should be based on the type of resource that the Company would actually consider building to meet incremental peak loads on its system. In contrast to selecting a peaker resource based solely on its capital cost, there are many other factors that the Company would consider when selecting a resource to meet incremental peak loads. Factors such as flexibility, emissions, and maintenance costs are a few of the characteristics that the Company may weigh when selecting a peaker resource.

Q. SHOULD THE MARGINAL ENERGY RESOURCE INFLUENCE THE SELECTION OF THE MARGINAL CAPACITY RESOURCE?

A. Yes. The capacity resource should be selected based on cost data that is consistent with the cost data used to select the marginal energy resource. Much like buying a car, there are a large number of models and configurations to choose from when selecting a generation resource in actual operations, resulting in a wide range of potential costs associated with building any specific type of resource. Because the generation marginal cost study is concerned with the relationship between the capacity and energy resources, it is critical that the costs be established consistently for both the energy and capacity resources. For example, to the extent

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3/ In re Investigation of Methods for Estimating Marginal Cost of Service for Electric Utilities, Docket No. UM 827, 1998 Ore. PUC LEXIS 246 at *6 (Sept. 11, 1998) (quoting PGE witness Hethie Parmesano) (emphasis added).

that the cost estimate for the CCCT is based on the high-end of the range of cost estimates, the SCCT should also be based on the high-end of the range of cost estimates. Comparing a top-of-the-line CCCT to a basic, bare-bones SCCT would not make sense and will skew the results of the generation marginal cost study in favor of energy, a result that appears to be present in the Company's study.

Q. SHOULD THE COST OF THE MARGINAL CAPACITY AND ENERGY RESOURCES BE DEVELOPED FROM A SINGLE SOURCE?

A. Yes. It is preferable to select cost estimates for the marginal energy and capacity resources from the same data source, as a single data source will typically measure costs consistently for all resource types. For purposes of the Company's marginal generation cost study, this means that if the cost data for the marginal energy resource was developed from an RFP, the cost data for the marginal capacity resource should also be developed from the same RFP. Or, if the cost data for the marginal capacity resource is developed from an EIA data source, the cost of the marginal energy resource should also be based on the same EIA data source.

Q. SHOULD THE COST OF THE MARGINAL CAPACITY AND ENERGY RESOURCES BE MEASURED AT THE SAME POINT IN TIME?

A. Yes. The costs of capacity and energy resources are largely related and constantly evolving over time. As a result, both resources need to be evaluated at a static point in time. For example, it would not be consistent to compare cost data for a marginal capacity resource that was measured several years ago against cost data for a marginal energy resource that was measured recently.

Q. DOES THE FRAME CT MEET THESE CRITERIA?

A. No. As discussed below, the Company has repeatedly indicated that a Frame CT is not a peaker resource that it would consider for meeting its peak load obligations. This creates inconsistency between the Company's marginal energy and marginal capacity resources in terms of the cost data it uses. While the Company uses cost data developed in the 2012 Request for Proposals for Capacity and Baseload Energy Resources ("2012 RFP") for the marginal energy resource, it is forced to rely on an EIA report titled "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants" to price its marginal capacity resource because it has no comparable Company-specific data for a Frame CT.[4/] Based on the Company's workpapers, for resource attributes not presented in the EIA report, the Company relied on the IRP of another regional utility to acquire those attributes.

Q. DID THE COMPANY CONSIDER A FRAME CT IN ITS MOST RECENT REQUEST FOR PROPOSALS FOR GENERATING RESOURCES?

A. No. As noted in Table 3, combustion turbines based on Frame CT technology have high heat rates and limited flexibility, making them unsuitable resources for maintaining the level of reliability required by the Company to meet incremental peak loads on its system. As a result, the Company has recognized that a Frame CT is not a viable peaker resource in its resource planning. In its 2012 RFP, the Company's independent evaluator noted that the Company had "determined that frame SCCT technology would not meet the flexibility requirements of the RFP."[5/]

Q. DID THE COMPANY EVALUATE A FRAME CT IN ITS 2013 INTEGRATED RESOURCE PLAN ("IRP")?

A. No. The supply side analysis in the Company's 2013 IRP excluded a Frame CT from the list of traditional peaker resource options available to the Company in its resource expansion

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4/ Energy Information Administration, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants ("EIA Report) at A-18 (Apr. 2013). http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

5/ In re Portland General Electric Company Request for Proposals for Capacity and Baseload Energy Resources, Docket No. UM 1535, Independent Evaluator Report for PGE 2012 Capacity and Energy Power Supply Resources RFP at 13 (Jan. 31, 2013) ("2012 RFP Independent Evaluator Report").

plan.[6/] The only traditional capacity technologies considered by the Company in the 2013 IRP were a Wärtsilä reciprocating engine facility and an LMS100 inter-cooled aero-derivative combustion turbine.[7/] For purposes of evaluating capacity resources, the Company stated that "[w]e use capital and operating costs from B&V for the GE LMS100 SCCT and Wärtsilä rapid-start reciprocating engines."[8/]

Q. HOW DOES THE EIA COST DATA FOR THE FRAME CT COMPARE WITH THE COST DATA USED FOR THE MARGINAL ENERGY RESOURCE?

A. For the marginal energy resource, the Company used the costs of the Carty Generation Station as proposed in the 2012 RFP.[9/] Based on the Company's generation marginal cost workpapers, the Carty Generating Station is priced at a total overnight capital cost of $[redacted]/kW. In the EIA report relied upon by the Company for the Frame CT costs, however, the equivalent natural gas combined cycle is priced at $1,009/kW, approximately [redacted]% less than the cost of the Carty Generating Station included in the marginal cost of energy.[10/] It follows that it is inaccurate to use the cost of a Frame CT selected from the EIA report as the marginal capacity resource while simultaneously using the cost of the Carty Generating Station established through a competitive bidding process as the marginal energy resource.

Q. WHAT CAPACITY RESOURCE DO YOU RECOMMEND?

A. The Carty Generating Station is the resource the Company has selected to meet its marginal energy needs. The same criteria should apply to its marginal capacity needs. The resource most recently selected to meet those needs is Port Westward II, which should also be used as

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6/ In re Portland General Electric Company 2013 Integrated Resource Plan, Docket No. LC 56, 2013 IRP Report, Appendix G, Characterization of Supply Side Options at 39-40 (Mar. 2013). https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp_appG.pdf
7/ Id.
8/ Id. at 152.
9/ PGE/1300 at 3:22
10/ EIA Report at A-10.

the marginal capacity resource in the generation marginal cost study. In addition to being more reflective of the actual resource type that the Company would build to meet peak load requirements, the use of Port Westward II will result in a consistent comparison between the marginal cost of both energy and capacity, as the 2012 RFP was conducted simultaneously for both resources. Based on the marginal cost inputs for Port Westward II provided by the Company in discovery,[11/] using Port Westward II as the marginal capacity resource will result in a marginal capacity cost of $[redacted]/kW-yr.

Q. WHAT IS YOUR ALTERNATIVE RECOMMENDATION?

A. As an alternative proposal, the cost of an LMS100 could be used to calculate the marginal cost of capacity. This is a capacity resource that the Company has also considered building, and thus, could also represent the Company's marginal capacity costs. I would propose to base this resource on the cost data published in the EIA report. For consistency purposes, however, I propose that the CCCT marginal energy resource be based on the same set of EIA cost data as the LMS100, rather than using the Carty Generating Station as the marginal energy resource. This alternative recommendation will result in a marginal capacity cost of $[redacted]/kW-yr, as well as an approximate $4.70/MWH reduction to the marginal cost of energy.

b. Dispatchability Credit

Q. WHAT IS YOUR RECOMMENDATION RELATED TO DISPATCHABILITY?

A. The Company calculated the variable energy component of marginal thermal energy costs based solely on fuel costs. Because the thermal energy resource, however, is dispatchable, its fuel cost does not represent the true cost of energy from that resource. Rather, in some hours, the Company has the option not to dispatch the marginal energy resource and to purchase

[11/] Exhibit ICNU/204 at 1-2 (the Company's response to ICNU Data Request ("DR") 21).

energy on the market, resulting in lower overall energy costs relative to the cost of fuel. I propose to reflect this dispatch benefit in the calculation of the marginal cost of energy, which, based on my analysis, will reduce the marginal cost of energy by approximately $1.34/MWh.

Q. HOW DOES THE COMPANY CALCULATE MARGINAL THERMAL ENERGY COSTS?

A. The marginal cost of the thermal energy resource consists of three cost components. These cost components are all based on the characteristics of the marginal thermal energy resource and are: 1) variable energy costs; 2) variable O&M costs; and 3) capitalized energy costs.

Q. WHY DOES THE USE OF FUEL COSTS OVERSTATE THE VARIABLE ENERGY COST COMPONENT OF THE MARGINAL THERMAL ENERGY RESOURCE?

A. The Company calculated the variable energy cost component of the marginal thermal energy resource based on the fuel cost of generation from that resource. This calculation was performed by applying the heat rate of the marginal thermal energy resource to the fuel price forecast. This calculation, however, overstates the variable energy cost associated with the marginal thermal energy resource because it does not account for dispatchability. In practice, the Company will dispatch the energy resource only in hours when its generation cost is less than market prices and will purchase market energy in hours when the fuel prices exceeds market prices.

Q. HOW DOES DISAPTCHABILITY REDUCE ENERGY COSTS?

A. In hours when fuel costs are less than market prices the Company can dispatch the resource in order to serve its loads. In hours when the fuel cost exceeds market prices, however, the Company can choose not to dispatch the resource and, instead, purchase power on the market to supply energy to loads, saving money relative to the resource fuel cost. The result of this dispatch option is a reduction of the overall cost of energy relative to the fuel cost of the marginal energy resource.

Q. HOW DID YOU ESTIMATE THE IMPACT OF DISPATCHABILITY ON THE VARIABLE ENERGY COST COMPONENT?

A. I performed an analysis comparing the fuel price for calendar year 2016 for the marginal thermal energy resource to the hourly market prices modeled in the Company's MONET model. I calculated the hourly cost savings that the Company would achieve by purchasing on the market in hours when market costs are less than fuel costs. I aggregated the cost savings for the calendar year and divided that number by the total fuel cost, determining that the dispatchability savings represented approximately 4.5% of total fuel costs. I then applied this percentage as a credit reduction to the variable energy cost component used in the marginal energy cost calculation.

Q. WHAT IS THE IMPACT OF THIS DISPTACHABILITY CREDIT?

A. Incorporating this dispatchability credit into the variable energy cost component of the marginal thermal energy resource cost will result in an approximate $1.34/MWH reduction to the overall marginal cost of energy.

c. Capitalized Energy Cost

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR RECOMMENDATION RELATED TO THE CALCULATION OF CAPITALIZED ENERGY COSTS.

A. Capitalized energy costs, a component of the marginal thermal energy costs, are based on the difference between the fixed cost of the marginal energy resource and the fixed cost of the marginal capacity resource. The Company's calculation of these capitalized energy costs included the fixed cost of fuel transportation for the marginal energy resource but excluded the fixed cost of fuel transportation for the marginal capacity resource. My recommendation is to include the fixed cost of fuel transportation for both the marginal energy and marginal capacity resources when calculating capitalized energy costs. Adopting this recommendation will reduce marginal energy costs by $3.72/MWH.

Q. WHAT IS CAPITALIZED ENERGY COST?

A. Capitalized energy is the portion of the marginal energy resource fixed cost that exceeds the fixed cost of the marginal capacity resource. It is included in the marginal cost of energy as a result of the tradeoff that utilities often make between purchasing a peaker resource and a baseload resource. It may make economic sense for a utility to pay more to purchase a baseload resource, relative to the capital cost of a peaking resource, in order to receive energy cost savings associated with a lower heat rate. For example, a utility may pay more to acquire a CCCT, rather than an SCCT, due to the ultimate energy cost savings associated with the CCCT's lower heat rate. Because the additional capital expenditures are made in order to generate energy cost savings, the incremental fixed cost is considered by some to be a long-run marginal cost of energy.

Q. WHAT IS THE PROBLEM WITH THE COMPANY'S CALCULATION OF CAPITALIZED ENERGY COST?

A. When performing the capitalized energy cost calculation, the Company included fixed fuel transportation costs for the marginal energy resource but not for the marginal capacity resource, overstating the difference in fixed costs between the two resource types. Assuming capitalized energy is, indeed, reflected in the marginal cost of energy, the calculation needs to be based on a consistent set of fixed cost items between the marginal capacity and energy resources. If fixed pipeline capacity costs are included for the marginal energy resource, they should also be included for the marginal capacity resource.

Q. ARE FIXED PIPELINE COSTS OTHERWISE INCLUDED IN THE MARGINAL COST OF CAPACITY?

A. Yes. Fixed pipeline costs are included in the marginal cost of capacity in the context of the overall generation marginal cost study. They are only excluded in the calculation of the capitalized energy component of the marginal cost of energy. The Company provides no justification for why the fixed pipeline costs were included in the marginal cost of capacity but excluded from the calculation of capitalized energy, indicating that this is an error in the Company's calculation.

Q. HOW SHOULD THE CAPITALIZED ENERGY COST CALCULATION BE CORRECTED?

A. Either the fixed pipeline costs need to be included for both the marginal energy and capacity resources, or they need to be excluded from both the marginal energy and capacity resources. While the calculation of capitalized energy could be corrected either way, my proposal, for purposes of this proceeding, is to include the fixed pipeline capacity for both the energy and capacity resources, resulting in a $3.72/MWH reduction to overall marginal energy costs.

III. LOAD FOLLOWING CREDIT

Q. WHAT IS YOUR PROPOSAL REGARDING THE LOAD FOLLOWING CREDIT.

A. In the Company's last two rate cases, it has allocated the cost of the load following credit adopted in Docket No. UE 262 to all customers in proportion to their generation allocation factor. In this proceeding, however, the Company has proposed to change the approved methodology and allocate the credit solely to Schedule 89 customers.[12/] I disagree with the Company's proposal and recommend that the load following credit be allocated in a manner

[12/] PGE/1400 at 22:1-8.

that is consistent with how it has been allocated the prior two rate cases, assigned to all customers in proportion to their generation allocation factor.

Q. WHAT IS THE LOAD FOLLOWING CREDIT?

A. The load following credit was adopted in the Company's 2013 general rate case, Docket No. UE 262.[13/] It is applicable to all large customers with loads exceeding 100 aMW.[14/] It accounts for the costs of ancillary services that are not needed for very large customers, and therefore, are excluded from the rates charged to those customers. As stated in the joint testimony in support of the partial stipulation that adopted the credit in Docket No. UE 262, "[t]he credit recognizes the lower load following costs to serve very large, stable loads."[15/] Because customers with very large loads typically have a uniform and predictable load profile, it is not necessary for the Company to provide balancing services for much of those large customers' loads. The Company could, for example, simply purchase large blocks of market power to serve the large customer, without having to provide balancing and other ancillary services otherwise required to serve other full requirements customers.

Q. HOW DID THE COMPANY PROPOSE TO ALLOCATE THE LOAD FOLLOWING CREDIT IN THIS PROCEEDING?

A. The Company proposed to allocate all of the cost of the load following credit solely to Schedule 89 customers. This is in contrast to how the Company allocated the cost of the load following credit in the last two rate cases, where it allocated the cost of the credit to all customers in proportion to their generation allocation percentage.

13/ In re Portland General Electric Company Request for a General Rate Revision, Docket No. UE 262, Order No. 13-459, App. A at 7 (Dec. 9, 2013).

14/ Id.

15/ Docket No. UE 262, Stipulating Parties / 100, Testimony in Support of Partial Stipulation at 13:18-23 (July 10, 2013).

Q. WHAT WAS THE COMPANY'S JUSTIFICATION FOR CHANGING THE ALLOCATION?

A. The Company stated that the allocation change was made "in order to better equalize the base rate price impacts across the major rate schedules."[16/] In other words, the Company has proposed to use the allocation of the load following credit in a manner that is similar to the customer impact offset adjustment.

Q. DO YOU AGREE WITH THE CHANGE?

A. No. The Company already has a customer impact offset methodology in place in its rate spread analysis that is designed to equalize rate impacts across rate schedules. Thus, it is unnecessary for the Company to use the load following credit as a supplemental methodology to equalize rate impacts between rate schedules, when it already has an established methodology to do so. It is also unfair to Schedule 89 customers to arbitrarily allocate costs associated with very large customers simply because the marginal cost study results in a lower rate increase for those customers in this proceeding. This is a particularly inequitable result since Schedule 89 received an above average rate increase in Docket No. UE 283, the Company's 2014 rate case, yet the load following credit was not used to offset the unfavorable impact of the marginal cost study to Schedule 89 customers in that proceeding.

Q. WHAT WAS THE SCHEDULE 89 RATE INCREASE RELATIVE TO THE AVERAGE APPROVED IN UE 283?

A. In Docket No. 283, Schedule 89 customers received a 3.4% base rate increase, relative to an overall base rate increase of 2.4%.[17] Thus, Schedule 89 received a 42% larger base rate increase than the average customer in that proceeding. Penalizing the Schedule 89 rate class

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16/ PGE/1400 at 22:6-8.

17/ These values are based on rate spread calculations that were provided by the Company following the settlement stipulation in UE 283. These calculations have been included in my workpapers.

now, when the marginal cost of service is mitigating the impact of above average rate increases in prior years, is not an equitable result.

Q. WHAT DO YOU RECOMMEND?

A. I recommend using the same allocation methodology for the load following credit that was approved in the Docket Nos. UE 283 and UE 262, based on the proportion of each rate schedule's marginal generation cost. Doing so will have the rate spread impacts detailed in Exhibit ICNU/205.

IV. CAPITAL ADDITIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION ON CAPITAL ADDITIONS.

A. In addition to the $488.3 million of capital associated with the Carty Generating Station, the Company has proposed to include in rate base approximately $[redacted] million of capital additions expected to be placed in service in calendar year 2015, resulting in nearly one billion dollars of capital added into the Company's rate base in this proceeding. Much of the proposed capital additions, however, are based on forecasts that are not well documented, leading to questions regarding the ultimate amount of capital additions that should be reflected in the Company's rates in this proceeding. In order to address this issue, I performed an audit of the Company's capital addition forecast. Based upon that audit, the workpapers for which are presented in Confidential Exhibit ICNU/206, I propose a $[redacted] million reduction to the Company's capital forecast in this proceeding, resulting in a revenue requirement reduction of approximately $9.5 million.

Q. HOW MUCH CAPITAL HAS THE COMPANY ADDED IN RECENT YEARS?

A. The Company has undertaken a capital program that increased gross plant from approximately $7.2 billion[18/] in the 2013 general rate case to approximately $9.2 billion in this proceeding,[19/] an approximate $2.0 billion increase over a three year period. This is a substantial amount of new capital, which is concerning given utilities' incentive to over-build their systems. Thus, capital additions deserve particular attention in this proceeding.

Q. DOES THE COMPANY HAVE AN INCENTIVE TO INCREASE ITS RATE BASE?

A. Yes. In investor reports, the Company details its rapidly increasing rate base as a positive aspect of the Company's overall financial condition.[20/] The Company has been clear with its investors that its financial strategy has revolved around increasing rate base, referring to new rate base additions as positive opportunities.[21/] As a result of the Company's clear intent to increase its rate base for the benefit of investors, the Commission should take great caution in reviewing and approving the Company's capital forecast, which I will address below.

Q. HOW DID THE COMPANY DEVELOP RATE BASE IN THIS PROCEEDING?

A. The Company developed rate base in this proceeding based on an end-of-period December 31, 2015 calculation.[22/] The rate base amount was forecasted based on actual plant in service on December 31, 2014, adjusted for capital additions forecast over calendar year 2015.[23/] Finally, the Company added the rate base associated with the Carty Generation Station, which will be incorporated into rates through a separate tariff rider.[24/]

18/ See Docket No. UE 283, PGE/308.
19/ See PGE/201.
20/ See ICNU/207 at 2.
21/ Id. at 4.
22/ PGE/200 at 23:13-24:6.
23/ Id.
24/ Id. at 26:1-27:12

Q. PLEASE DESCRIBE THE 2015 RATE BASE ADDITIONS PROPOSED BY THE COMPANY.

A. The Company provided a list of [redacted] capital additions that it has forecast to be placed in service in calendar 2015.[25/] The list consists of both discrete capital projects, as well as blanket capital projects. Blanket capital projects are non-discrete, or routine, capital expenditures, such as replacing distribution poles and installing new distribution lines. Collectively these capital additions amount to $[redacted] million.[26/]

Q. WHAT DOCUMENTATION DOES THE COMPANY HAVE SURROUNDING THESE CAPITAL PROJECTS?

A. For most projects the Company has provided a "Project Justification Form," containing a high level description, as well as approved budget amounts, for the project. Attached as Exhibit ICNU/208 is a sample of Project Justification Forms for projects that I have reviewed in this proceeding. As can be noted, the Project Justification Forms contain little detail surrounding the specific project activities to be undertaken on a project. They also do not contain project timelines or a calculation of the expected customer benefit—other than high-level statements that the project will be beneficial—of undertaking the project.

Q. ARE THE PROJECT JUSTIFICATION FORMS ADEQUATE DOCUMENTATION FOR THE COMPANY'S PROPOSED CAPITAL PROJECTS?

A. No. The Project Justification Forms do not contain adequate information to determine whether a particular project is, in fact, beneficial to ratepayers. In addition, the Project Justification Forms are indicative of the fact that the Company is not undertaking a rigorous program to prioritize its capital expenditures and to invest in only those projects that will produce concrete economic benefits to ratepayers. The Project Justification Forms contain no such calculations,

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25/ See Confidential ICNU/206 at Workpaper A2.
26/ Id.

indicating that the Company may not be performing a sufficient evaluation of these economic factors when budgeting new capital projects. In addition, the budget amounts approved in the Project Justification Forms are often materially different from the capital amounts proposed in the Company's filing.

Q. GIVEN THESE INADEQUACIES, WHAT METHODOLOGY DID YOU EMPLOY TO REVIEW THE LARGE NUMBER OF CAPITAL PROJECTS?

A. I focused my review on the 20 largest projects in the Company's list of capital additions, which collectively amount to approximately 72% of the Company's total request related to capital additions. I then extrapolated my findings regarding the large projects to the remaining [redacted] projects.

Q. WHAT WAS THE RESULT OF YOUR REVIEW?

A. A detailed review of each of these projects can be found in Confidential Exhibit ICNU/206, including specific adjustments to each of the projects. Generally, I have developed three types of adjustments to the capital forecasts for these projects. First, I remove all projects that are no longer expected to come, or that the Company has not demonstrated are capable of coming, online prior to December 31, 2015. Second, I evaluated capital attributable to blanket capital projects by using the actual capital placed into service as of April 2015 and comparing the remainder of the year to historical amounts spent on a particular blanket capital category. Finally, for discrete capital additions, I compared the amount in the Company's filing to the requisition amounts detailed in the respective Project Justification Forms, and, to the extent that the Project Justification Form included a lower number than included in the Company's filing, I relied on the amount included in the Project Justification Form. Based on this framework, my workpapers support reducing the Company's capital forecast, for the top 20 projects, by approximately $[redacted] million.

Q. WHAT IS YOUR RECOMMENDATION RELATED TO THE REMAINING [redacted] PROJECTS?

A. The remaining [redacted] capital projects constitute $[redacted] million. Based on my review of the 20 largest projects, I propose a 10% undistributed reduction to the capital forecast associated with these remaining projects. My review indicates that the Company overstated its capital budget for the 20 largest projects by approximately 20%. For the smaller projects, the Company was not capable of providing the data necessary to evaluate the accuracy of their forecast on the same level as the large capital projects.[27/] Accordingly, I recommend an adjustment to these remaining projects to reflect the fact that, similar to the 20 largest projects, many are likely overstated. However, based on the assumption that the potential for budget variance for these smaller projects is likely less than that of large projects, I recommend a conservative 10% undistributed reduction, rather than the 20% determined for the 20 largest projects. The impact of this undistributed reduction to the remaining capital items is an approximate $[redacted] million reduction to capital additions.

Q. WHAT IS THE TOTAL ADJUSTMENT THAT YOU ARE PROPOSING?

A. In total, I am proposing an adjustment of approximately $[redacted] million to the Company's $[redacted] million capital addition forecast. The revenue requirement impact of this adjustment is approximately $9.5 million.

[27/] See Confidential Exhibit ICNU/204 at 3-5 (the Company's Response to ICNU DR 111; the Company limited its response to only the 20 largest projects).

Q. ARE THERE ANY PARTICULAR PROJECTS DETAILED IN YOUR ANALYSIS THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. In order to provide an indication of the type of capital adjustments that I have made in my review, I will provide a brief description of my evaluation of four particular capital projects: [redacted]. Additional descriptions related to these adjustments, as well as adjustments to the remaining projects, can be found in Confidential Exhibit ICNU/206.

Q. WHAT IS YOUR ADJUSTMENT RELATED TO THE [redacted]?

A. In the Company's initial filing, it forecast that this project would be placed into service in October 2015 at a total capital cost of $[redacted] million. In response to ICNU DR 114, however, the Company indicated that this project is no longer expected to be placed into service in the test period.[28/] Accordingly, my adjustment is to remove this project entirely from the Company's capital forecast.

Q. WHAT IS YOUR ADJUSTMENT RELATED TO THE [redacted]?

A. [redacted]. The Company proposes a capital budget of approximately $[redacted] million for these activities. I have several concerns with both the nature and amount of expenditures forecast under this project.

28/ Confidential Exhibit ICNU/204 at 11(Company's Response to ICNU DR 114, Confidential Attachment A).
29/ Confidential Exhibit ICNU/208 at 8 (Project No. P35908).

First, capital should not be replaced simply because it is at the end of its accounting useful life and is no longer providing the Company with a return on rate base. The life of capital deployed on the Company's system should be maximized, without regard to the accounting depreciation methods used, in order to provide the greatest level of customer benefit associated with an asset. If failure is imminent and system reliability is threatened, then there is a reason to replace the equipment. However, this should not be done in an ad hoc manner, as suggested in the Project Justification Form. Rather, the equipment should be inspected in order to determine if failure is imminent and if replacement is necessary.

Second, the Company already has proposed a substantial capital budget for [redacted], titled "[redacted]" for which it has requested approximately $[redacted] million. To the extent that the Company is [redacted], the capital budget for [redacted] should be declining, offsetting the [redacted] proposed in this category.

Third, the amount that the Company has requested is not consistent with the [redacted] work that has been performed to date on this project. Over the first four months of calendar year 2015, the Company has performed virtually no [redacted] activities. To date it has deployed only $[redacted] in capital related to this activity, only 0.01% of what it has requested for calendar year 2015 in its capital addition forecast.[30/] Thus, it appears that the Company is not actually performing any activities related to [redacted] at this time.

Finally, the amount proposed by the Company is also inconsistent with the amounts historically expended on this activity, which appears to not have exceeded $[redacted] million in prior

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30/ Confidential Exhibit ICNU/204 at 7 (Company's Response to ICNU DR 112, Confidential Attachment A).

years. While the Company was not capable of providing the actual capital placed into service on this project in calendar year 2014, it was not among the top 20 projects in 2014, indicating that some amount less than $3.0 million was spent on the activity.[31/]

As a result of the fact that virtually no proactive cable replacement activities have been performed to date in calendar year 2015, this capital project should be removed from the Company's capital forecast, reducing its rate base request by $7.0 million.

Q. WHAT IS YOUR ADJUSTMENT RELATED TO VEHICLE VINTAGE REPLACEMENT?

A. The Company has proposed a capital budget of approximately $9.3 million, which, based solely on the project description, appears to be related to replacements of the Company's vehicle fleet. The Company, however, did not produce a Project Justification Form for this capital project in response to Staff DR 178, so the actual nature of the project is not entirely clear.

Notwithstanding, the amount of capital requested for this project far exceeds the amounts actually expended on this capital category in prior years. For example, in calendar year 2014 the Company spent only $5.8 million on this capital category.[32/] In calendar year 2013 the Company spent only $5.2 million.[33/] In addition, through April of 2015, the Company spent only $1.4 million on this capital category, or approximately $1.9 million less than it forecast over the same period.[34/]

Because of these large discrepancies, my proposal is to forecast the capital for this account based on the actual monthly plant placed in service as of April 2015 and to use the

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31/ Confidential Exhibit ICNU/204 at 5 (Company's Response to ICNU DR 111, Confidential Attachment A).
32/ Id.
33/ Id.
34/ Confidential Exhibit ICNU/204 at 9 (Company's Response to ICNU DR 113, Confidential Attachment A)

average actual monthly plant placed in service in calendar year 2014 for the remaining months in calendar year 2015. I use this same methodology for adjusting the capital budgets of several other capital categories, which, as applied to the Vehicle Vintage Replacement project, will result in a $4.1 million reduction to the Company's capital forecast.

Q. WHAT IS YOUR ADJUSTMENT RELATED TO THE PORTLAND SERVICE CENTER UPGRADE?

A. The Company has proposed a capital budget of $18 7 million for the Portland Service Center Upgrade, which the Company forecasts to go into service in late 2015. Because of the amount of capital and the proximity to the December 31, 2015 cut-off date, special attention should be paid to the timing of this project to determine if it will actually be capable of being placed into service in time to be included in the test period.

The Project Justification Form is the only data provided by the Company on this project and it does not provide sufficient information to determine whether this project will be capable of being placed into service by the cut-off date. When asked for the most recent detailed workplan for this project in ICNU DRs 116 and 117, the Company referred to the Project Justification Form, which does not contain a workplan that can be used to demonstrate whether the project is, in fact, capable of being placed into service by the end of the calendar year.[35/] Through April of 2014, the Company has only expended approximately 21% of the total capital forecast on this project, which is evidence that the project may be delayed beyond the December 31, 2015 cut-off date.

[35/] Confidential Exhibit ICNU/204 at 12-13 (The Company's Response to ICNU DRs 116 and 117).

Because the Company has provided insufficient evidence to demonstrate that the project will be capable of being completed in the test period, my recommendation is to remove this project from the Company's capital forecast.

Q. WHAT ARE YOUR REMAINING CAPITAL ADJUSTMENTS FOR THE 20 LARGEST CAPITAL ADDITIONS?

A. Detailed descriptions of my review and adjustments proposed for the remaining projects can be found in Confidential Exhibit ICNU/206.

Q. PLEASE SUMMARIZE WHY IT IS IMPORTANT THAT THE COMMISSION ADOPT THIS RECOMMENDATION.

A. In summary, the recent trajectory of the Company's capital additions is placing a great deal of strain on its customers. The Company has demonstrated that it has a clear intention to aggressively increase its rate base for the benefit of investors. Accordingly, the Commission should exercise great caution when evaluating the Company's capital forecasts, and should adopt my adjustment to remove unsupported capital amounts from the Company's forecast, reducing its overall rate base by $76 0 million and reducing revenue requirement by approximately $9.5 million.

V. RATE SCHEDULE ISSUES

a. Schedules 75 & 76R

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REVISION TO SCHEDULE 75.

A. The Company has proposed to modify the language of Special Condition 8 in Schedule 75 (and Special Condition 7 of the direct access equivalent, Schedule 575) to include a provision that allows the Company to modify the customer's baseload demand if it determines that this level does not match the customer's load, adjusted for actual customer generation.[36/]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED CHANGE?

A. No. The proposed change is one-sided and ambiguous. It gives the Company full control over the frequency and magnitude of any changes to the customer's baseload demand that the Company initiates. Additionally, the proposed change appears to effectively invalidate Schedule 76R's Partial Requirements Economic Replacement Power Rider available to customers who take service under Schedule 75.

Q. PLEASE DESCRIBE SCHEDULE 75.

A. Schedule 75 is a Partial Requirements Service tariff that is available to nonresidential customers with a load over 30 kW and that self-generate all or a portion of their own power.[37/] Under the tariff, the Company provides a baseline level of energy that is priced under Schedule 89, the Company's large industrial cost-of-service tariff.[38/] The Company and the customer determine a Baseline Demand level that is defined as "the Demand normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating as planned by the Customer."[39/] The difference between the baseline level of energy supplied by the Company under Schedule 89 and the customer's total demand is either provided by the customer's own generation, or is purchased under Schedule 76R.[40/]

36/ PGE/1400 at 25:7-13.

37/ PGE Schedule 75 at 1, available at: https://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/Sched_075.pdf.

38/ Id. at 5.

39/ Id. at 2.

40/ PGE Schedule 76R at 1, available at: https://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/Sched_076R.pdf.

Q. PLEASE DESCRIBE SCHEDULE 76R.

A. Schedule 76R is a rider available to customers on Schedule 75 that gives these customers "the option of purchasing Energy from the Company to replace some, or all, of the Customer's on-site generation when the Customer deems it is more economically beneficial than self-generating."[41/] To take advantage of Schedule 76R, the customer provides the Company with an Energy Needs Forecast that identifies the amount of Economic Replacement Power requested.[42/] The Company can either meet the Energy Needs Forecast by purchasing the requested power on the market, or can inform the customer that Economic Replacement Power is unavailable.[43/] Thus, whenever it is more economical for the customer to purchase Economic Replacement Power from the Company, rather than generating that power itself, the customer has the option to do so under Schedule 76R, subject to availability requirements.

Q. HOW IS BASELINE DEMAND DETERMINED UNDER SCHEDULE 75?

A. The tariff allows the customer to select its Baseline Demand, subject to certain notice requirements. Under Special Condition 8 of the tariff as it currently reads:

> The Customer's Baseline Demand may be increased or decreased as requested by the Customer for planned, long-term load changes including changes resulting from the addition of long-term energy efficiency measures, load shedding, the addition or removal of equipment or the permanent removal of generating capacity from the Customer location. Such changes will be effective upon verification of the change by the Company. "Long-term" or "permanent" mean changes that are implemented with the purpose of being in place indefinitely.[44/]

Under Special Condition 9, any proposed change in Baseline Demand that does not exceed 5 MW requires that the customer provide the Company with six months' written notice and may

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41/ Id.
42/ Id. at 2.
43/ Id.
44/ PGE Schedule 75 at 8.

not be made more than once in a calendar year.[45] Any proposed change in Baseline Demand that exceeds 5 MW requires that the customer provide the Company with at least 13 months' written notice and is effective on January 1st of the applicable year.[46]

Q. HOW DOES THE COMPANY'S PROPOSAL CHANGE THESE REQUIREMENTS?

A. The Company has proposed to add the following sentence at the end of Special Condition 8: "The Customer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the actual Customer generation."[47]

Q. WHAT IS WRONG WITH THE COMPANY'S PROPOSED LANGUAGE?

A. There are a number of problems with this language. First, because Special Condition 9 applies the notice requirements to a change in Baseline Demand specifically to the customer, any modification to the customer's Baseline Demand made by the Company has no notice requirements at all. Additionally, Special Condition 9 imposes limitations on the frequency with which a customer can propose a modification to Baseline Demand. No such limitation applies to the Company under its proposed language. Thus, customers on Schedule 75 could be subject to frequent and significant changes in their Baseline Demand with little or no notice from the Company under its proposed language. This has the potential to expose customers to substantial price fluctuations, which can cause significant economic strain and severely inhibit future planning efforts.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE COMPANY'S PROPOSED LANGUAGE?

A. Yes. It is unclear what the Company means by "actual Customer generation." Currently, a customer may be able to supply 45 MW of its load through self-generation but, because market

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[45] Id.
[46] Id.
[47] PGE/1401 at 17.

prices are lower than its cost of self-generating, chooses to purchase economic replacement power under Schedule 76R rather than running its own generating units. That is expressly what Schedule 76R is for.[48/] Under the Company's proposed language, however, it appears that if the customer is capable of self-generating 45 MW, it must do so or risk having its Baseline Demand modified by the Company. This would effectively invalidate Schedule 76R.

Q. DO YOU HAVE A PROPOSAL TO MODIFY SCHEDULE 75 THAT ADDRESSES THESE ISSUES?

A. Yes. Exhibit ICNU/209 contains my changes to Schedule 75 in redline. These changes apply the notice requirements of Special Condition 9 to both the customer and the Company. They also modify the Company's addition to Special Condition 8 to read: "The Customer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the Customer's generating capacity." Rather than tying Baseline Demand to the customer's actual generation, this language ties it to what the customer is capable of self-generating, which ensures that Schedule 76R remains a viable option for Schedule 75 customers and preserves the purpose of this tariff rider.

b. Schedule 77

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S FIRM LOAD REDUCTION PROGRAM UNDER SCHEDULE 77.

A. Schedule 77 is the Company's Firm Load Reduction Program, which was implemented as a permanent program through Advice No. 13-08 and approved by the Commission on August 6, 2013. The program provides the Company with the opportunity to interrupt certain non-residential customer loads in consideration of a $3/kW-mo or $6/kW-mo Reservation Payment,

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48/ PGE Schedule 76R at 1.

depending on agreed upon notice requirements.[49/] The purpose of the program is to reduce the Company's need for capacity by allowing participating customers "to operate as a capacity resources during critical events, such as large load increases (typically caused by extreme weather), large declines in generation (such as a generator going off-line or a sudden decline in wind generation) or significant regional transmission constraints."[50/] Thus, the participants in this program are providing a capacity benefit to the Company's system in exchange for a Reservation Payment. The Company has described this as "a win-win demand-response proposition, economically and environmentally."[51/]

Q. WHAT IS YOUR RECOMMENDATION RELATED TO SCHEDULE 77?

A. I have two general recommendations related to Schedule 77. First, I propose that the Reservation Payment rates be updated to be consistent with the marginal cost of capacity ultimately adopted in this proceeding. Second, I recommend that the customers electing to participate in the program for the entire year should be provided with a Reservation Payment in all months of the year, rather than limiting the payment to the Participation Months.

Q HOW WERE THE CURRENT SCHEDULE 77 RESERVATION PAYMENT RATES DEVELOPED?

A. The current Reservation Payment on Schedule 77 is $3.00/kW-mo for customers that require 18 hours' advance notice and $6.00/kW-mo for customers that only require 4 hours' advance notice of a Load Reduction Event. These reservation payment rates were established through Advice No. 13-08. No economic justification was provided to support the level of the Reservation Payment rates proposed in that filing.

49/ PGE Schedule 77 at 2, available at: https://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/Sched_077.pdf.

50/ Advice No. 13-08, Attachment A at 1 (Aug. 6, 2013).

51/ Id.

Q. HOW DO YOU PROPOSE THAT THE RESERVATION PAYMENT RATES BE CALCULATED?

A. Because the participants in the Firm Load Reduction program are providing a valuable capacity benefit to the Company's system, my recommendation is that the Reservation Payment be tied to the marginal cost of capacity ultimately approved in this proceeding. This will send an effective price signal to customers participating in the program and will result in an equitable level of consideration for the services provided by those customers.

Q. HOW DO YOU PROPOSE TO DIFFERENTIATE BETWEEN CUSTOMERS THAT REQUIRE 18 HOURS' VERSUS 4 HOURS' NOTICE FOR A FIRM LOAD REDUCTION EVENT?

A. I propose to continue the Company's convention that customers requiring 18 hours of notice for a firm load reduction event should receive one-half of the Reservation Payment offered to customers requiring only 4 hours of notice. Thus, the customers requiring 4 hours of notice will receive a Reservation Payment based on the full marginal cost of capacity, and the customers requiring 18 hours of notice will receive Reservation Payment based on one-half the marginal cost of capacity.

Q. HOW WILL THE USE OF THE MARGINAL COST OF CAPACITY IMPACT THE RESERVATION PAYMENT?

A. The impact of relying on the marginal cost of capacity to establish the Reservation Payment will depend on the marginal capacity resource ultimately selected in the generation marginal cost study in this proceeding. If my recommendation to use Port Westward II is adopted, the marginal cost of capacity will be $163 17/kW-yr, which equates to a reservation payment of $13.60/kW-mo. If the Frame CT, as proposed in the Company's initial filing, is selected, the marginal cost of capacity will be $127.44/kW-yr,[52/] which equates to a Reservation Payment of $10.62/kW-mo. Either way, then, participants in the Firm Load Reduction Program are not currently receiving the full value of their capacity contributions to the system.

Q. DO YOU AGREE THAT THE RESERVATION PAYMENT SHOULD BE LIMITED TO ONLY THE PARTICIPATING MONTHS?

A. No. Limiting the Reservation Payment to the participation months—defined in the tariff as December, January, February, July, August, and September—denies participants the full value of the capacity that they are providing to the system. Participation in the program during these months will avoid a resource for the entire year, not just in the six months when a curtailment is possible. Thus, because participants are only receiving six months of Reservation Payments, they are only being compensated for half of the capacity value that they are contributing to the system. My proposal is to provide a reservation payment in all months for those customers that elect to participate in the program for the entire year.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

52/ PGE/1301 at 2 (See footing in column titled "Weighted Capacity Costs $/kW-year").

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/201

REVENUE REQUIREMENT CALCULATIONS

June 15, 2015

Revenue Requirement Calculations
Impact of Cost of Capital
($000)

	Settlement ROO (9)	Rev. Change For COC (10)	COC ROO (11)
Sales to Consumers	1,837,761	(22,264)	1,815,497
Sales for Resale	-		-
Other Revenues	25,138		25,138
Total Operating Revenues	1,862,900	(22,264)	1,840,635
Net Variable Power Costs	556,895		556,895
Production O&M (excludes Trojan)	146,000		146,000
Trojan O&M	93		93
Transmission O&M	14,251		14,251
Distribution O&M	94,457		94,457
Customer & MBC O&M	72,083		72,083
Uncollectibles Expense	7,902	(96)	7,807
OPUC Fees	6,892	(83)	6,808
A&G, Ins/Bene., & Gen. Plant	153,003		153,003
Total Operating & Maintenance	1,051,577	(179)	1,051,397
Depreciation	270,257		270,257
Amortization	49,697		49,697
Property Tax	59,947		59,947
Payroll Tax	14,187		14,187
Other Taxes	1,798		1,798
Franchise Fees	46,809	(567)	46,242
Utility Income Tax	62,984	(8,536)	54,447
Total Operating Expenses & Taxes	1,557,256	(9,283)	1,547,973
Utility Operating Income	305,644	(12,982)	292,662
	305,644		292,662
Rate Base			
Gross Plant	8,705,924		8,705,924
Accum. Deprec. / Amort	(4,219,464)		(4,219,464)
Accum. Def Tax	(591,970)		(591,970)
Accum. Def ITC	-		-
Net Utility Plant	3,894,490	-	3,894,490
Operating Materials & Fuel	79,458		79,458
Misc. Deferred Debits	26,623		26,623
Misc. Deferred Credits	(70,321)		(70,321)
Working Cash	56,499	(337)	56,162
Rate Base	3,986,749	(337)	3,986,412
Rate of Return	7.667%		7.342%
Implied Return on Equity	9.900%		9.250%

Revenue Requirement Calculations
Impact of Cost of Capital (Carty)
($000)

	Carty Settlement ROO	Carty Rev. Change For COC	Carty Rev. Change For COC
	(12)	(13)	(14)
Sales to Consumers	83,583	(2,701)	80,882
Sales for Resale	-	-	-
Other Revenues	-	-	-
Total Operating Revenues	83,583	(2,701)	80,882
Net Variable Power Costs	(1,599)	-	(1,599)
Production O&M (excludes Trojan)	10,130	-	10,130
Trojan O&M	-	-	-
Transmission O&M	-	-	-
Distribution O&M	-	-	-
Customer & MBC O&M	-	-	-
Uncollectibles Expense	359	(12)	348
OPUC Fees	313	(10)	303
A&G, Ins/Bene., & Gen. Plant	1,644	-	1,644
Total Operating & Maintenance	10,849	(22)	10,827
Depreciation	14,397	-	14,397
Amortization	-	-	-
Property Tax	2,433	-	2,433
Payroll Tax	226	-	226
Other Taxes	-	-	-
Franchise Fees	2,129	(69)	2,060
Utility Income Tax	16,464	(1,036)	15,429
Total Operating Expenses & Taxes	46,498	(1,126)	45,371
Utility Operating Income	37,086	(1,575)	35,510
Rate Base			
Gross Plant	488,250	-	488,250
Accum. Deprec. / Amort	(6,598)	-	(6,598)
Accum. Def Tax	1,354	-	1,354
Accum. Def ITC	-	-	-
Net Utility Plant	483,007	-	483,007
Misc. Deferred Debits	-		-
Operating Materials & Fuel	-		-
Misc. Deferred Credits	(959)	-	(959)
Working Cash	1,687	(41)	1,646
Rate Base	483,735	(41)	483,694
Rate of Return			7.342%
Implied Return on Equity			9.250%

Revenue Requirement Calculations
Impact of Capital Additions
($000)

	COC ROO	Adjustment	Adjusted ROO	Rev. Change for ROE	Adjusted ROO at ROE
	(15)	(16)	(17)	(18)	(19)
Sales to Consumers	1,815,497		1,815,497	(9,455)	1,806,042
Sales for Resale			-		-
Other Revenues	25,138		25,138		25,138
Total Operating Revenues	1,840,635	-	1,840,635	(9,455)	1,831,181
Net Variable Power Costs	556,895		556,895		556,895
Production O&M (excludes Trojan)	146,000		146,000		146,000
Trojan O&M	93		93		93
Transmission O&M	14,251		14,251		14,251
Distribution O&M	94,457		94,457		94,457
Customer & MBC O&M	72,083		72,083		72,083
Uncollectibles Expense	7,807	-	7,807	(41)	7,766
OPUC Fees	6,808	-	6,808	(35)	6,773
A&G, Ins/Bene., & Gen. Plant	153,003		153,003		153,003
Total Operating & Maintenance	1,051,397	-	1,051,397	(76)	1,051,321
Depreciation (See Note 1)	270,257	(2,533)	267,724		267,724
Amortization	49,697		49,697		49,697
Property Tax	59,947		59,947		59,947
Payroll Tax	14,187		14,187		14,187
Other Taxes	1,798		1,798		1,798
Franchise Fees	46,242	-	46,242	(241)	46,001
Utility Income Tax	54,447	1,858	56,305	(3,625)	52,680
Total Operating Expenses & Taxes	1,547,973	(675)	1,547,298	(3,942)	1,543,356
Utility Operating Income	292,662	675	293,338	(5,513)	287,825
	292,662				287,825
Rate Base					
Gross Plant	8,705,924	(75,988)	8,629,935		8,629,935
Accum. Deprec. / Amort	(4,219,464)	(1,266)	(4,220,731)		(4,220,731)
Accum. Def Tax (See Note 2)	(591,970)	(1,773)	(593,743)		(593,743)
Accum. Def ITC	-		-		-
Net Utility Plant	3,894,490	(79,028)	3,815,462	-	3,815,462
Operating Materials & Fuel	79,458		79,458		79,458
Misc. Deferred Debits	26,623		26,623		26,623
Misc. Deferred Credits	(70,321)		(70,321)		(70,321)
Working Cash	56,162	(25)	56,138	(143)	55,995
Rate Base	3,986,412	(79,053)	3,907,360	(143)	3,907,216
Rate of Return	7.367%		7.507%		7.366%
Implied Return on Equity	9.300%		9.582%		9.300%

Note 1: Depreciation included in the Company's filing for removed capital additions was not readily available. Assumed an average usefull life of 30 years, using straight line depreciation.

Note 2: Assumed an average MACRS life of 10 years

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/202

RATE SPREAD IMPACT OF GENERATION MARGINAL COST ADJUSTMENTS

June 15, 2015

ADJUSTEMENT 1: PORT WESTWARD II
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS INCLUDING CARTY
2016

		Forecast SDEC14E16		TOTAL ELECTRIC BILLS					
				CURRENT	PROPOSED				
CATEGORY	**RATE SCHEDULE**	CUSTOMERS	MWH SALES	with all supplementals except LIA & PPC	with all supplementals except LIA & PPC	**Change** AMOUNT	PCT.	FILED	DELTA
Residential	7	748,413	7,620,805	$890,590,890	$924,986,900	$34,396,011	3.9%	3.1%	0.8%
Employee Discount				($913,107)	($949,404)	($36,297)			
Subtotal				$889,677,782	$924,037,496	$34,359,714	3.9%	3.1%	0.8%
Outdoor Area Lighting	15	0	16,308	$3,720,472	$3,547,514	($172,957)	-4.6%	-4.2%	-0.5%
General Service <30 kW	32	90,384	1,599,950	$177,983,371	$188,513,282	$10,529,911	5.9%	6.0%	-0.1%
Opt. Time-of-Day G.S. >30 kW	38	548	39,036	$5,425,870	$6,117,620	$691,750	12.7%	12.7%	0.0%
Irrig. & Drain. Pump. < 30 kW	47	3,152	20,845	$3,672,577	$3,693,243	$20,667	0.6%	0.6%	-0.1%
Irrig. & Drain. Pump. > 30 kW	49	1,349	62,677	$7,699,051	$8,743,247	$1,044,196	13.6%	13.5%	0.0%
General Service 31-200 kW	83	11,029	2,795,179	$256,178,020	$268,908,169	$12,730,149	5.0%	5.3%	-0.4%
General Service 201-4,000 kW									
Secondary	85-S	1,263	2,464,564	$200,716,499	$206,638,569	$5,922,070	3.0%	3.8%	-0.9%
Primary	85-P	192	713,162	$54,524,372	$56,336,648	$1,812,276	3.3%	4.3%	-0.9%
Schedule 89 > 4 MW									
Primary	89-P	18	851,370	$56,124,536	$57,658,744	$1,534,208	2.7%	4.7%	-2.0%
Subtransmission	89-T	5	83,072	$7,078,279	$6,868,477	($209,802)	-3.0%	-1.5%	-1.5%
Schedule 90	90-P	4	1,498,007	$92,205,662	$94,652,861	$2,447,198	2.7%	4.9%	-2.3%
Street & Highway Lighting	91/95	205	74,544	$14,537,886	$14,110,804	($427,082)	-2.9%	-2.4%	-0.6%
Traffic Signals	92	17	3,243	$260,663	$270,132	$9,469	3.6%	5.7%	-2.1%
COS TOTALS		856,579	17,842,764	$1,769,805,039	$1,840,096,807	$70,291,767	4.0%	4.0%	0.0%
Direct Access Service 201-4,000 kW									
Secondary	485-S	159	438,339	$9,228,297	$8,351,932	($876,365)			
Primary	485-P	44	273,576	$5,874,711	$5,570,848	($303,863)			
Direct Access Service > 4 MW									
Secondary	489-S	1	14,393	$446,088	$325,322	($120,766)			
Primary	489-P	9	533,149	$6,418,097	$4,003,647	($2,414,451)			
Subtransmission	489-T	3	305,980	$2,742,245	$2,079,837	($662,408)			
DIRECT ACCESS TOTALS		216	1,565,436	$24,709,438	$20,331,585	($4,377,853)			
COS AND DA CYCLE TOTALS		856,795	19,408,200	$1,794,514,477	$1,860,428,392	$65,913,914	3.7%	3.7%	0.0%

ADJUSTEMENT 1: PORT WESTWARD II
2016 MARGINAL ENERGY AND CAPACITY COSTS

Year	Thermal Capacity SCCT $/kW-year	Fixed Gas Transport $/kW-year	VERBS $/kW-year	Thermal Capacity $/kW-year	Wind Capacity w VERBS $/kW-year	Thermal Marginal Energy $/MWh	Wind Marginal Energy $/MWh	RPS	Weighted Capacity Costs $/kW-year	Weighted Marginal Energy $/MWh
2016	128.36	34.81	0.00	163.17	163.17	38.56	66.51	15.00%	163.17	42.75
2017	130.84	35.48	0.00	166.32	166.32	39.30	67.80	15.00%	166.32	43.58
2018	133.36	36.17	0.00	169.53	169.53	40.06	69.10	15.00%	169.53	44.42
2019	135.94	36.87	0.00	172.80	172.80	40.84	70.44	15.00%	172.80	45.28
2020	138.56	37.58	0.00	176.14	176.14	41.62	71.80	15.00%	176.14	46.15
2021	141.23	38.30	0.00	179.54	179.54	42.43	73.18	20.00%	179.54	48.58
2022	143.96	39.04	0.00	183.00	183.00	43.25	74.60	20.00%	183.00	49.52
2023	146.74	39.80	0.00	186.54	186.54	44.08	76.03	20.00%	186.54	50.47
2024	149.57	40.56	0.00	190.14	190.14	44.93	77.50	20.00%	190.14	51.45
2025	152.46	41.35	0.00	193.80	193.80	45.80	79.00	20.00%	193.80	52.44
2026	155.40	42.15	0.00	197.55	197.55	46.68	80.52	25.00%	197.55	55.14
2027	158.40	42.96	0.00	201.36	201.36	47.58	82.08	25.00%	201.36	56.21
2028	161.46	43.79	0.00	205.24	205.24	48.50	83.66	25.00%	205.24	57.29
2029	164.57	44.63	0.00	209.21	209.21	49.44	85.28	25.00%	209.21	58.40
2030	167.75	45.49	0.00	213.24	213.24	50.39	86.92	25.00%	213.24	59.52
2031	170.99	46.37	0.00	217.36	217.36	51.36	88.60	25.00%	217.36	60.67
2032	174.29	47.27	0.00	221.55	221.55	52.36	90.31	25.00%	221.55	61.84
2033	177.65	48.18	0.00	225.83	225.83	53.37	92.05	25.00%	225.83	63.04
2034	181.08	49.11	0.00	230.19	230.19	54.40	93.83	25.00%	230.19	64.25
2035	184.57	50.06	0.00	234.63	234.63	55.45	95.64	25.00%	234.63	65.49
Real Levelized	$128.36	$34.81	$0.00	$163.17	$163.17	$38.56	$66.51		$163.17	$44.23
NPV	$1,650	$447	$0	$2,097	$2,097	$496	$855		$2,097	$568
Nominal Levelized	$148.94	$40.39	$0.00	$189.33	$189.33	$44.74	$77.17		$189.33	$51.32
Real Levelized	$128.36	$34.81	$0.00	$163.17	$163.17	$38.56	$66.51		$163.17	$44.23

ADJUSTEMENT 2: PORT WESTWARD II + DISPATCH CREDIT
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS INCLUDING CARTY
2016

CATEGORY	RATE SCHEDULE	Forecast SDEC14E16 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.	FILED	DELTA
Residential	7	748,413	7,620,805	$890,590,890	$925,518,845	$34,927,956	3.9%	3.1%	0.8%
Employee Discount				($913,107)	($949,972)	($36,865)			
Subtotal				$889,677,782	$924,568,873	$34,891,091	3.9%	3.1%	0.8%
Outdoor Area Lighting	15	0	16,308	$3,720,472	$3,545,884	($174,588)	-4.7%	-4.2%	-0.5%
General Service <30 kW	32	90,384	1,599,950	$177,983,371	$188,511,479	$10,528,108	5.9%	6.0%	-0.1%
Opt. Time-of-Day G.S. >30 kW	38	548	39,036	$5,425,870	$6,118,010	$692,140	12.8%	12.7%	0.0%
Irrig. & Drain. Pump. < 30 kW	47	3,152	20,845	$3,672,577	$3,693,035	$20,458	0.6%	0.6%	-0.1%
Irrig. & Drain. Pump. > 30 kW	49	1,349	62,677	$7,699,051	$8,743,874	$1,044,823	13.6%	13.5%	0.0%
General Service 31-200 kW	83	11,029	2,795,179	$256,178,020	$268,824,314	$12,646,294	4.9%	5.3%	-0.4%
General Service 201-4,000 kW									
Secondary	85-S	1,263	2,464,564	$200,716,499	$206,415,969	$5,699,470	2.8%	3.8%	-1.0%
Primary	85-P	192	713,162	$54,524,372	$56,279,830	$1,755,458	3.2%	4.3%	-1.1%
Schedule 89 > 4 MW									
Primary	89-P	18	851,370	$56,124,536	$57,566,388	$1,441,852	2.6%	4.7%	-2.2%
Subtransmission	89-T	5	83,072	$7,078,279	$6,859,422	($218,857)	-3.1%	-1.5%	-1.6%
Schedule 90	90-P	4	1,498,007	$92,205,662	$94,488,080	$2,282,418	2.5%	4.9%	-2.4%
Street & Highway Lighting	91/95	205	74,544	$14,537,886	$14,104,095	($433,791)	-3.0%	-2.4%	-0.6%
Traffic Signals	92	17	3,243	$260,663	$269,743	$9,080	3.5%	5.7%	-2.2%
COS TOTALS		856,579	17,842,764	$1,769,805,039	$1,839,988,996	$70,183,957	4.0%	4.0%	0.0%
Direct Access Service 201-4,000 kW									
Secondary	485-S	159	438,339	$9,228,297	$8,341,184	($887,112)			
Primary	485-P	44	273,576	$5,874,711	$5,563,794	($310,916)			
Direct Access Service > 4 MW									
Secondary	489-S	1	14,393	$446,088	$325,432	($120,656)			
Primary	489-P	9	533,149	$6,418,097	$4,005,706	($2,412,391)			
Subtransmission	489-T	3	305,980	$2,742,245	$2,077,928	($664,317)			
DIRECT ACCESS TOTALS		216	1,565,436	$24,709,438	$20,314,045	($4,395,393)			
COS AND DA CYCLE TOTALS		856,795	19,408,200	$1,794,514,477	$1,860,303,041	$65,788,564	3.7%	3.7%	0.0%

ADJUSTEMENT 2: PORT WESTWARD II + DISPATCH CREDIT
2016 MARGINAL ENERGY AND CAPACITY COSTS

Year	Thermal Capacity SCCT $/kW-year	Fixed Gas Transport $/kW-year	VERBS $/kW-year	Thermal Capacity $/kW-year	Wind Capacity w VERBS $/kW-year	Thermal Marginal Energy $/MWh	Wind Marginal Energy $/MWh	RPS	Weighted Capacity Costs $/kW-year	Weighted Marginal Energy $/MWh
2016	128.36	34.81	0.00	163.17	163.17	37.22	66.51	15.00%	163.17	41.61
2017	130.84	35.48	0.00	166.32	166.32	37.94	67.80	15.00%	166.32	42.41
2018	133.36	36.17	0.00	169.53	169.53	38.67	69.10	15.00%	169.53	43.23
2019	135.94	36.87	0.00	172.80	172.80	39.41	70.44	15.00%	172.80	44.07
2020	138.56	37.58	0.00	176.14	176.14	40.17	71.80	15.00%	176.14	44.92
2021	141.23	38.30	0.00	179.54	179.54	40.95	73.18	20.00%	179.54	47.40
2022	143.96	39.04	0.00	183.00	183.00	41.74	74.60	20.00%	183.00	48.31
2023	146.74	39.80	0.00	186.54	186.54	42.55	76.03	20.00%	186.54	49.24
2024	149.57	40.56	0.00	190.14	190.14	43.37	77.50	20.00%	190.14	50.19
2025	152.46	41.35	0.00	193.80	193.80	44.20	79.00	20.00%	193.80	51.16
2026	155.40	42.15	0.00	197.55	197.55	45.06	80.52	25.00%	197.55	53.92
2027	158.40	42.96	0.00	201.36	201.36	45.93	82.08	25.00%	201.36	54.96
2028	161.46	43.79	0.00	205.24	205.24	46.81	83.66	25.00%	205.24	56.02
2029	164.57	44.63	0.00	209.21	209.21	47.72	85.28	25.00%	209.21	57.11
2030	167.75	45.49	0.00	213.24	213.24	48.64	86.92	25.00%	213.24	58.21
2031	170.99	46.37	0.00	217.36	217.36	49.58	88.60	25.00%	217.36	59.33
2032	174.29	47.27	0.00	221.55	221.55	50.53	90.31	25.00%	221.55	60.48
2033	177.65	48.18	0.00	225.83	225.83	51.51	92.05	25.00%	225.83	61.64
2034	181.08	49.11	0.00	230.19	230.19	52.50	93.83	25.00%	230.19	62.83
2035	184.57	50.06	0.00	234.63	234.63	53.52	95.64	25.00%	234.63	64.05
Real Levelized	$128.36	$34.81	$0.00	$163.17	$163.17	$37.22	$66.51		$163.17	$43.16
NPV	$1,650	$447	$0	$2,097	$2,097	$478	$855		$2,097	$555
Nominal Levelized	$148.94	$40.39	$0.00	$189.33	$189.33	$43.18	$77.17		$189.33	$50.08
Real Levelized	$128.36	$34.81	$0.00	$163.17	$163.17	$37.22	$66.51		$163.17	$43.16

ADJUSTEMENT 3: PORT WESTWARD II + DISPATCH CREDIT + CAPITALIZED ENERGY
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS INCLUDING CARTY
2016

CATEGORY	RATE SCHEDULE	Forecast SDEC14E16 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.	FILED	DELTA
Residential	7	748,413	7,620,805	$890,590,890	$927,191,320	$36,600,431	4.1%	3.1%	1.0%
Employee Discount				($913,107)	($951,756)	($38,649)			
Subtotal				$889,677,782	$926,239,564	$36,561,782	4.1%	3.1%	1.0%
Outdoor Area Lighting	15	0	16,308	$3,720,472	$3,541,970	($178,502)	-4.8%	-4.2%	-0.6%
General Service <30 kW	32	90,384	1,599,950	$177,983,371	$188,465,625	$10,482,254	5.9%	6.0%	-0.1%
Opt. Time-of-Day G.S. >30 kW	38	548	39,036	$5,425,870	$6,118,010	$692,140	12.8%	12.7%	0.0%
Irrig. & Drain. Pump. < 30 kW	47	3,152	20,845	$3,672,577	$3,692,618	$20,041	0.5%	0.6%	-0.1%
Irrig. & Drain. Pump. > 30 kW	49	1,349	62,677	$7,699,051	$8,743,247	$1,044,196	13.6%	13.5%	0.0%
General Service 31-200 kW	83	11,029	2,795,179	$256,178,020	$268,656,603	$12,478,583	4.9%	5.3%	-0.5%
General Service 201-4,000 kW									
Secondary	85-S	1,263	2,464,564	$200,716,499	$206,071,719	$5,355,220	2.7%	3.8%	-1.2%
Primary	85-P	192	713,162	$54,524,372	$56,179,752	$1,655,380	3.0%	4.3%	-1.2%
Schedule 89 > 4 MW									
Primary	89-P	18	851,370	$56,124,536	$57,310,894	$1,186,358	2.1%	4.7%	-2.6%
Subtransmission	89-T	5	83,072	$7,078,279	$6,836,103	($242,176)	-3.4%	-1.5%	-1.9%
Schedule 90	90-P	4	1,498,007	$92,205,662	$93,999,421	$1,793,759	1.9%	4.9%	-3.0%
Street & Highway Lighting	91/95	205	74,544	$14,537,886	$14,085,459	($452,427)	-3.1%	-2.4%	-0.7%
Traffic Signals	92	17	3,243	$260,663	$268,543	$7,880	3.0%	5.7%	-2.7%
COS TOTALS		856,579	17,842,764	$1,769,805,039	$1,840,209,528	$70,404,488	4.0%	4.0%	0.0%
Direct Access Service 201-4,000 kW									
Secondary	485-S	159	438,339	$9,228,297	$8,353,736	($874,561)			
Primary	485-P	44	273,576	$5,874,711	$5,568,722	($305,989)			
Direct Access Service > 4 MW									
Secondary	489-S	1	14,393	$446,088	$325,533	($120,555)			
Primary	489-P	9	533,149	$6,418,097	$4,009,507	($2,408,591)			
Subtransmission	489-T	3	305,980	$2,742,245	$2,083,140	($659,106)			
DIRECT ACCESS TOTALS		216	1,565,436	$24,709,438	$20,340,636	($4,368,802)			
COS AND DA CYCLE TOTALS		856,795	19,408,200	$1,794,514,477	$1,860,550,164	$66,035,687	3.7%	3.7%	0.0%

ADJUSTEMENT 3: PORT WESTWARD II + DISPATCH CREDIT + CAPITALIZED ENERGY
2016 MARGINAL ENERGY AND CAPACITY COSTS

Year	Thermal Capacity SCCT $/kW-year	Fixed Gas Transport $/kW-year	VERBS $/kW-year	Thermal Capacity $/kW-year	Wind Capacity w VERBS $/kW-year	Thermal Marginal Energy $/MWh	Wind Marginal Energy $/MWh	RPS	Weighted Capacity Costs $/kW-year	Weighted Marginal Energy $/MWh
2016	128.36	34.81	0.00	163.17	163.17	33.50	66.51	15.00%	163.17	38.45
2017	130.84	35.48	0.00	166.32	166.32	34.15	67.80	15.00%	166.32	39.20
2018	133.36	36.17	0.00	169.53	169.53	34.81	69.10	15.00%	169.53	39.95
2019	135.94	36.87	0.00	172.80	172.80	35.48	70.44	15.00%	172.80	40.72
2020	138.56	37.58	0.00	176.14	176.14	36.16	71.80	15.00%	176.14	41.51
2021	141.23	38.30	0.00	179.54	179.54	36.86	73.18	20.00%	179.54	44.13
2022	143.96	39.04	0.00	183.00	183.00	37.57	74.60	20.00%	183.00	44.98
2023	146.74	39.80	0.00	186.54	186.54	38.30	76.03	20.00%	186.54	45.85
2024	149.57	40.56	0.00	190.14	190.14	39.04	77.50	20.00%	190.14	46.73
2025	152.46	41.35	0.00	193.80	193.80	39.79	79.00	20.00%	193.80	47.63
2026	155.40	42.15	0.00	197.55	197.55	40.56	80.52	25.00%	197.55	50.55
2027	158.40	42.96	0.00	201.36	201.36	41.34	82.08	25.00%	201.36	51.53
2028	161.46	43.79	0.00	205.24	205.24	42.14	83.66	25.00%	205.24	52.52
2029	164.57	44.63	0.00	209.21	209.21	42.95	85.28	25.00%	209.21	53.53
2030	167.75	45.49	0.00	213.24	213.24	43.78	86.92	25.00%	213.24	54.57
2031	170.99	46.37	0.00	217.36	217.36	44.63	88.60	25.00%	217.36	55.62
2032	174.29	47.27	0.00	221.55	221.55	45.49	90.31	25.00%	221.55	56.69
2033	177.65	48.18	0.00	225.83	225.83	46.37	92.05	25.00%	225.83	57.79
2034	181.08	49.11	0.00	230.19	230.19	47.26	93.83	25.00%	230.19	58.90
2035	184.57	50.06	0.00	234.63	234.63	48.17	95.64	25.00%	234.63	60.04
Real Levelized	$128.36	$34.81	$0.00	$163.17	$163.17	$33.50	$66.51		$163.17	$40.20
NPV	$1,650	$447	$0	$2,097	$2,097	$431	$855		$2,097	$517
Nominal Levelized	$148.94	$40.39	$0.00	$189.33	$189.33	$38.87	$77.17		$189.33	$46.64
Real Levelized	$128.36	$34.81	$0.00	$163.17	$163.17	$33.50	$66.51		$163.17	$40.20

ALTERNATIVE ADJUSTEMENT 1 : LMS100
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS INCLUDING CARTY
2016

CATEGORY	RATE SCHEDULE	Forecast SDEC14E16 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.	FILED	DELTA
Residential	7	748,413	7,620,805	$890,590,890	$922,934,681	$32,343,791	3.6%	3.1%	0.5%
Employee Discount				($913,107)	($947,215)	($34,107)			
Subtotal				$889,677,782	$921,987,466	$32,309,684	3.6%	3.1%	0.5%
Outdoor Area Lighting	15	0	16,308	$3,720,472	$3,552,896	($167,576)	-4.5%	-4.2%	-0.3%
General Service <30 kW	32	90,384	1,599,950	$177,983,371	$188,560,939	$10,577,568	5.9%	6.0%	-0.1%
Opt. Time-of-Day G.S. >30 kW	38	548	39,036	$5,425,870	$6,117,229	$691,360	12.7%	12.7%	0.0%
Irrig. & Drain. Pump. < 30 kW	47	3,152	20,845	$3,672,577	$3,693,869	$21,292	0.6%	0.6%	0.0%
Irrig. & Drain. Pump. > 30 kW	49	1,349	62,677	$7,699,051	$8,742,620	$1,043,569	13.6%	13.5%	0.0%
General Service 31-200 kW	83	11,029	2,795,179	$256,178,020	$269,187,876	$13,009,855	5.1%	5.3%	-0.3%
General Service 201-4,000 kW									
Secondary	85-S	1,263	2,464,564	$200,716,499	$207,170,204	$6,453,706	3.2%	3.8%	-0.6%
Primary	85-P	192	713,162	$54,524,372	$56,490,027	$1,965,655	3.6%	4.3%	-0.7%
Schedule 89 > 4 MW									
Primary	89-P	18	851,370	$56,124,536	$57,993,140	$1,868,604	3.3%	4.7%	-1.4%
Subtransmission	89-T	5	83,072	$7,078,279	$6,900,052	($178,227)	-2.5%	-1.5%	-1.0%
Schedule 90	90-P	4	1,498,007	$92,205,662	$95,280,342	$3,074,680	3.3%	4.9%	-1.6%
Street & Highway Lighting	91/95	205	74,544	$14,537,886	$14,135,404	($402,482)	-2.8%	-2.4%	-0.4%
Traffic Signals	92	17	3,243	$260,663	$271,754	$11,091	4.3%	5.7%	-1.4%
COS TOTALS		856,579	17,842,764	$1,769,805,039	$1,840,083,818	$70,278,779	4.0%	4.0%	0.0%
Direct Access Service 201-4,000 kW									
Secondary	485-S	159	438,339	$9,228,297	$8,338,925	($889,372)			
Primary	485-P	44	273,576	$5,874,711	$5,564,156	($310,555)			
Direct Access Service > 4 MW									
Secondary	489-S	1	14,393	$446,088	$324,890	($121,198)			
Primary	489-P	9	533,149	$6,418,097	$3,995,643	($2,422,454)			
Subtransmission	489-T	3	305,980	$2,742,245	$2,075,366	($666,879)			
DIRECT ACCESS TOTALS		216	1,565,436	$24,709,438	$20,298,980	($4,410,458)			
COS AND DA CYCLE TOTALS		856,795	19,408,200	$1,794,514,477	$1,860,382,798	$65,868,321	3.7%	3.7%	0.0%

ALTERNATIVE ADJUSTEMENT 1 : LMS100
2016 MARGINAL ENERGY AND CAPACITY COSTS

Year	Thermal Capacity SCCT $/kW-year	SCCT Fixed Gas Transport $/kW-year	VERBS $/kW-year	Thermal Capacity $/kW-year	Wind Capacity w VERBS $/kW-year	Thermal Marginal Energy $/MWh	Wind Marginal Energy $/MWh	RPS	Weighted Capacity Costs $/kW-year	Weighted Marginal Energy $/MWh
2016	104.57	40.60	0.00	145.17	145.17	37.37	66.51	15.00%	145.17	41.74
2017	106.59	41.38	0.00	147.98	147.98	38.09	67.80	15.00%	147.98	42.54
2018	108.65	42.18	0.00	150.83	150.83	38.82	69.10	15.00%	150.83	43.36
2019	110.75	43.00	0.00	153.74	153.74	39.57	70.44	15.00%	153.74	44.20
2020	112.88	43.83	0.00	156.71	156.71	40.34	71.80	15.00%	156.71	45.05
2021	115.06	44.67	0.00	159.74	159.74	41.11	73.18	20.00%	159.74	47.53
2022	117.28	45.53	0.00	162.82	162.82	41.91	74.60	20.00%	162.82	48.44
2023	119.55	46.41	0.00	165.96	165.96	42.72	76.03	20.00%	165.96	49.38
2024	121.85	47.31	0.00	169.16	169.16	43.54	77.50	20.00%	169.16	50.33
2025	124.21	48.22	0.00	172.43	172.43	44.38	79.00	20.00%	172.43	51.30
2026	126.60	49.15	0.00	175.76	175.76	45.24	80.52	25.00%	175.76	54.06
2027	129.05	50.10	0.00	179.15	179.15	46.11	82.08	25.00%	179.15	55.10
2028	131.54	51.07	0.00	182.61	182.61	47.00	83.66	25.00%	182.61	56.17
2029	134.08	52.05	0.00	186.13	186.13	47.91	85.28	25.00%	186.13	57.25
2030	136.66	53.06	0.00	189.72	189.72	48.83	86.92	25.00%	189.72	58.35
2031	139.30	54.08	0.00	193.38	193.38	49.77	88.60	25.00%	193.38	59.48
2032	141.99	55.13	0.00	197.12	197.12	50.74	90.31	25.00%	197.12	60.63
2033	144.73	56.19	0.00	200.92	200.92	51.71	92.05	25.00%	200.92	61.80
2034	147.52	57.27	0.00	204.80	204.80	52.71	93.83	25.00%	204.80	62.99
2035	150.37	58.38	0.00	208.75	208.75	53.73	95.64	25.00%	208.75	64.21
Real Levelized	$104.57	$40.60	$0.00	$145.17	$145.17	$37.37	$66.51		$145.17	$43.28
NPV	$1,344	$522	$0	$1,866	$1,866	$480	$855		$1,866	$556
Nominal Levelized	$121.34	$47.11	$0.00	$168.45	$168.45	$43.36	$77.17		$168.45	$50.22
Real Levelized	$104.57	$40.60	$0.00	$145.17	$145.17	$37.37	$66.51		$145.17	$43.28

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/203

NORTHWEST POWER AND CONSERVATION COUNCIL PLANNING DOCUMENTS

June 15, 2015

Northwest **Power** and
Conservation Council

February 3, 2015

MEMORANDUM

TO: **Power Committee**

FROM: **Gillian Charles, Energy Policy Analyst**
Steve Simmons, Energy Analyst

SUBJECT: **Draft Seventh Plan Generating Resource Characteristics for use in the Regional Portfolio Model**

BACKGROUND:

Presenter: Gillian Charles and Steve Simmons

Summary: Staff will present a high level summary of the proposed draft Seventh Plan generating resource characteristics that will be inputs to the modeling analysis performed in the Regional Portfolio Model (RPM). These resources include: natural gas combined cycle combustion turbines, natural gas single cycle combustion turbines, reciprocating engines, utility-scale solar photovoltaic, and utility-scale on-shore wind. In addition to presenting the resource reference plants and cost estimates, staff will also compare the draft assumptions with the final assumptions used in the Sixth Power Plan.

Relevance: Staff anticipates that it will begin conducting scenario analysis using the updated RPM in mid-March. Draft generating resource characteristics are being presented to the Power Committee in February. Committee member feedback and comments will be incorporated into a revised set of characteristics to be presented to the full Council in March for acceptance to use as the generating resource assumptions in the RPM analysis for the draft Seventh plan.

Work plan: 1.D. Prepare for Seventh Power Plan and maintain analytical capability – generating resource characterization

Background: Staff previously presented generating resource characteristics information during detailed Power Committee webinars on November 18th and January 29th. The Council's Generating Resources Advisory Committee (GRAC) has also reviewed and vetted over multiple meetings the assumptions being proposed.

More Info: For detailed information on the work that has been presented to the GRAC, see the GRAC past meetings webpage - http://www.nwcouncil.org/energy/grac/meetings/. In addition, the presentation materials from the previous Power Committee webinars are available on the Council website - http://www.nwcouncil.org/news/meetings/.

Draft Seventh Plan Generating Resource Characteristics for use in Regional Portfolio Model

Gillian Charles, Steve Simmons

2/10/15

Power Committee

Purpose of Today's Presentation

- High level summary of proposed draft Seventh Plan generating resource characteristics*
  - Technology overviews
  - Reference plants and cost assumptions
  - Comparison to final Sixth Plan assumptions – what changed and why?
- Looking for P4 consensus to present to full Council in March → input to RPM for draft plan analysis

*These characteristics were previously presented at Power Committee webinars and reviewed at multiple Generating Resource Advisory Committee meetings.

Reminder: Reviewed with P4 for Input in RPM for Draft 7th Plan

November 18, 2014 - P4 Webinar

- ✓ Utility-scale Solar PV
- ✓ Natural Gas - Combined Cycle Combustion Turbines

January 29, 2015 – P4 Webinar

- ✓ Utility-scale Wind
- ✓ Natural Gas – Peakers (Single Cycle Turbines and Reciprocating Engines)

March 2015 – P4

- ❑ RPS Analysis for input to RPM

GRAC Meetings To Date

GRAC Meeting	Solar PV	CCCT	Gas Peakers	Wind	Hydro Scoping	Offshore Wind	Storage	SMR	EGS
1) Jun 20 2013	1								
2) Oct 16 2013	2	1			1				
3) Feb 27 2014		2	1						
4) May 28 2014	3	3	2	1	2	1			
5) Oct 2 2014			3	2	3				
6) Nov 7 2014	4								
7) Nov 21 2014					4				
8) Dec 18 2014			4	3			1		
9) Jan 27 2015							2	1	1

SMR = Small Modular Reactors, EGS = Enhanced Geothermal (as opposed to conventional geothermal)

Categorization of Resources for the Draft Seventh Power Plan (1)

Prioritization based on a resource's commercial availability, constructability, cost-effectiveness, and quantity of developable resource.

Primary; Significant: Resources that look to play a major role in the future PNW power system
Assessment : In-depth, quantitative characterization to support system integration and risk analysis modeling. Will be modeled in RPM

Secondary; Commercial w/ Limited Availability: Resources that are fully commercial but that don't have a lot of developmental potential in the PNW
Assessment : Quantitative characterization sufficient to estimate levelized costs. Will *not* be modeled in RPM.

Long-term Potential: Resources that have long term potential in the PNW but may not be commercially available yet
Assessment: Qualitative discussion of status & PNW potential, quantify key numbers as available. Will *not* be modeled in RPM.

Northwest Power and Conservation Council 5 SEVENTH NORTHWEST POWER PLAN

Categorization of Resources for the Draft Seventh Power Plan (2)

Primary; Significant	Secondary; Commercial w/ Limited Availability	Long-Term Potential
Natural Gas Combined Cycle	Biogas Technologies (landfill, wastewater treatment, animal waste, etc.)	Engineered Geothermal **Power Plan Narratives**
Wind	Biomass - Woody residues	Offshore Wind
Solar PV	Conventional hydrothermal Geothermal	Modular Nuclear Units
Natural Gas Simple Cycle, Reciprocating Engine	New Hydropower	Wave Energy
	Hydropower Upgrades	Tidal Energy
	Waste heat recovery and CHP	Coal Technologies w/ CO_2 Separation
RPM Input Resources	Storage Technologies*	CO_2 Sequestration
	Power Plan Narratives	Storage Technologies*

* Various storage technologies may fall under different categories

Northwest Power and Conservation Council 6 SEVENTH NORTHWEST POWER PLAN

Reference Plant

COMBINED CYCLE COMBUSTION TURBINE

Overview of Technology

Description of Technology: Combined Cycle Combustion Turbine - consists of one or more gas turbine generators combined with one or more heat recovery steam generators (HRSG).

- Extremely efficient for baseload power, becoming more flexible, lowest CO2 emitting of fossil-fuel based generators
- Can be augmented with duct firing – boosts power output as needed at the expense of a higher heat rate
- Wet or dry cooling configurations: For sites with water constraints, dry cooling configuration results in significantly less water usage but with higher capital costs
- Emits CO2 – but within proposed EPA regulations for new plants. Also related methane emissions from natural gas production and transportation.

Importance/Relevance to PNW: Plays a significant role in the region as a dispatchable baseload power source. The technology benefits from a robust natural gas infrastructure in the region which can tap a diverse set of supply sources from both the US and Canada (BC, Alberta)

Main GRAC issues: Discussion included

- Expected plant size consistent a 1x1 configuration (1 gas-turbine coupled with 1 HRSG)
- Requested configurations for both Wet-Cooled, and Dry-Cooled

Role in future power system: provide efficient baseload power along with some flexibility

Changes since Sixth Plan analysis: Slightly higher capital and O&M cost in Seventh Plan, but with improved technology and efficiency

Reference Plant(s)

	CCCT 1	CCCT 2
Location	PNW East	PNW East
Capacity (MW)	370 (390)	425
Economic Life (years)	30	30
Earliest In –Service	2018	2020
Development time (years)	5	5
Capital Cost ($/kW) In-service year 2016	1,147 (1,046)	1,287
Fuel	Natural Gas – East	Natural Gas – East
Heat Rate (btu/kWh)	6,770 (6,930)	6,704
Capacity Factor % (for presentation purposes)	60	60
Inv. /Prod. Tax Credit	-	-
O&M Fixed ($/kW-yr), Variable ($/MWh)	$15.37, $3.27 $14.00, $1.70	15.37/3.27

Northwest Power and Conservation Council

All costs represented in 2012 $

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Black = Draft 7th Plan Assumption
Red = Final 6th Plan Assumption

SEVENTH NORTHWEST POWER PLAN

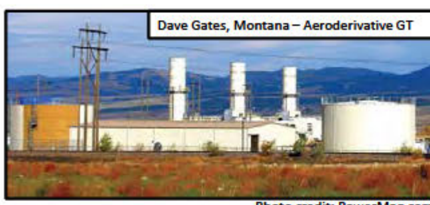

Photo credit: PowerMag.com

Photo credit: Tim Bondy

Photo credit: PGE flickr

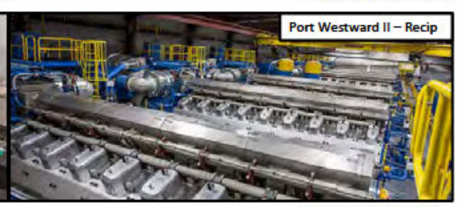

Photo credit: PGE flickr

Reference Plants

GAS PEAKERS – SINGLE CYCLE AND RECIPROCATING ENGINES

Northwest Power and Conservation Council

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SEVENTH NORTHWEST POWER PLAN

Overview of Technology

Description of Technology:

- Single Cycle – One or more combustion gas turbines driving an electric generator. Compact, modular plants used for meeting short-duration peak loads. Rapid response start-up and load following capability.
- Reci rocatin Engine – One or more compression spark or spark-ignition reci rocatin engine generators driving an electric generator. Very modular. Used for emergency back-up and isolated systems; more recently for peaking and load following services.

Importance/Relevance to PNW: Historically used for hydro shaping; now with continued improvements in technology resulting in more flexible and efficient equipment, primary role changing towards variable energy integration, contribution to peak load

Main GRAC issues: Main discussion focused on which technologies to include in the Council's RPM analysis. Proposal was to consider whatever technology is selected by the model as a "proxy" for any of the others.

Role in future power system: With increased variable energy resources (wind, solar) on the system, role of gas peakers to help with integration is becoming increasingly important.

Changes since Sixth Plan analysis: The recovery from the 2008 recession did not occur as quickly as forecast, so instead of costs decreasing, they continued to increase until about 2010 and are not decreasing as fast as forecast. Seems to be a shift in WECC towards aeros, intercooled, and recips, and not much development of frame units.

Reference Plant(s)

	Frame GE 7F 5-Series 1 X 216 MW	Aero GE LM6000 PF 4 X 47 MW	Intercooled GE LMS 100 PB 2 X 100 MW	Recip Engine Wärtsilä 12 X 18 MW
Location	PNW West	PNW West	PNW West	PNW West
Capacity (MW)	216 (85)	190 (92)	200 (100)	220
Economic Life (years)	30	30	30	30
Earliest In –Service	2018	2018	2018	2018
Development time (years)	2.75	2.75	2.75	2.75
Capital Cost ($/kW) In-service year 2016	$800 ($561)	$1,100 ($980)	$1,000 ($1,052)	$1,300 ($1,082)
Fuel	Natural gas	Natural gas	Natural gas	Natural gas
Heat Rate (btu, kWh,	9801 ,11960,	9048 ,9370,	8541 ,8870,	8370 ,8850,
Capacity Factor % (for presentation purposes)	25%	25%	25%	25%
Inv. Tax Credit	--	--	--	--
O&M Fixed ($/kW-yr), Variable ($/MWh)	$7.00, $10.00 ($12.30, $1.20)	$25.00, $5.00 ($14.50, $4.50)	$11.00, $7.00 ($9.00, $5.60)	$10.00, $9.00 ($14.50, $11.20)

Northwest Power and Conservation Council

All costs represented in 2012 $

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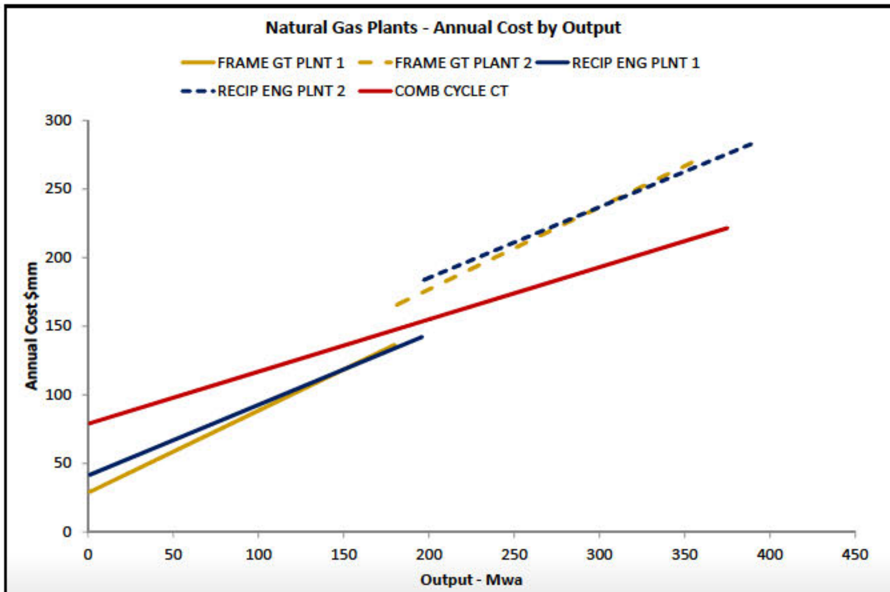
Black = Draft 7th Plan Assumption
Red = Final 6th Plan Assumption

SEVENTH NORTHWEST POWER PLAN

Discussion

- Which resource(s) to include in RPM analysis?
  - Can one be considered a proxy for all?
- If purpose/use of resource trumps cost (in the case of gas peakers), does it matter which one we select?




Outback Solar PV Plant, 5 MW, Oregon

Photo credit: Obsidian Renewables


Copper Mountain Solar facility, 48 MW, Arizona

Photo credit: Sempra Energy


Sandhill Solar Farm, 19 MW, Colorado

Photo credit: Solar Professional

Reference Plants

UTILITY-SCALE SOLAR PV

Overview of Technology

Description of Technology: Solar PV systems convert sunlight directly into electricity. These systems are comprised of 3 primary components:

1) PV Modules: typically silicon based, or thin film materials
2) Power Electronics: including DC to AC inverters, and control electronics
3) Balance of System: including foundations, mounts - fixed or tracking systems, land permitting

Rapidly evolving technology – improving in both efficiency and cost

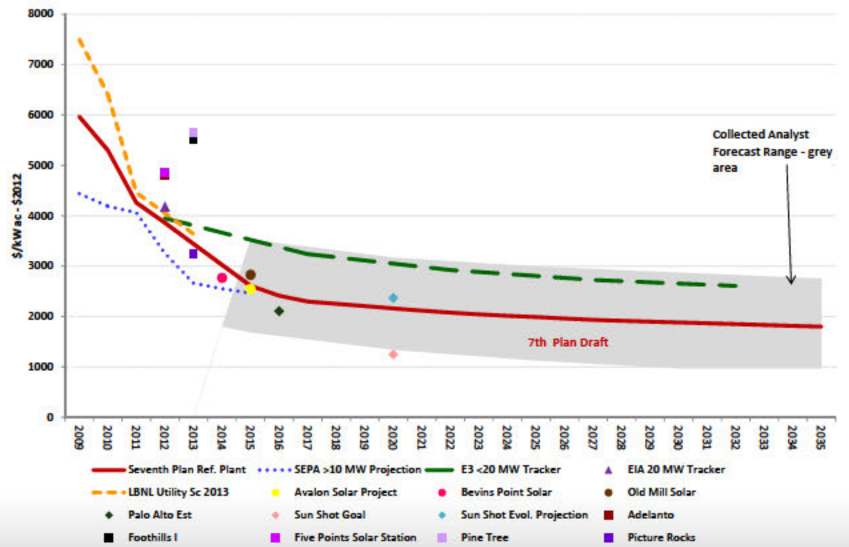
Importance/Relevance to PNW: Although there is a limited presence in the region, activity has recently picked up in Southern Idaho – which is probably the best solar resource region for the Northwest.

Main GRAC issues: Much discussion over the declining solar costs. Several iterations of capital cost forecasts for the next 20 years. Also important and unique financing arrangements in order to best capture value of the ITC.

Role in future power system: Non-dispatchable variable resource – output varies seasonally. If costs continue to decline, could become important renewable resource in the region

Changes since Sixth Plan analysis: Significant improvements in technology and cost – have resulted in solar PV being an input to the RPM model for Seventh Plan.

Utility Scale Solar PV Capital Cost Estimate - $/kWac



Northwest Power and Conservation Council 17 SEVENTH NORTHWEST POWER PLAN

Reference Plant(s)

	Solar PV Utility Scale
Location	S. ID
Capacity (MW)	**20 (20)**
Economic Life (years)	30
Earliest In –Service	2016
Development time (years)	3
Capital Cost ($/kWac) In-service year 2016	**2,413 (5,919)**
Fuel	-
Heat Rate (btu/kWh)	-
Capacity Factor % (for presentation purposes)	26.2
Inv. /Prod. Tax Credit	ITC 30%/10%
O&M Fixed ($/kW-yr), Variable ($/MWh)	**$16.63 ($36.00)**

Northwest Power and Conservation Council All costs represented in 2012 $ 18 Black = Draft 7th Plan Assumption Red = Final 6th Plan Assumption SEVENTH NORTHWEST POWER PLAN

Tucannon River Wind Farm, 267 MW, 2014

Photo credit: PGE flickr

Reference Plant

ONSHORE-WIND

Overview of Technology

Description of Technology: Wind turbine blades are propelled by air flow, which causes the shaft to spin the rotor, which in turn spins the generator to create electricity.

Importance/Relevance to PNW: Wind has played a significant role in the region over the past decade. With the Renewable Portfolio Standards (RPS) enacted by OR, WA, MT and others in WECC spurring development in the PNW, the region has installed ~7,500 MW capacity since 2000 (~8,500 MW when PAC WY projects are included).

Main GRAC issues:

- Capacity factors – With improvements in technology increasing the capacity factors of wind projects, how will the Council account for this? Proposal – institute a capacity factor improvement curve in the RPM, similar to the treatment of increased thermal efficiencies
- Montana wind – MT is a high wind resource potential state, and the generation shape is winter peaking (as opposed to spring/fall peaks in the Col. Gorge). Upgrading/building transmission to get the wind to western load centers has been a central discussion.

Role in future power system: There has been a significant lull in wind development since the boom in 2012 (when ~2,000 MW were developed) due in part to uncertainty over Federal tax incentives, but more likely due to utilities reaching their near-term RPS goals. As the next round of goals approaches in 2020, we are likely to see another pick-up in development of renewable resources – including wind.

Changes since Sixth Plan analysis: The recovery from the 2008 recession did not occur as quickly as forecast, so instead of costs decreasing, they continued to increase until about 2010 and are not decreasing as fast as forecast. The resource potential in the region has declined since the Sixth Plan, to account for the major development in 2010-2012. MT wind is looking more cost-effective than it was in the previous plan.

Reference Plant(s)

	On-Shore Wind 40 X 2.5MW	On-Shore Wind 40 X 2.5MW
Location	Columbia Basin	Central Montana, delivered to BPA system
Capacity (MW)	100	100
Economic Life (years)	25 (20)	25 (20)
Earliest In –Service	2019	2019
Development time (years)	4 (4.5)	4 (4.5)
Capital Cost ($/kW) In-service year 2016	$2,240 ($1,850)	$2,240 ($1,850)
Fuel	--	--
Heat Rate (btu/kWh)	--	--
Capacity Factor % (for presentation purposes)	32%	40% (38%)
Inv. /Prod. Tax Credit	--	--
O&M Fixed ($/kW-yr), Variable ($/MWh)	$35.00, $2.00 ($44.70, $2.20)	$35.00, $2.00 ($44.70, $2.20)

Northwest Power and Conservation Council

All costs represented in 2012 $

Black = Draft 7th Plan Assumption
Red = Final 6th Plan Assumption

SEVENTH NORTHWEST POWER PLAN

MT Wind Resource Blocks

Name	Description	Capacity MW	Available starting in
MT Wind – Existing Transmission	Wind delivered to BPA system via NWES, IM14	130	2016
MT Wind – NorthWestern Transmission Expansion	Wind delivered to BPA system via new 230kV line, NWES	330-400	2017
MT Wind M2W	Wind delivered to BPA system via M2W update on BPA & Colstrip systems	550	2020
MT Wind w/Colstrip 1&2 Retirement	Wind	700	Depends on scenario

Northwest Power and Conservation Council

SEVENTH NORTHWEST POWER PLAN

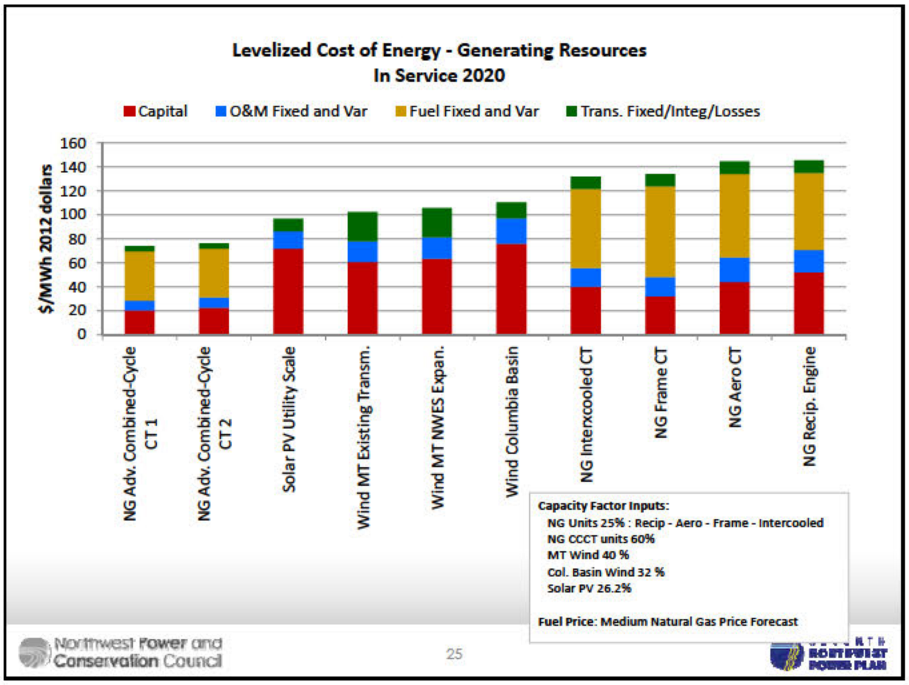
Fixed ($/kW-yr) and full ($/MWh)– annualized cost of capital and operation across the lifecycle

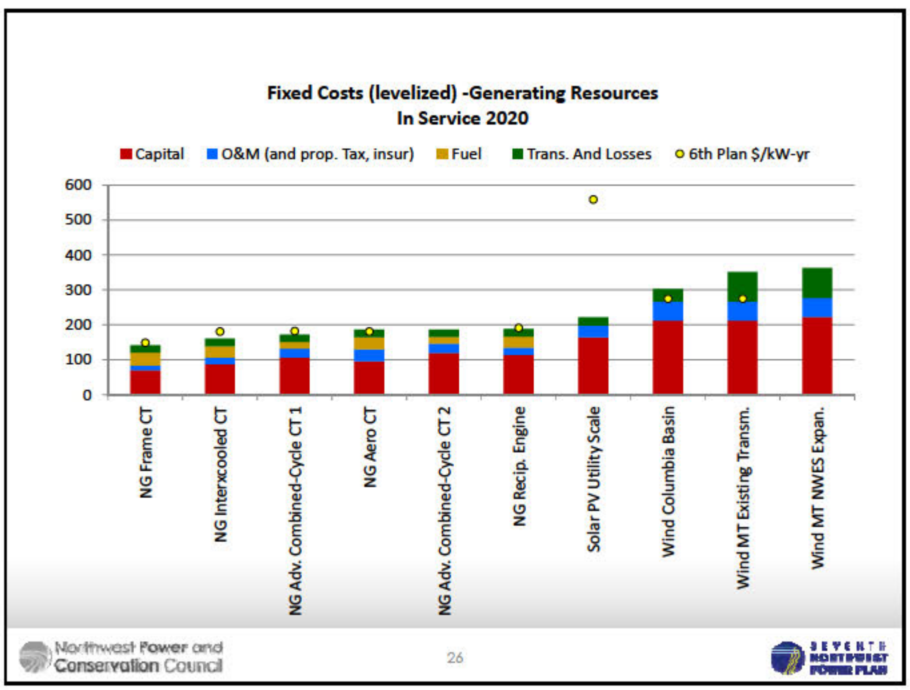
LEVELIZED COST OF ENERGY

Levelized Cost

MicroFin - revenue requirements financial model

- 1. Calculates annual cash flows over the plant lifetime that satisfy revenue requirements
- Annual cash flows are compressed into a single year dollar value – Net Present Value (NPV)
- NPV is levelized - converted into an even, annualized payment (like a mortgage)
- When divided by annual energy production – it becomes the Levelized Cost of Energy $/MWh
- Levelized Cost of Energy can be used to compare the average lifecycle costs of different types of resources
- The estimated Fixed Levelized Cost ($/kW-year) is input to RPM for each resource


Levelized Cost of Energy - Generating Resources
In Service 2020
Capital
O&M Fixed and Var
Fuel Fixed and Var
Trans. Fixed/Integ/Losses
$/MWh 2012 dollars
160
140
120
100
80
60
40
20
0
NG Adv. Combined-Cycle CT 1
NG Adv. Combined-Cycle CT 2
Solar PV Utility Scale
Wind MT Existing Transm.
Wind MT NWES Expan.
Wind Columbia Basin
NG Interxcooled CT
NG Frame CT
NG Aero CT
NG Recip. Engine
Capacity Factor Inputs:
NG Units 25% : Recip - Aero - Frame - Intercooled
NG CCCT units 60%
MT Wind 40 %
Col. Basin Wind 32 %
Solar PV 26.2%
Fuel Price: Medium Natural Gas Price Forecast
Northwest Power and Conservation Council
25
SEVENTH NORTHWEST POWER PLAN


Fixed Costs (levelized) -Generating Resources
In Service 2020
Capital
O&M (and prop. Tax, insur)
Fuel
Trans. And Losses
6th Plan $/kW-yr
600
500
400
300
200
100
0
NG Frame CT
NG Interxcooled CT
NG Adv. Combined-Cycle CT 1
NG Aero CT
NG Adv. Combined-Cycle CT 2
NG Recip. Engine
Solar PV Utility Scale
Wind Columbia Basin
Wind MT Existing Transm.
Wind MT NWES Expan.
Northwest Power and Conservation Council
26
SEVENTH NORTHWEST POWER PLAN

Next Steps

- Incorporate Power Committee feedback from today
- Presentation to full Council in March re: generating resource characteristics for use in draft RPM analysis
- RPS Analysis
  - GRAC – webinar in late February
  - Power Committee – March meeting

BACKGROUND MATERIAL

Properties of Peaking Technologies

Frame (80MW – 250 MW units) • Stationary device, weight not an issue • Strengths - longevity and durability • Weaknesses – slower response time; higher heat rate; higher exhaust temperatures/difficult air quality control • Typical use – on for several days, then shut down • PNW – several frame units built in 1970's – 1990's for hydro back-up (firming)	**Aeroderivative (15 – 60 MW units)** • Designed from aircraft engine; lighter, more delicate than frame • Strengths – rapid response time; lower heat rate than frame; easy maintenance; smaller unit size • Typical use – meeting short-term peak loads and variable resource integration • PNW – several Pratt and Whitney and a few LM6000 plants
Intercooled (100 MW units) • Hybrid of frame and aeroderivative – intercooled equipment required • Strengths – rapid response; lowest GT heat rate. Especially useful in summer peaking • Weaknesses - requires continuous source of cooling water • Typical use –short-term peak loads and variable resource integration • PNW – none currently planned or in operation; numerous in WECC, esp. California	**Reciprocating Engine (2 - 20 MW units)** • Largest gas engines in world – 4 stroke • Strengths – highly modular; very rapid response, low heat rate, duel fuel capability, not sensitive to temps and elevation • Typical use – short-term peak loads and variable resource integration • PNW – PGE built first large plant in region (Port Westward II); several smaller units in operation • Note: aside from NG peaking, used for small biogas and cogen applications, back-up gen

Northwest Power and Conservation Council 29 Seventh Northwest Power Plan

Preliminary Assumptions for Natural Gas Peaking Technologies

Gillian Charles and Steve Simmons

GRAC

5/28/14

Today's Discussion

- Overview of peaking technologies
  - Key attributes, applications, and characteristics
- Discussion of overnight capital cost assumptions and estimations
- Preliminary draft reference plants and capital cost estimates for peaking technologies
  - Frame, Aeroderivative, Intercooled, Reciprocating Engines
- Next steps

Definitions

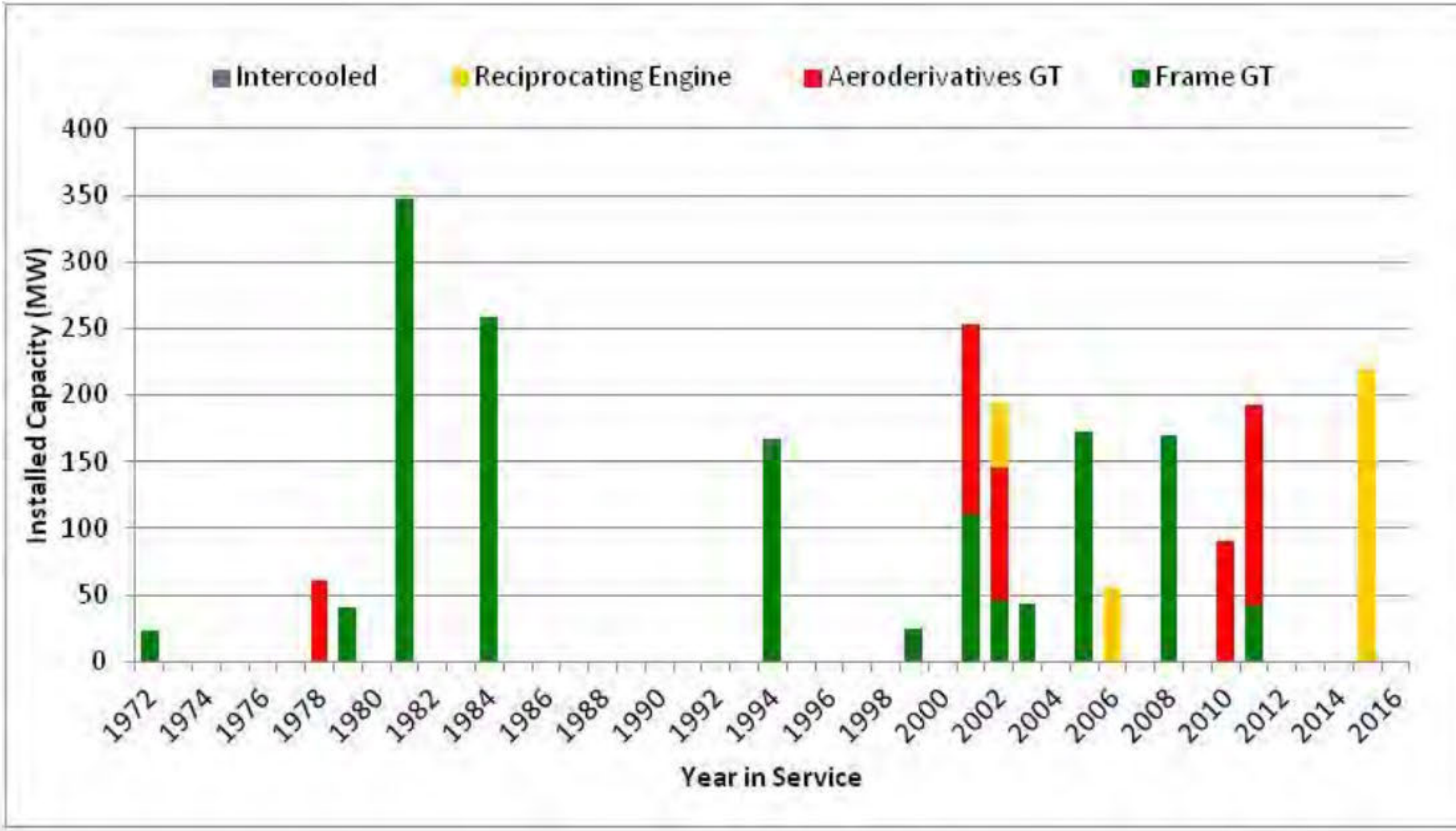
- Baseload Energy: power generated (or conserved) across a period of time to serve system demands for electricity
- Peaking Capacity: capability of power generating and demand-management resources to satisfy maximum system demands for electricity at a specific point in time (~daily occurrence)
- Hydro firming: extended operation during poor water years and may be inactive for years at a time
- Flexibility: ability to continuously and reliably match generating and demand-side resources to system demands for electricity (ramp rate, etc.)

Applications of Gas Units

	Peaking	Hydro Firming	System Balancing/ Flexibility	Base load/Intermediate Load
CCCT				X
Advanced CCCT			X	X
Recip	X	Y	X	
Aeroderivative	X	Y	X	
Intercooled	X	Y	X	
Frame	Y+	X	Y+	

X – primary use
Y – alternative use, but wouldn't build as primary purpose

Historical Peaking Plant Additions in the Region (MW)



Note: There are currently no intercooled/aero hybrid plants in the PNW

Overnight Capital Cost Assumptions and Normalizations

Capital Cost Assumptions and Normalizations

1. Reference sources – reported plant data, generic reports
2. Objective - normalize to draft Seventh Plan reference plant design
   - Overnight capital costs in $2012
   - ISO capacity and heat rate
   - Typical configuration for PNW
3. Look for outliers, trends; forecast future 20 year trend line

Reference Sources

- Project-specific publically available reported info
- Technical data from manufacturer
- Regional utility IRPs
- Gas Turbine World (2013 Handbook)
- Black & Veatch analysis for Black Hills (2011)
- NERA analysis for NYISO (2010)
- EIA Capital Cost (2013), EIA AEO (2014)
- National Energy Technology Laboratory (2013)
- National Renewable Energy Laboratory (2012; prepared by Black & Veatch)
- California Energy Commission (May 2014)

Some assumptions may have a significant effect on the final estimate of capital cost

- **Unit scaling factor** – The more units in a project, the greater the economies of scale
  - Currently assuming single unit plants cost 15% more per kw than multi-unit plants (6th Plan – 30%)
- **Owner's Cost** – 25% of EPC (6th Plan – 12%)
- Acknowledgements – limited information to make adjustments
  - Brownfield vs. Greenfield
  - Location and local air quality regulations

Draft Seventh Plan Reference Plants and Capital Cost

Proposed Configuration for 7th Plan Reference Plants

Technology	Proposed Configuration	Capacity
Frame GT	(1) 215.8 MW GE 7F 5-series	~ 216 MW
Aeroderivative GT	(4) 47.3 MW GE LM 6000PF Sprint	~ 190MW
Intercooled/Aero Hybrid GT	(2) 100 MW GE LMS100 PB	200 MW
Reciprocating Engine	(12) 18 MW Wärtsilä	220 MW

Proposing reference plants that resemble capacity of Port Westward II (220MW) – most recent peaking plant to be constructed in the PNW

Properties of Frame Technologies

Frame (80MW – 250 MW units)

- Stationary device, weight not an issue
- Strengths - longevity and durability
- Weaknesses – slower response time; higher heat rate; higher exhaust temperatures/more expensive air quality control
- Typical use – on for several days, then shut down; newer models tout flexibility
- PNW – several frame units built in 1970's – 1990's for hydro back-up (firming)

Proposed Frame Reference Plant (1)

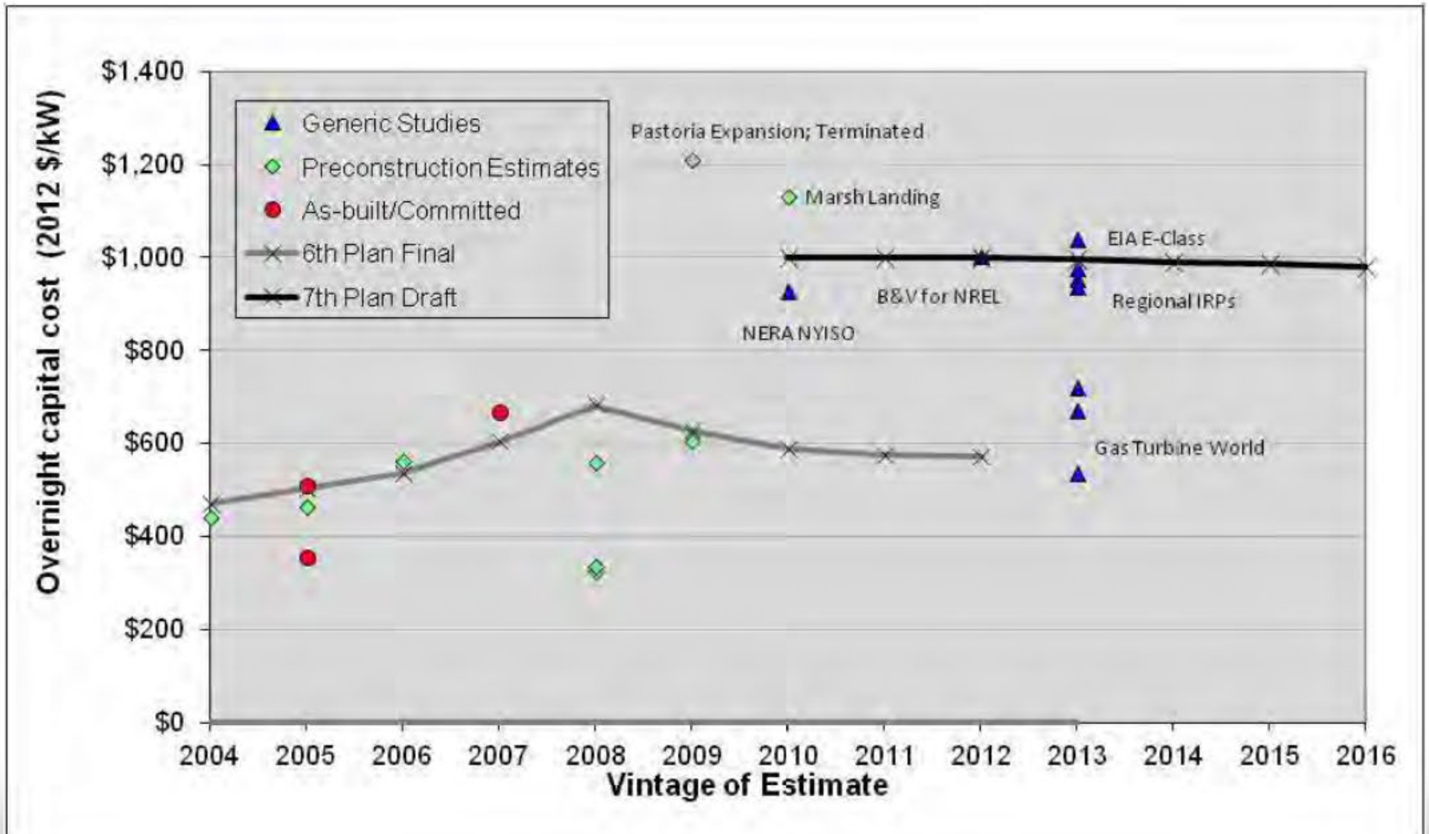
- **GE 7F 5 Series**
  - 216 MW nominal output
  - Available starting in 2009
  - 7E and 7F are popular among new installations in WECC
  - Start time – 11 minutes to base load
  - Ramp rate – 40 MW/minute per turbine
  - Turndown to minimum load – 36% baseload
  - We selected GE's 7F 5-series over 3-series
    - 5-series builds on advancements to inlet, compressor, combustion and power turbine systems
    - 5-series touts enhanced flexibility

Proposed Frame Reference Plant (2)

Technology & Configuration base	(1) GE 7F 5-Series
Output per unit (MW)	216 (nominal, ISO)
Output Total (MW)	216 nominal / 202 lifecycle avg
Fuel	Natural Gas
Heat Rate (btu/kWh)	9801 HHV
Capital Cost (mm$ 2012)	$216 MM
Capital Cost ($/kW 2012)	$1,000/kw
Fixed O&M	TBD
Variable O&M	TBD
Economic Life (Years)	30
Construction Time (Months)	18 mos development 9 mos early construction 6 mos committed construction

* All SCCT reference plants to match Port Westward II – 220 MW

Preliminary Capital Cost Estimates for Frame Technology



Properties of Aeroderivative Technologies

Aeroderivative (15 – 60 MW units)

- Designed from aircraft engine; lighter, more delicate than frame
- Strengths – rapid response; lower heat rate; easy maintenance; smaller unit size; can use SCR and OxyCat
- Weaknesses - ???
- Typical use – meeting short-term peak loads
- PNW – several Pratt and Whitney and a few LM6000 plants

Proposed Aeroderivative Reference Plant (1)

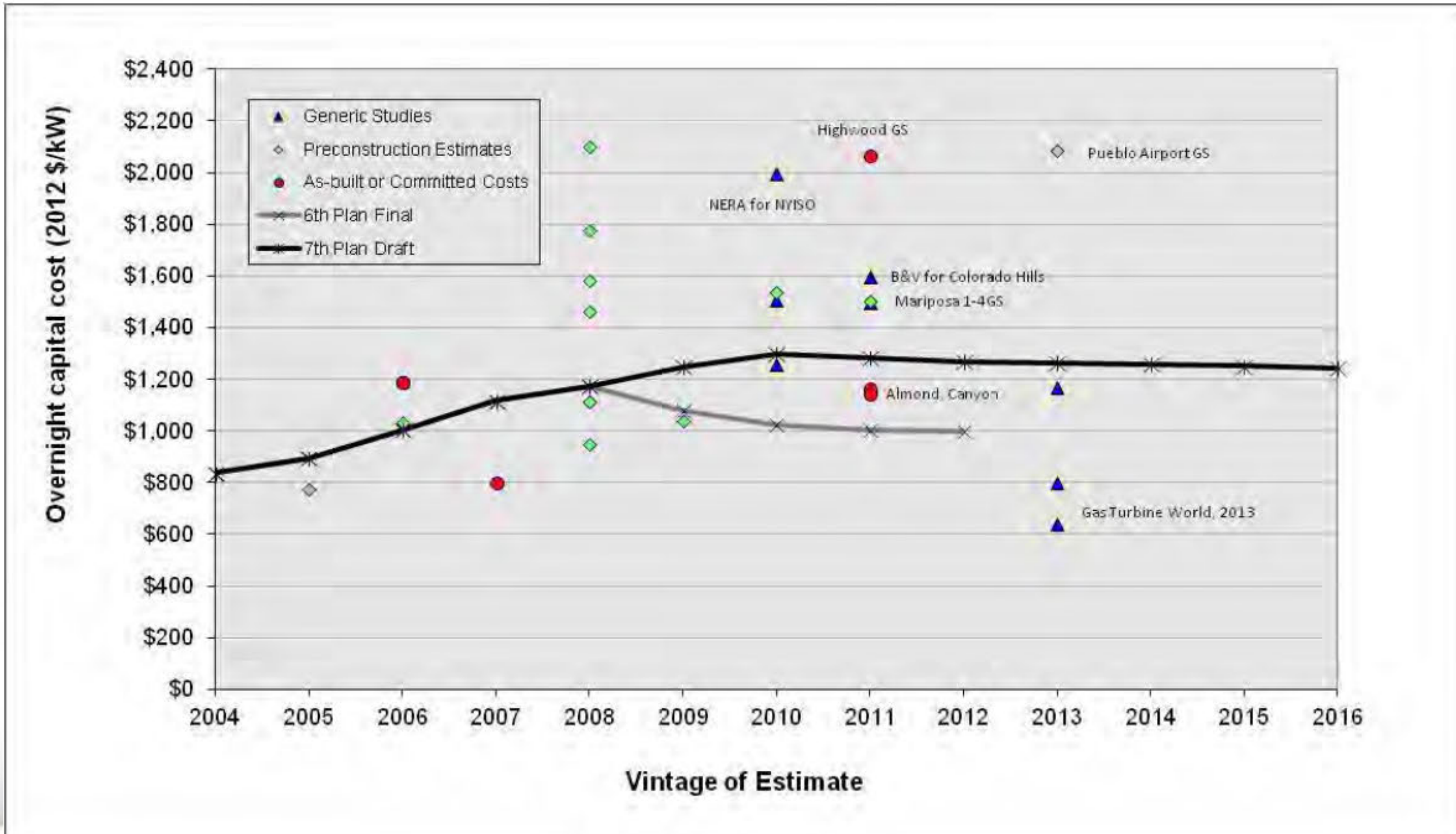
- **LM6000-PF gas turbine**
  - 42 – 47MW output (w/ SPRINT)
  - Available starting in 2007
  - Popular choice among new installs in WECC
  - More available information on cost and performance
  - Second of three LM6000 generations
    - Same gen as LM6000PD used in Sixth Plan, but with improved NOx emissions reductions
  - 5-minute fast start, 10-minute full power
  - Advanced emissions technology
    - Reduced NOx emissions to 15 ppm

Proposed Aeroderivative Ref Plant (2)

Technology & Configuration base	**(4) GE LM6000 PF SPRINT**
Output per unit (MW)	48 MW (nominal, ISO)
Output Total (MW)	192 MW nominal; 180 MW lifecycle avg
Fuel	Natural Gas
Heat Rate (btu/kWh)	9048 HHV
Capital Cost (mm$ 2012)	$228.6 (lifecycle)
Capital Cost ($/kW 2012)	$1,270 (lifecycle)
Fixed O&M	TBD
Variable O&M	TBD
Economic Life (Years)	30
Construction Time (Months)	18 mos development 9 mos early construction 6 mos committed construction

* All SCCT reference plants to match Port Westward II – 220 MW

Preliminary Capital Cost Estimates for Aeroderivative



Properties of Intercooled Technologies

Intercooled (100 MW units)

- Hybrid of frame and aeroderivative → compressor intercooler
- Strengths – rapid response; lowest GT heat rate; good turndown characteristics; can use SCR and OxyCat
- Weaknesses - requires continuous source of cooling water
- Typical use –short-term peak loads and variable resource integration
- PNW – none currently planned or in operation; numerous in WECC

Proposed Intercooled Reference Plant (1)

GE LMS100 PB

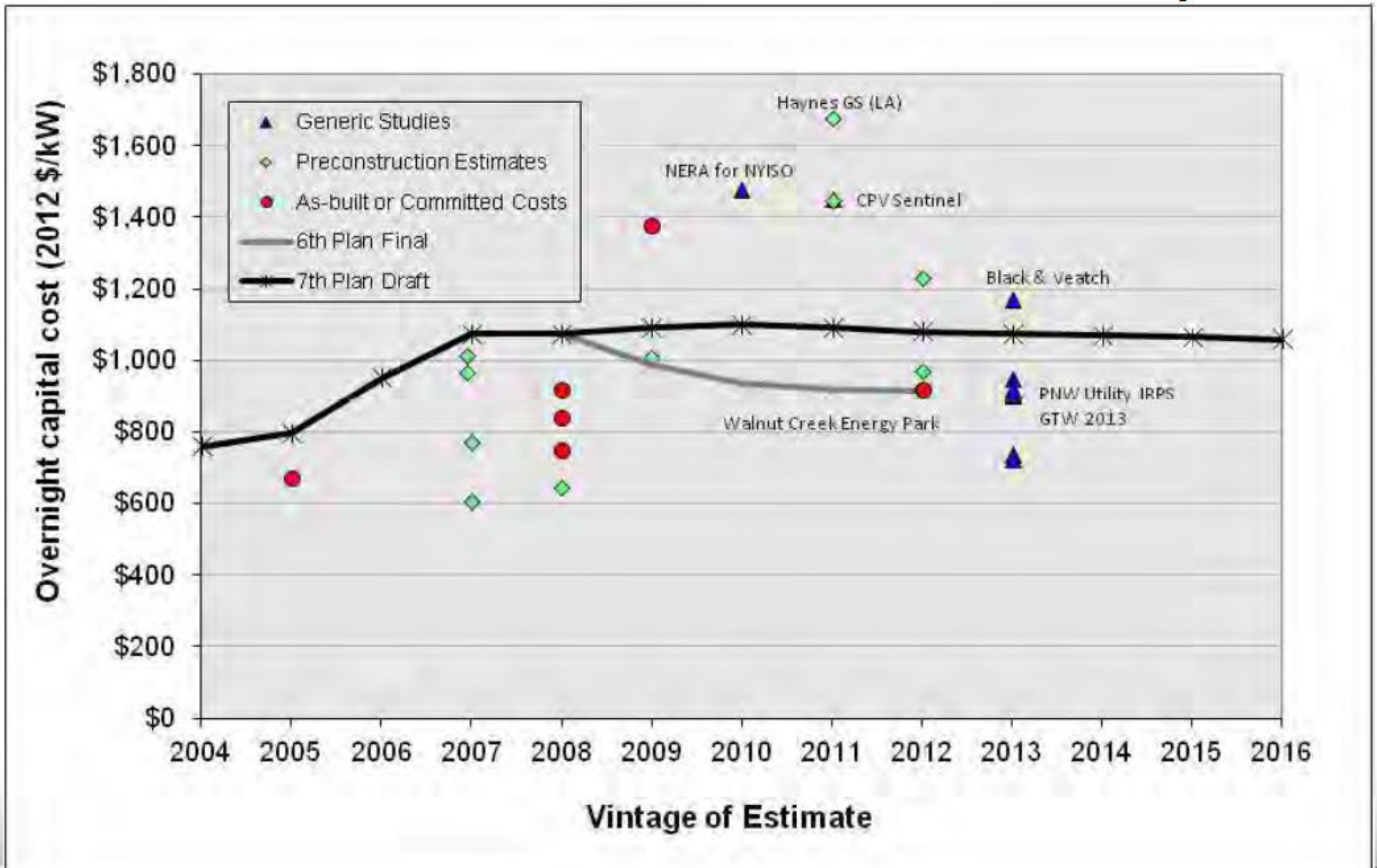
- 99.4 MW output (103.5 MW PA)
- Available starting in 2010
- Similar to PA, but with DLE instead of water injection for NOx emission control
- Based on frame 6FA and Boeing 747 technologies
- Fast start capability, 10 minutes full power

Proposed Intercooled Ref Plant (2)

Technology & Configuration base	(2) GE LMS100 PB
Output per unit (MW)	99.4 MW (nominal, ISO)
Output Total (MW)	199 MW nominal; 187 MW lifecycle avg
Fuel	Natural Gas
Heat Rate (btu/kWh)	8541 HHV
Capital Cost (mm$ 2012)	$214.9 (lifecycle)
Capital Cost ($/kW 2012)	$1,080 (lifecycle)
Fixed O&M	TBD
Variable O&M	TBD
Economic Life (Years)	30
Construction Time (Months)	18 mos development 9 mos early construction 6 mos committed construction

* All SCCT reference plants to match Port Westward II – 220 MW

Preliminary Capital Cost Estimates for Intercooled Hybrid



Reciprocating Engines

Steven Simmons
Northwest Power & Conservation Council

May 28, 2014

Engine Hall at Goodman Energy Center Kansas

Reciprocating Engines for Electric Power Generation

Recips are internal combustion engines – an air/fuel(Ntrl Gas) mixture is compressed by a piston and ignited within a cylinder to drive a piston and turn the shaft.

These engines can burn a variety of fuels including natural gas, fuel oil and biofuels.

Often individual engines are grouped into blocks called generating sets.

Strengths

1. Start quickly
2. Follow load well
3. Have good part-load efficiencies and due to modularity can operate a subset at full load
4. Maintain output at increasing elevation
5. Good reliability
6. Minimal water usage

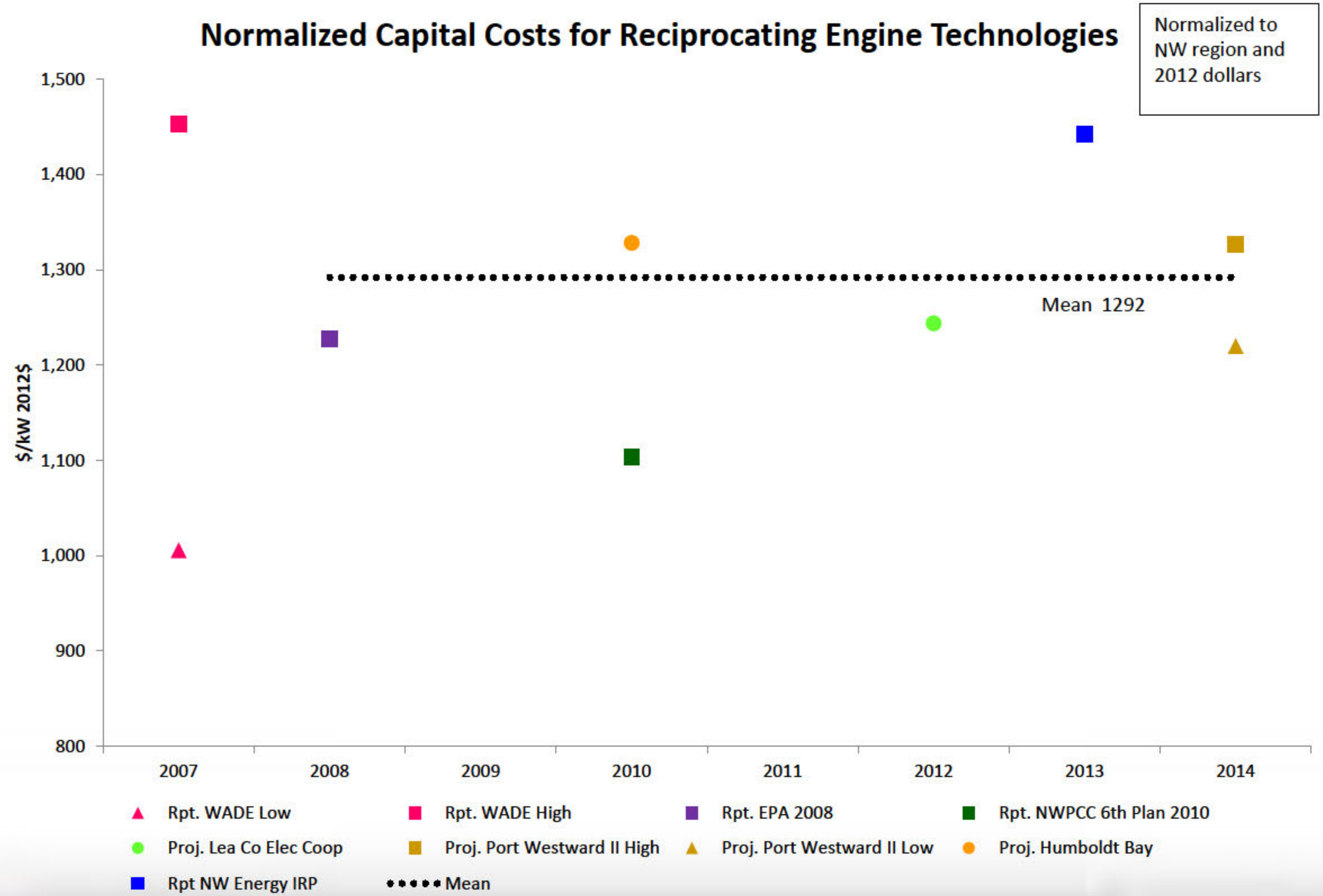
Recip. Cost Information

REPORTS

1. Northwest Power & Conservation Council 6th Plan – 2010
2. EPA Tech. Char. Of Recip. Eng. – 2008
3. World Alliance for Decentralized Energy (WADE) 2007

PROJECTS

1. Humboldt Bay (PG&E) 2010
   - Eureka CA
   - 110 MW
   - 6x18V50SG Wartsilia
2. Port Westward II (Portland Gen.) 2015
   - Clatskanie OR
   - 220 MW
   - 12x18V50SG Wartsilia
3. Lea County Electric Coop 2012
   - Lovington New Mexico
   - 46.5 MW
   - 5x20V34SG Wartsilia


Normalized Capital Costs for Reciprocating Engine Technologies
Normalized to NW region and 2012 dollars
$/kW 2012$
1,500
1,400
1,300
1,200
1,100
1,000
900
800
2007
2008
2009
2010
2011
2012
2013
2014
Mean 1292
Rpt. WADE Low
Rpt. WADE High
Rpt. EPA 2008
Rpt. NWPCC 6th Plan 2010
Proj. Lea Co Elec Coop
Proj. Port Westward II High
Proj. Port Westward II Low
Proj. Humboldt Bay
Rpt NW Energy IRP
Mean

Recip Proposed Reference Plant

Technology & Configuration base	Wartsilia 12x18V50SG
Output per unit (MW)	18.7
Output Total (MW)	224
Fuel	Natural Gas
Heat Rate (btu/kWh)	8,176
Capital Cost (mm$ 2012)	289
Capital Cost ($/kW 2012)	1,292
Fixed O&M	TBD
Variable O&M	TBD
Economic Life (Years)	25
Construction Time (Months)	12

Preliminary Capital Cost Peaking Units

Technology	Capital Cost (2012 $/kW)
Frame (7F 5-Series)	$1,000/kw (lifecycle)
Aeroderivative (LM6000PF Sprint)	$1,272/kw (lifecycle)
Intercooled Hybrid (LMS100 PB)	$1,080/kw (lifecycle)
Reciprocating Engine (Wartsila 18V50SG)	$1,292/kw (new and clean)

Next Steps for Peaking Units

- O&M costs
- Part load heat rate curves
- Availability (planned outage rate, FOR)
- Resource potential in region
- Local air permitting
- Development, early construction, committed construction schedule and cost payout for RPM

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

REDACTED EXHIBIT ICNU/204

COMPANY RESPONSES TO DATA REQUESTS

June 15, 2015

April 13, 2015

TO: Jesse Gorsuch
Davison Van Cleve (ICNU)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to ICNU Data Request No. 021
Dated March 30, 2015

Request:

Please state the following for the Port Westward 2 Generating Facility:

- **a. Total overnight capital costs ($/kW)**
- **b. Total fixed O&M ($/kW-yr)**
- **c. Variable O&M ($/MWh)**
- **d. Useful life (yrs)**
- **e. Heat Rate (btu/kWh)**
- **f. Availability factor**

Response:

PGE objects to this request to the extent that it requires new analysis. Without waiving its objection, PGE replies as follows:

a. Capital costs (excluding property taxes and allowance for funds used during construction) in Docket No. UE 294 for Port Westward 2 (PW2) equal approximately $298 million. Using the project size modeled in MONET, capital costs are approximately $1,345/kW.[1] The capital costs in this docket reflect an estimated completion cost. PGE's construction related capital expenditures will conclude in 2015.

[1] $1,345/kW = $298,000,000 divided by 221,632 kW.

b. PGE did not identify a fixed component of plant O&M for PW2 in Docket No. UE 294. PW2's fixed O&M is a part of the plant O&M PGE reported in the PGE Exhibit 700 work paper titled, "Production O&M WP Final_Revised_2-18-15.xls". See cell L14 of the worksheet titled, "PW2". Total plant O&M (which can be fixed or variable) reported in PGE Exhibit 700 is $2,549,798.

c. PGE reports the variable O&M ($/MWh) used in MONET for simulating the dispatch of PW2 in the ToPUC folder of PGE's Minimum Filing Requirement (MFR) documentation submitted on April 1, 2015 in Docket No. UE 294. See row 662 in the PC Input worksheet of the file titled "#M610PUC10-073-2016 GRC.xlsm".

d. Per Commission Order 14-297 in Docket No. UM 1679, the average service life of PW2 is 45 years. See the "Survivor Curve" value for plant account 344 on page 13 of Appendix A in Commission Order 14-297.

e. PGE reports the net heat rate of PW2 (with degradation) in the ToPUC folder of PGE's MFR documentation submitted on April 1, 2015 in Docket No. UE 294. See row 581 of the "PC Input" worksheet of the file titled "#M610PUC10-073-2016 GRC.xlsm".

f. PGE reports the availability factor of PW2 in the Assumptions Summary files that accompany its MFR documentation. For example, see the file titled "#SumM610PUC10-00h-2016 GRC.xls" in the ToPUC folder of PGE's MFR documentation submitted on February 12, 2015 in Docket No. UE 294. PW2's availability factor is listed in cell D38.

June 2, 2015

TO: Jesse Gorsuch
Davison Van Cleve (ICNU)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to ICNU Data Request No. 111
Dated May 19, 2015

Request:

Please provide a detail of the Company's historical capital expenditures placed into service on a monthly basis and by project number, including a project description, over the period January 2011 to April 2015 (inclusive), in a manner consistent with OPUC_DR_176_Supp 1, Attachment 176-D CONF.

Response:

Per discussion with ICNU, PGE is limiting this response to the 20 largest capital projects for each year. In addition, ICNU has agreed to allow PGE to exclude projects from 2011 since those data come from a legacy accounting system.

Attachment 111-A provides the requested data for 2012, 2013, 2014, and through April 2015.

Attachment 111-A is confidential and subject to Protective Order No. 15-036.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

June 2, 2015

TO: Jesse Gorsuch
Davison Van Cleve (ICNU)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to ICNU Data Request No. 112
Dated May 19, 2015

Request:

Reference OPUC_DR_176_Supp 1, Attachment 176-D CONF. For each project listed in this attachment, please detail the total amount of project expenditures that have actually been placed in service on a monthly basis as of May 1, 2015.

Response:

Per discussion with ICNU, PGE is limiting this response to the project list ICNU provided for ICNU Data Request Nos. 116 and 117.

Attachment 112-A provides the total amount of project expenditures that have been placed in service as of May 1, 2015. The list represents the amounts that were placed in service in that particular month. Attachment 112-A does not include all amounts that have been placed in service prior to January 1, 2015.

Attachment 112-A is confidential and subject to Protective Order No. 15-036.

[redacted]

[redacted]

[redacted]

[redacted]

June 2, 2015

TO: Jesse Gorsuch
Davison Van Cleve (ICNU)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to ICNU Data Request No. 113
Dated May 19, 2015

Request:

Reference OPUC_DR_176_Supp 1, Attachment 176-D CONF. For each project listed in this attachment, please detail the total amount of actual capital spending on a monthly basis between January 2014 and April 2015 (inclusive). Please also include a column to indicate the total amount of expenditures made in prior years, as of January 1, 2014.

Response:

Per discussion with ICNU, PGE is limiting this response to the project list ICNU provided for ICNU Data Request Nos. 116 and 117.

Attachment 113-A provides the total amount of capital spending during the period January 2014 through April 2015.

Attachment 113-A is confidential and subject to Protective Order No. 15-036.

[redacted]

[redacted]

[redacted]

June 2, 2015

TO: Jesse Gorsuch
Davison Van Cleve (ICNU)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to ICNU Data Request No. 114
Dated May 19, 2015

Request:

Reference OPUC_DR_176_Supp 1, Attachment 176-D CONF. For each project listed in this attachment please provide the most recently estimated in-service date and most recently estimated total project capital expenditures.

Response:

Per discussion with ICNU, PGE is limiting this response to the project list ICNU provided for ICNU Data Request Nos. 116 and 117.

Attachment 114-A provides the most recent estimated in-service date and total project capital expenditures.

Attachment 114-A is confidential and subject to Protective Order No. 15-036.

[redacted]

[redacted]

[redacted]

June 2, 2015

TO: Jesse Gorsuch
Davison Van Cleve (ICNU)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to ICNU Data Request No. 116
Dated May 19, 2015

Request:

Reference the project numbers listed in Attach ICNU DR 116 (attached to these data requests). For each project number detailed in the attachment, please provide the initial workplan for the project, including detail of the timing of the various construction and other project tasks to be performed and expected expenditures for each task.

Response:

All project justifications provided in PGE's response to OPUC Data Request No. 176, Attachments 176-B, 176-E, 176-F, 176-G, which are confidential and subject to Protective Order No. 15-036, provide the initial detail as well as detail for each subsequent revision.

June 2, 2015

TO: Jesse Gorsuch
Davison Van Cleve (ICNU)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to ICNU Data Request No. 117
Dated May 19, 2015

Request:

Reference the project numbers listed in Attach ICNU DR 116. For each project detailed in the attachment, please provide the most recent project workplan including detail of the timing of the various construction and other project tasks to be performed and expected costs for each task. Please also detail the timing and actual expenditures for completed tasks, including for completed projects.

Response:

Attachment 117-A provides project revisions that have been approved since we initially provided project justifications in PGE's response to OPUC Data Request No. 176, Attachments 176-B, 176-E, 176-F, 176-G. PGE's response to ICNU Data Request No. 114, Attachment 114-A, column G, indicates which projects have updated justifications and which do not.

Attachments 114-A and 117-A is confidential and subject to Protective Order No. 15-036.

March 20, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 176
Dated March 2, 2015

Request:

Regarding Exhibit UE 294/PGE/208, Tooman-Brown, Page 1 of 1, where the Company provided "Rate Base Comparison" from "UE283" versus "2016 Test Year," please:

a. **Provide a list of all the plant in service additions (i.e., investments, projects, capital additions, etc.) that in aggregate comprise the approximately $581 million plant in service differential between the 2016 Test Year and UE 283;[1] please provide the annual amounts of transfers to plant in service additions;**

b. **For each plant in service addition requested in part "a" of this data request, provide the following information:**
   i. **A description of such plant in service addition;**
   ii. **A detailed breakdown of capital costs of such plant in service addition (e.g., labor, materials, vehicles, other), including a description of each category, in electronic spreadsheet format with all formulae and cell references intact;**
   iii. **The specific location of such plant in service addition (if applicable);**
   iv. **One-line diagram, which shall include such plant in service addition (if applicable);**
   v. **The Company's analysis supporting the need for such plant in service addition, including but not limited to financial analyses (in electronic spreadsheet format with cell references and formulae intact), investment appraisals, planning documents (not limited to integrated resource plans), studies, reports, etc.;**
   vi. **Copies of all internal correspondence and presentations related to the final decision to go forward with such plant in service addition;**
   vii. **A statement of whether OPUC has acknowledged such plant in service addition in any integrated resource plan (if applicable) and, if so, identify**

[1] $581 million is the approximation of $581,465 thousand. $$581 million is the difference between $87,254,345 minus $3,394,661 thousand.

the docket and order (including page number) indicating such acknowledgment;

viii. **The in-service date of such plant in service addition as of the date of PGE filing this current general rate case and as of today; and**

ix. **A statement of whether the plant in service will be "used and useful" when it comes online and a detailed narrative explanation on this point.**

Please include the workpapers used to respond to any of the above sub-questions (e.g., "a," "b," "i," "ii," etc.). If the information requested in such sub-questions was derived or obtained from other sources, please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format indicating the specific page, section, etc. of the relevant source document.

Response:

PGE object to this request on the grounds that it is overly broad and unduly burdensome. Subject to and without waiving its objection, PGE responds as follows:

a. Attachment 176-A provides plant additions beginning with 2014 year end actuals through PGE's forecasted year end 2015. The total plant additions included in this filing for 2014 are approximately $432 million. In addition, approximately $165 million is assumed for PGE's PRC/BAL purchase, approved in Commission Orders No. 14-149, 14-422 and amended Order No. 14-442. These two amounts more than account for PGE's request for plant in service in this filing. Attachment 176-A is confidential and subject to Protective Order No. 15-036.

b. See parts (i) through (ix) below:

    i. Attachment 176-B includes project justifications and other documents that provide a detailed description of projects. Attachment 176-B is confidential and subject to Protective Order No. 15-036.

    ii. Attachment 176-A, tab 'Detail' provides a detailed breakdown of the capital costs by cost element.

    iii. The location of projects is included in the project justifications and other documents in Attachment 176-B.

    iv. All documentation for projects is included in project justifications and other documents in Attachment 176-B.

    v. Discussions of the necessity of these investments are included in Attachment 176-B, project justification and other documents.

vi. Where available, presentations and/or excerpts from Board of Directors presentations have been included for the respective project in Attachment 176-B.

vii PGE generally includes only significant new generation and transmission proposals in its IRP action plans. Based on PGE's future resource needs, the Commission approved PGE's Action Plan from the 2009 IRP that led to PGE's Carty Generating Station. The Commission acknowledged the action plan in Order No. 10-457 (pages 29-30) issued in Docket No. LC 48 on November 23, 2010.

viii. Attachment 176-A, tab "In-Service" provides the projects that are included in this rate case filing and also the projects we expect to close as of the date of this data response.

ix. It is PGE's policy that when a project is "substantially complete," the project will be identified as closed-to-utility plant-in-service. Substantial completion means the completion of the installation, modification, or construction of all elements essential to the project and, the project is ready for its intended use, or assigned function. The capital expenditures included in UE 294 that closed to plant-in-service have/will have met the above criteria and would be considered used and useful.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/205

RATE SPREAD IMPACT OF LOAD FOLLOWING CREDIT ALLOCATION

June 15, 2015

RATE SPRED IMPACT OF LOAD FOLLOWING CREDIT RECOMMENDATION
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS INCLUDING CARTY
2016

CATEGORY	RATE SCHEDULE	Forecast SDEC14E16 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.	FILED	DELTA
Residential	7	748,413	7,620,805	$890,590,890	$918,982,226	$28,391,336	3.2%	3.1%	0.1%
Employee Discount				($913,107)	($942,997)	($29,890)			
Subtotal				$889,677,782	$918,039,228	$28,361,446	3.2%	3.1%	0.1%
Outdoor Area Lighting	15	0	16,308	$3,720,472	$3,567,247	($153,225)	-4.1%	-4.2%	0.0%
General Service <30 kW	32	90,384	1,599,950	$177,983,371	$188,815,224	$10,831,853	6.1%	6.0%	0.1%
Opt. Time-of-Day G.S. >30 kW	38	548	39,036	$5,425,870	$6,115,668	$689,798	12.7%	12.7%	0.0%
Irrig. & Drain. Pump. < 30 kW	47	3,152	20,845	$3,672,577	$3,697,204	$24,627	0.7%	0.6%	0.1%
Irrig. & Drain. Pump. > 30 kW	49	1,349	62,677	$7,699,051	$8,740,113	$1,041,062	13.5%	13.5%	0.0%
General Service 31-200 kW	83	11,029	2,795,179	$256,178,020	$270,110,285	$13,932,265	5.4%	5.3%	0.1%
General Service 201-4,000 kW									
Secondary	85-S	1,263	2,464,564	$200,716,499	$208,673,589	$7,957,090	4.0%	3.8%	0.1%
Primary	85-P	192	713,162	$54,524,372	$56,917,924	$2,393,552	4.4%	4.3%	0.1%
Schedule 89 > 4 MW									
Primary	89-P	18	851,370	$56,124,536	$57,397,348	$1,272,811	2.3%	4.7%	-2.5%
Subtransmission	89-T	5	83,072	$7,078,279	$6,842,019	($236,260)	-3.3%	-1.5%	-1.9%
Schedule 90	90-P	4	1,498,007	$92,205,662	$96,733,409	$4,527,747	4.9%	4.9%	0.0%
Street & Highway Lighting	91/95	205	74,544	$14,537,886	$14,201,003	($336,883)	-2.3%	-2.4%	0.0%
Traffic Signals	92	17	3,243	$260,663	$275,743	$15,079	5.8%	5.7%	0.1%
COS TOTALS		856,579	17,842,764	$1,769,805,039	$1,840,126,003	$70,320,963	4.0%	4.0%	0.0%
Direct Access Service 201-4,000 kW									
Secondary	485-S	159	438,339	$9,228,297	$8,329,416	($898,881)			
Primary	485-P	44	273,576	$5,874,711	$5,569,028	($305,683)			
Direct Access Service > 4 MW									
Secondary	489-S	1	14,393	$446,088	$325,154	($120,934)			
Primary	489-P	9	533,149	$6,418,097	$4,004,972	($2,413,125)			
Subtransmission	489-T	3	305,980	$2,742,245	$2,080,644	($661,601)			
DIRECT ACCESS TOTALS		216	1,565,436	$24,709,438	$20,309,214	($4,400,224)			
COS AND DA CYCLE TOTALS		856,795	19,408,200	$1,794,514,477	$1,860,435,217	$65,920,739	3.7%	3.7%	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

REDACTED EXHIBIT ICNU/206

CAPITAL EXPENDITURE REVIEW WORKPAPERS

June 15, 2015

Exhibit ICNU/206 is confidential pursuant to Protective Order No. 15-036 and has been redacted in its entirety.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/207

SELECTIONS FROM PGE INVESTOR PRESENTATIONS ON RATE BASE ADDITIONS

June 15, 2015

ICNU/207
Mullins/1

Portland General Electric

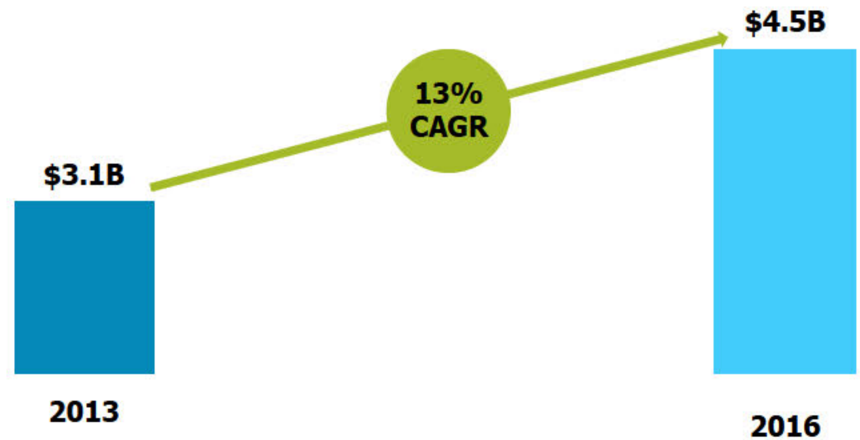
Investor Presentation

March 2015

Rate Base and Capital Expenditures

Portland General Electric

$1.4B of expected increase in rate base



Capital Expenditures

(in millions)	2013	2014	2015E	2016E	2017E	2018E	TOTAL
Base Capital Spending[1]	$335	$342	$408	$363	$341	$301	**$2,090**
Port Westward Unit 2	$155	$118	$20				**$293**
Tucannon River Wind Farm	$95	$380	$29				**$504**
Carty Generating Station	$135	$108	$172	$35			**$450**
TOTAL	**$720**	**$948**	**$629**	**$398**	**$341**	**$301**	**$3,337**

1) Consists of board-approved ongoing CapEx and hydro relicensing per the Annual 2014 Form 10-K filed on February 13, 2015
Note: Amounts exclude AFDC debt and equity

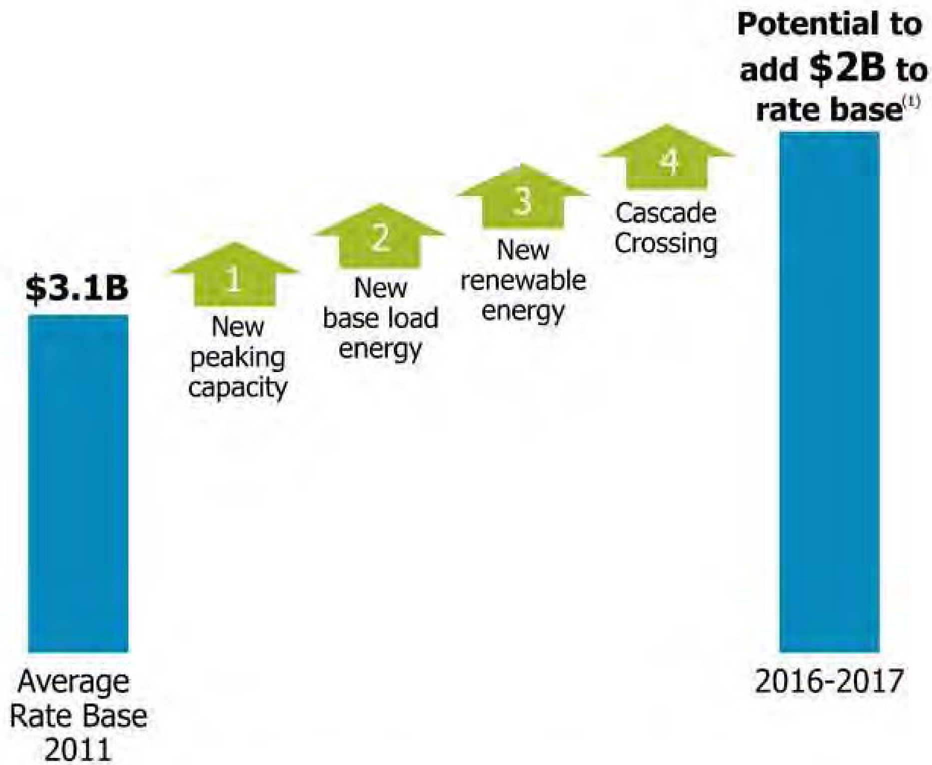
Exhibit 99.1

Portland General Electric

Investor Presentation

August 2012

Potential Opportunities for Rate Base Growth



1) Rate base growth dependent on outcome of RFP processes; PGE is committed to move forward with the least cost, least risk option for customers

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

REDACTED EXHIBIT ICNU/208

SELECT CAPITAL ADDITION PROJECT JUSTIFICATION FORMS

June 15, 2015

Exhibit ICNU/208 is confidential pursuant to Protective Order No. 15-036 and has been redacted in its entirety.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/209

PROPOSED REDLINE TO SCHEDULE 75

June 15, 2015

SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$~~5,130~~2,670.00	$~~4,580~~1,620.00	$~~5,280~~3,090.00	~~(I)~~
Transmission and Related Services Charge				(R)
per kW of monthly On-Peak Demand	$0.~~80~~79	$0.77	$0.76	
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				(R)
First 4,000 kW	$~~1.85~~0.99	$~~1.82~~0.96	$~~1.82~~0.96	
Over 4,000 kW	$~~1.26~~0.99	$~~1.23~~0.96	$~~1.23~~0.96	
per kW of monthly On-Peak Demand	$2.~~12~~38	$2.~~06~~32	$~~0.78~~1.21	
Generation Contingency Reserves Charges				(R)
Spinning Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	~~(I)~~(R)
Supplemental Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	(I)
System Usage Charge				
per kWh	0.~~081~~083 ¢	0.~~078~~080 ¢	0.~~075~~077 ¢	
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

BASELINE DEMAND

Baseline Demand is the Demand normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating as planned by the Customer. Initially, the Customer's Baseline Demand will be the Customer's typical peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations. Subsequently, Customer may select its Baseline Demand in accordance with the applicable notice requirements set forth in this schedule adjusted for changes in load and planned generator operations. Planned generator operations include the Electricity planned to be produced by the generator as well as the Customer's plans to sell Electricity produced by the generator to the Company or third parties. The Company and Customer may mutually agree to use an alternate method to determine the Baseline Demand when the Customer's Demand is highly variable. Any modification to the Baseline Demand must be consistent with the Special Conditions.

For Customers who are also receiving service under Schedule 76R, monthly Demand charges under Schedule 75 will be based on Demand up to the Baseline Demand.

FACILITY CAPACITY

For the first three months of service under this schedule, the Facility Capacity will be equal to the Customer's Baseline Demand. Starting with the fourth month, the Facility Capacity will be the average of the two greatest non-zero monthly Demands established during the 12-month period which includes and ends with the current Billing Period, but will not be less than the Customer's Baseline Demand.

RESERVED CAPACITY

The Reserved Capacity is the lesser of the nameplate rating of the Customer's generation or the maximum kW of Customer load supplied by the Customer's generation. Additionally, upon agreement with the Customer, the Company will reduce the Reserved Capacity by the Customer's demonstrated, instantaneous load reduction capability in kW associated with generation output reductions.

The Customer and Company will enter into a written agreement that specifies the Reserved Capacity in kW, the load reduction capability in kW (if any), the requirements for Customer notification to the Company of any changes in the Reserved Capacity, the Company's ability to request a demonstration of load reduction capability annually, additional metering requirements and any other necessary notification requirements.

Except during the first three months of operation, if the Customer's operations result in an actual Reserve Capacity requirement above the level specified by the agreement, the Reserved Capacity will immediately be adjusted to the actual kW level for that month and the following three months. Thereafter, the Reserved Capacity will remain at that increased kW level until the Customer has demonstrated to the Company's reasonable satisfaction that the Reserved Capacity should be revised.

SCHEDULE 75 (Continued)

GENERATION CONTINGENCY RESERVES

Generation Contingency Reserves consist of the following components:

Spinning Reserves

Spinning Reserves provide Electricity immediately after a Customer's generator output falls below the Reserved Capacity. Spinning Reserves in combination with Supplemental Reserves, transition a Customer's load to Unscheduled Power. A Customer on Schedule 75 must take Spinning Reserves in all Billing Periods that its generator is expected to operate. Spinning Reserves are not required for a Customer with Reserved Capacity of 2,000 kW or less, or when the Customer's generator is not normally scheduled to operate during an entire Billing Period.

Supplemental Reserves

Supplemental Reserves provide Electricity within the first 10 minutes after a Customer's generator output falls below the Reserved Capacity. In lieu of purchasing Supplemental Reserves, a Customer may choose to reduce load within the 10 minutes of generator failure. The Customer's Load Reduction Plan must be approved by the Company.

Self-Supplied Reserves

Customers with nameplate Generation of 15 MW or greater may self-supply needed Generation Contingency Reserves upon agreement between Customer and the Company. The agreement will specify the kW of Contingency Reserves provided by the Customer at 7% of Reserved Capacity, the notification processes for delivery of reserve Energy, the requirements for Customer delivery of requested reserves, the requirements for Customer notification to the Company of any changes in the ability to self-supply reserves, the settlement process to be used when Contingency Reserves are supplied by the Customer, the provisions for an annual demonstration of such capability, any additional metering requirements and other necessary notification requirements. Customers who self-supply Generation Contingency Reserves will not be charged for Spinning and Supplemental Reserves under this schedule.

Supplemental Reserves Load Reduction Plan

In lieu of self supplying Supplemental Reserves through a self-supply agreement, a Customer may provide Supplemental Reserves through the submittal to the Company of a Load Reduction Plan that demonstrates the ability to reduce load within the first ten minutes of generator failure and specifies a kW amount of load reduction equal to 3.5% of the Reserved Capacity.

SCHEDULE 75 (Continued)

GENERATION CONTINGENCY RESERVES (Continued)

Supplemental Reserves Load Reduction Plan (Continued)

The Load Reduction Plan also will specify the notification processes for delivery of Supplemental Reserves, the requirements for Customer delivery of requested Supplemental Reserves, the requirements for Customer notification to Company of any changes in the ability to supply Supplemental Reserves, the settlement process to be used when Supplemental Reserves are supplied by the Customer, the provisions for a demonstration of such capability, any additional metering requirements and other necessary notification, plant and financial requirements. The Customer Load Reduction Plan must be approved by the Company. If approved by the Company, and adhered to by the Customer, a credit to the Supplemental Reserves charges will be applied to Customer's bill based on the Supplemental Reserves Level as specified in the Load Reduction Plan.

If Customer fails to follow the Company-approved Load Reduction Plan, all Supplemental Reserves credits for the subsequent three months (Penalty Period) will be forfeited. If the Customer satisfactorily follows the Company-approved Load Reduction Plan during the Penalty Period, the Load Reduction Plan kW credit will be reinstated at the end of the three month Penalty Period.

If the Customer fails to follow the Company-approved Load Reduction Plan a second time during the Penalty Period and the following three months, the Load Reduction Plan will be terminated.

The duration of the Penalty Period will not be limited by the establishment of a new service agreement under this schedule.

Following termination or contract expiration, Customer may submit a new Load Reduction Plan to the Company. Company will approve the new Load Reduction Plan if the Customer is able to demonstrate the load reduction capability of the Plan to Company's satisfaction.

Notwithstanding the above, Customer may terminate the Company-approved Load Reduction Plan upon giving 6 month written notice to Company.

ENERGY CHARGE

The Energy Charge is comprised of the following:

Baseline Energy

Unless otherwise agreed to, the Baseline Energy is the Energy normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating as planned. Usage on an hourly basis up to and including the Baseline Demand will be considered Baseline Energy. The Company may, in collaboration with the Customer, develop an alternate method to determine Baseline Energy when the Customer is new to the Company's system or has changed operations from the previous year.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Baseline Energy (Continued)

If other than the typical operations are used to determine Baseline Energy, the Customer and the Company must agree on the Baseline Energy before the Customer may take service under this schedule. The Company may require use of an alternate method to determine the Baseline Energy when the Customer's usage not normally supplied by its generator is highly variable.

Baseline Energy will be charged at the applicable Energy Charge, including adjustments, under Schedule 89. All Energy Charge options included in Schedule 89 are available to the Customer on Schedule 75 based on the terms and conditions under Schedule 89. For Energy supplied in excess of Baseline Energy, the Scheduled Maintenance Energy and/or Unscheduled Energy charges will apply except for Energy supplied pursuant to Schedule 76R.

Any Energy Charge option for Baseline Energy selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service.

Scheduled Maintenance Energy

Scheduled Maintenance Energy is Energy prescheduled for delivery, up to 744 hours per calendar year, to serve the Customer's load normally served by the Customer's own generation (i.e. above Baseline Energy). Scheduled Maintenance must be prescheduled at least one month (30 days) before delivery for a time period mutually agreeable to the Company and the Customer.

When the Customer preschedules Energy for an entire calendar month, the Customer may choose that the Scheduled Maintenance Energy Charge be either the Monthly Fixed or Daily Price Energy Charge Option, including adjustments as identified in Schedule 100 and notice requirements as described under Schedule 89. When the Customer preschedules Energy for less than an entire month, the Scheduled Maintenance Energy will be charged at the Daily Price Energy Option, including adjustments, under Schedule 89.

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Powerdex Mid-Columbia Hourly Firm Electricity Price Index (Powerdex-Mid-C Hourly Firm Index) plus 0.~~300~~305¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, plus losses. (I)

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)
Unscheduled Energy (Continued)

If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported.

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

The Company may request that a Customer taking Unscheduled Energy during more than 1,000 hours during a calendar year provide information detailing the reasons that the generator was not able to run during those hours in order to determine the appropriate Baseline Demand.

LOSSES

Losses will be included by multiplying the applicable Energy Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0356	(I)
Primary Delivery Voltage	1.0496	(I)
Secondary Delivery Voltage	1.0685	(R)

DIRECT ACCESS PARTIAL REQUIREMENTS SERVICE

A Customer served under this schedule may elect to receive Direct Access Partial Requirements Service from an Electricity Service Supplier (ESS) under the terms of Schedule 575 provided it has given notice consistent with any Baseline Energy option requirements. A Customer may return to Schedule 75 provided it has met any term requirements of Schedule 575 and any requirements needed to purchase Baseline Energy if needed.

MINIMUM CHARGE

The Minimum Charge will be the Basic, Transmission, Distribution, Demand and Generation Contingency Reserves Charges, when applicable. In addition, the Company may require a higher Minimum Charge, if necessary, to justify the Company's investment in service Facilities.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 75 (Continued)

ADJUSTMENTS

Service under this schedule will be subject to all adjustments as summarized in Schedule 100. Applicable adjustments will be applied to Baseline Energy and Scheduled Maintenance Energy with the exception of Schedules 108 and 115, which are applied to factors other than usage as required by statute.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written service agreement specifying the terms and conditions of service, the Customer's Baseline Demand and Energy Pricing Option under Schedule 89, the Customer's Reserved Capacity, the Company's and Customer's contact information, and any other information necessary for implementation of service under this schedule. The term of the service agreement will be one calendar year (except that the term of the first service agreement will be the remainder of the year when signed plus the next calendar year) and will renew annually thereafter for successive one year terms, unless the Customer gives 90 days prior written notice. These terms and conditions will be consistent with this schedule.

2. A Customer must inform the Company within 30 minutes of taking Unscheduled Energy at a rate of five MW or greater and inform the Company of the anticipated time that the generator will return to normal operations.

3. Customers must have Company approved interval metering and meter communications in place prior to initiation of service under this schedule. The Company requires metering that measures the net quantity and direction of flow at the Point of Delivery and total Generator output.

4. If the Customer is served at Primary or Subtransmission Voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and the necessary wiring on both sides of the transformers. All transformers, equipment and wiring will be of types and characteristics approved by the Company and their installation, operation and maintenance will be subject to inspection and approval by the Company.

5. If during a Billing Period the Customer is billed for Transmission and Related Services under this schedule and Transmission Services under the Company's FERC Open Access Transmission Tariff (OATT) for the purpose of effecting a wholesale power sale from the Customer's generator, the payments for OATT charges for Transmission Service (Schedules 7 or 8) and Schedule 3, Regulation and Frequency Response Service will be credited to the Transmission and Related Services Charge under this schedule. The credit will be the actual OATT demand incurred but will not exceed the Monthly Demand for the Schedule 75 monthly Transmission Demand multiplied by the applicable OATT (OATT Schedules 3, 7 or 8) and such credit will not exceed the Transmission and Related Services Charge incurred under this schedule.

SCHEDULE 75 (Concluded)

SPECIAL CONDITIONS (Continued)

6. The Customer will not use Electricity sold by the Company to directly or indirectly make or continue a delivery of Electricity to another Customer or wholesale power purchaser.

7. A Customer's failure to inform the Company of the use of on-site generation will not relieve the Customer of responsibility for the charges and requirements under this schedule.

8. The Customer's Baseline Demand may be increased or decreased as requested by the Customer for planned, long-term load changes including changes resulting from the addition of long-term energy efficiency measures, load shedding, the addition or removal of equipment or the permanent removal of generating capacity from the Customer location. Such changes will be effective upon verification of the change by the Company. "Long-term" or "permanent" mean changes that are implemented with the purpose of being in place indefinitely. The Customer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the ~~actual Customer generation~~Customer's generating capacity. (N)

(N)

9. A change in Baseline Demand related to modifications in generating capacity or planned generation operations may be made provided the Company or Customer provides the following notice:
   a) for a change to Baseline Demand that within a one calendar year period does not exceed 5 MW, the Company or Customer may make one such request per calendar year and will provide at least 6 months written notice;

   b) for a change in Baseline Demand that is greater than 5 MW, the Company or Customer must provide at least 13 months written notice ~~to the Company~~ with such change effective on January 1 of the applicable year. Any subsequent notice by the Company or Customer under this special condition must be made consistent with these notice requirements.

10. If the Customer's Baseline Demand is increased, any Energy used above the initial Baseline Demand, and below the revised Baseline Demand will be priced at the Daily Price Option contained in Schedule 89 unless the Customer has given the required notice to change the applicable Schedule 89 Energy Charge Option.

11. The Company reserves the right to modify any agreements existing under this schedule as a result of changes in Western Electricity Coordinating Council guidelines.

12. If the Customer is receiving service under this schedule and Schedule 76R, the monthly Basic and Facility Capacity charges may be replaced and billed pursuant to Schedule 76R Special Conditions.

13. A Customer may not change service options until it has satisfied any Baseline Energy term provisions as established in Schedule 89.

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~~Pamela Grace Lesh,~~James F. Lobdell, Senior Vice Presidenton and after ~~January 17, 2007~~March 16, 2015

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

OPENING TESTIMONY OF MICHAEL P. GORMAN

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 15, 2015

**TABLE OF CONTENTS TO THE
OPENING TESTIMONY OF MICHAEL P. GORMAN**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017. I am employed by the firm of Brubaker & Associates, Inc. ("BAI"), regulatory and economic consultants with corporate headquarters in Chesterfield, Missouri. My qualifications are provided in Exhibit ICNU/301.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including Portland General Electric Company ("PGE" or the "Company").

Q. WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A. My testimony will address PGE's overall rate of return including return on equity, embedded debt cost, and capital structure. I will also respond to PGE witness Dr. Bente Villadsen.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibits ICNU/301 through ICNU/318.

I. SUMMARY

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS ON PGE'S RATE OF RETURN.

A. I recommend the Public Utility Commission of Oregon (the "Commission") award PGE a return on common equity of 9.25%, which is the midpoint of my recommended range of 8.90% to 9.60%. My recommended return on equity will fairly compensate PGE for its current market cost of common equity, and it will mitigate the claimed revenue deficiency in this proceeding by providing PGE fair compensation with the lowest cost to customers.

My recommended return on equity is developed on my Exhibit ICNU/302, and produces an overall rate of return of 7.34%. This rate of return is based on my recommended return on equity, and the Company's proposed capital structure and embedded cost of debt.

My recommended reduction to the Company's return on equity will lower its claimed revenue deficiency by $21.5 million to $24.1 million, without and with Carty Generating Station included in rate base.

II. RATE OF RETURN

Q. PLEASE DESCRIBE THIS SECTION OF YOUR TESTIMONY.

A. I begin my estimate of a fair return on equity for PGE by reviewing the market's assessment of the regulated utility industry investment risk, credit standing, and stock price performance. I used this information to get a sense of the market's perception of the risk characteristics of regulated utility investments in general, which is then used to produce a refined estimate of the market's return requirement for assuming investment risk similar to PGE's utility operations.

As described below, I find the credit rating outlook of the industry to be strong, supportive of the industry's financial integrity and access to capital. Further, regulated utilities' stocks have exhibited strong price performance over the last several years, which is evidence of utility access to capital.

Based on this review of credit outlooks and stock price performance, I conclude that the market continues to embrace the regulated utility industry as a safe-haven investment, and views utility equity and debt investments as low-risk securities.

II.A. Regulated Utility Industry Market Outlook

Q. PLEASE DESCRIBE REGULATED UTILITIES' CREDIT RATING OUTLOOK.

A. Utilities' credit ratings have improved over the recent past and the credit outlook is Stable. Further, credit analysts have observed that utilities currently have strong access to capital at attractive pricing (i.e., low capital costs).

Standard & Poor's ("S&P") recently published a report titled "The Outlook For U.S. Regulated Utilities Remains Stable On Increasing Capital Spending And Robust Financial Performance." In that report, S&P noted the following:

> **Capital Spending Will Grow**
>
> Consistent with the trend over the past 10 years, we expect that utility company capital spending will continue to grow (see related article "U.S. Regulated Electric Utilities' Annual Capital Spending Is Poised To Eclipse $100 Billion," July 29, 2014). We project that capital spending will reach an all-time high of about $95 billion in 2014, reflecting growing funding needs for environmental compliance projects and new transmission investments. For 2015-2016, we expect capital spending overall to slow somewhat, but transmission investments to continue to grow to address reliability, accommodate new generation, and integrate renewable energy projects into the grid. The slowdown in the next few years is due to environmental compliance-related capital spending that reflects the completion of [sic] the necessary projects for much of coal-fired generation to meet the existing U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS). Beginning in 2017, we expect the industry's generation and overall capital spending needs to pick up significantly, consistently exceeding $100 billion annually. This hike reflects some utilities' decisions to proactively boost lower carbon-intensive generation capital spending in order to meet the EPA's recently announced proposed carbon pollution rules.

* * *

> **INDUSTRY RATINGS OUTLOOK: STABLE**
>
> Our outlook on the regulated utility sector, which encompasses electric, natural gas, and water companies, is stable with a slightly positive bias, with about 20% of companies in the sector having a positive outlook. The positive bias is not industrywide, rather it is the result of certain issuers undertaking actions that can benefit their credit profiles, a trend that has been making its way through the industry over the past few years. We have seen companies, when opportune, endeavor to reduce business risk while maintaining or slightly enhancing their financial profiles. Overall, our fundamental view of the sector is a stable one, supported by the essential nature of the services provided, making the companies somewhat insensitive to economic fluctuations; the rate-regulated nature of the business, which lends a measure of stability and predictability to cash flow generation; and the <u>generally supportive posture of regulators</u> toward cost recovery of incremental investments facilitated by the ongoing low power prices.[1/]

Similarly, Fitch states:

> **Stable Sector Outlook:** Fitch Ratings' stable outlook for the U.S. Utilities, Power and Gas (UPG) sector reflects modest recovery in electricity sales after three years of stagnant growth. The recently observed positive momentum in industrial sales could sustain in line with the broader economic recovery and potentially spill over to other sectors. This is welcome news for electric utilities wrestling with structural headwinds posed by energy efficiency and distributed generation, and pressure on retail prices as costs are spread over declining units of sales.
>
> * * *
>
> **Divergence in Subsector Rating Outlook**
>
> The outlook for electric and gas utilities and utility parent companies <u>is stable</u> given the backdrop of gradual economic recovery, low inflation and subdued interest rates, and stable commodity prices. Issuer Default Ratings should remain on the cusp of 'BBB+' to 'A–', with more than 90% of debt issuances being rated in the 'A' category. Long-term debt instrument ratings of Fitch's entire universe of regulated utilities carry investment-grade ratings, a testament to the sound credit profile of the industry. The outlook for gencos is negative, reflecting poor sector fundamentals, including weak electricity demand and low power prices. Affiliated gencos generally have investment-grade ratings and may be

[1/] *Standard & Poor's RatingsDirect*: "Industry Report Card: The Outlook For U.S. Regulated Utilities Remains Stable On Increasing Capital Spending And Robust Financial Performance," December 16, 2014, at 4, emphasis added.

> under greater rating pressure. Recent consolidation among independent gencos has added scale and diversity, and is a credit positive.[2/]

Moody's recent comments on the U.S. Utility Sector state as follows:

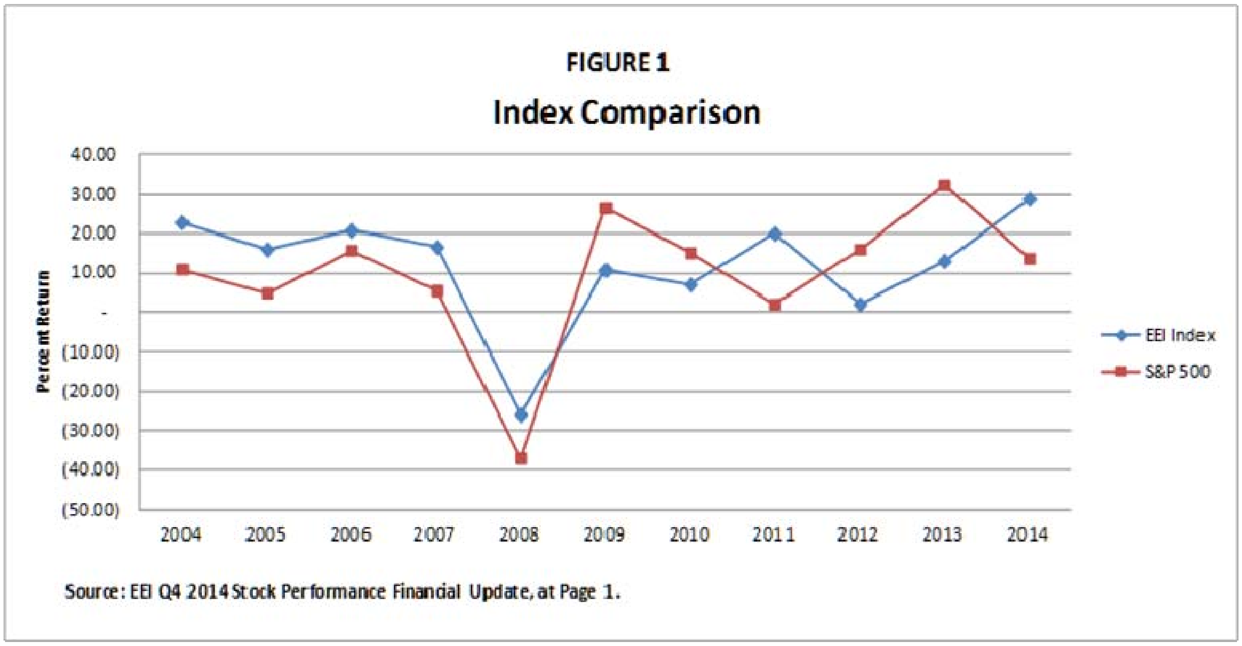
> Our outlook for the US regulated utilities industry is stable. This outlook reflects our expectation for the fundamental business conditions in the industry over the next 12 to 18 months.
>
> » **Regulatory support is the most important driver of our stable outlook**. Our stable outlook for the US regulated utility industry is based on our expectation that regulators will continue to help utilities recover costs and maintain stable cash flow, such that the ratio of cash flow from operations (CFO) to debt will remain close to 20%, on average, for the industry.
>
> » **Capital spending will decline in 2015, which reduces borrowing needs.** The credit profiles of large, integrated utilities that generate, transmit and distribute power will benefit from a drop in capital spending in 2015, because most of the heavy capital expenditures for environmental compliance have been made. This will reduce the industry's debt needs and stabilize financial metrics, at least for the next two years.[3/]

Q. PLEASE DESCRIBE UTILITY STOCK PRICE PERFORMANCE OVER THE LAST SEVERAL YEARS.

A. As shown in the graph below, the Edison Electric Institute ("EEI") has recorded utility stock price performance compared to the market. The EEI data shows that its Utility Index has outperformed the market in downturns and trailed the market during recovery. This supports my conclusion that utility stock investments are regarded by market participants as a moderate- to low-risk investment.

[2/] *Fitch Ratings*: "2015 Outlook: U.S. Utilities, Power and Gas," December 16, 2014, at 1-2, emphasis added.

[3/] *Moody's Investors Service*: "2015 Outlook – US Regulated Utilities: Regulatory Support Drives Our Stable Outlook," December 15, 2014, at 1, emphasis added.



Q. WHAT ARE THE IMPORTANT TAKEAWAY POINTS FROM THIS ASSESSMENT OF UTILITY INDUSTRY CREDIT AND INVESTMENT RISK OUTLOOKS?

A. Credit rating agencies consider the regulated utility industry to be stable and believe investors will continue to provide an abundance of capital to support utilities' large capital programs at moderate capital costs. All of this supports the continued belief that utility investments are generally regarded as safe-haven or low-risk investments, and the market embraces low-risk investments, such as utility investments. The demand for low-risk investments will provide funding for regulated utilities in general.

<u>II.B. PGE Investment Risk</u>

Q. PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF THE INVESTMENT RISK OF PGE.

A. The market's assessment of PGE's investment risk is described by credit rating analysts' reports. PGE's current corporate and senior secured bond ratings from S&P and

Moody's are BBB and A-, and A- and A1, respectively.[4/] Both rating agencies have a Stable outlook for PGE.

Specifically, S&P states the following:

> **Business Risk: Strong**
>
> Our assessment of Portland General's business risk profile is "strong," as defined in our criteria, based on the company's "satisfactory" competitive position, "very low" industry risk derived from the regulated utility industry, and "very low" country risk of the U.S. Portland General's competitive position reflects the company's low-risk regulated operations under a generally constructive regulatory environment, a midsize customer base, and competitive rates across customer classes. Portland General's reliance on power purchases and its exposure to hydroelectric power variability result in the careful management of power resources and collateral needs.
>
> Portland General serves roughly 840,000 customers, or 46% of Oregon's population, including the Portland and Salem regions. This concentration makes the company dependent on successfully managing regulatory relationships in Oregon, including navigating state energy policy initiatives and environmental mandates, which have become increasingly complex in recent years. Regulatory mechanisms such as forecast test periods help reduce regulatory lag since the costs are projected and recovered on a timely basis. Power cost costs are recovered through the power cost adjustment mechanism and a renewable adjustment clause mechanism enables Portland General to recover the revenue requirements of new renewable resources.
>
> **Financial Risk: Significant**
>
> We base our financial risk profile assessment of "significant" on the medial volatility financial ratio benchmarks. Our assessment takes into consideration the mostly steady cash flows from the utility business. Our base case indicates that discretionary cash flow, or operating cash flow less capital spending and dividends, will turn positive after 2015 when the Carty gas plant construction is largely completed. In 2015, the negative discretionary cash flow will be partially reduced through proceeds from the equity forward.[5/]

[4/] *SNL Financial*, May 17, 2015.

[5/] *Standard & Poor's RatingsDirect:* "Summary: Portland General Electric Co.," May 20, 2015, at 3-4, emphasis added.

II.C. PGE's Proposed Capital Structure

Q. WHAT IS PGE'S PROPOSED CAPITAL STRUCTURE?

A. PGE's proposed capital structure is shown in Table 1 below:

TABLE 1

PGE's Proposed Capital Structure
(Test Year 2016)

Description	Weight
Long-Term Debt	50.00%
Common Equity	50.00%
Total Regulatory Capital Structure	100.00%

Source: Direct Testimony of Patrick Hager and Brett Greene.

PGE's proposed capital structure is sponsored by its witnesses Patrick Hager and Brett Greene.

II.D. Embedded Cost of Debt

Q. WHAT IS THE EMBEDDED COST OF DEBT THAT THE COMPANY IS PROPOSING IN THIS PROCEEDING?

A. The Company is proposing an embedded debt cost of 5.43%. The embedded debt cost is sponsored by Company witnesses Mr. Hager and Mr. Greene, who develop the proposed embedded cost of debt on PGE Exhibit 1001.

II.E. Return on Equity

Q. PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."

A. A utility's cost of common equity is the return investors require on an investment in the utility. Investors expect to achieve their return requirement from receiving dividends and stock price appreciation.

Q. PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A. In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: <u>Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.</u>, 262 U.S. 679 (1923) and <u>Fed. Power Comm'n v. Hope Natural Gas Co.</u>, 320 U.S. 591 (1944).

These decisions identify the general standards to be considered in establishing the cost of common equity for a public utility. Those general standards provide that the authorized return should: (1) be sufficient to maintain financial integrity; (2) attract capital under reasonable terms; and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

Q. PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE PGE'S COST OF COMMON EQUITY.

A. I have used several models based on financial theory to estimate PGE's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a Capital Asset Pricing Model ("CAPM"). I have applied these models to a group of publicly traded utilities that have investment risk similar to PGE.

II.F. Risk Proxy Group

Q. HOW DID YOU SELECT A UTILITY PROXY GROUP SIMILAR IN INVESTMENT RISK TO PGE TO ESTIMATE ITS CURRENT MARKET COST OF EQUITY?

A. I relied on an electric utility proxy group that I determined to be comparable in investment risk to PGE. My recommended proxy group is based on the same proxy group used by PGE witness Ms. Bente Villadsen to estimate PGE's return on equity.

Q. PLEASE DESCRIBE WHY YOU BELIEVE YOUR PROXY GROUP IS REASONABLY COMPARABLE IN INVESTMENT RISK TO PGE.

A. The proxy group is shown in Exhibit ICNU/303. The proxy group has an average corporate credit rating from S&P of BBB+, while S&P's corporate credit rating for PGE is BBB. The proxy group has an average corporate credit rating from Moody's of Baa1, and PGE's corporate credit rating from Moody's is A-. The proxy group's average Moody's bond rating is one notch stronger and its average S&P bond rating is one notch weaker than that of PGE. Based on this information, I believe it is reasonably comparable in investment risk to PGE.

The proxy group has an average common equity ratio of 46.5% (including short-term debt) from SNL Financial ("SNL") and 49.3% (excluding short-term debt) from *The Value Line Investment Survey* ("*Value Line*") in 2015.

PGE's requested 50.00% common equity ratio is comparable to the proxy group. Based on these risk factors, I conclude the proxy group reasonably approximates the investment risk of PGE.

II.G. Discounted Cash Flow Model

Q. PLEASE DESCRIBE THE DCF MODEL.

A. The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \; .\;.\;.\;. \; \frac{D_\infty}{(1+K)^\infty} \qquad \text{(Equation 1)}$$

P_0 = Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return, "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A. As shown in Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

Q. WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A. I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on May 15, 2015. An average stock price is less susceptible to market price variations than a spot price. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value.

A 13-week average stock price reflects a period that is still short enough to contain data that reasonably reflects current market expectations, but the period is not so short as to be susceptible to market price variations that may not reflect the stock's long-term value. In my judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and the need to capture sufficient data to smooth out aberrant market movements.

Q. WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A. I used the most recently paid quarterly dividend, as reported in *Value Line*.[6/] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above.

Q. WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A. There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market-required return on common equity, one must attempt to estimate investors' consensus about what the dividend or earnings growth rate will be, and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[7/] That is, assuming the market generally makes rational investment decisions, analysts' growth

[6/] *The Value Line Investment Survey*, March 20, May 1, and May 22, 2015.

[7/] *See, e.g.,* David Gordon, Myron Gordon, and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

projections are more likely to influence investors' decisions which are captured in observable stock prices than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, SNL, and Reuters. All such projections were available on May 15, 2015, and all were reported online.

Each consensus growth rate projection is based on a survey of security analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not as reliably predict consensus investor outlooks as does a consensus of market analysts' projections. The consensus estimate is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations.

Q. WHAT ARE THE GROWTH RATES YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A. The growth rates I used in my DCF analysis are shown in Exhibit ICNU/304. The average growth rate for my proxy group is 5.09%.

Q. WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A. As shown in Exhibit ICNU/305, page 1, the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 8.87% and 8.79%, respectively.

Q. DO YOU HAVE ANY COMMENTS ON THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS?

A. Yes. The constant growth DCF analysis for my proxy group is based on a long-term sustainable growth rate of 5.09%. This growth rate is higher than my estimate of a maximum long-term sustainable growth rate of 4.6%, which I discuss later in this testimony. I believe the constant growth DCF analysis produces slightly overstated return estimates.

Q. HOW DID YOU ESTIMATE A MAXIMUM LONG-TERM SUSTAINABLE GROWTH RATE?

A. A long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. Hence, a reasonable proxy for the long-term maximum sustainable growth rate for a utility investment is best proxied by the projected long-term Gross Domestic Product ("GDP"). *Blue Chip Economic Indicators* projects that over the next 5 and 10 years, the U.S. nominal GDP will grow in the range of 4.7% to 4.4%. As such, the average growth rate over the next 10 years is around 4.6%, which I believe is a reasonable proxy of long-term sustainable growth.[8/]

I discuss in my multi-stage growth DCF analysis academic and investment practitioner evidence that accepts the projected long-term GDP growth outlook as a maximum sustainable growth rate projection. Hence, recognizing the long-term GDP growth rate as a maximum sustainable growth is logical, and generally consistent with academic and economic practitioner accepted practices.

8/ *Blue Chip Economic Indicators*, March 10, 2015, at 14.

II.H. Sustainable Growth DCF

Q. PLEASE DESCRIBE HOW YOU ESTIMATED A SUSTAINABLE LONG-TERM GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A. A sustainable growth rate is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment. These reinvested earnings increase the earnings base (rate base). Earnings grow when plant funded by reinvested earnings is put into service, and the utility is allowed to earn its authorized return on such additional rate base investment.

The internal growth methodology is tied to the percentage of earnings retained in the company and not paid out as dividends. The earnings retention ratio is 1 minus the dividend payout ratio. As the payout ratio declines, the earnings retention ratio increases. An increased earnings retention ratio will fuel stronger growth because the business funds more investments with retained earnings.

The payout ratios of the proxy group are shown in my Exhibit ICNU/306. These dividend payout ratios and earnings retention ratios then can be used to develop a sustainable long-term earnings retention growth rate. A sustainable long-term earnings retention ratio will help gauge whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time.

The data used to estimate the long-term sustainable growth rate is based on the Company's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit ICNU/307, pages 1 and 2, the average sustainable growth rate for the proxy group using this internal growth rate model is 5.15%.

Q. WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE LONG-TERM GROWTH RATES?

A. A DCF estimate based on these sustainable growth rates is developed in Exhibit ICNU/308. As shown there, a sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 8.93% and 8.61%, respectively.

II.I. Multi-Stage Growth DCF Model

Q. HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A. Yes. My first constant growth DCF is based on consensus analysts' growth rate projections, so it is a reasonable reflection of rational investment expectations over the next three to five years. The limitation on the constant growth DCF model is that it cannot reflect a rational expectation that a period of high/low short-term growth can be followed by a change in growth to a rate that is more reflective of long-term sustainable growth. Hence, I performed a multi-stage growth DCF analysis to reflect this outlook of changing growth expectations.

Q. WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?

A. Analyst projected growth rates over the next three to five years will change as utility earnings growth outlooks change. Utility companies go through cycles in making investments in their systems. When utility companies are making large investments, their rate base grows rapidly, which accelerates their earnings growth. Once a major construction cycle is completed or levels off, growth in the utility rate base slows, and its earnings growth slows from an abnormally high three- to five-year rate to a lower sustainable growth rate.

As major construction cycles extend over longer periods of time, even with an accelerated construction program, the growth rate of the utility will slow simply because rate base growth will slow and the utility has limited human and capital resources available to expand its construction program. Hence, the three- to five-year growth rate projection should be used as a long-term sustainable growth rate but not without making a reasonable informed judgment to determine whether it considers the current market environment, the industry, and whether the three- to five-year growth outlook is sustainable.

Q. PLEASE DESCRIBE YOUR MULTI-STAGE GROWTH DCF MODEL.

A. The multi-stage growth DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period, which consists of the first five years; (2) a transition period, which consists of the next five years (6 through 10); and (3) a long-term growth period, starting in year 11 through perpetuity.

For the short-term growth period, I relied on the consensus analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor, which reflects the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable long-term growth rate.

Q. WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A. Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. Utilities' earnings/dividend growth is created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth, and sales growth, in turn, is tied to economic growth in their service areas.

The U.S. Department of Energy, Energy Information Administration ("EIA") has observed that utility sales growth tracks the U.S. GDP growth, albeit at a lower level, as shown in Exhibit ICNU/309. Utility sales growth has lagged behind GDP growth for more than a decade. As a result, nominal GDP growth is a very conservative proxy for utility sales growth, rate base growth, and earnings growth. Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.

Q. IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE GROWTH OF THE U.S. GDP?

A. Yes. This concept is supported in both published analyst literature and academic work. Specifically, in a textbook entitled "Fundamentals of Financial Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).[9/]

9/ "*Fundamentals of Financial Management*," Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298.

Q. IS THERE ANY ACTUAL INVESTMENT HISTORY THAT SUPPORTS THE NOTION THAT THE CAPITAL APPRECIATION FOR STOCK INVESTMENTS WILL NOT EXCEED THE NOMINAL GROWTH OF THE U.S. GDP?

A. Yes. This is evident by a comparison of the compound annual growth of the U.S. GDP compared to the geometric growth of the U.S. stock market. Morningstar measures the historical geometric growth of the U.S. stock market over the period 1926-2013 to be approximately 5.8%. During this same time period, the U.S. nominal compound annual growth of the U.S. GDP was approximately 6.2%.[10/]

As such, the compound geometric growth of the U.S. nominal GDP has been higher but comparable to the nominal growth of the U.S. stock market capital appreciation. This historical relationship indicates the U.S. GDP growth outlook is a conservative estimate of the long-term sustainable growth of U.S. stock investments.

Q. HOW DID YOU DETERMINE A SUSTAINABLE LONG-TERM GROWTH RATE THAT REFLECTS THE CURRENT CONSENSUS OUTLOOK OF THE MARKET?

A. I relied on the consensus analysts' projections of long-term GDP growth. *Blue Chip Economic Indicators* publishes consensus economists' GDP growth projections twice a year. These consensus analysts' GDP growth outlooks are the best available measure of the market's assessment of long-term GDP growth. These analyst projections reflect all current outlooks for GDP, as reflected in analyst projections, and are likely the most influential on investors' expectations of future growth outlooks. The consensus economists' published GDP growth rate outlook is 4.7% to 4.4% over the next 10 years.[11/]

10/ *Morningstar, Inc., Ibbotson SBBI 2015 Classic Yearbook* inflation rate of 3.0%, and U.S. Bureau of Economic Analysis, March 27, 2015.

11/ *Blue Chip Economic Indicators*, March 10, 2015, at 14.

Therefore, I propose to use the consensus economists' projected 5- and 10-year average GDP consensus growth rates of 4.7% and 4.4%, respectively, as published by *Blue Chip Economic Indicators*, as an estimate of long-term sustainable growth. *Blue Chip Economic Indicators* projections provide real GDP growth projections of 2.5% and 2.3%, and GDP inflation of 2.1%,[12/] over the 5-year and 10-year projection periods, respectively. These consensus GDP growth forecasts represent the most likely views of market participants because they are based on published consensus economist projections.

Q. DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A. Yes, and these sources corroborate my consensus analysts' projections. The U.S. EIA in its *Annual Energy Outlook* projects real GDP out until 2040. In its 2015 Annual Report, the EIA projects real GDP through 2040 to be in the range of 1.8% to 2.9%, with a midpoint or reference case of 2.4%, and a long-term GDP price inflation projection of 1.8%. The EIA data supports a long-term nominal GDP growth outlook of 4.2%.[13/]

Also, the Congressional Budget Office ("CBO") makes long-term economic projections. The CBO is projecting real GDP growth of 2.5% to 2.1% during the next 5 and 10 years, respectively, with a GDP price inflation outlook of 2.0%.[14/] The CBO's real GDP and GDP inflation projections are slightly lower than the consensus economists. The five- and 10-year outlooks for nominal GDP based on these projections are 4.4% and 4.2%, respectively.

12/ *Id.*

13/ *DOE/EIA Annual Energy Outlook 2015 With Projections to 2040*, April 2015, at MT-3.

14/ *CBO: The Budget and Economic Outlook:* Fiscal Years 2015 to 2025, January 2015, at 155.

Moody's Analytics also makes long-term economic projections. In its recent 30-year outlook to 2044, Moody's Analytics is projecting real GDP growth of 2.1% with GDP inflation of 2.0%.[15/] Moody's projection of real GDP and GDP inflation is slightly below the consensus economists. Based on these projections, Moody's is projecting nominal GDP growth of 4.1% over the next 30 years.

The Social Security Administration makes long-term economic projections out to 2090. The Social Security Administration's nominal GDP projections, under its intermediate cost scenario for 30 and 75 years, ranges from 4.7% to 4.5%, respectively.[16/] These projections are in line with the consensus economists.

The Economist Intelligence Unit, a division of *The Economist* and a third-party data provider to SNL Financial, makes a long-term economic projection out to 2030.[17/] The Economist Intelligence Unit is projecting real GDP growth of 2.4% with an inflation rate of 2.3% out to 2030. The real GDP growth projection is in line with the consensus economists, while projected inflation is slightly higher. The long-term nominal GDP projection based on these outlooks is approximately 4.7%.

The real GDP and nominal GDP growth projections made by these independent sources support the use of the consensus economist 5-year and 10-year projected GDP growth outlooks as a reasonable estimate of market participants' long-term GDP growth outlooks.

15/ www.economy.com, *Moody's Analytics Forecast*, February 11, 2015.

16/ www.ssa.gov, "2014 OASDI Trustees Report," Table VI.G4.

17/ *SNL Financial, Economist Intelligence Unit*, downloaded on March 11, 2015.

Q. WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE GROWTH DCF ANALYSIS?

A. I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For stage one growth, I used the consensus analysts' growth rate projections discussed above in my constant growth DCF model. The first stage growth covers the first five years, consistent with the term of the analyst growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The second stage growth transitions the growth rate from the first stage to the third stage using a linear trend. For the third stage, or long-term sustainable growth stage, which starts in year 11, I used a 4.6% long-term sustainable growth rate, which is based on the consensus economists' long-term projected nominal GDP growth rate.

Q. WHAT ARE THE RESULTS OF YOUR MULTI-STAGE GROWTH DCF MODEL?

A. As shown in Exhibit ICNU/310, the average and median DCF returns on equity for my proxy group using the 13-week average stock price are 8.47% and 8.48%, respectively.

Q. PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A. The results from my DCF analyses are summarized in Table 2 below:

TABLE 2

Summary of DCF Results

Description	Proxy Group Average
Constant Growth DCF Model (Analysts' Growth)	8.87%
Constant Growth DCF Model (Sustainable Growth)	8.93%
Multi-Stage Growth DCF Model	8.47%
Average	8.76%

I concluded that my DCF studies indicate a return on equity of 8.90% for PGE. This return on equity is supported by my DCF studies in this proceeding.

II.J. Risk Premium Model

Q. PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A. This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be more risky than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds. The difference between the required return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year over the period 1986 through March 2015. The common equity required returns were based on regulatory commission-authorized returns for electric utility companies. Authorized returns are typically based on expert witnesses' estimates of the contemporary investor-required return.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period 1986 through March 2015 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit ICNU/311, which shows that the market to book ratio since 1986 for the electric utility industry was consistently above a multiple of 1.0x. Over this period, regulatory authorized returns were sufficient to support market prices that at least exceeded book value. This is an indication that regulatory authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit ICNU/312, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.43%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology.

I incorporated five-year and 10-year rolling average risk premiums over the study period to gauge the variability over time of risk premiums. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. As shown on my Exhibit ICNU/312, the five-year rolling average risk premium over Treasury bonds ranged from 4.25% to 6.62%, while the 10-year rolling average risk premium ranged from 4.38% to 6.26%.

As shown on my Exhibit ICNU/313, the average indicated equity risk premium over contemporary Moody's utility bond yields was 4.05%. The five-year and 10-year rolling average risk premiums ranged from 2.88% to 5.54% and 3.20% to 4.94%, respectively.

Q. DO YOU BELIEVE THAT THESE EQUITY RISK PREMIUM ESTIMATES ARE BASED ON A TIME PERIOD THAT IS TOO LONG OR TOO SHORT TO DRAW ACCURATE CONCLUSIONS CONCERNING CONTEMPORARY MARKET CONDITIONS?

A. No. The time period I use in this risk premium study is a generally accepted period to develop a risk premium study using "expectational" data.

Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value is an indication that the authorized returns on equity and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

Alternatively, studies have recommended that use of "actual achieved investment return data" in a risk premium study should be based on long historical time periods. The studies find that achieved returns over short time periods may not reflect investors' expected returns due to unexpected and abnormal stock price performance. Short-term abnormal actual returns would be smoothed over time and the achieved actual investment returns over long time periods would approximate investors' expected returns. Therefore, it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns.

My risk premium study is based on expectational data, not actual investment returns, and, thus, need not encompass a very long historical time period.

Q. BASED ON HISTORICAL DATA, WHAT RISK PREMIUM HAVE YOU USED TO ESTIMATE PGE'S COST OF COMMON EQUITY IN THIS PROCEEDING?

A. The equity risk premium should reflect the relative market perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit ICNU/314. In that exhibit, I show the yield spread between utility bonds and Treasury bonds over the last 36 years. As shown in this exhibit, the average utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.52% and 1.95%, respectively. The utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utilities through March 2015 were 1.11% and 1.89%, respectively. The current average "A" and "Baa" rated utility bond yield spreads over Treasury bond yields are now lower than the 35-year average spreads.

A current 13-week average "A" rated utility bond yield of 3.82%, when compared to the current Treasury bond yield of 2.67% as shown in Exhibit ICNU/315, page 1, implies a yield spread of around 115 basis points. This current utility bond yield spread is lower than the 36-year average spread for "A" rated utility bonds of 1.52%. Similarly, the current spread for the "Baa" rated utility bond yield of 1.90% is lower than the 36-year average spread of 1.95%.

These utility bond yield spreads are clear evidence that the market considers the utility industry to be a relatively low-risk investment and demonstrates that utilities continue to have strong access to capital in the current market.

Q. HOW DID YOU ESTIMATE PGE'S COST OF COMMON EQUITY WITH THIS RISK PREMIUM MODEL?

A. I added a projected long-term Treasury bond yield to my estimated equity risk premium over Treasury yields. The 13-week average 30-year Treasury bond yield, ending May 15, 2015, was 2.67%, as shown in Exhibit ICNU/315, page 1. *Blue Chip Financial Forecasts* projects the 30-year Treasury bond yield to be 3.70%, and a 10-year Treasury bond yield to be 3.20%.[18] Using the projected 30-year Treasury bond yield of 3.70%, and a Treasury bond risk premium of 4.25% to 6.62%, as developed above, produces an estimated common equity return in the range of 7.95% (3.70% + 4.25%) to 10.32% (3.70% + 6.62%). My risk premium estimates fall in the range of 7.95% to 10.32%.

I next added my equity risk premium over utility bond yields to a current 13-week average yield on "Baa" rated utility bonds for the period ending May 15, 2015, of 4.57%. Adding the utility equity risk premium of 2.88% to 5.54%, as developed above, to a

[18] *Blue Chip Financial Forecasts*, May 1, 2015.

"Baa" rated bond yield of 4.57%, produces a cost of equity in the range of 7.45% (4.57% + 2.88%) to 10.11% (4.57% + 5.54%).

Q. WHAT IS YOUR RECOMMENDED RETURN FOR PGE BASED ON YOUR RISK PREMIUM STUDY?

A. My recommendation considers both utility security risk and market interest rate risk. Current interest rate spreads suggest the market is embracing utility investments as relatively low-risk investment alternatives. This is clearly evident from the low utility bond spreads relative to Treasury bonds currently compared to the historical time period studied.[19/] Also, the market is pricing Baa utility bonds to produce lower yields compared to general corporate Baa bonds. On average over time, Baa utility bond yields are higher than Baa corporate bond yields, but not currently.[20/] All of this supports my conclusion that the utility industry is perceived as a low-risk stable investment.

On the other hand, the Federal Reserve has been procuring long-term Treasury and collateralized bonds in an effort to stimulate the U.S. economy. This stimulus has reduced long-term interest rates. This government stimulus initiative was terminated in October 2014. The termination of the Federal Reserve's stimulus has not caused long-term interest rates to increase; however, I believe there continues to be risk in long-term interest rate markets.

I recommend giving more weight to the high-end of my risk premium results to reflect the greater current market interest rate risk. I propose to provide 75% weight to the high-end of my risk premium estimates and 25% to the low-end of my risk premium estimates. Providing more weight to the high-end risk premium captures the greater

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19/ *See* Exhibit ICNU/314.
20/ *Id.*

market interest rate risk. This results in a risk premium estimate over Treasury bond yields of 9.73%,[21] and a risk premium estimate over Baa utility bond yields of 9.45%.[22]

My risk premium analyses produce a return estimate in the range of 9.45% to 9.73%, with a midpoint of 9.59%, rounded to 9.60%.

II.K. Capital Asset Pricing Model ("CAPM")

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \text{ x } (R_m - R_f)$ where:

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

The stock-specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, firm-specific risks can be eliminated by balancing the portfolio with securities that react in the opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix, and production limitations).

The risks that cannot be eliminated when held in a diversified portfolio are non-diversifiable risks. Non-diversifiable risks are related to the market in general and are

21/ 75% (10.32%) + 25% (7.95%) = 9.73%.
22/ 75% (10.11%) + 25% (7.45%) = 9.45%.

referred to as systematic risks. Risks that can be eliminated by diversification are regarded as non-systematic risks. In a broad sense, systematic risks are market risks, and non-systematic risks are business risks. The CAPM theory suggests that the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risk that investors will be compensated for are systematic or non-diversifiable risks. The beta is a measure of the systematic or non-diversifiable risks.

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A. The CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.

Q. WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A. As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 3.70%.[23/] The current 30-year Treasury bond yield is 2.67%, as shown in Exhibit ICNU/315, page 1. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 3.70% for my CAPM analysis.

Q. WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A. Treasury securities are backed by the full faith and credit of the United States government, so long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term

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[23/] *Blue Chip Financial Forecasts*, May 1, 2015 at 2.

bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. A Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic or market risks. Consequently, for companies with betas less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q. WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A. As shown in Exhibit ICNU/316, the proxy group average *Value Line* beta estimate is 0.75.

Q. HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATE?

A. I derived two market risk premium estimates, a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

Morningstar's *Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook* estimates the historical arithmetic average real market return over the period 1926 to 2014 as 8.9%.[24/] A current consensus analysts' inflation projection, as measured by the

[24/] *Morningstar, Inc., Ibbotson SBBI 2015 Classic Yearbook* at 92.

Consumer Price Index, is 2.4%.[25/] Using these estimates, the expected market return is 11.51%.[26/] The market risk premium then is the difference between the 11.51% expected market return, and my 3.70% risk-free rate estimate, or approximately 7.8%.

The historical estimate of the market risk premium was also estimated by Morningstar in *Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook*. Over the period 1926 through 2014, Morningstar's study estimated that the arithmetic average of the achieved total return on the S&P 500 was 12.1%,[27/] and the total return on long-term Treasury bonds was 6.10%.[28/] The indicated market risk premium is 6.0% (12.1% - 6.1% = 6.0%). The average of my market risk premium estimates is 6.90% (6.0% to 7.8%).

Q. HOW DOES YOUR ESTIMATED MARKET RISK PREMIUM RANGE COMPARE TO THAT ESTIMATED BY MORNINGSTAR?

A. Morningstar's analysis indicates that a market risk premium falls somewhere in the range of 6.3% to 7.0%. My market risk premium falls in the range of 6.0% to 7.8%. My average market risk premium of 6.90% is within Morningstar's range.

Morningstar estimates a forward-looking market risk premium based on actual achieved data from the historical period of 1926 through 2014. Using this data, Morningstar estimates a market risk premium derived from the total return on large company stocks (S&P 500), less the income return on Treasury bonds. The total return includes capital appreciation, dividend or coupon reinvestment returns, and annual yields received from coupons and/or dividend payments. The income return, in contrast, only reflects the income return received from dividend payments or coupon yields. Morningstar argues that the income return is the only true risk-free rate associated with

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25/ *Blue Chip Financial Forecasts*, May 1, 2015 at 2.
26/ $\{ [(1 + 0.089) * (1 + 0.024)] - 1 \} * 100$.
27/ *Morningstar, Inc., Ibbotson SBBI 2015 Classic Yearbook* at 91.
28/ *Id.*

Treasury bonds and is the best approximation of a truly risk-free rate.[29] I disagree with this assessment from Morningstar, because it does not reflect a true investment option available to the marketplace and therefore does not produce a legitimate estimate of the expected premium of investing in the stock market versus that of Treasury bonds. Nevertheless, I will use Morningstar's conclusion to show the reasonableness of my market risk premium estimates.

Morningstar's range is based on several methodologies. First, Morningstar estimates a market risk premium of 7.0% based on the difference between the total market return on common stocks (S&P 500) less the income return on Treasury bond investments. Second, Morningstar found that if the New York Stock Exchange ("NYSE") was used as the market index rather than the S&P 500, that the market risk premium would be 6.8%, not 7.0%. Third, if only the two deciles of the largest companies included in the NYSE were considered, the market risk premium would be 6.3%.[30]

Finally, Morningstar found that the 7.0% market risk premium based on the S&P 500 was influenced by an abnormal expansion of price-to-earnings ("P/E") ratios relative to earnings and dividend growth during the period 1980 through 2001. Morningstar believes this abnormal P/E expansion is not sustainable.[31] Therefore, Morningstar adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings. Based on this alternative

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[29] *Id.* at 153.

[30] Morningstar observes that the S&P 500 and the NYSE Decile 1-2 are both large capitalization benchmarks. *Id.* at 152.

[31] *Id.* at 156.

methodology, Morningstar published a long-horizon supply-side market risk premium of 6.1%.[32]

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A. As shown in Exhibit ICNU/317, based on Morningstar's market risk premium of 6.0% and my market risk premium of 7.8%, a risk-free rate of 3.7%, and a beta of 0.75, my CAPM analysis produces a return of 8.19% to 9.54%. Because of the relatively low historical level of the risk-free rates, I recommend giving 75% weight to my high-end CAPM return estimate and 25% weight to the low-end return estimate. This produces a recommended CAPM return estimate of 9.20%.

This CAPM estimate reflects a projected risk-free rate that is 103 basis points higher than the current long-term risk-free rate as proxied by the U.S. Treasury security. Using this projected Treasury bond yield largely captures the additional risk in the marketplace related to the uncertainty of long-term interest rates after the Federal Reserve discontinues its economic stimulus intervention.

II.L. Return on Equity Summary

Q. BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR PGE?

A. Based on my analyses, I estimate PGE's current market cost of equity to be 9.25%.

[32] *Id.* at 157.

TABLE 3

Return on Common Equity Summary

Description	**Results**
DCF	8.90%
Risk Premium	9.60%
CAPM	9.20%

My recommended return on common equity of 9.25% is at the midpoint of my estimated range of 8.90% to 9.60%. The high-end of my estimated range is based on my risk premium studies. The low-end is based on my DCF studies. The CAPM return estimate falls within this recommended range.

This range reflects current market capital costs, increased interest rate risk in the current market due to Federal Reserve policies and other factors, and represents fair compensation to PGE's investors for the total investment risk of its regulated utility.

II.M. Financial Integrity

Q. WILL YOUR RECOMMENDED OVERALL RATE OF RETURN SUPPORT AN INVESTMENT GRADE BOND RATING FOR PGE?

A. Yes. I have reached this conclusion by comparing the key credit rating financial ratios for PGE, at my proposed return on equity, and the Company's proposed capital structure, to S&P's benchmark financial ratios using S&P's new credit metric ranges.

Q. PLEASE DESCRIBE THE MOST RECENT S&P FINANCIAL RATIO CREDIT METRIC METHODOLOGY.

A. S&P publishes a matrix of financial ratios that correspond to its assessment of the business risk of utility companies and related bond ratings. On May 27, 2009, S&P

expanded its matrix criteria by including additional business and financial risk categories.[33]

Based on S&P's most recent credit matrix, the business risk profile categories are "Excellent," "Strong," "Satisfactory," "Fair," "Weak," and "Vulnerable." Most utilities have a business risk profile of "Excellent" or "Strong."

The financial risk profile categories are "Minimal," "Modest," "Intermediate," "Significant," "Aggressive," and "Highly Leveraged." Most of the utilities have a financial risk profile of "Aggressive." PGE has a "Strong" business risk profile and a "Significant" financial risk profile.

Q. PLEASE DESCRIBE S&P'S USE OF THE FINANCIAL BENCHMARK RATIOS IN ITS CREDIT RATING REVIEW.

A. S&P evaluates a utility's credit rating based on an assessment of its financial and business risks. A combination of financial and business risks equates to the overall assessment of PGE's total credit risk exposure. On November 19, 2013, S&P updated its methodology. In its update, S&P published a matrix of financial ratios that defines the level of financial risk as a function of the level of business risk.

S&P publishes ranges for three primary financial ratios that it uses as guidance in its credit review for utility companies. The two core financial ratio benchmarks it relies on in its credit rating process include: (1) Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"); and (2) Funds From Operations ("FFO") to Total Debt.[34]

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[33] S&P updated its 2008 credit metric guidelines in 2009, and incorporated utility metric benchmarks with the general corporate rating metrics. *Standard & Poor's RatingsDirect*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

[34] *Standard & Poor's RatingsDirect*: "Criteria: Corporate Methodology," November 19, 2013.

Q. HOW DID YOU APPLY S&P'S FINANCIAL RATIOS TO TEST THE REASONABLENESS OF YOUR RATE OF RETURN RECOMMENDATIONS?

A. I calculated each of S&P's financial ratios based on PGE's cost of service for its retail jurisdictional operations. While S&P would normally look at total consolidated PGE financial ratios in its credit review process, my investigation in this proceeding is not the same as S&P's. I am attempting to judge the reasonableness of my proposed cost of capital for rate-setting in PGE's retail regulated utility operations. Hence, I am attempting to determine whether my proposed rate of return will in turn support cash flow metrics, balance sheet strength, and earnings that will support an investment grade bond rating and PGE's financial integrity.

Q. DID YOU INCLUDE ANY OFF-BALANCE SHEET DEBT EQUIVALENTS?

A. Yes. As shown on page 3 of my Exhibit ICNU/318, I included $266 million of off-balance sheet debt equivalents including power purchase agreements and operating leases and their associated interest and depreciation expenses. I did not include some of the off-balance sheet debt equivalents that S&P includes in its credit rating review. Certain off-balance sheet debt equivalents, such as pension and other post-employment benefits ("OPEB"), and accrued interest expense, were excluded from my jurisdictional credit metric study because these items are controllable by utility management or do not relate to regulated cost of service.

Q. PLEASE DESCRIBE THE RESULTS OF THIS CREDIT METRIC ANALYSIS FOR PGE.

A. The S&P financial metric calculations for PGE at a 9.25% return are developed on Exhibit ICNU/318, page 1. S&P currently rates PGE's business risk as "Strong" and financial risk as "Significant." The credit metrics produced below, with this financial and business risk outlook by S&P, will be used to assess the strength of the credit metrics based on PGE's retail operations in Oregon.

PGE's adjusted total debt ratio is approximately 52.6%. This adjusted debt ratio is generally comparable to, albeit somewhat stronger than, the adjusted debt ratios for utilities with an S&P bond rating of BBB+, one notch stronger than PGE's bond rating. Hence, I concluded this capital structure reasonably supports PGE's current investment grade bond rating. This adjusted total debt ratio will support an investment grade bond rating.

Based on an equity return of 9.25%, PGE will be provided an opportunity to produce a debt to EBITDA ratio of 2.7x. This is within S&P's "Intermediate" guideline range of 2.5x to 3.5x,[35/] which reflects less risk and stronger metrics than needed to support PGE's "Intermediate" risk ranking of "Significant." This ratio also supports an investment grade credit rating.

PGE's retail operations FFO to total debt coverage at a 9.25% equity return is 24%, which is also within S&P's "Intermediate" metric guideline range of 23% to 35%. This FFO/total debt ratio will support an investment grade bond rating.

At my recommended return on equity of 9.25% and the Company's proposed embedded debt cost and capital structure, PGE's financial credit metrics are supportive of its investment grade utility bond rating.

35/ *Id.*

III. RESPONSE TO PGE WITNESS DR. VILLADSEN

Q. WHAT RETURN ON COMMON EQUITY IS PGE PROPOSING IN THIS PROCEEDING?

A. PGE's proposed return on equity is supported by its witness Dr. Bente Villadsen. She recommends a return on equity for PGE in the range of 9.80% to 11.20%, with a point estimate of 10.25% (PGE/1100, Villadsen/1). The Company is requesting 9.9% in this case.

Q. PLEASE DESCRIBE DR. VILLADSEN'S METHODOLOGY SUPPORTING HER RETURN ON COMMON EQUITY.

A. She arrived at this estimate using several models: a simple DCF, a multi-stage growth DCF, a risk premium using a regression formula, and two other risk premium studies, one using allowed returns on equity and one using earned returns on equity. Dr. Villadsen checks her results with a traditional CAPM and an empirical CAPM ("ECAPM"). These models were applied to a group of 27 integrated electric utility companies, which Dr. Villadsen found had risk comparable to PGE (PGE/1100, Villadsen/2).

Q. IS DR. VILLADSEN'S ESTIMATED RETURN ON EQUITY FOR PGE REASONABLE?

A. No. Dr. Villadsen's recommended return on equity of 10.25% (and the Company's requested 9.9%) for PGE are excessive and unreasonable for a low-risk regulated electric utility company. The unreasonableness of Dr. Villadsen's recommendation is evident from a detailed assessment of the rate of return models supporting her recommendation in this proceeding.

Q. PLEASE SUMMARIZE DR. VILLADSEN'S RETURN ON EQUITY STUDY RESULTS.

A. Dr. Villadsen's return on equity study results are summarized in the table below.

TABLE 4

Summary of Dr. Villadsen's Results

Model	**Model ROE Results (1)**	**ATWACC ROE Adder (2)**	**Recommended ROE (3)**	**Adjusted ROE (4)**
DCF				
Simple (1/4 Growth)	9.3%	1.8%	11.2%	9.3%
Multi-Stage (Blue Chip)	8.6%	1.3%	9.8%	8.6%
Multi-Stage (Blue Chip and OMB)	8.7%	1.3%	10.0%	8.7%
				8.9%
CAPM				
Traditional CAPM	9.2%	0.6%	9.8%	9.2%
ECAPM (0.5%)	9.4%	0.6%	10.0%	Reject
ECAPM (1.5%)	9.6%	0.6%	10.2%	Reject
				9.2%
Risk Premium				
Regression			10.7%	8.7%
Allowed ROE			10.0%	9.7%
Earned ROE			10.6%	8.7%
Range			10.0% - 10.6%	8.9% - 9.7%

ROE = Return on Equity

ATWACC = After-Tax Weighted Average Cost of Capital

As shown in Table 4 above, the model return on equity results of Dr. Villadsen's studies applied to her proxy group indicate that PGE's current market return on equity is in the range of 8.6% to 9.6% for her DCF and CAPM studies, and 10.0% to 10.7% based on her risk premium studies.

She then increases her market return on equity estimate by adding a return on equity adder in the range of 0.6% to 1.8% based on an After-Tax Weighted Average Cost of Capital ("ATWACC") adder methodology. This ATWACC adder increases her recommended range up to 9.8% to 11.2%. Dr. Villadsen asserts this ATWACC return on equity adder is necessary to properly recognize PGE's financial risk when applying a market return on equity to its book value common equity.

However, as described below and as shown in Table 4 above under Column 4, Dr. Villadsen's own studies, adjusted to remove her flawed ATWACC return on equity adder and incorporate reasonable estimates of Treasury bond yields currently and forecasted, support a return on equity of 8.9% to 9.7%, which supports my estimated return on equity range for PGE in this proceeding.

Q. PLEASE DESCRIBE THE ISSUES YOU HAVE WITH DR. VILLADSEN'S ANALYSES.

A. The issues I have with Dr. Villadsen's analyses in this case include: (1) her ATWACC return on equity adder, and (2) her reliance on an inflated Treasury bond yield and risk premium in her risk premium studies.

The ATWACC adder increases her market cost of equity by 0.6 to 1.8 percentage points. Excluding this ATWACC return on equity adder, Dr. Villadsen's return on equity range would be approximately 8.6% to 9.6% based on the DCF and CAPM analyses. These results support my recommended return on equity of 9.25%.

Dr. Villadsen's ATWACC return on equity adder is severely flawed and should be rejected. This return on equity adder increases the return on equity to a level that is not just and reasonable and far above PGE's current market cost of equity.

Finally, all of Dr. Villadsen's risk premium studies are based on a risk premium of approximately 6% relative to Treasury bond yields. The current Treasury bond yield is around 2.67%, and projected yield is around 3.8%. Without taking issue with her estimated equity risk premiums, Dr. Villadsen's own risk premium studies show that a return on equity for PGE in this proceeding based on her risk premium studies should be in the range of 8.7% to 9.7%.

Q. PLEASE DESCRIBE DR. VILLADSEN'S PROPOSED ATWACC RETURN ON EQUITY ADDER.

A. Dr. Villadsen uses the ATWACC to increase the estimated market return on equity based on her DCF and CAPM analyses, to a higher return on equity that can be applied to PGE's book value common equity. She does this by calculating the ATWACC using the market return on equity estimate (DCF and CAPM estimates) and market weighted capital structures for each proxy company. She then uses this market ATWACC and each company's book value capital structures to derive a return on equity that produces the same ATWACC on the proxy group's book capital structure that was produced on its market value capital structure.

These ATWACC adjustments to her return on equity estimates are discussed on pages 8-12 of her direct testimony and developed in the workpapers accompanying her exhibits for the DCF and CAPM return estimates.

Q. WHY DOES DR. VILLADSEN BELIEVE THE ATWACC ADJUSTMENT TO HER DCF AND CAPM RETURN ESTIMATES IS REASONABLE?

A. On pages 9-10 of her testimony, Dr. Villadsen suggests that the sample firms' financial risk is lower based on the market value of common equity than is the financial risk based on the book value of common equity. Therefore, Dr. Villadsen proposes to upwardly adjust her DCF and CAPM model results for the difference in financial risk based on the proxy companies' market value of common equity, compared to its book value common equity.

Dr. Villadsen's general assessment is that a return on equity should be higher based on book value because book value has more financial risk than does the market value of common equity. She is in effect suggesting that firms have a different level of financial risk, depending on whether one is observing its market value capital structure or the book value capital structure.

Q. IS THE ATWACC ADJUSTMENT TO THE BASE RETURN ON EQUITY REASONABLE?

A. No. This is flawed for several reasons. First, the Company only has one level of financial risk, not two. Investors do not assess a different amount of financial risk for market and book common equity valuation. Rather, financial risk is a singular risk factor which describes its financial capital structure, cash flow strength to support financial obligations, and default provisions in its financial obligations.

Dr. Villadsen's belief that there are two levels of financial risk is simply not supported. Indeed, it is contradicted by data used by independent market participants to assess investment risk and security valuation. For example, S&P and *Value Line* provide general assessments of the financial and operating (or total investment) risks to the market investors. S&P does this in terms of rating the credit quality of the utility, based on the utility's ability to produce cash flows adequate to meet its book value financial obligations. S&P assesses a company's risk of failing to meet its financial obligations and is a direct assessment of a company's financial risk.

Value Line on the other hand provides information to the market participants to help them assess the total investment risk including both financial risk and business risk for the utilities and other stock investments. The data *Value Line* provides to investors concerning these investment risk characteristics relates to book value factors including book value capital structure, book value cash flows, and book value earnings. All these book value factors are then used by investors to assess investment risk which allows them to derive market value stock prices. The book value parameters are an integral part of assessing risk and allowing investors to produce market valuations. There is not a difference in financial risk for a company if you are examining its book financial risk or market value financial risk. Rather, the book value and market value financial risks for the same company are interconnected to one another, and produce a single level of financial risk for the company.

Q. DO YOU BELIEVE THAT THE ATWACC METHODOLOGY IS REASONABLE POLICY FOR SETTING AN APPROVED RETURN ON EQUITY?

A. No. The ATWACC methodology is poor regulatory policy and should be rejected for several reasons.

First, it does not produce clear and transparent objectives for management to use that will accomplish the objective of minimizing its overall rate of return while preserving its financial integrity. Therefore, a regulatory commission cannot oversee the reasonableness and prudence of management decisions in managing its capital structure. Under the ATWACC theory, management's decisions to manage its capital structure can be skewed by changes in market value which change the market value capitalization mix. Management simply has no control over the market value capital structure, but it does have control over the book value capital structure. As such, setting the rate of return and measuring risk based on book value capital structure creates a more transparent and clear path for regulatory oversight of management's effort to maintain a balanced and reasonable capital structure.

Second, book value capital structure weights permit the utility to hedge or lock-in a large portion of capital market costs in arriving at the rate of return used to set rates. This rate of return cost hedge stabilizes the utility's cost of service, which in turn helps stabilize utility rates. A stable method of setting rates also allows investors to more accurately assess the future earnings and cash flow outlooks for the utility, which will reduce the business risk of the utility. The ATWACC, on the other hand, will produce an overall rate of return which will change based on both changes to market value capital structure weights and also based on changes to market capital costs. Hence, a major component of the cost structure of the utility (i.e., the overall rate of return) will vary based on market forces from rate case to rate case. This rate of return variability will introduce significant instability in the utility's cost of service (via rate of return changes) and hence instability in tariff rates. Introducing additional instability in the utility's cost structure and rates will not benefit either investors or ratepayers.

The ATWACC unnecessarily increases rates to produce an excessive return on equity opportunity for utility investors. Inflating a utility's rates to provide this excessive earnings opportunity is unjust and unreasonable and should be rejected.

Q. HAS THE ATWACC METHODOLOGY PROPOSED BY DR. VILLADSEN BEEN ACCEPTED IN RATE-SETTING PROCEEDINGS IN THE UNITED STATES?

A. No. The ATWACC methodology has been consistently rejected in state jurisdictions throughout the country. The ATWACC methodology has been rejected by regulators for many reasons:

1. Designed to produce a higher return and no confidence in evidence supporting the ATWACC. (California Public Utilities Commission, Docket No. A.08-05-002, California-American Water Company, May 2009).
2. Method that inflates the rate of return by overstating the Company's financial risk and inflating rates to overcompensate utility investors. The Company simply provided inadequate justification for departing from the traditional method of estimating the rate of return. (Arizona Corporation Commission, Arizona-American Water Company, Docket No. W-01303A-05-0405, July 2006).

3. Is an unproven and never used methodology that is not reliable for setting rates. (Ohio Public Utilities Commission, Cause Nos. 07-551-EL-AIR *et al.*, Ohio Edison Company *et al.*, January 2009).

4. The Commission was not persuaded that the ATWACC methodology was appropriate for setting rates and declined to use it in the rate proceeding. (Public Service Commission of Wisconsin, Wisconsin Electric Power Company, 5-UR-103).

III.A. Dr. Villadsen's Risk Premium Analyses

Q. PLEASE DESCRIBE DR. VILLADSEN'S RISK PREMIUM ANALYSES.

A. As shown on her Exhibit PGE/1102, Dr. Villadsen performed three separate risk premium analyses. Based on these analyses, she concludes that her recommended range is conservative.

In her first analysis, Dr. Villadsen measured the relationship of authorized returns on equity to long-term interest rates between 1990 and the third quarter of 2014 through a regression analysis. She then uses the resulting regression formula to predict a risk premium based on an obsolete forecasted long-term Treasury yield of 4.64% from October 2014.[36/] This regression formula and forecasted Treasury yield of 4.64% produced an estimated risk premium of 6.03%. Dr. Villadsen then added her estimated risk premium of 6.03% to the forecasted Treasury yield of 4.64% to produce a cost of equity estimate of 10.67%, rounded to 10.7%.

In her second risk premium analysis, Dr. Villadsen measured the average historical equity risk premium of authorized returns (allowed returns) reported by SNL Financial over prevailing Treasury yields for the 1997-2014 time period. Her average historical equity risk premium is 5.98%. She then adds a *Blue Chip* projected 10-year

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36/ PGE/1100, Villadsen/42, footnote 56.

Treasury yield of 4.00% to her equity risk premium of 5.98%, which produces a return on equity estimate of 9.98%, rounded to 10.00%.

In her third risk premium analysis, Dr. Villadsen relies on earned returns on equity relative to long-term Treasury yield to produce the historical equity risk premium over the same 1997-2014 time period. This analysis produced an average equity risk premium of 5.93%. Dr. Villadsen then adds to her average risk premium "her" projected 20-year Treasury yield of 4.64%. This produces a return estimate of 10.57% (4.64% + 5.93%), rounded to 10.6%.

Q. DO YOU HAVE ANY ISSUES WITH DR. VILLADSEN'S FIRST RISK PREMIUM BASED ON A REGRESSION ANALYSIS OF INTEREST RATES AND RISK PREMIUM?

A. Yes. Dr. Villadsen's regression model reflects a simplistic, linear relationship between equity risk premiums and interest rates. This overly simplistic relationship is not supported by academic research. While academic studies have shown that there has been a linear and inverse relationship between these variables in the past, researchers have found that the relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, rather than simply changes to interest rates.[37/]

In the 1980s, equity risk premiums were inversely related to interest rates, but that was likely attributable to the interest rate volatility that existed at that time. When interest rates were more volatile, the relative perception of bond investment risk

[37/] "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," Robert S. Harris and Felicia C. Marston, *Journal of Applied Finance*, Volume 11, No. 1, 2001; "The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management*, Spring 1985.

increased relative to the investment risk of equities. This changing investment risk perception caused changes in equity risk premiums.

In today's marketplace, interest rate volatility is not as extreme as it was during the 1980s.[38] Nevertheless, changes in the perceived risk of bond investments relative to equity investments still drive changes in equity premiums. However, a relative investment risk differential cannot be measured simply by observing nominal interest rates. Changes in nominal interest rates are highly influenced by changes to inflation outlooks, which also change equity return expectations. As such, the relevant factor needed to explain changes in equity risk premiums is the relative changes to the risk of equity versus debt securities investments, and not simply changes in interest rates.

Importantly, Dr. Villadsen's analysis simply ignores investment risk differentials. She bases her adjustment to the equity risk premium exclusively on changes in nominal interest rates. This is a flawed methodology and does not produce accurate or reliable risk premium estimates. As such, her argument should be rejected by the Commission.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH DR. VILLADSEN'S FIRST RISK PREMIUM STUDY?

A. Yes. She uses a forecasted Treasury bond yield of 4.64%, which was based on a *Blue Chip Economic Indicator* from October 2014. This forecasted Treasury bond yield substantially exceeds the current market's outlook for future Treasury bond yields, at least over the next two years, a period rates determined in this proceeding likely will be in effect. As discussed above, *Blue Chip Financial Forecasts*' current projected Treasury bond yield over the next two years is 3.7%.[39] Had Dr. Villadsen used current outlooks

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[38] Morningstar SBBI, 2009 Classic Yearbook at 95-96.

[39] *Blue Chip Financial Forecasts*, May 1, 2015 at 2.

for future Treasury bond yields, rather than those from nearly a year ago, her first risk premium study would have been reduced by over a full percentage point.

Q. DO YOU HAVE ANY COMMENTS ON DR. VILLADSEN'S SECOND RISK PREMIUM ANALYSIS BASED ON ALLOWED RETURNS ON EQUITY RELATIVE TO LONG-TERM TREASURY BOND RATES OVER THE PERIOD 1997 THROUGH 2014?

A. Yes. My primary issue with Dr. Villadsen's second risk premium study is her use of a 4.0% Treasury bond yield. As noted above, current observable and current forecasted Treasury bond rates are much lower than the rates used by Dr. Villadsen. Reflecting a 3.7% long-term 30-year Treasury bond rate, rather than the 4.0% used in her study, would lower her risk premium estimate from 10.0% down to 9.7%. This single adjustment reduces her risk premium study toward the high-end of my estimated return on equity range for PGE in this proceeding.

Q. DO YOU HAVE ANY COMMENTS CONCERNING DR. VILLADSEN'S THIRD RISK PREMIUM STUDY BASED ON EARNED RETURNS ON EQUITY RELATIVE TO LONG-TERM TREASURY BOND YIELDS?

A. Yes. I have two concerns with Dr. Villadsen's third risk premium study. First, her estimate of an earned return on equity was not based on her own study, but rather was based on another witness's study in another proceeding. It is not known based on Dr. Villadsen's testimony and workpapers whether or not the earned return on equity was calculated correctly.

Second, Dr. Villadsen produces a risk premium estimate by developing her own projected Treasury bond yield of 4.64%. Her projection of a Treasury bond risk premium appears to be based by adding a 0.64% premium to the 10-year Treasury bond rate of 4.0%. The 4.0% rate initially overstates current market outlooks for cost of capital. Further, her claim of a 10-year yield spread between 20-year and 10-year bonds of 0.64%

results in a long-term Treasury bond rate that is highly inflated and not in line with any market participant's outlook for interest rates in this market, or projected interest rates out over the next several years. Her projected interest rate is simply flawed, unreliable and not reflective of current or near-term capital market costs.

Therefore, the Treasury bond yield projection she offered is not useful in estimating the market-required return on common equity because it reflects Dr. Villadsen's outlook for capital market costs, rather than the market's outlook.

Q. BASED ON YOUR REVIEW OF DR. VILLADSEN'S RISK PREMIUM STUDIES, DO YOU BELIEVE HER ESTIMATES PRODUCE A REASONABLE RETURN ON EQUITY ESTIMATE FOR PGE?

A. Risk premium models are producing rather high return on equity estimates in this proceeding. All three of her analyses are based on risk premium estimates of around 6%. These risk premium studies can be applied to current observable Treasury bond yields of 2.67% (Exhibit ICNU/315) and updated projected Treasury bond yields of 3.7% (Exhibit ICNU/317). These Treasury bond yields and Dr. Villadsen's risk premium of 6.0% suggest the return on equity falls in the range of 8.7% up to 9.7% (with a midpoint estimate of 9.2%). This risk premium range and midpoint are useful in estimating PGE's current market cost of equity.

Q. DO YOU BELIEVE IT IS APPROPRIATE TO USE CURRENT OBSERVABLE AND CURRENT PROJECTED TREASURY BOND YIELDS IN ESTIMATING PGE'S COST OF EQUITY IN THIS PROCEEDING?

A. Yes. Capital market costs can vary over time, so it is critical to use actual observable market evidence and current projections made by independent market participants in estimating PGE's current market cost of equity. Using data from previous publications as Dr. Villadsen has done, is not an accurate or valid method of estimating a fair return on equity.

PGE's cost of equity can increase and decrease over time, and if rates are set to provide it an opportunity to earn its current market cost of equity, then rates will be just and reasonable and investors will be treated fairly.

Dr. Villadsen's data sources are stale and obsolete, or they cannot be validated. Most importantly, her Treasury yield projections have not been proven to reflect market participants' or investors' outlooks of projected capital market costs. For all these reasons, her risk premium studies simply are neither reliable nor accurate.

Q. DO YOU HAVE ANY COMMENTS CONCERNING DR. VILLADSEN'S CAPM STUDIES?

A. Yes. Dr. Villadsen explains that she only uses her CAPM analyses to corroborate her recommended range. The primary concern with Dr. Villadsen's traditional CAPM return estimate is that she is using a stale risk-free rate estimate of 4.03%. Her traditional CAPM return estimate would be reduced by at least 30 basis points if she used a current projected Treasury bond yield rather than the stale data used in her study.

More importantly, her ECAPM studies are flawed. An ECAPM study is designed to use an "unadjusted" beta within the ECAPM. In contrast, Dr. Villadsen used a *Value Line* "adjusted" beta within the ECAPM study. This is inconsistent with the academic development of the ECAPM model, and produces a flawed and inflated return estimate.

Q. PLEASE EXPLAIN WHY IT IS NOT APPROPRIATE TO USE *VALUE LINE* ADJUSTED BETAS WITHIN AN ECAPM STUDY.

A. *Value Line* adjusted betas are designed to increase CAPM return estimates for companies with betas less than 1.0 and decrease CAPM return estimates for companies with betas greater than 1.0. The adjusted beta accomplishes this by adjusting the slope of the security market line, and increases the intercept point for a zero risk investment.

The ECAPM analysis accomplishes the same thing by including an alpha coefficient in the traditional CAPM analysis, which flattens the security market line, and increases the intercept point.

The problem with Dr. Villadsen's ECAPM study is that she used adjusted betas in an ECAPM analysis which had the impact of creating a "double adjustment" to the security market line and intercept point. This double adjustment to the security market line distorts the risk return relationships, and distorts the ability of the CAPM to produce an accurate market cost of equity estimate. For companies less than 1.0, including electric utility companies as she studied in this case, this has the effect of increasing her CAPM return for PGE, and rendering her ECAPM analysis flawed and unreliable. The resulting risk return is distorted and the CAPM return is flawed and unreliable.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
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Request for a General Rate Revision.	)
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EXHIBIT ICNU/301

QUALIFICATIONS OF MICHAEL P. GORMAN

June 15, 2015

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1983 I received a Bachelors of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Arkansas, Arizona, California, Colorado, Delaware, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Louisiana, Michigan, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta and Nova Scotia, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q. PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

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EXHIBIT ICNU/302

RATE OF RETURN

June 15, 2015

Portland General Electric

Rate of Return

Line	Description	Amount[1] (1)	Weight[1/a] (2)	Cost [2/1] (3)	Weighted Cost (4)
1	Common Equity	$ 2,443,817	50.00%	**9.25%**	4.63%
2	Long-Term Debt	$ 2,441,400	50.00%	**5.43%**	2.72%
3	**Total**	$ 4,885,217	**100.00%**		7.34%

Source:
[1]Hager-Greene Direct at 2.
[2]Gorman Direct Testimony, at 2.

[a]The dollar amounts shown produce slightly different results:
50.02% Equity / 49.98% Debt. Hager - Greene notes that the
Company proposes to use its target capital structure of 50/50 Debt/Equity.

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EXHIBIT ICNU/303

PROXY GROUP

June 15, 2015

Portland General Electric Company

Proxy Group

		Credit Ratings[1]		Common Equity Ratios	
Line	Company	S&P (1)	Moody's (2)	SNL[1] (3)	Value Line[2] (4)
1	ALLETE, Inc.	BBB+	A3	53.9%	55.8%
2	Alliant Energy Corporation	A-	A3	44.8%	47.5%
3	American Electric Power Company, Inc.	BBB	Baa1	45.0%	51.0%
4	Ameren Corporation	BBB+	Baa1	48.6%	51.5%
5	CenterPoint Energy, Inc.	A-	Baa1	33.9%	36.0%
6	CMS Energy Corporation	BBB+	Baa2	29.5%	31.0%
7	Consolidated Edison, Inc.	A-	A3	49.2%	52.0%
8	Dominion Resources, Inc.	A-	Baa2	30.5%	34.6%
9	DTE Energy Company	BBB+	A3	48.0%	50.0%
10	Edison International	BBB+	A3	43.8%	47.2%
11	El Paso Electric Company	BBB	Baa1	45.8%	46.5%
12	Entergy Corporation	BBB	Baa3	41.1%	44.0%
13	Great Plains Energy Inc.	BBB+	Baa2	46.8%	50.5%
14	IDACORP, Inc.	BBB	Baa1	54.2%	54.7%
15	MGE Energy, Inc.	N/A	N/A	61.9%	62.5%
16	OGE Energy Corp.	A-	A3	53.2%	54.0%
17	Otter Tail Corporation	BBB	Baa2	52.9%	53.5%
18	PG&E Corporation	BBB	Baa1	49.6%	50.7%
19	Pinnacle West Ca ital Cor oration	A-	Baa1	54.0%	59.0%
20	Portland General Electric Company	BBB	A3	43.3%	47.3%
21	Public Service Enterprise Group Incorporat	BBB+	Baa2	57.1%	59.6%
22	SCANA Corporation	BBB+	Baa3	43.0%	47.4%
23	Sempra Energy	BBB+	Baa1	42.8%	48.2%
24	Southern Company	A	Baa1	43.1%	47.3%
25	Vectren Corporation	A-	N/A	48.1%	53.3%
26	Westar Energy, Inc.	BBB+	Baa1	46.9%	50.0%
27	Xcel Energy Inc.	A-	A3	44.4%	47.0%
28	**Average**	**BBB+**	**Baa1**	**46.5%**	**49.3%**
29	**Portland General Electric Company**	**BBB**[3]	**A-**[3]		**50.0%**[4]

Sources:
[1] SNL Financial, Downloaded on May 17, 2015.
[2] *The Value Line Investment Survey* , March 20, May 1, and May 22, 2015.
[3] Villadesen Direct at 34.
[4] Villadesen Direct at 35.

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EXHIBIT ICNU/304

CONSENSUS ANALYSTS' GROWTH RATES

June 15, 2015

Portland General Electric Company

Consensus Analysts' Growth Rates

		Zacks		SNL		Reuters		Average of
Line	Company	Estimated Growth %[1] (1)	Number of Estimates (2)	Estimated Growth %[2] (3)	Number of Estimates (4)	Estimated Growth %[3] (5)	Number of Estimates (6)	Growth Rates (7)
1	ALLETE, Inc.	NA	N/A	6.00%	1	NA	NA	6.00%
2	Alliant Energy Corporation	5.30%	N/A	6.10%	2	5.45%	2	5.62%
3	American Electric Power Company, Inc.	5.00%	N/A	5.30%	5	5.18%	4	5.16%
4	Ameren Corporation	6.80%	N/A	6.90%	3	5.85%	2	6.52%
5	CenterPoint Energy, Inc.	5.00%	N/A	5.30%	3	1.91%	3	4.07%
6	CMS Energy Corporation	6.20%	N/A	5.90%	3	6.73%	3	6.28%
7	Consolidated Edison, Inc.	2.70%	N/A	2.10%	3	2.47%	4	2.42%
8	Dominion Resources, Inc.	6.30%	N/A	6.60%	5	5.89%	5	6.26%
9	DTE Energy Company	5.00%	N/A	5.50%	4	4.51%	4	5.00%
10	Edison International	4.20%	N/A	5.40%	3	0.70%	4	3.43%
11	El Paso Electric Company	6.70%	N/A	N/A	N/A	NA	NA	6.70%
12	Entergy Corporation	- 1.00%	N/A	- 0.10%	4	- 3.05%	3	N/A
13	Great Plains Energy Inc.	5.40%	N/A	5.70%	4	6.90%	2	6.00%
14	IDACORP, Inc.	4.00%	N/A	4.00%	1	4.00%	1	4.00%
15	MGE Energy, Inc.	NA	N/A	N/A	N/A	NA	NA	N/A
16	OGE Energy Corp.	5.00%	N/A	5.20%	2	4.00%	2	4.73%
17	Otter Tail Corporation	NA	N/A	N/A	N/A	NA	NA	N/A
18	PG&E Corporation	5.30%	N/A	5.20%	2	4.71%	4	5.07%
19	Pinnacle West Capital Corporation	4.30%	N/A	5.40%	3	4.70%	2	4.80%
20	Portland General Electric Company	5.20%	N/A	5.60%	3	4.72%	4	5.17%
21	Public Service Enterprise Group Incorporated	3.70%	N/A	4.90%	4	2.85%	3	3.82%
22	SCANA Corporation	4.20%	N/A	5.50%	2	4.30%	2	4.67%
23	Sempra Energy	8.50%	N/A	9.30%	3	7.93%	6	8.58%
24	Southern Company	3.50%	N/A	3.70%	6	3.32%	5	3.51%
25	Vectren Corporation	5.70%	N/A	5.50%	2	5.50%	2	5.57%
26	Westar Energy, Inc.	3.50%	N/A	4.70%	2	3.40%	2	3.87%
27	Xcel Energy Inc.	4.70%	N/A	5.30%	3	4.58%	4	4.86%
28	**Average**	**5.05%**	**N/A**	**5.44%**	**3**	**4.53%**	**3**	**5.09%**

Sources:
[1] Zacks Elite, http://www.zackselite.com/, downloaded on May 15, 2015.
[2] SNL Interactive, http://www.snl.com/, downloaded on May 15, 2015.
[3] Reuters, http://www.reuters.com/, downloaded on May 15, 2015.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/305

CONSTANT GROWTH DCF MODEL
(CONSENSUS ANALYSTS' GROWTH RATES)

June 15, 2015

Portland General Electric Company

Constant Growth DCF Model
(Consensus Analysts' Growth Rates)

Line	Company	13-Week AVG Stock Price[1] (1)	Analysts' Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE, Inc.	$52.10	6.00%	$2.02	4.11%	10.11%
2	Alliant Energy Corporation	$62.30	5.62%	$2.20	3.73%	9.35%
3	American Electric Power Company, Inc.	$56.62	5.16%	$2.12	3.94%	9.10%
4	Ameren Corporation	$41.76	6.52%	$1.64	4.18%	10.70%
5	CenterPoint Energy, Inc.	$20.88	4.07%	$0.99	4.94%	9.01%
6	CMS Energy Corporation	$34.54	6.28%	$1.16	3.57%	9.85%
7	Consolidated Edison, Inc.	$61.61	2.42%	$2.60	4.32%	6.75%
8	Dominion Resources, Inc.	$71.63	6.26%	$2.59	3.84%	10.11%
9	DTE Energy Company	$80.83	5.00%	$2.76	3.59%	8.59%
10	Edison International	$62.55	3.43%	$1.67	2.76%	6.19%
11	El Paso Electric Company	$37.46	6.70%	$1.12	3.19%	9.89%
12	Entergy Corporation	$77.49	N/A	$3.32	N/A	N/A
13	Great Plains Energy Inc.	$26.52	6.00%	$0.98	3.92%	9.92%
14	IDACORP, Inc.	$61.57	4.00%	$1.88	3.18%	7.18%
15	MGE Energy, Inc.	$42.69	N/A	$1.13	N/A	N/A
16	OGE Energy Corp.	$32.24	4.73%	$1.00	3.25%	7.98%
17	Otter Tail Corporation	$31.38	N/A	$1.23	N/A	N/A
18	PG&E Corporation	$53.04	5.07%	$1.82	3.61%	8.68%
19	Pinnacle West Capital Corporation	$63.01	4.80%	$2.38	3.96%	8.76%
20	Portland General Electric Company	$36.28	5.17%	$1.12	3.25%	8.42%
21	Public Service Enterprise Group Incorporated	$41.56	3.82%	$1.56	3.90%	7.71%
22	SCANA Corporation	$54.83	4.67%	$2.18	4.16%	8.83%
23	Sempra Energy	$108.06	8.58%	$2.80	2.81%	11.39%
24	Southern Company	$44.71	3.51%	$2.17	5.02%	8.53%
25	Vectren Corporation	$43.84	5.57%	$1.52	3.66%	9.23%
26	Westar Energy, Inc.	$38.15	3.87%	$1.44	3.92%	7.79%
27	Xcel Energy Inc.	$34.52	4.86%	$1.28	3.89%	8.75%
28	**Average**	**$50.82**	**5.09%**	**$1.80**	**3.78%**	**8.87%**
29	**Median**					**8.79%**

Sources:
[1] SNL Financial, Downloaded on May 17, 2015.
[2] Exhibit ICNU/304.
[3] *The Value Line Investment Survey* , March 20, May 1, and May 22, 2015.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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In the Matter of	)
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PORTLAND GENERAL ELECTRIC COMPANY	)
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EXHIBIT ICNU/306

PAYOUT RATIOS

June 15, 2015

Portland General Electric Company

Payout Ratios

Line	Company	Dividends Per Share 2014 (1)	Dividends Per Share Projected (2)	Earnings Per Share 2014 (3)	Earnings Per Share Projected (4)	Payout Ratio 2014 (5)	Payout Ratio Projected (6)
1	ALLETE, Inc.	$1.96	$2.40	$2.90	$4.00	67.59%	60.00%
2	Alliant Energy Corporation	$2.04	$2.85	$3.48	$4.25	58.62%	67.06%
3	American Electric Power Company, Inc.	$2.03	$2.65	$3.34	$4.50	60.78%	58.89%
4	Ameren Corporation	$1.61	$1.85	$2.40	$3.25	67.08%	56.92%
5	CenterPoint Energy, Inc.	$0.95	$1.15	$1.42	$1.45	66.90%	79.31%
6	CMS Energy Corporation	$1.08	$1.50	$1.74	$2.25	62.07%	66.67%
7	Consolidated Edison, Inc.	$2.52	$2.90	$3.62	$4.50	69.61%	64.44%
8	Dominion Resources, Inc.	$2.40	$3.50	$3.05	$4.75	78.69%	73.68%
9	DTE Energy Company	$2.69	$3.50	$5.10	$5.75	52.75%	60.87%
10	Edison International	$1.48	$2.45	$4.33	$5.00	34.18%	49.00%
11	El Paso Electric Company	$1.11	$1.40	$2.27	$2.75	48.90%	50.91%
12	Entergy Corporation	$3.32	$3.80	$5.77	$6.00	57.54%	63.33%
13	Great Plains Energy Inc.	$0.94	$1.20	$1.57	$2.00	59.87%	60.00%
14	IDACORP, Inc.	$1.76	$2.25	$3.85	$3.90	45.71%	57.69%
15	MGE Energy, Inc.	$1.11	$1.35	$2.32	$3.30	47.84%	40.91%
16	OGE Energy Corp.	$0.95	$1.55	$1.98	$2.25	47.98%	68.89%
17	Otter Tail Corporation	$1.21	$1.32	$1.55	$2.35	78.06%	56.17%
18	PG&E Corporation	$1.82	$2.10	$3.06	$3.75	59.48%	56.00%
19	Pinnacle West Capital Corporation	$2.33	$2.95	$3.58	$4.50	65.08%	65.56%
20	Portland General Electric Company	$1.12	$1.55	$2.18	$2.75	51.38%	56.36%
21	Public Service Enterprise Group Incorporated	$1.48	$1.90	$2.99	$3.25	49.50%	58.46%
22	SCANA Corporation	$2.10	$2.50	$3.79	$4.50	55.41%	55.56%
23	Sempra Energy	$2.64	$3.60	$4.63	$7.25	57.02%	49.66%
24	Southern Company	$2.08	$2.43	$2.77	$3.50	75.09%	69.43%
25	Vectren Corporation	$1.46	$1.80	$2.02	$3.20	72.28%	56.25%
26	Westar Energy, Inc.	$1.40	$1.65	$2.35	$3.00	59.57%	55.00%
27	Xcel Energy Inc.	$1.20	$1.60	$2.03	$2.50	59.11%	64.00%
28	**Average**	**$1.73**	**$2.21**	**$2.97**	**$3.72**	**59.56%**	**60.04%**

Source:
The Value Line Investment Survey , March 20, May 1, and May 22, 2015.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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In the Matter of	)
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EXHIBIT ICNU/307

SUSTAINABLE GROWTH RATE

June 15, 2015

Portland General Electric Company

Sustainable Growth Rate

		3 to 5 Year Projections										Sustainable
Line	**Company**	**Dividends Per Share (1)**	**Earnings Per Share (2)**	**Book Value Per Share (3)**	**Book Value Growth (4)**	**ROE (5)**	**Adjustment Factor (6)**	**Adjusted ROE (7)**	**Payout Ratio (8)**	**Retention Rate (9)**	**Internal Growth Rate (10)**	**Growth Rate (11)**
1	ALLETE, Inc.	$2.40	$4.00	$42.25	3.80%	9.47%	1.02	9.64%	60.00%	40.00%	3.86%	4.40%
2	Alliant Energy Corporation	$2.85	$4.25	$34.65	2.19%	12.27%	1.01	12.40%	67.06%	32.94%	4.08%	4.81%
3	American Electric Power Company, Inc.	$2.65	$4.50	$42.25	4.23%	10.65%	1.02	10.87%	58.89%	41.11%	4.47%	4.73%
4	Ameren Corporation	$1.85	$3.25	$34.00	4.22%	9.56%	1.02	9.76%	56.92%	43.08%	4.20%	4.51%
5	CenterPoint Energy, Inc.	$1.15	$1.45	$12.00	2.51%	12.08%	1.01	12.23%	79.31%	20.69%	2.53%	3.42%
6	CMS Energy Corporation	$1.50	$2.25	$17.75	5.88%	12.68%	1.03	13.04%	66.67%	33.33%	4.35%	5.46%
7	Consolidated Edison, Inc.	$2.90	$4.50	$50.75	3.40%	8.87%	1.02	9.02%	64.44%	35.56%	3.21%	3.21%
8	Dominion Resources, Inc.	$3.50	$4.75	$28.00	7.24%	16.96%	1.03	17.56%	73.68%	26.32%	4.62%	8.52%
9	DTE Energy Company	$3.50	$5.75	$59.00	4.63%	9.75%	1.02	9.97%	60.87%	39.13%	3.90%	5.08%
10	Edison International	$2.45	$5.00	$44.25	5.64%	11.30%	1.03	11.61%	49.00%	51.00%	5.92%	5.92%
11	El Paso Electric Company	$1.40	$2.75	$29.50	3.88%	9.32%	1.02	9.50%	50.91%	49.09%	4.66%	4.86%
12	Entergy Corporation	$3.80	$6.00	$65.75	3.32%	9.13%	1.02	9.27%	63.33%	36.67%	3.40%	3.41%
13	Great Plains Energy Inc.	$1.20	$2.00	$26.75	2.84%	7.48%	1.01	7.58%	60.00%	40.00%	3.03%	3.06%
14	IDACORP, Inc.	$2.25	$3.90	$47.05	3.90%	8.29%	1.02	8.45%	57.69%	42.31%	3.57%	3.58%
15	MGE Energy, Inc.	$1.35	$3.30	$25.00	5.62%	13.20%	1.03	13.56%	40.91%	59.09%	8.01%	8.95%
16	OGE Energy Corp.	$1.55	$2.25	$20.25	4.50%	11.11%	1.02	11.36%	68.89%	31.11%	3.53%	3.78%
17	Otter Tail Corporation	$1.32	$2.35	$18.10	3.30%	12.98%	1.02	13.19%	56.17%	43.83%	5.78%	8.32%
18	PG&E Corporation	$2.10	$3.75	$40.75	4.25%	9.20%	1.02	9.39%	56.00%	44.00%	4.13%	5.21%
19	Pinnacle West Capital Corporation	$2.95	$4.50	$47.00	3.54%	9.57%	1.02	9.74%	65.56%	34.44%	3.36%	4.13%
20	Portland General Electric Company	$1.55	$2.75	$30.50	4.54%	9.02%	1.02	9.22%	56.36%	43.64%	4.02%	5.35%
21	Public Service Enterprise Group Incorporated	$1.90	$3.25	$30.50	4.83%	10.66%	1.02	10.91%	58.46%	41.54%	4.53%	4.54%
22	SCANA Corporation	$2.50	$4.50	$45.50	5.42%	9.89%	1.03	10.15%	55.56%	44.44%	4.51%	5.01%
23	Sempra Energy	$3.60	$7.25	$58.75	5.02%	12.34%	1.02	12.64%	49.66%	50.34%	6.37%	6.93%
24	Southern Company	$2.43	$3.50	$25.75	3.22%	13.59%	1.02	13.81%	69.43%	30.57%	4.22%	4.48%
25	Vectren Corporation	$1.80	$3.20	$21.25	1.79%	15.06%	1.01	15.19%	56.25%	43.75%	6.65%	7.96%
26	Westar Energy, Inc.	$1.65	$3.00	$29.25	3.17%	10.26%	1.02	10.42%	55.00%	45.00%	4.69%	5.33%
27	Xcel Energy Inc.	$1.60	$2.50	$24.50	3.94%	10.20%	1.02	10.40%	64.00%	36.00%	3.74%	4.03%
28	**Average**	**$2.21**	**$3.72**	**$35.22**	**4.10%**	**10.92%**	**1.02**	**11.14%**	**60.04%**	**39.96%**	**4.42%**	**5.15%**

Sources and Notes:
Cols. (1), (2) and (3): *The Value Line Investment Survey*, March 20, May 1, and May 22, 2015.
Col. (4): [Col. (3) / Page 2 Col. (2)] ^ (1/5) - 1.
Col. (5): Col. (2) / Col. (3).
Col. (6): [2 * (1 + Col. (4))] / (2 + Col. (4)).
Col. (7): Col. (6) * Col. (5).
Col. (8): Col. (1) / Col. (2).
Col. (9): 1 - Col. (8).
Col. (10): Col. (9) * Col. (7).
Col. (11): Col. (10) + Page 2 Col. (9).

Portland General Electric Company

Sustainable Growth Rate

Line	Company	13-Week Average Stock Price[1]	2014 Book Value Per Share[2]	Market to Book Ratio	Common Shares Outstanding (in Millions)[2] 2013	3-5 Years	Growth	S Factor[3]	V Factor[4]	S * V
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	ALLETE, Inc.	$52.10	$35.06	1.49	45.90	48.50	1.11%	1.65%	32.71%	0.54%
2	Alliant Energy Corporation	$62.30	$31.09	2.00	110.94	115.00	0.72%	1.45%	50.10%	0.72%
3	American Electric Power Company, Inc.	$56.62	$34.35	1.65	490.00	500.00	0.40%	0.67%	39.34%	0.26%
4	Ameren Corporation	$41.76	$27.65	1.51	242.65	250.00	0.60%	0.90%	33.79%	0.31%
5	CenterPoint Energy, Inc.	$20.88	$10.60	1.97	430.00	450.00	0.91%	1.80%	49.22%	0.89%
6	CMS Energy Corporation	$34.54	$13.34	2.59	275.20	285.00	0.70%	1.82%	61.38%	1.12%
7	Consolidated Edison, Inc.	$61.61	$42.94	1.43	292.88	293.00	0.01%	0.01%	30.30%	0.00%
8	Dominion Resources, Inc.	$71.63	$19.74	3.63	585.30	630.00	1.48%	5.38%	72.44%	3.90%
9	DTE Energy Company	$80.83	$47.05	1.72	177.00	192.00	1.64%	2.82%	41.79%	1.18%
10	Edison International	$62.55	$33.64	1.86	325.81	325.81	0.00%	0.00%	46.22%	0.00%
11	El Paso Electric Company	$37.46	$24.39	1.54	40.36	41.10	0.36%	0.56%	34.89%	0.20%
12	Entergy Corporation	$77.49	$55.85	1.39	179.25	179.50	0.03%	0.04%	27.92%	0.01%
13	Great Plains Energy Inc.	$26.52	$23.25	1.14	154.20	155.50	0.17%	0.19%	12.34%	0.02%
14	IDACORP, Inc.	$61.57	$38.85	1.58	50.27	50.30	0.01%	0.02%	36.90%	0.01%
15	MGE Energy, Inc.	$42.69	$19.02	2.24	34.67	36.00	0.76%	1.70%	55.45%	0.94%
16	OGE Energy Corp.	$32.24	$16.25	1.98	199.50	202.00	0.25%	0.49%	49.60%	0.25%
17	Otter Tail Corporation	$31.38	$15.39	2.04	37.22	42.00	2.45%	4.99%	50.96%	2.54%
18	PG&E Corporation	$53.04	$33.09	1.60	475.91	520.00	1.79%	2.87%	37.61%	1.08%
19	Pinnacle West Capital Corporation	$63.01	$39.50	1.60	110.57	118.00	1.31%	2.09%	37.31%	0.78%
20	Portland General Electric Company	$36.28	$24.43	1.49	78.23	89.50	2.73%	4.05%	32.67%	1.32%
21	Public Service Enterprise Group Incorporatec	$41.56	$24.09	1.73	505.84	506.00	0.01%	0.01%	42.03%	0.00%
22	SCANA Corporation	$54.83	$34.95	1.57	142.70	149.00	0.87%	1.36%	36.25%	0.49%
23	Sempra Energy	$108.06	$45.98	2.35	246.33	251.50	0.42%	0.98%	57.45%	0.56%
24	Southern Company	$44.71	$21.98	2.03	907.78	919.00	0.25%	0.50%	50.84%	0.25%
25	Vectren Corporation	$43.84	$19.45	2.25	82.60	87.00	1.04%	2.35%	55.64%	1.31%
26	Westar Energy, Inc.	$38.15	$25.02	1.52	131.69	140.00	1.23%	1.88%	34.42%	0.65%
27	Xcel Energy Inc.	$34.52	$20.20	1.71	505.73	516.00	0.40%	0.69%	41.48%	0.29%
28	**Average**	**$50.82**	**$28.78**	**1.84**	**254.02**	**262.66**	**0.80%**	**1.53%**	**42.63%**	**0.73%**

Sources and Notes:
[1] SNL Financial, Downloaded on May 17, 2015.
[2] *The Value Line Investment Survey*, March 20, May 1, and May 22, 2015.
[3] Expected Growth in the Number of Shares, Column (3) * Column (6).
[4] Expected Profit of Stock Investment, [1 - 1 / Column (3)].

BEFORE THE PUBLIC UTILITY COMMISSION

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EXHIBIT ICNU/308

CONSTANT GROWTH DCF MODEL
(SUSTAINABLE GROWTH RATE)

June 15, 2015

Portland General Electric Company

Constant Growth DCF Model
(Sustainable Growth Rate)

Line	Company	13-Week AVG Stock Price[1] (1)	Sustainable Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE, Inc.	$52.10	4.40%	$2.02	4.05%	8.44%
2	Alliant Energy Corporation	$62.30	4.81%	$2.20	3.70%	8.51%
3	American Electric Power Company, Inc.	$56.62	4.73%	$2.12	3.92%	8.65%
4	Ameren Corporation	$41.76	4.51%	$1.64	4.10%	8.61%
5	CenterPoint Energy, Inc.	$20.88	3.42%	$0.99	4.90%	8.32%
6	CMS Energy Corporation	$34.54	5.46%	$1.16	3.54%	9.00%
7	Consolidated Edison, Inc.	$61.61	3.21%	$2.60	4.36%	7.56%
8	Dominion Resources, Inc.	$71.63	8.52%	$2.59	3.92%	12.44%
9	DTE Energy Company	$80.83	5.08%	$2.76	3.59%	8.67%
10	Edison International	$62.55	5.92%	$1.67	2.83%	8.75%
11	El Paso Electric Company	$37.46	4.86%	$1.12	3.14%	7.99%
12	Entergy Corporation	$77.49	3.41%	$3.32	4.43%	7.84%
13	Great Plains Energy Inc.	$26.52	3.06%	$0.98	3.81%	6.86%
14	IDACORP, Inc.	$61.57	3.58%	$1.88	3.16%	6.74%
15	MGE Energy, Inc.	$42.69	8.95%	$1.13	2.88%	11.84%
16	OGE Energy Corp.	$32.24	3.78%	$1.00	3.22%	7.00%
17	Otter Tail Corporation	$31.38	8.32%	$1.23	4.25%	12.58%
18	PG&E Corporation	$53.04	5.21%	$1.82	3.61%	8.82%
19	Pinnacle West Capital Corporation	$63.01	4.13%	$2.38	3.93%	8.07%
20	Portland General Electric Company	$36.28	5.35%	$1.12	3.25%	8.60%
21	Public Service Enterprise Group Incorporated	$41.56	4.54%	$1.56	3.92%	8.46%
22	SCANA Corporation	$54.83	5.01%	$2.18	4.18%	9.18%
23	Sempra Energy	$108.06	6.93%	$2.80	2.77%	9.70%
24	Southern Company	$44.71	4.48%	$2.17	5.07%	9.55%
25	Vectren Corporation	$43.84	7.96%	$1.52	3.74%	11.70%
26	Westar Energy, Inc.	$38.15	5.33%	$1.44	3.98%	9.31%
27	Xcel Energy Inc.	$34.52	4.03%	$1.28	3.86%	7.89%
28	**Average**	**$50.82**	**5.15%**	**$1.80**	**3.78%**	**8.93%**
29	**Median**					**8.61%**

Sources:
[1] SNL Financial, Downloaded on May 17, 2015.
[2] Exhibit ICNU/307, page 1.
[3] *The Value Line Investment Survey*, March 20, May 1, and May 22, 2015.

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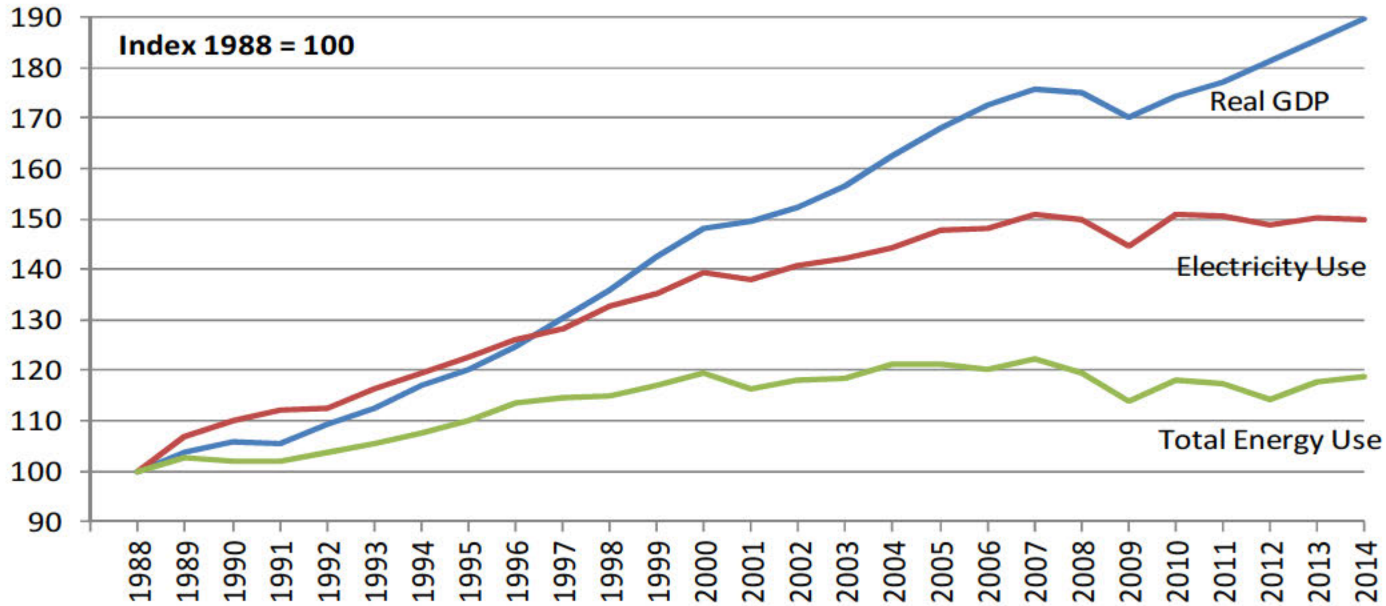
EXHIBIT ICNU/309

ELECTRICITY SALES ARE LINKED TO U.S. ECONOMIC GROWTH

June 15, 2015

Portland General Electric Company

Electricity Sales Are Linked to U.S. Economic Growth



Note:
1988 represents the base year. Graph depicts increases or decreases from the base year.

Sources:
U.S. Department of Energy, Energy Information Administration.
Edison Electric Institute, http://www.eei.org.

BEFORE THE PUBLIC UTILITY COMMISSION

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EXHIBIT ICNU/310

MULTI-STAGE GROWTH DCF MODEL

June 15, 2015

Portland General Electric Company

Multi-Stage Growth DCF Model

Line	Company	13-Week AVG Stock Price[1] (1)	Annualized Dividend[2] (2)	First Stage Growth[3] (3)	Second Stage Growth Year 6 (4)	Year 7 (5)	Year 8 (6)	Year 9 (7)	Year 10 (8)	Third Stage Growth[4] (9)	Multi-Stage Growth DCF (10)
1	ALLETE, Inc.	$52.10	$2.02	6.00%	5.77%	5.53%	5.30%	5.07%	4.83%	4.60%	9.02%
2	Alliant Energy Corporation	$62.30	$2.20	5.62%	5.45%	5.28%	5.11%	4.94%	4.77%	4.60%	8.54%
3	American Electric Power Company, Inc.	$56.62	$2.12	5.16%	5.07%	4.97%	4.88%	4.79%	4.69%	4.60%	8.66%
4	Ameren Corporation	$41.76	$1.64	6.52%	6.20%	5.88%	5.56%	5.24%	4.92%	4.60%	9.22%
5	CenterPoint Energy, Inc.	$20.88	$0.99	4.07%	4.16%	4.25%	4.34%	4.42%	4.51%	4.60%	9.40%
6	CMS Energy Corporation	$34.54	$1.16	6.28%	6.00%	5.72%	5.44%	5.16%	4.88%	4.60%	8.50%
7	Consolidated Edison, Inc.	$61.61	$2.60	2.42%	2.79%	3.15%	3.51%	3.87%	4.24%	4.60%	8.44%
8	Dominion Resources, Inc.	$71.63	$2.59	6.26%	5.99%	5.71%	5.43%	5.15%	4.88%	4.60%	8.80%
9	DTE Energy Company	$80.83	$2.76	5.00%	4.94%	4.87%	4.80%	4.73%	4.67%	4.60%	8.26%
10	Edison International	$62.55	$1.67	3.43%	3.63%	3.82%	4.02%	4.21%	4.41%	4.60%	7.16%
11	El Paso Electric Company	$37.46	$1.12	6.70%	6.35%	6.00%	5.65%	5.30%	4.95%	4.60%	8.17%
12	Entergy Corporation	$77.49	$3.32	N/A	N/A	N/A	N/A	N/A	N/A	4.60%	N/A
13	Great Plains Energy Inc.	$26.52	$0.98	6.00%	5.77%	5.53%	5.30%	5.07%	4.83%	4.60%	8.82%
14	IDACORP, Inc.	$61.57	$1.88	4.00%	4.10%	4.20%	4.30%	4.40%	4.50%	4.60%	7.66%
15	MGE Energy, Inc.	$42.69	$1.13	N/A	N/A	N/A	N/A	N/A	N/A	4.60%	N/A
16	OGE Energy Corp.	$32.24	$1.00	4.73%	4.71%	4.69%	4.67%	4.64%	4.62%	4.60%	7.87%
17	Otter Tail Corporation	$31.38	$1.23	N/A	N/A	N/A	N/A	N/A	N/A	4.60%	N/A
18	PG&E Corporation	$53.04	$1.82	5.07%	4.99%	4.91%	4.84%	4.76%	4.68%	4.60%	8.29%
19	Pinnacle West Capital Corporation	$63.01	$2.38	4.80%	4.77%	4.73%	4.70%	4.67%	4.63%	4.60%	8.60%
20	Portland General Electric Company	$36.28	$1.12	5.17%	5.08%	4.98%	4.89%	4.79%	4.70%	4.60%	7.94%
21	Public Service Enterprise Group Incorporatec	$41.56	$1.56	3.82%	3.95%	4.08%	4.21%	4.34%	4.47%	4.60%	8.33%
22	SCANA Corporation	$54.83	$2.18	4.67%	4.66%	4.64%	4.63%	4.62%	4.61%	4.60%	8.78%
23	Sempra Energy	$108.06	$2.80	8.58%	7.91%	7.25%	6.59%	5.93%	5.26%	4.60%	8.09%
24	Southern Company	$44.71	$2.17	3.51%	3.69%	3.87%	4.05%	4.24%	4.42%	4.60%	9.34%
25	Vectren Corporation	$43.84	$1.52	5.57%	5.41%	5.24%	5.08%	4.92%	4.76%	4.60%	8.45%
26	Westar Energy, Inc.	$38.15	$1.44	3.87%	3.99%	4.11%	4.23%	4.36%	4.48%	4.60%	8.36%
27	Xcel Energy Inc.	$34.52	$1.28	4.86%	4.82%	4.77%	4.73%	4.69%	4.64%	4.60%	8.54%
28	**Average**	**$50.82**	**$1.80**	**5.09%**	**5.01%**	**4.93%**	**4.84%**	**4.76%**	**4.68%**	**4.60%**	**8.47%**
29	**Median**										**8.48%**

Sources:
[1] SNL Financial, Downloaded on May 17, 2015.
[2] *The Value Line Investment Survey* , March 20, May 1, and May 22, 2015.
[3] Exhibit ICNU/305.
[4] Blue Chip Economic Indicators, March 10, 2015 at 14.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

In the Matter of	)
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PORTLAND GENERAL ELECTRIC COMPANY	)
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Request for a General Rate Revision.	)
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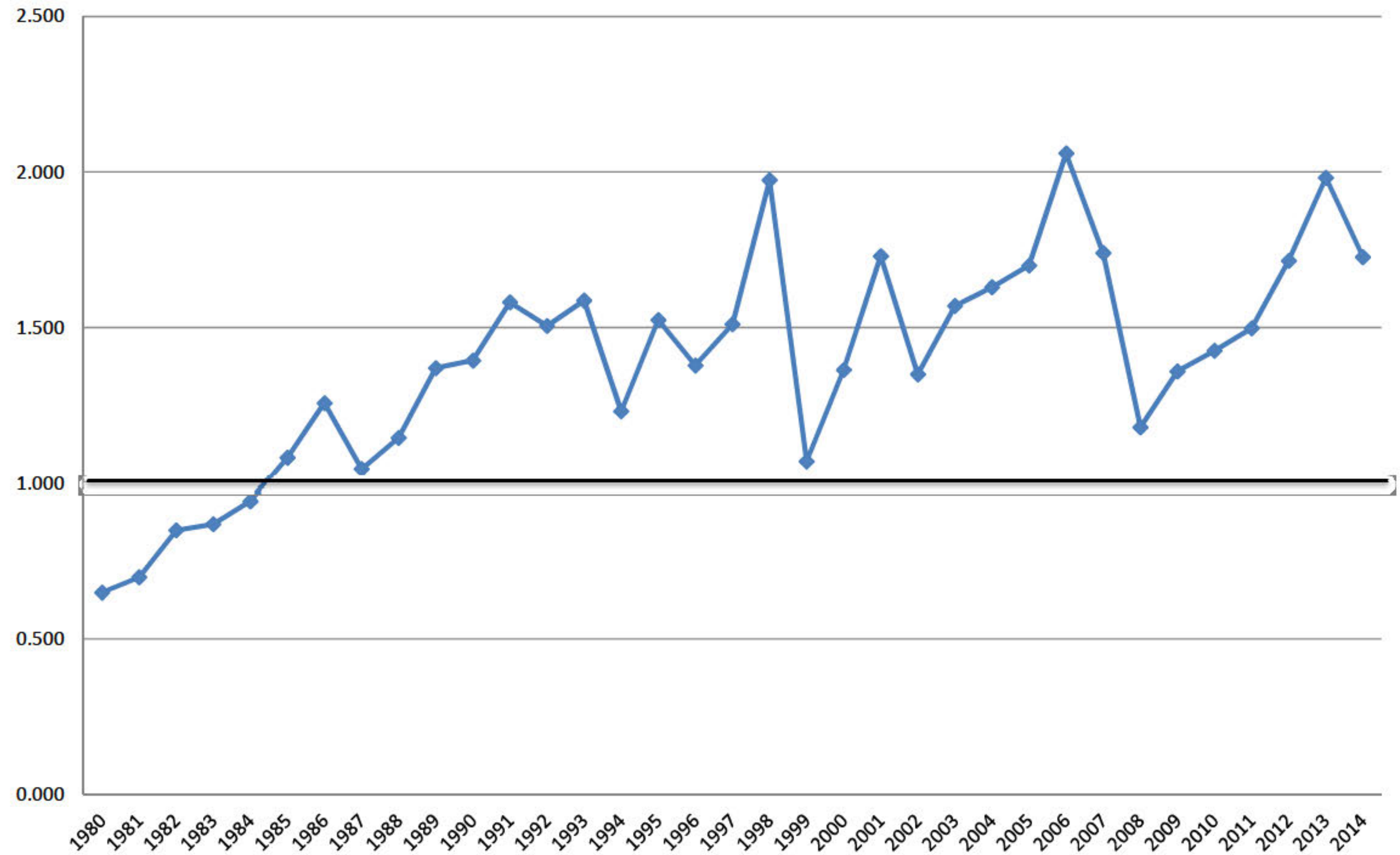
EXHIBIT ICNU/311

COMMON STOCK MARKET/BOOK RATIO

June 15, 2015

Portland General Electric Company

Common Stock Market/Book Ratio



Source:
1980 - 2000: Mergent Public Utility Manual.
2001 - 2014: AUS Utility Reports, various dates.

BEFORE THE PUBLIC UTILITY COMMISSION

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EXHIBIT ICNU/312

EQUITY RISK PREMIUM – TREASURY BOND

June 15, 2015

Portland General Electric Company

Equity Risk Premium - Treasury Bond

Line	Year	Authorized Electric Returns[1] (1)	Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.93%	7.80%	6.13%		
2	1987	12.99%	8.58%	4.41%		
3	1988	12.79%	8.96%	3.83%		
4	1989	12.97%	8.45%	4.52%		
5	1990	12.70%	8.61%	4.09%	4.60%	
6	1991	12.55%	8.14%	4.41%	4.25%	
7	1992	12.09%	7.67%	4.42%	4.26%	
8	1993	11.41%	6.60%	4.81%	4.45%	
9	1994	11.34%	7.37%	3.97%	4.34%	
10	1995	11.55%	6.88%	4.67%	4.46%	4.53%
11	1996	11.39%	6.70%	4.69%	4.51%	4.38%
12	1997	11.40%	6.61%	4.79%	4.59%	4.42%
13	1998	11.66%	5.58%	6.08%	4.84%	4.65%
14	1999	10.77%	5.87%	4.90%	5.03%	4.68%
15	2000	11.43%	5.94%	5.49%	5.19%	4.82%
16	2001	11.09%	5.49%	5.60%	5.37%	4.94%
17	2002	11.16%	5.43%	5.73%	5.56%	5.07%
18	2003	10.97%	4.96%	6.01%	5.55%	5.19%
19	2004	10.75%	5.05%	5.70%	5.71%	5.37%
20	2005	10.54%	4.65%	5.89%	5.79%	5.49%
21	2006	10.36%	4.99%	5.37%	5.74%	5.56%
22	2007	10.36%	4.83%	5.53%	5.70%	5.63%
23	2008	10.46%	4.28%	6.18%	5.73%	5.64%
24	2009	10.48%	4.07%	6.41%	5.88%	5.79%
25	2010	10.24%	4.25%	5.99%	5.89%	5.84%
26	2011	10.07%	3.91%	6.16%	6.05%	5.90%
27	2012	10.01%	2.92%	7.09%	6.37%	6.03%
28	2013	9.79%	3.45%	6.34%	6.40%	6.07%
29	2014	9.76%	3.34%	6.42%	6.40%	6.14%
30	2015 [3]	9.66%	2.55%	7.11%	6.62%	6.26%
31	**Average**	**11.22%**	**5.80%**	**5.43%**	**5.36%**	**5.35%**
32	**Minimum**				**4.25%**	**4.38%**
33	**Maximum**				**6.62%**	**6.26%**

Sources:

[1] Regulatory Research Associates, Inc., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 through Apr. 2015. In 2010 forward, the Virginia cases, which are subject to an adjustment for certain generation assets up to 200 basis points, are excluded.

[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/. The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.

[3] The data includes the period Jan - Mar 2015.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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EXHIBIT ICNU/313

EQUITY RISK PREMIUM – UTILITY BOND

June 15, 2015

Portland General Electric Company

Equity Risk Premium - Utility Bond

Line	Year	Authorized Electric Returns[1] (1)	Average "A" Rated Utility Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.93%	9.58%	4.35%		
2	1987	12.99%	10.10%	2.89%		
3	1988	12.79%	10.49%	2.30%		
4	1989	12.97%	9.77%	3.20%		
5	1990	12.70%	9.86%	2.84%	3.12%	
6	1991	12.55%	9.36%	3.19%	2.88%	
7	1992	12.09%	8.69%	3.40%	2.99%	
8	1993	11.41%	7.59%	3.82%	3.29%	
9	1994	11.34%	8.31%	3.03%	3.26%	
10	1995	11.55%	7.89%	3.66%	3.42%	3.27%
11	1996	11.39%	7.75%	3.64%	3.51%	3.20%
12	1997	11.40%	7.60%	3.80%	3.59%	3.29%
13	1998	11.66%	7.04%	4.62%	3.75%	3.52%
14	1999	10.77%	7.62%	3.15%	3.77%	3.52%
15	2000	11.43%	8.24%	3.19%	3.68%	3.55%
16	2001	11.09%	7.76%	3.33%	3.62%	3.56%
17	2002	11.16%	7.37%	3.79%	3.61%	3.60%
18	2003	10.97%	6.58%	4.39%	3.57%	3.66%
19	2004	10.75%	6.16%	4.59%	3.86%	3.81%
20	2005	10.54%	5.65%	4.89%	4.20%	3.94%
21	2006	10.36%	6.07%	4.29%	4.39%	4.00%
22	2007	10.36%	6.07%	4.29%	4.49%	4.05%
23	2008	10.46%	6.53%	3.93%	4.40%	3.98%
24	2009	10.48%	6.04%	4.44%	4.37%	4.11%
25	2010	10.24%	5.46%	4.78%	4.35%	4.27%
26	2011	10.07%	5.04%	5.03%	4.49%	4.44%
27	2012	10.01%	4.13%	5.88%	4.81%	4.65%
28	2013	9.79%	4.48%	5.31%	5.09%	4.74%
29	2014	9.76%	4.28%	5.48%	5.30%	4.83%
30	2015 [3]	9.66%	3.67%	5.99%	5.54%	4.94%
31	**Average**	**11.22%**	**7.17%**	**4.05%**	**3.97%**	**3.95%**
32	**Minimum**				**2.88%**	**3.20%**
33	**Maximum**				**5.54%**	**4.94%**

Sources:

[1] Regulatory Research Associates, Inc., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 through Apr. 2015. In 2010 forward, the Virginia cases, which are subject to an adjustment for certain generation assets up to 200 basis points, are excluded.

[2] Mergent Public Utility Manual, Mergent Weekly News Reports, 2003. The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record. The utility yields from 2010-2014 were obtained from http://credittrends.moodys.com/.

[3] The data includes the period Jan - Mar 2015.

BEFORE THE PUBLIC UTILITY COMMISSION

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EXHIBIT ICNU/314

BOND YIELD SPREADS

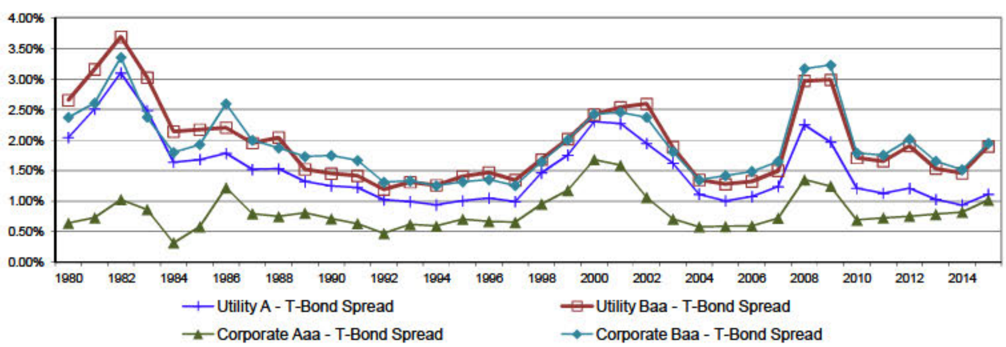
June 15, 2015

Portland General Electric Company

Bond Yield Spreads

			Public Utility Bond				Corporate Bond				Utility to Corporate	
Line	Year	T-Bond Yield[1] (1)	A[2] (2)	Baa[2] (3)	A-T-Bond Spread (4)	Baa-T-Bond Spread (5)	Aaa[1] (6)	Baa[1] (7)	Aaa-T-Bond Spread (8)	Baa-T-Bond Spread (9)	Baa Spread (10)	A-Aaa Spread (11)
1	1980	11.30%	13.34%	13.95%	2.04%	2.65%	11.94%	13.67%	0.64%	2.37%	0.28%	1.40%
2	1981	13.44%	15.95%	16.60%	2.51%	3.16%	14.17%	16.04%	0.73%	2.60%	0.56%	1.78%
3	1982	12.76%	15.86%	16.45%	3.10%	3.69%	13.79%	16.11%	1.03%	3.35%	0.34%	2.07%
4	1983	11.18%	13.66%	14.20%	2.48%	3.02%	12.04%	13.55%	0.86%	2.38%	0.65%	1.62%
5	1984	12.39%	14.03%	14.53%	1.64%	2.14%	12.71%	14.19%	0.32%	1.80%	0.34%	1.32%
6	1985	10.79%	12.47%	12.96%	1.68%	2.17%	11.37%	12.72%	0.58%	1.93%	0.24%	1.10%
7	1986	7.80%	9.58%	10.00%	1.78%	2.20%	9.02%	10.39%	1.22%	2.59%	-0.39%	0.56%
8	1987	8.58%	10.10%	10.53%	1.52%	1.95%	9.38%	10.58%	0.80%	2.00%	-0.05%	0.72%
9	1988	8.96%	10.49%	11.00%	1.53%	2.04%	9.71%	10.83%	0.75%	1.87%	0.17%	0.78%
10	1989	8.45%	9.77%	9.97%	1.32%	1.52%	9.26%	10.18%	0.81%	1.73%	-0.21%	0.51%
11	1990	8.61%	9.86%	10.06%	1.25%	1.45%	9.32%	10.36%	0.71%	1.75%	-0.29%	0.54%
12	1991	8.14%	9.36%	9.55%	1.22%	1.41%	8.77%	9.80%	0.63%	1.67%	-0.25%	0.59%
13	1992	7.67%	8.69%	8.86%	1.02%	1.19%	8.14%	8.98%	0.47%	1.31%	-0.12%	0.55%
14	1993	6.60%	7.59%	7.91%	0.99%	1.31%	7.22%	7.93%	0.62%	1.33%	-0.02%	0.37%
15	1994	7.37%	8.31%	8.63%	0.94%	1.26%	7.96%	8.62%	0.59%	1.25%	0.01%	0.35%
16	1995	6.88%	7.89%	8.29%	1.01%	1.41%	7.59%	8.20%	0.71%	1.32%	0.09%	0.30%
17	1996	6.70%	7.75%	8.17%	1.05%	1.47%	7.37%	8.05%	0.67%	1.35%	0.12%	0.38%
18	1997	6.61%	7.60%	7.95%	0.99%	1.34%	7.26%	7.86%	0.66%	1.26%	0.09%	0.34%
19	1998	5.58%	7.04%	7.26%	1.46%	1.68%	6.53%	7.22%	0.95%	1.64%	0.04%	0.51%
20	1999	5.87%	7.62%	7.88%	1.75%	2.01%	7.04%	7.87%	1.18%	2.01%	0.01%	0.58%
21	2000	5.94%	8.24%	8.36%	2.30%	2.42%	7.62%	8.36%	1.68%	2.42%	-0.01%	0.62%
22	2001	5.49%	7.76%	8.03%	2.27%	2.54%	7.08%	7.95%	1.59%	2.45%	0.08%	0.68%
23	2002	5.43%	7.37%	8.02%	1.94%	2.59%	6.49%	7.80%	1.06%	2.37%	0.22%	0.88%
24	2003	4.96%	6.58%	6.84%	1.62%	1.89%	5.67%	6.77%	0.71%	1.81%	0.08%	0.91%
25	2004	5.05%	6.16%	6.40%	1.11%	1.35%	5.63%	6.39%	0.58%	1.35%	0.00%	0.53%
26	2005	4.65%	5.65%	5.93%	1.00%	1.28%	5.24%	6.06%	0.59%	1.42%	-0.14%	0.41%
27	2006	4.99%	6.07%	6.32%	1.08%	1.32%	5.59%	6.48%	0.60%	1.49%	-0.16%	0.48%
28	2007	4.83%	6.07%	6.33%	1.24%	1.50%	5.56%	6.48%	0.72%	1.65%	-0.15%	0.52%
29	2008	4.28%	6.53%	7.25%	2.25%	2.97%	5.63%	7.45%	1.35%	3.17%	-0.20%	0.90%
30	2009	4.07%	6.04%	7.06%	1.97%	2.99%	5.31%	7.30%	1.24%	3.23%	-0.24%	0.72%
31	2010	4.25%	5.46%	5.96%	1.21%	1.71%	4.94%	6.04%	0.69%	1.79%	-0.08%	0.52%
32	2011	3.91%	5.04%	5.56%	1.13%	1.65%	4.64%	5.66%	0.73%	1.75%	-0.10%	0.40%
33	2012	2.92%	4.13%	4.83%	1.21%	1.91%	3.67%	4.94%	0.75%	2.01%	-0.11%	0.46%
34	2013	3.45%	4.48%	4.98%	1.03%	1.53%	4.24%	5.10%	0.79%	1.65%	-0.12%	0.24%
35	2014	3.34%	4.28%	4.80%	0.94%	1.46%	4.16%	4.85%	0.82%	1.51%	-0.06%	0.11%
36	2015[3]	2.55%	3.67%	4.45%	1.11%	1.89%	3.57%	4.50%	1.02%	1.95%	-0.05%	0.10%
37	**Average**	**6.83%**	**8.35%**	**8.77%**	**1.52%**	**1.95%**	**7.66%**	**8.76%**	**0.83%**	**1.93%**	**0.02%**	**0.69%**

Yield Spreads
Treasury Vs. Corporate & Treasury Vs. Utility



Sources:

[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.

[2] Mergent Public Utility Manual, Mergent Weekly News Reports, 2003. The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record. The utility yields from 2010-2014 were obtained from http://credittrends.moodys.com/.

[3] The data includes the period Jan - Mar 2015.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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PORTLAND GENERAL ELECTRIC COMPANY	)
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EXHIBIT ICNU/315

TREASURY AND UTILITY BOND YIELDS

June 15, 2015

Portland General Electric Company

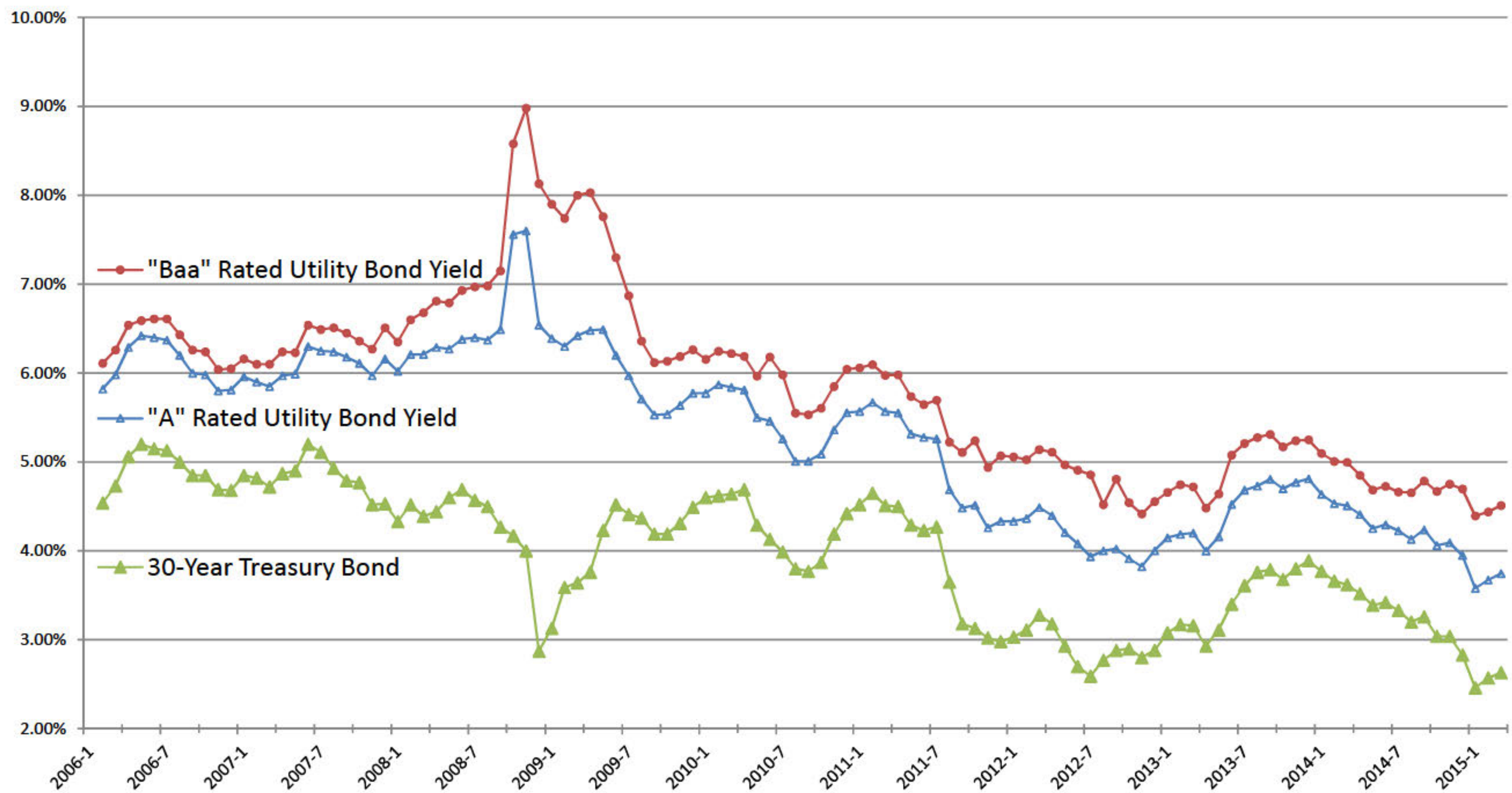
Treasury and Utility Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	05/15/15	2.93%	4.14%	4.88%
2	05/08/15	2.90%	4.10%	4.83%
3	05/01/15	2.82%	4.01%	4.75%
4	04/24/15	2.62%	3.79%	4.52%
5	04/17/15	2.51%	3.67%	4.43%
6	04/10/15	2.58%	3.75%	4.52%
7	04/03/15	2.49%	3.65%	4.44%
8	03/27/15	2.53%	3.68%	4.48%
9	03/20/15	2.50%	3.64%	4.42%
10	03/13/15	2.70%	3.81%	4.57%
11	03/06/15	2.83%	3.91%	4.64%
12	02/27/15	2.60%	3.69%	4.39%
13	02/20/15	2.73%	3.83%	4.57%
14	**Average**	**2.67%**	**3.82%**	**4.57%**
15	**Spread To Treasury**		**1.15%**	**1.90%**

Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[2] http://credittrends.moodys.com/.

Portland General Electric Company

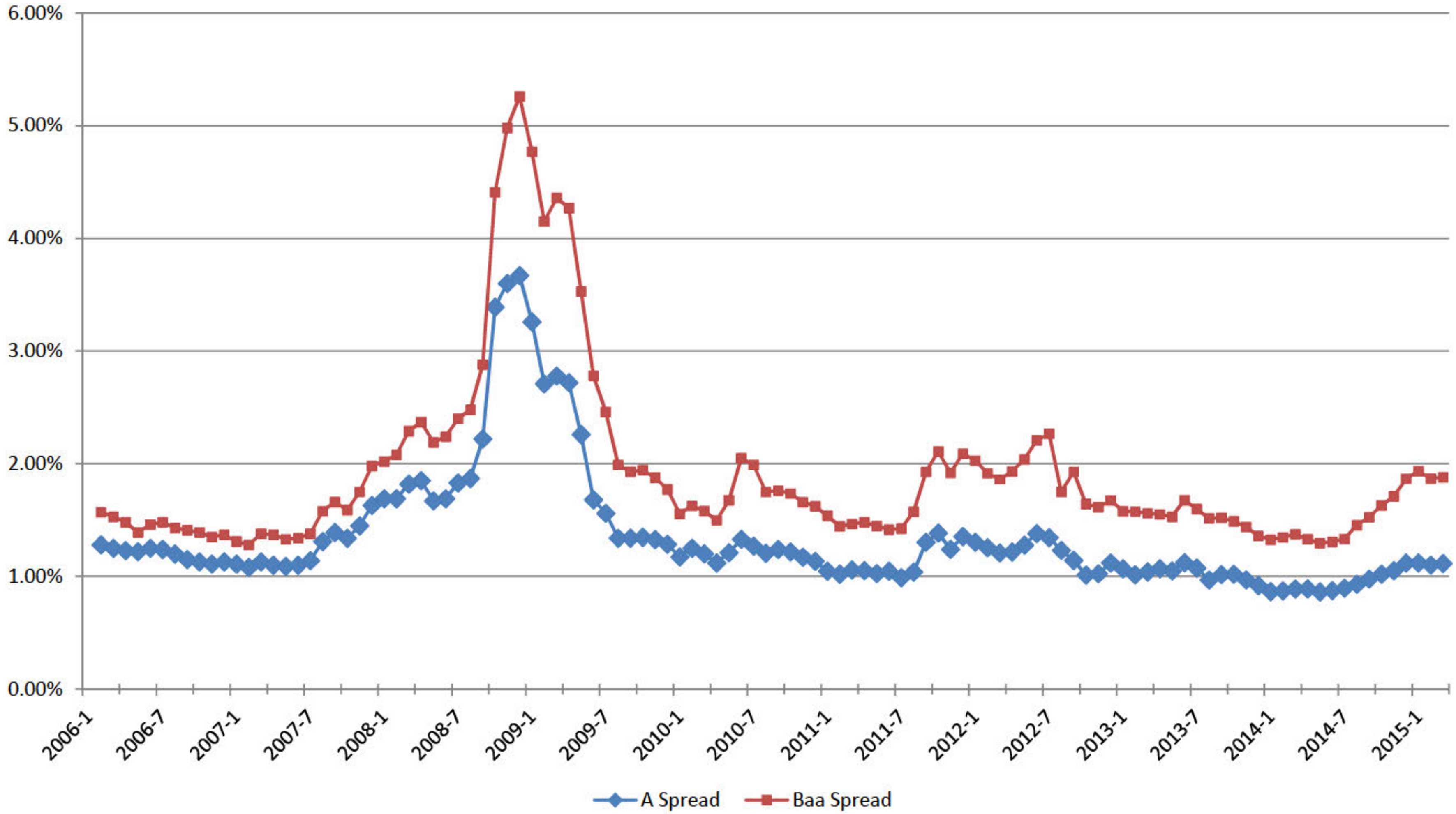
Trends in Bond Yields



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

Portland General Electric Company

Yield Spread Between Utility Bonds and 30-Year Treasury Bonds



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/316

VALUE LINE BETA

June 15, 2015

Portland General Electric Company

Value Line Beta

Line	Company	Beta
1	ALLETE, Inc.	0.80
2	Alliant Energy Corporation	0.80
3	American Electric Power Company, Inc.	0.70
4	Ameren Corporation	0.75
5	CenterPoint Energy, Inc.	0.80
6	CMS Energy Corporation	0.75
7	Consolidated Edison, Inc.	0.60
8	Dominion Resources, Inc.	0.70
9	DTE Energy Company	0.75
10	Edison International	0.75
11	El Paso Electric Company	0.70
12	Entergy Corporation	0.70
13	Great Plains Energy Inc.	0.85
14	IDACORP, Inc.	0.80
15	MGE Energy, Inc.	0.70
16	OGE Energy Corp.	0.90
17	Otter Tail Corporation	0.90
18	PG&E Corporation	0.65
19	Pinnacle West Capital Corporation	0.70
20	Portland General Electric Company	0.80
21	Public Service Enterprise Group Incorporated	0.75
22	SCANA Corporation	0.75
23	Sempra Energy	0.80
24	Southern Company	0.60
25	Vectren Corporation	0.80
26	Westar Energy, Inc.	0.75
27	Xcel Energy Inc.	0.65
28	**Average**	**0.75**

Source:
The Value Line Investment Survey,
March 20, May 1, and May 22, 2015.

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EXHIBIT ICNU/317

CAPM RETURN

June 15, 2015

Portland General Electric Company

CAPM Return

Line	Description	High Market Risk Premium (1)	Low Market Risk Premium (2)
1	Risk-Free Rate[1]	3.70%	3.70%
2	Risk Premium[2]	7.80%	6.00%
3	Beta[3]	0.75	0.75
4	**CAPM**	**9.54%**	**8.19%**
5	**Average**	**8.86%**	

Sources:
[1] Blue Chip Financial Forecasts; May 1, 2015, at 2.
[2] Morningstar, Inc. Ibbotson SBBI 2015 Classic Yearbook at 91 and 152.
[3] Exhibit ICNU/316.

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EXHIBIT ICNU/318

STANDARD & POOR'S CREDIT METRICS

June 15, 2015

Portland General Electric

Standard & Poor's Credit Metrics

Thousands of Dollars

Line	Description	Retail Cost of Service Amount (1)	S&P Benchmark (Medial Volatility)[1/2] Intermediate (2)	Significant (3)	Aggressive (4)	Reference (5)
1	Rate Base - OR	$ 4,470,484				PGE Exhibit 201 (Including Carty)
2	Weighted Common Return	4.63%				Page 2, Line 1, Col. 3.
3	Pre-Tax Rate of Return	10.65%				Page 2, Line 3, Col. 4.
4	Income to Common	$ 206,760				Line 1 x Line 2.
5	EBIT	$ 476,147				Line 1 x Line 3.
6	Depreciation & Amortization	$ 334,351				PGE Exhibit 201 (Including Carty)
7	Imputed Amortization	$ 16,427				S&P Global Credit Portal, accessed on June 9, 2015.
8	Deferred Income Taxes & ITC	$ 10,543				PGE Exhibit 201 (Including Carty)
9	Funds from Operations (FFO)	$ 568,080				Sum of Line 4 and Lines 6 through 8.
10	Imputed & Capitalized Interest Expense	$ 40,692				S&P Global Credit Portal, accessed on June 9, 2015.
11	EBITDA	$ 867,617				Sum of Lines 5 through 7 and Line 10.
12	Total Adjusted Debt Ratio	52.6%				Page 3, Line 4, Col. 2.
13	Debt to EBITDA	2.7x	2.5x - 3.5x	3.5x - 4.5x	4.5x - 5.5x	(Line 1 x Line 12) / Line 11.
14	FFO to Total Debt	24%	23% - 35%	13% - 23%	9% - 13%	Line 9 / (Line 1 x Line 12).

Sources:

[1] Standard & Poor's: "Criteria: Corporate Methodology," November 19, 2013.

[2] Ratings Direct: "Summary: Portland General Electric," May 20, 2015.

Note:

Based on the May 2015 S&P report, PGE has a "Strong" business profile and a "Significant" financial profile, and falls under the 'Medial Volatility' matrix.

Portland General Electric

Standard & Poor's Credit Metrics
(Pre-Tax Rate of Return)

Line	Description	Weight[1] (1)	Cost (2)	Weighted Cost (3)	Pre-Tax Weighted Cost (4)
1	Common Equity	50.0%	**9.25%**	4.63%	7.93%
2	Long-Term Debt	50.0%	**5.43%**	2.72%	2.72%
3	**Total**	**100.0%**		**7.34%**	**10.65%**
4	Tax Conversion Factor[2]				1.72

Sources:
[1]Exhibit ICNU/302.
[2]Exhibit PGE 201.

Portland General Electric

Standard & Poor's Credit Metrics
(Financial Capital Structure)
Thousands of Dollars

Line	Description	Amount[1] (1)	Weight (2)
1	Long-Term Debt	$ 2,441,400	47.4%
2	Off-Balance Sheet Debt for Operating Leases[2]	$ 119,218	2.3%
3	Off-Balance Sheet Debt for PPAs[2]	$ 146,700	2.8%
4	Total Long-Term Debt	$ 2,707,318	52.6%
5	Common Equity	$ 2,443,817	47.4%
6	**Total**	**$ 5,151,135**	**100.0%**

Sources:
[1]Exhibit ICNU/302.
[2]S&P Global Credit Portal, accessed on June 9, 2015.

Portland General Electric

Electric Industry Credit Metrics

Line	Description	FFO/Debt (%)	Debt / EBITDA (x)	Debt/Debt plus Equity (%)
		(1)	(2)	(3)
	'BBB+' Rated			
1	Average	20.80	3.88	53.30
2	Median	20.10	3.80	53.90
	'BBB' Rated			
3	Average	20.91	3.86	54.39
4	Median	19.60	3.90	54.30
	'BBB-' Rated			
5	Average	19.29	4.42	60.31
6	Median	18.30	4.30	60.80

Source:
Exhibit ICNU/318, page 5.

Portland General Electric

Electric Industry Credit Metrics

Line	Company	Corp. Credit Rating	FFO/Debt (%)	Debt / EBITDA (x)	Debt/Debt plus Equity (%)
1	ALLETE Inc.	BBB+	19.2	4.0	50.8
2	Atlantic City Electric Co.	BBB+	19.1	4.5	53.9
3	Central Maine Power Co.	BBB+	22.8	3.7	44.1
4	Cleco Corp.	BBB+	26.1	2.7	47.0
5	Cleco Power LLC	BBB+	24.7	3.0	50.5
6	DTE Electric Co.	BBB+	19.3	3.5	59.9
7	Duke Energy Carolinas LLC	BBB+	26.4	3.1	47.8
8	Duke Energy Corp.	BBB+	15.5	4.9	50.3
9	Duke Energy Florida Inc.	BBB+	15.4	5.0	57.5
10	Duke Energy Indiana Inc.	BBB+	18.9	4.2	52.3
11	Duke Energy Kentucky Inc.	BBB+	23.9	3.2	50.6
12	Duke Energy Ohio Inc.	BBB+	23.8	3.7	33.5
13	Duke Energy Progress Inc.	BBB+	23.7	3.6	53.4
14	Edison International	BBB+	23.1	3.5	61.1
15	Great Plains Energy Inc.	BBB+	16.3	4.5	56.5
16	Kansas City Power & Light Co.	BBB+	18.1	4.2	54.7
17	Nevada Power Co.	BBB+	14.6	4.8	57.6
18	Oncor Electric Delivery Co. LLC	BBB+	20.1	3.8	64.6
19	PEPCO Holdings Inc.	BBB+	15.8	4.9	57.1
20	Potomac Electric Power Co.	BBB+	20.5	4.4	54.0
21	Progress Energy Inc.	BBB+	13.0	5.6	61.6
22	Public Service Electric & Gas Co.	BBB+	25.0	3.3	53.1
23	Rochester Gas & Electric Corp.	BBB+	22.0	3.0	54.8
24	Sierra Pacific Power Co.	BBB+	17.4	4.3	56.4
25	South Carolina Electric & Gas Co.	BBB+	17.0	4.0	51.4
26	Southern California Edison Co.	BBB+	26.1	3.2	57.1
27	Tampa Electric Co.	BBB+	31.5	2.7	47.9
28	Union Electric Co. d/b/a Ameren Missouri	BBB+	25.4	3.1	49.8
29	Westar Energy Inc.	BBB+	18.4	4.1	56.5
30	AEP Texas Central Co.	BBB	25.2	2.7	48
31	AEP Texas North Co.	BBB	22.5	3.1	54.2
32	American Electric Power Co. Inc.	BBB	19.6	3.9	56
33	Appalachian Power Co.	BBB	14.5	4.9	58.1
34	Black Hills Power Inc.	BBB	22.3	3.4	49.2
35	Commonwealth Edison Co.	BBB	17.1	4.2	48.5
36	El Paso Electric Co.	BBB	22.4	3.5	56.3
37	Empire District Electric Co.	BBB	19.9	3.8	54.3
38	Entergy Arkansas Inc.	BBB	24.2	3.3	60.9
39	Entergy Corp.	BBB	21.1	3.6	60.9
40	Entergy Gulf States Louisiana LLC	BBB	25.4	3.6	58.6
41	Entergy Louisiana LLC	BBB	17.6	5.7	52.8
42	Entergy Mississippi Inc.	BBB	18.6	4.1	56.9
43	Entergy New Orleans Inc.	BBB	22.3	3.2	58.8
44	Entergy Texas Inc.	BBB	14	5.5	59.2
45	Exelon Corp.	BBB	21.5	3.5	51.6
46	IDACORP Inc.	BBB	15.2	4.8	53
47	Idaho Power Co.	BBB	15.5	4.6	54.3
48	Indiana Michigan Power Co.	BBB	20.8	3.8	60.6
49	Kentucky Power Co.	BBB	18.5	3.9	52.3
50	Kentucky Utilities Co.	BBB	21.5	3.8	43.6
51	LG&E and KU Energy LLC	BBB	16.7	5	56.4
52	Ohio Power Co.	BBB	28.1	2.7	53.2
53	Otter Tail Corp.	BBB	22.1	3.5	51.4
54	Pacific Gas & Electric Co.	BBB	17.5	4.4	58
55	PECO Energy Co.	BBB	28	2.8	45.1
56	PNM Resources Inc.	BBB	17.3	4.1	55.6
57	Portland General Electric Co.	BBB	19	3.9	55.8
58	PPL Corp.	BBB	17	4.2	59
59	PPL Electric Utilities Corp.	BBB	19.3	4	50.2
60	Public Service Co. of New Mexico	BBB	17.3	4.4	55.8
61	Public Service Co. of Oklahoma	BBB	24.6	3.2	53
62	Southwestern Electric Power Co.	BBB	18.2	4.6	52.4
63	System Energy Resources Inc.	BBB	48.2	1.6	48.2
64	Texas-New Mexico Power Co.	BBB	25.9	2.9	42.3
65	Tucson Electric Power Co.	BBB	18.5	4.1	64.7
66	UIL Holdings Corp.	BBB	16.3	4.5	63.2
67	Cleveland Electric Illuminating Co.	BBB-	11.3	5.5	60.9
68	FirstEnergy Corp.	BBB-	15.6	4.8	62.4
69	FirstEnergy Solutions Corp.	BBB-	14	6.2	55.1
70	Hawaiian Electric Co. Inc.	BBB-	19.1	4.1	53.2
71	Hawaiian Electric Industries Inc.	BBB-	19	4.1	56.6
72	Monongahela Power Co.	BBB-	15.8	5.4	65.9
73	Ohio Edison Co.	BBB-	27.2	2.7	68.8
74	Potomac Edison Co.	BBB-	25.3	3.6	60.7
75	Toledo Edison Co.	BBB-	17.6	4.5	68.1
76	West Penn Power Co.	BBB-	28	3.3	51.4

Source:
Standard & Poor's RatingsDirect, "CreditStats: Electric Utilities--U.S.," August 29, 2014.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
Request for a General Rate Revision.	)
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OPENING TESTIMONY OF JAMES W. DANIEL

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 15, 2015

**OPENING TESTIMONY AND EXHIBITS OF
JAMES W. DANIEL**

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James W. Daniel. My business address is 919 Congress Avenue, Suite 800, Austin, Texas 78701.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I received the degree of Bachelor of Science from the Georgia Institute of Technology in 1973 with a major in economics.

Q. WHAT IS YOUR PRESENT POSITION?

A. I am a Vice President of the firm GDS Associates, Inc. ("GDS") and Manager of GDS' office in Austin, Texas.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

A. From July 1974 through September 1979 and from August 1983 through February 1986, I was employed by Southern Engineering Company. During that time, I participated in the preparation of economic analyses regarding alternative power supply sources and generation and transmission feasibility studies for rural electric cooperatives. I participated in wholesale and retail rate and contract negotiations with investor-owned and publicly-owned utilities, prepared cost of service studies on investor-owned and publicly-owned utilities and prepared and submitted testimony and exhibits in utility rate and other regulatory proceedings on behalf of publicly-owned utilities, industrial customers, associations and government agencies. From October 1979 through July 1983, I was employed as a public utility consultant by R. W. Beck and Associates. During that time, I participated in rate studies for publicly-owned electric, gas, water and wastewater utilities. My primary responsibility was the development of revenue requirements, cost of service, and rate design studies as well as the preparation and submittal of testimony and exhibits in utility rate proceedings on behalf of publicly-owned utilities, industrial customers and other customer groups. Since February 1986, I have held the position of Manager of GDS' office in Austin, Texas. In April 2000, I was elected as a Vice President of GDS. While at GDS, I have provided testimony in numerous regulatory proceedings involving electric, natural gas, and water utilities, I have participated in generic rulemaking proceedings, I have prepared retail rate studies on behalf of publicly-owned utilities, I have prepared utility valuation analyses, I have prepared economic feasibility studies, and I have procured and contracted for wholesale and retail energy supplies.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. I have testified many times before regulatory commissions. I have submitted testimony before the following state regulatory authorities: the Public Utility Commission of Texas ("PUC" or the "Commission"), the Texas Commission on Environmental Quality, the Texas Railroad Commission, the Alaska Regulatory Commission, the Arkansas Public Service Commission, the Arizona Corporation Commission, the Delaware Public Service Commission, the Florida Public Service Commission, the Georgia Public Service Commission, the Illinois Commerce Commission, the State Corporation Commission of Kansas, the Louisiana Public Service Commission, the New Mexico Public Service Commission, the Oklahoma Corporation Commission, the Pennsylvania Public Utility Commission, the South Dakota Public Utilities Commission, the Virginia State Corporation Commission, and the West Virginia Public Service Commission. I have also testified before the Federal Energy Regulatory Commission ("FERC"), and two

Condemnation Courts appointed by the Supreme Court of Nebraska, and I have submitted an expert opinion report before the United States Tax Court on utility issues. A list of regulatory proceedings in which I have presented expert testimony is provided as ICNU/401.

Q. WOULD YOU PLEASE DESCRIBE GDS?

A. GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Auburn, Alabama; Manchester, New Hampshire; Madison, Wisconsin, and Orlando Florida. GDS has over 175 employees with backgrounds in engineering, accounting, management, economics, finance, and statistics. GDS provides rate and regulatory consulting services in the electric, natural gas, water, storm, and telephone utility industries. GDS also provides a variety of other services in the electric utility industry including power supply planning, generation support services, energy procurement and contracting, energy efficiency program development, financial analysis, load forecasting, and statistical services. Our clients are primarily privately-owned utilities, publicly-owned utilities, municipalities, customers of investor-owned utilities, groups or associations of customers, and government agencies.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU includes several large industrial customers of Portland General Electric Company ("PGE" or "Company").

II. PURPOSE OF TESTIMONY

Q. WHAT WAS YOUR ASSIGNMENT IN THIS PROCEEDING?

A. My assignment was to review PGE's proposed marginal cost of service study and proposed revenue spread.

Q. WOULD YOU PLEASE SUMMARIZE THE RESULTS OF YOUR REVIEW AND ANALYSIS?

A. Yes. Based upon my review and analysis of certain issues regarding PGE's rate increase application, I have reached the following conclusions and recommendations:

(1) PGE's generation marginal costs should be determined per the recommendation of ICNU witness Bradley Mullins.

(2) Franchise fees are not related to generation and should only be assigned to the transmission and distribution functions.

(3) ICNU's revised rate spread model should be used to allocate the cost of service to customer classes.

(4) A Consumer Impact Offset (CIO) should be implemented in this proceeding that limits rate increases to customer classes by 12%. The 12% cap should be applied based on customer class rate increases after the inclusion of the increase for the Carty Generating Station ("Carty").

III. CLASS COST OF SERVICE STUDY

Q. WOULD YOU BRIEFLY DESCRIBE THE PURPOSE OF A CLASS COST OF SERVICE STUDY?

A. The purpose of a class cost of service or rate spread study ("COSS") is to determine the portion of the utility's total cost of service or revenue requirement that should be borne by each customer class absent other factors that may be appropriate to consider. Each cost component of the utility's total cost of service is either directly assigned or allocated to the various customer classes. The results are then considered to determine the level of revenues needed to be recovered from rates for each customer class. The results of the COSS will also provide important information for designing rates.

Q. WHAT ARE THE BASIC STEPS FOR PREPARING A CLASS COSS?

A. Typically, there are three steps. These are the functionalization, classification, and allocation of costs. Some utilities which provide service in more than one jurisdiction also perform a jurisdictional allocation step.

Q. PLEASE DESCRIBE THE FUNCTIONALIZATION, CLASSIFICATION, AND ALLOCATION STEPS.

A. As stated in my previous answer, cost of service studies are typically developed in three distinct steps. First the various components of the utility's overall revenue requirements are assigned to their functional use, e.g., generation, transmission, distribution, and customer service. Next, the functionalized costs are classified based on cost causation factors to the cost categories of fixed or capacity-related, variable or commodity- related, and customer-related. Finally, the classified costs are directly assigned or allocated to customer classes using allocation factors developed for each classified cost category. Various methodologies or approaches exist for conducting each step in the cost of service study.

Q. PLEASE DESCRIBE THE ALLOCATED COST OF SERVICE STUDY INCLUDED IN PGE'S RATE INCREASE APPLICATION.

A. PGE's allocated COSS is sponsored by PGE witness Marc Cody. A summary of Mr. Cody's allocated COSS is attached to his direct testimony as PGE Exhibit 1404. The COSS is also referred to as the rate spread model or exhibit. In my direct testimony, I will use the terms class COSS and rate spread model interchangeably.

Q. ARE THERE DIFFERENT COST BASES FOR DETERMINING A CUSTOMER CLASS' ALLOCATED COST OF SERVICE?

A. Yes. There are two different cost bases that can be used for an allocated COSS. First, the COSS can be based on the utility's average embedded costs. Average embedded costs are the utility's booked costs, as revised for known and measurable adjustments. Average embedded costs can be based on an historic test year or on a projected test year. Second, the COSS can be based on the utility's marginal costs. PGE's proposed COSS is based on its marginal costs. The Public Utility Commission of Oregon ("OPUC" or "Commission") is one of the state regulatory agencies that allows the use of marginal costs as the basis for determining the class COSS.

Q. ARE THERE ANY ADDITIONAL STEPS OR CALCULATIONS THAT MUST BE MADE WHEN USING MARGINAL COSTS AS THE BASIS FOR A COSS?

A. Yes. A utility's marginal costs are typically greater than the utility's actual or embedded costs used to set its revenue requirements. In some instances, the marginal costs may be lower than the embedded costs. Therefore, it is necessary to adjust the allocated marginal costs downward or upward so that the allocated costs in the COSS will equal the overall Company revenue requirement.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING MARGINAL COST-BASED COST OF SERVICE STUDIES?

A. Yes. Marginal cost-based COSSs typically classify more of a utility's costs as energy-related. In general, this results in more costs being allocated to high load factor customers or customer classes.

IV. ALLOCATION OF PRODUCTION COSTS

Q. IS ICNU RECOMMENDING ANY ADJUSTMENT TO PGE'S PROPOSED MARGINAL GENERATION COSTS?

A. Yes. ICNU witness Bradley Mullins is presenting testimony on the proper marginal generation costs to be used in this case.

Q. HAVE YOU INCLUDED ICNU'S RECOMMENDED MARGINAL GENERATION COSTS IN YOUR CLASS COSS?

A. Yes.

Q. DOES THIS REVISION TO PGE'S MARGINAL GENERATION COSTS IMPACT THE ALLOCATION OF OTHER COSTS?

A. Yes. Other costs in PGE's rate spread model are allocated on the basis of the allocated marginal generation costs. For example, ancillary services costs are allocated to customer classes based on their allocated generation costs. Therefore, this change in PGE's marginal generation costs will directly impact the allocation of test year ancillary services costs. Another example is the allocation of PGE's proposed revenue requirement for Carty. The allocation of some general costs and other revenues are also indirectly affected by this change in marginal generation costs. My revised COSS or rate spread model also reflects these other cost allocations impacted by ICNU's revised marginal generation costs.

V. FUNCTIONALIZATION OF FRANCHISE FEES

Q. IS PGE PROPOSING TO RECOVER TEST YEAR FRANCHISE FEES IN ITS PROPOSED BASE RATES?

A. Yes. As shown on PGE Exhibit 1404, the Company is proposing to recover $46,809,000 in franchise fees in its proposed rates. The amount adjusted to cycle is $46,791,000.

Q. PLEASE DESCRIBE THE PURPOSE OF A PUBLIC UTILITY FRANCHISE AND THE RELATED FRANCHISE FEES.

A. A public utility franchise agreement is an agreement between a governmental entity (usually a municipality) and a public utility that typically provides for:

- The public utility's use of public right-of-ways ("ROWs) within the governmental entity's jurisdiction,

- Determines the obligations of the public utility,
- Sets forth the rules for the use of public ROWs, and
- Provides for compensation by the public utility for use of the public ROWs.

The franchise fee establishes the basis for the compensation to be paid to the governmental entity by the public utility. Usually the basis for the franchise fee is a set percentage of the revenues received by the public utility for the utility services provided within the jurisdiction of the governmental entity.

Q. ARE THE FRANCHISE FEES PAID BY PGE CONSISTENT WITH YOUR GENERAL DESCRIPTION?

A. Yes. According to PGE's response to ICNU data request 136, the Company has franchise agreements with 51 municipalities in its service territory (ICNU/402). In some instances, the terms of the franchise are set forth in a city ordinance rather than in a franchise agreement. The franchise fees paid by PGE under these franchise agreements is primarily based on a percent of the revenues collected by PGE for electric service within the municipality's city limits. In some situations where customers have chosen direct access service, the franchise fee may be based on an amount per kWh delivered to the direct access customers. A sample of a typical franchise fee agreement for the Company is included as Exhibit ICNU/403.

Q. IS THE FRANCHISE FEE ALSO COMPENSATION FOR THE RIGHT TO SERVE CUSTOMERS WITHIN THE MUNICIPALITY'S CITY LIMITS?

A. No. Typically the franchise agreement does not convey to the public utility the exclusive right to serve the customers within the city limits. Instead, as previously stated, the franchise fee is only for the use of public ROWs within the city by the utility. This is true for PGE's franchise agreements. Below is language from page 17, ICNU/403, which is standard language in many PGE franchise agreements regarding the purpose of the franchise fee:

SECTION 12: PAYMENT FOR USE OF PUBLIC ROW.

> A. Use of Public ROW. In consideration for its use of the Public ROW in accordance with the terms of this Franchise, Grantee agrees to pay the City an amount equal to 3½ percent of the Gross Revenue received by Grantee from its customers within the City unless such percentage is changed during the Term of this Franchise in accordance with its terms.

Q. SHOULD THE FRANCHISE FEE BE CONSIDERED AS A TAX?

A. No, it is not a tax. A franchise fee is a rental payment or use fee for the utility's right to use the municipality's public ROWs.

Q. HOW ARE PUBLIC ROWS DEFINED IN FRANCHISE AGREEMENTS?

A. Public ROWs are generally described as space on, above and below streets, alleys, roads, highways, sidewalks, bridges, parks and other public property. In some agreements, public utility easements (PUEs) are also included as public ROWs.

Q. HOW CAN THE UTILITY USE THE PUBLIC ROWS?

A. The franchise agreement will specify how the utility can use the public ROWs. Typically the franchise agreement will allow the utility to install, operate, and maintain poles, conduit, overhead and underground conductors, transformers, communications equipment, and other facilities necessary to deliver electricity to customers in the city. Pages 1-2 of Exhibit ICNU/403, for instance, contains the following standard language in many of PGE's franchise agreements:

> SECTION 1. NATURE OF FRANCHISE.
>
> (A) The City hereby grants to Grantee and its successors and assigns, subject to the terms and conditions in this Franchise, a nonexclusive franchise to erect, construct, repair, maintain, upgrade and operate an

> electric light and power system within the City as it now exists or may be extended in the future, including related communication equipment for Grantee's internal use and Grantee Facilities. This Franchise includes the privilege to install, repair, maintain, upgrade and operate Facilities necessary for the operation of Grantee's Electric Light and Power System (as defined below) upon, over, along, and across the surface of and the space above and below the streets, alleys, roads, highways, sidewalks, bridges, City park property and other public ways (collectively, "Public ROW"), as well as public utility easements ("PUEs") on third party property as shown on recorded final plats that which will be managed by the City thereafter … for the provision of public utility services within the City as Grantee's Electric Light and Power System now exists or is extended or upgraded in the future.

Q. HOW IS "GRANTEE'S ELECTRIC LIGHT AND POWER SYSTEM" DEFINED IN PGE'S FRANCHISE AGREEMENTS?

A. Not all of PGE's franchise agreements are identical. However, page 6 of Exhibit ICNU/403 contains the most common definition, which is as follows:

> (9) "Grantee's Electric Light and Power System" means all real property and Grantee Facilities used by Grantee in the transmission and distribution of its services that are located inside the boundaries of the City.

Q. AS THIS DEFINITION SUGGESTS, ARE THE PUBLIC ROWS PRIMARILY USED FOR DISTRIBUTION FACILITIES?

A. Yes. Electric utilities primarily use public ROWs for their distribution system facilities. In some cities, public ROWs may also be used for transmission facilities.

Q. ARE THE PUBLIC ROWS ALSO USED FOR GENERATION FACILITIES?

A. No. Typically, utilities own the land where generation facilities are located. Also, most generation facilities are located outside of municipalities' city limits. In addition, as the definition of "Grantee's Electric Light and Power System" demonstrates, the PGE franchise agreements only provide for delivery system facilities on public ROWs.

Q. HOW HAS PGE FUNCTIONALIZED ITS TEST YEAR FRANCHISE FEES?

A. PGE is proposing to functionalize its franchise fees of $46,791,000 to the generation, transmission and distribution functions. As shown on page 8 of PGE/1400, the amount assigned to each function is based on the total revenue requirement for each function. The table below provides PGE's proposed functionalization of test year franchise fees:

TABLE 1

PGE'S FUNCTIONALIZATION OF FRANCHISE FEES ($ x 1,000)		
FUNCTION	**FRANCHISE FEE AMOUNT**	
Production	$	29,183
Transmission		998
Distribution		16,610
Total	**$**	**46,791**

Source: PGE Exhibit 1404, Page 8. Production amount includes $231,000 assigned to Schedule 129.

Q. DOES PGE INITIALLY INCLUDE THE ENTIRE FRANCHISE FEE AMOUNT IN THE DISTRIBUTION FUNCTION?

A. Yes. As stated on page 30 of PGE/200, the direct testimony of PGE witnesses Alex Tooman and Rebeca Brown, the test year franchise fees are initially assigned entirely to the distribution function, consistent with OAR 860-038-0200(9)(c)(B)(i)(IV). However, in the PGE rate spread model, as shown on PGE Exhibit 1404, page 2, the Company later removes franchise fees from the distribution function and re-functionalizes the franchise fees as shown above.

Q. DO YOU AGREE WITH PGE'S PROPOSED FUNCTIONALIZATION OF FRANCHISE FEES?

A. No. As previously discussed, franchise fees are incurred for PGE's transmission and distribution delivery system. Therefore, in order to functionalize franchise fees based on cost causation, they should only be functionalized to the transmission and distribution functions. Using PGE's approach for assigning franchise fees to functions, the table below shows the results of my franchise fee functionalization recommendation.

TABLE 2

ICNU'S FUNCTIONALIZATION OF FRANCHISE FEES ($ x 1,000)	
FUNCTION	**FRANCHISE FEE AMOUNT**
Production	$0
Transmission	2,653
Distribution	44,138
Total	**$ 46,791**

Source: ICNU Exhibit 405, page 6.

Q. DOES YOUR RECOMMENDED FUNCTIONALIZATION OF FRANCHISE FEES MAINTAIN CONSISTENCY WITH COMMISSION ORDER 12-500?

A. Yes. While my revised functionalization of franchise fees will increase or decrease the franchise fee rate element in each rate schedule, the change is consistent with the requirements of Order 12-500.

Q. HAVE YOU PREPARED AN EXHIBIT THAT COMPARES THE AMOUNT OF FRANCHISE FEES ALLOCATED TO CUSTOMER CLASSES UNDER PGE'S PROPOSED AND YOUR RECOMMENDED FUNCTIONALIZATION OF FRANCHISE FEES?

A. Yes. My Exhibit ICNU/404 compares the amount of franchise fees allocated to customer classes under both PGE's and my recommended functionalization methodologies.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING PGE'S PROPOSED FUNCTIONALIZATION AND ALLOCATION OF FRANCHISE FEES?

A. Yes. PGE's proposed functionalization appears to be based on how the amount of the franchise fee payment to cities is calculated rather than on the cause of the franchise fee. Although the franchise fee payment is based on a percentage of total revenue, this should not influence how the franchise fee amount should be functionalized and allocated.

Instead, the cause for the fee, i.e., the utility's transmission and distribution costs, should be the basis used for functionalizing the fee. If the basis for the franchise fee, i.e., total revenues or revenue requirement, is used to functionalize franchise fees, then the logical allocation of franchise fees would be to only allocate this cost to customers inside city limits. I am not suggesting or proposing this allocation. I am just pointing out that to consistently allocate franchise fees with PGE's proposed functionalization of franchise fees would be to not allocate and charge franchise fees to customers located outside of city limits since the franchise fee is not based on their revenues.

VI. RECOMMENDED RATE SPREAD

Q. HAVE YOU PREPARED A REVISED REVENUE SPREAD MODEL THAT REFLECTS THE RECOMMENDED ADJUSTMENTS OF ICNU WITNESS BRADLEY MULLINS AND YOURSELF?

A. Yes. A summary of my revised rate spread model is provided as ICNU/405.

Q. HOW DO THE RESULTS OF YOUR REVISED REVENUE SPREAD MODEL COMPARE TO PGE'S PROPOSED REVENUE SPREAD MODEL?

A. My Exhibit ICNU/406 provides several summary comparisons by customer class under PGE's current and proposed revenues and allocated cost of service and under my recommended proposed revenues and allocated cost of service. The first page of this exhibit includes the Company's proposed revenue requirement increase for Carty. The second page of this exhibit excludes the amounts for Carty should the Commission disallow the Company's Carty proposal. Lines 15 and 9 on page 1 of ICNU/406 shows the cost of service allocated to the customer classes under my revised revenue spread model and the allocated cost of service amounts under PGE's proposed revenue spread model. Both rate spread models are based on the Company's proposed revenue requirement of approximately $1,921,056,000 with Carty. The table below compares the results of PGE's rate spread model with the results of my revised rate spread model for PGE's proposed revenue requirement with Carty.

TABLE 3

COMPARISON OF CUSTOMER CLASS ALLOCATED COSTS INCLUDING CARTY (RATE SPREAD) ($ x 1,000)			
CUSTOMER CLASS	PGE'S PROPOSED ALLOCATED COST OF SERVICE	ICNU'S RECOMMENDED ALLOCATED COST OF SERVICE	DIFFERENCE
Schedule 7	$ 974,865	$ 988,922	$ 14,057
Schedule 15	3,672	3,740	68
Schedule 32	187,481	188,046	565
Schedule 38	5,735	5,749	14
Schedule 47	5,631	5,818	187
Schedule 49	14,621	15,128	507
Schedule 83	263,977	261,688	(2,289)
Schedule 85	272,508	267,574	(4,933)
Schedule 89	71,130	67,083	(4,047)
Schedule 90	98,415	94,057	(4,357)
Schedule 91 & 95	13,750	13,934	185
Schedule 92	272	264	(8)
Total	$ 1,912,056	$ 1,912,005	$ (51)

Source: ICNU/406

Q. HOW DO THE RESULTS OF YOUR REVISED REVENUE SPREAD MODEL COMPARE WITH TEST YEAR REVENUES UNDER CURRENT RATES?

A. A comparison of the customer class revenues under current revenues with the results of my revised revenue spread model is provided in ICNU/406. The table below summarizes this comparison for PGE's proposed revenue requirement with Carty.

TABLE 4

COMPARISON OF CURRENT REVENUES WITH ICNU'S RECOMMENDED ALLOCATED COST OF SERVICE (INCLUDES CARTY) ($ x 1,000)			
CUSTOMER CLASS	**CURRENT REVENUES**	**ICNU'S RECOMMENDED ALLOCATED COST OF SERVICE**	**DIFFERENCE**
Schedule 7	$ 913,144	$ 988,922	$ 75,778
Schedule 15	3,628	3,740	112
Schedule 32	175,073	188,046	12,973
Schedule 38	5,251	5,749	498
Schedule 47	3,692	5,818	2,126
Schedule 49	7,829	15,128	7,299
Schedule 83	248,442	261,688	13,246
Schedule 85	262,216	267,574	5,358
Schedule 89	73,402	67,083	(6,319)
Schedule 90	91,891	94,057	2,166
Schedule 91 & 95	14,055	13,934	(121)
Schedule 92	251	264	13
Total	$ 1,798,875	$ 1,912,005	$ 113,130

Source: ICNU/406

Q. WHAT DOES THE COMPARISON IN TABLE 4 ABOVE INDICATE REGARDING INTER-CLASS SUBSIDIES?

A. This table shows that under current rates significant subsidies are being paid from the Schedule 89 customer class to other customer classes.

Q. HAVE YOU ALSO COMPARED THE RESULTS OF YOUR REVISED REVENUE SPREAD MODEL WITH TEST YEAR REVENUES UNDER PGE'S PROPOSED RATES?

A. Yes. A comparison of the customer class revenues under PGE's proposed rates with the results of my revised revenue spread model is provided in my Exhibit ICNU/406. The table below summarizes this comparison for PGE's proposed revenue requirement with Carty.

TABLE 5

COMPARISON OF PGE's PROPOSED REVENUES WITH ICNU'S RECOMMENDED ALLOCATED COST OF SERVICE (INCLUDING CARTY) ($ x 1,000)			
CUSTOMER CLASS	**PGE'S PROPOSED REVENUES**	**ICNU'S RECOMMENDED ALLOCATED COST OF SERVICE**	**DIFFERENCE**
Schedule 7	$ 974,861	$ 988,922	$ 14,061
Schedule 15	3,523	3,740	217
Schedule 32	189,310	188,046	(1,264)
Schedule 38	6,042	5,749	(293)
Schedule 47	3,799	5,818	2,019
Schedule 49	9,120	15,128	6,008
Schedule 83	268,807	261,688	(7,119)
Schedule 85	272,866	267,574	(5,292)
Schedule 89	71,128	67,083	(4,045)
Schedule 90	98,411	94,057	(4,354)
Schedule 91 & 95	13,898	13,934	37
Schedule 92	272	264	(8)
Total	$ 1,912,039	$ 1,912,005	$ (34)

Source: ICNU/406

Q. WHAT DOES THE COMPARISON IN TABLE 5 ABOVE INDICATE REGARDING INTER-CLASS SUBSIDIES UNDER PGE'S PROPOSED RATES?

A. As shown in the column on the right, significant inter-class subsidies among the customer classes will result from PGE's proposed rates. This is true even with consideration of PGE's proposed CIO adjustments.

VII. CONSUMER IMPACT OFFSET

Q. SHOULD THE CUSTOMER CLASS RATES ESTABLISHED IN THIS PROCEEDING BE SET EQUAL TO THE CLASS' ALLOCATED COST OF SERVICE?

A. While setting class revenue responsibility equal to its cost of service is the proper objective, it could be unreasonable to correct some inter-class subsidy problems entirely in one rate case. To do that could cause significant rate impacts on some customer classes. In that situation, the inter-class subsidies should be eliminated over two or three rate cases in order to gradually phase in the rate impacts. This process is commonly referred to as the gradualism principle.

Q. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE NEED TO GRADUALLY ELIMINATE INTER-CLASS SUBSIDIES, IF NECESSARY TO AVOID SIGNIFICANT RATE IMPACTS?

A. Yes, in prior PGE rate cases, the Commission has approved a CIO adjustment for this purpose. As stated on page 12 of the Commission's Order No. 14-422 in UE 283, the CIO is a mechanism that is designed to mitigate the effects of cost-justified increases that greatly exceed the overall average system percent increase.

Q. IS PGE PROPOSING A CIO ADJUSTMENT IN THIS CASE?

A. Yes. PGE's proposed CIO adjustment is described at page 25, line 14 through page 26, line 16 of PGE/1400, the direct testimony of PGE witness Marc Cody. As discussed in that testimony, PGE is proposing to mitigate the cost of service-based rate increases for the combined Schedules 38 and 49, and that Schedules 83 and 85 pay for the resulting revenue reductions. Under the Company's proposal, the rate increase before consideration of Carty for the combined group of Schedules 38 and 49 is limited to 12% above current rate revenues. The results of PGE's proposed CIO adjustment is provided on PGE/1403.

Q. DO YOU HAVE ANY ISSUES WITH PGE'S PROPOSED CIO ADJUSTMENT?

A. While I do not have a problem with applying a CIO in this case, the 12% rate increase cap should be applied to the proposed rate increases including Carty. The Direct Testimony of James J. Piro and Jim Lobdell (PGE/100 at 6:18) makes clear that "[t]he current case is necessary due primarily to the addition of Carty …." Since most of PGE's proposed revenue increase is related to Carty, the CIO adjustment should consider the impact of Carty.

Q. SHOULD AN ALTERNATIVE CIO BE MADE BASED ON THE RESULTS OF YOUR REVISED RATE SPREAD MODEL?

A. As shown on ICNU/406, setting rates equal to my allocated class cost of service amounts with Carty would result in substantial rate increases for some customer classes. Given this result, a revised CIO adjustment should be made.

Q. PLEASE DESCRIBE YOUR RECOMMENDED CIO ADJUSTMENT.

A. Under the Company's CIO proposal, the rate increase for each customer class before consideration of Carty is limited to 12%. I am utilizing this same threshold for my CIO recommendation except I apply this limit or threshold to customer class rate increases with the increase for Carty.

Q. HOW DO YOU PROPOSE TO ASSIGN TO THE OTHER CUSTOMER CLASSES THE REDUCED REVENUE INCREASES THAT ARE CAPPED BY THE 12% THRESHOLD?

A. Under my revised application of PGE's proposed CIO, the rate increases for the Schedule 38 and 49 customer classes would be reduced. Similar to PGE's CIO adjustment, the reduced revenue amounts from the Schedule 38 and 49 customer classes should be spread to the Schedule 83 and 85 customer classes proportionate to the Schedule 49 historic consumption of customers below or above 200 kW.

Q. WHAT IS THE AMOUNT OF YOUR PROPOSED CIO ADJUSTMENT?

A. My Exhibit ICNU/407 provides the calculation of my revised CIO adjustment at PGE's proposed revenue requirement with Carty. As shown on that exhibit, the cost-based revenue increase for the combined Schedule 38 and 49 customer classes should be reduced by $6,228,000 in order to limit the rate increase to 12%.

VIII. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE CONCLUSIONS YOU HAVE REACHED AND THE RECOMMENDATIONS YOU ARE MAKING TO THE COMMISSION.

A. I have reached the following conclusions and recommendations.

(1) PGE's generation marginal costs should be determined per the recommendation of ICNU witness Bradley Mullins.

(2) Franchise fees are not related to generation and should only be assigned to the transmission and distribution functions.

(3) ICNU's revised rate spread model should be used to allocate the cost of service to customer classes.

(4) A CIO should be implemented in this proceeding that limits rate increases to customer classes by 12%. The 12% cap should be applied based on customer class rate increases after the inclusion of the increase for Carty.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/401

LIST OF REGULATORY PROCEEDINGS

June 15, 2015

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
1/1/1976	Federal Power Commission	ER76-530	Arizona Public Service Company
2/76	South Dakota Public Utility Commission	F-3055	Northwestern Public Service Company
5/79	Federal Energy Regulatory Commission	ER78-379,ER78-380 ER78-381,ER78-382 ER78-383	Indiana & Michigan Electric Company
11/80	New Mexico Public Service Commission	1627	Kit Carson Electric Cooperative (Direct Testimony)
6/81	Arizona Corporation Commission	9962-E-1032	Citizens Utilities Company
9/81	Federal Energy Regulatory Commission	ER81-179	Arizona Public Service Commission (Direct Testimony)
3/84	Texas Public Utility Commission	5640	Texas Utilities Electric Company
4/2/1984	Public Utility Commission of Texas	5560	Gulf States Utility Company (Direct Testimony)
7/3/84	Texas Public Utility Commission	5640	Texas Utilities Electric Company (Direct Testimony)
11/15/1984	Texas Public Utility Commission	5709	Texas Utilities Electric Company (Direct Testimony)
1/85	Federal Energy Regulatory Commission	ER84-568-000	Gulf States Utilities Company (Direct Testimony)
11/20/1985	Federal Energy Regulatory Commission	ER85-538-001	Gulf States Utilities Company (Direct Testimony)
1/7/86	Louisiana Public Service Commission	U-16510	Central Louisiana Electric Company (Direct Testimony)
3/10/86	Texas Public Utility Commission	6677	Texas Utilities Electric Company
3/14/86	Federal Energy Regulatory Commission	ER85-538-001	Gulf States Utilities Company Rebuttal and Surrebuttal Testimony)
6/20/88	Texas Public Utility Commission	8032	Lower Colorado River Authority (Direct Testimony)
7/15/88	Texas Public Utility Commission	8032	Lower Colorado River Authority (Supplemental Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
3/7/90	Texas Public Utility Commission	9165	El Paso Electric Company (Direct Testimony)
4/12/90	Texas Public Utility Commission	9300	Texas Utilities Electric Company (Direct Testimony - Revenue Requirements Phase)
5/1/90	Texas Public Utility Commission	9300	Texas Utilities Electric Company (Direct Testimony - Phase II - Rate Design)
7/6/90	Texas Public Utility Commission	9300	Texas Utilities Electric Company (Supplemental Testimony - Revenue Requirements)
7/10/90	Texas Public Utility Commission	9427	Lower Colorado River Authority (Direct Testimony - Rate Design)
7/30/90	Texas Public Utility Commission	9427	Lower Colorado River Authority (Rebuttal Testimony - Rate Design)
8/23/90	Texas Public Utility Commission	9561	Central Power & Light Company (Direct Testimony - Rate Design)
1/11/91	Texas Public Utility Commission	9427	Lower Colorado River Authority (Rebuttal Testimony)
9/24/91	Texas Public Utility Commission	10404	Guadalupe Valley Electric Cooperative (Direct Testimony)
12/91	Rate Area 2 & 3 Nebraska Municipalities	N/A	Peoples Natural Gas Company
7/31/92	Texas Public Utility Commission	11266	Guadalupe-Blanco River Authority (Direct Testimony)
8/7/92	State Corporation Commission of Kansas	180,416-U	Peoples Natural Gas Company (Direct Testimony)
9/8/92	Texas Public Utility Commission	11266	Guadalupe-Blanco River Authority (Direct Testimony)
9/92	Texas Public Utility Commission	10894	Gulf States Utilities Company (Direct Testimony)
5/93	Texas Public Utility Commission	11735	Texas Utilities Electric Company (Rebuttal Testimony)
6/93	Texas Public Utility Commission	11892	Generic Proceeding Regarding Purchased Power (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
09/08/93	State Corporation Commission of Kansas	186,363-U	KN Energy (Direct Testimony)
09/94	State Corporation Commission of Kansas	190,362-U	Kansas Natural Pipeline and Kansas Natural Partnership (Direct Testimony)
10/17/94	Texas Public Utility Commission	12820	Central Power and Light Company (Direct Testimony)
11/15/1994	City of Houston	NA	Houston Lighting and Power Company (Direct Testimony)
11/15/1994	Texas Public Utility Commission	12065	Houston Lighting and Power Company (Direct Testimony - Revenue Requirements Phase)
12/12/1994	Texas Public Utility Commission	12820	Central Power & Light Company (Supplemental Testimony)
1/10/1995	Texas Public Utility Commission	12065	Houston Lighting & Power Company (Direct Testimony - Rate Design Phase)
5/23/95	Federal Energy Regulatory Commission	TX94-4-000	Texas Utilities Electric Company and Southwestern Electric Service (Affidavit)
8/7/95	Texas Public Utility Commission	13369	West Texas Utilities Company Rebuttal Testimony - Rate Design Phase)
10/31/95	Texas Public Utility Commission	14435	Southwestern Electric Power Company (Direct Testimony)
11/95	Rate Area 3 Nebraska Municipalities	N/A	Peoples Natural Gas Company (Municipal Report)
02/07/96	Federal Energy Regulatory Commission	TX96-2-000	City of College Station, Texas (Affidavit)
5/15/96	Texas Public Utility Commission	14965	Central Power & Light Company (Direct Testimony)
5/29/1996	Texas Public Utility Commission	14965	Central Power & Light Company (Rebuttal Testimony)
07/19/96	Texas Public Utility Commission	15766	City of Bryan, Texas (Direct Testimony)
8/29/1996	Texas Public Utility Commission	15296	City of Bryan, Texas (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
08/07/96	State of Illinois Commerce Commission	96-0245 & 96-0248	Commonwealth Edison Company (Direct Testimony)
09/06/96	Texas Public Utility Commission	15643	Central Power & Light Company and West Texas Utilities Company (Direct Testimony)
9/17/1996	Texas Public Utility Commission	15296	City of Bryan, Texas (Rebuttal Testimony)
09/18/96	Texas Public Utility Commission	15638	Texas Utilities Electric Company (Direct Testimony)
10/22/96	Texas Natural Resource Conservation Commission	96-0652-UCR	Longbranch Associates, L.P. (Direct Testimony)
08/05/97	Arkansas Public Service Commission	97-019-U	Arkansas Western Gas Company (Direct Testimony)
08/06/97	Texas Public Utility Commission	16705	Entergy Texas (Direct Testimony)
08/25/97	Texas Public Utility Commission	16705	Entergy Texas (Rebuttal Testimony - Rate Design Phase)
09/23/97	Arkansas Public Service Commission	97-019-U	Arkansas Western Gas Company Surrebuttal Testimony
09/30/97	Texas Public Utility Commission	16705	Entergy Texas (Direct Testimony - Competitive Issues Phase)
12/97	United States Tax Court	7685-96 and 4979-97	Lykes Energy, Inc. (Report)
12/97	Condemnation Court Appointed by the Supreme Court of Nebraska	13880	Peoples Natural Gas Company
12/1/1997	Condemnation Court Appointed by the Supreme Court of Nebraska	NA	Peoples Natural Gas Company (Report to City of Wahoo, Nebraska)
8/1/1998	Condemnation Court Appointed by the Supreme Court of Nebraska	101	Peoples Natural Gas Company (Report to City of Scribner, Nebraska)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
10/98	Federal Energy Regulatory Commission	EL-99-6-000	Entergy Gulf States, Inc. (Affidavit)
10/19/1998	Federal Energy Regulatory Commission	TX98-	Gulf States Utilities Company (Affidavit)
12/31/1998	Texas Public Utility Commission	20292	Sharyland Utilities, L.P. (Direct Testimony)
3/11/1999	Texas Public Utility Commission	20292	Sharyland Utilities, L.P. (Supplemental Testimony)
4/30/1999	Texas Public Utility Commission	20292	Sharyland Utilities, L.P. (Rebuttal Testimony)
7/16/1999	Texas Public Utility Commission	19265	Central and South West Corporation and American Electric Power Company, Inc. (Direct Testimony)
11/1/1999	Texas Public Utility Commission	21591	Sharyland Utilities, L.P. (Direct Testimony)
11/24/1999	Texas Public Utility Commission	21528	Central Power and Light Company (Direct Testimony)
1/27/2000	Texas Railroad Commission	8976	Texas Utilities Company Lone Star Pipeline (Direct Testimony)
3/31/2000	Texas Public Utility Commission	22348	Sharyland Utilities, L.P. (Direct Testimony)
08/2000	Texas Public Utility Commission	20624	Reliant Energy HL&P (Direct Testimony)
10/16/2000	Texas Public Utility Commission	22344	Generic Issues Associated with Unbundled Cost of Service Rate (Direct Testimony)
10/23/2000	Texas Public Utility Commission	21956	Reliant Energy, Inc. (Direct Testimony)
11/14/2000	Texas Public Utility Commission	22350	TXU Electric Company (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
11/17/2000	Texas Public Utility Commission	22352	Central Power and Light Company (Direct Testimony)
12/12/2000	Texas Public Utility Commission	22355	Reliant Energy HL&P (Direct Testimony - Final Phase)
12/21/2000	Texas Public Utility Commission	22355	Reliant Energy HL&P (Direct Testimony - Rate Case Expense Phase)
12/29/2000	Texas Public Utility Commission	22355	Reliant Energy HL&P (Supplemental & Rebuttal Testimonies)
7/5/2001	Texas Public Utility Commission	23950	Reliant Energy (Direct Testimony)
9/6/2001	Texas Public Utility Commission	24239	Mutual Energy CPL, LP (Direct Testimony)
4/22/2002	State Corporation Commission of Kansas	02-WSRE-301-RTS	Western Resources, Inc. and Kansas Gas and Electric Company (Direct Testimony)
6/19/2002	Federal Energy Regulatory Commission	TX96-2-000	City of College Station, Texas (Direct Testimony)
8/5/2002	Corporation Commission of the State of Oklahoma	200100455	Oklahoma Corporation Commission (Direct Testimony)
12/31/2002	Texas Public Utility Commission	26195	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
4/24/2003	Texas Public Utility Commission	25089	Market Protocols for the Portions of Texas Within the Southeastern Reliability Council (Rebuttal Testimony)
6/9/2003	Texas Public Utility Commission	25089	Market Protocols for the Portions of Texas Within the Southeastern Reliability Council (Supplemental Direct Testimony)
7/11/2003	State Corporation Commission of Kansas	03-KGSG-602-RTS	Kansas Gas Service, a Division of ONEOK, Inc. (Direct Testimony)
8/11/2003	Texas Public Utility Commission	25089	Market Protocols for the Portions of Texas Within the Southeastern Reliability Council (Second Supplemental Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
8/18/2003	State Corporation Commission of Kansas	03-KGSG-602-RTS	Kansas Gas Service, a Division of ONEOK, Inc. (Supplemental Testimony)
10/29/2003	Federal Energy Regulatory Commission	ER04-35-000	Entergy Services, Inc. (Affidavit)
11/5/2003	Texas Public Utility Commission	26195	CenterPoint Energy Houston Electric, LLC (Supplemental Direct Testimony)
2/9/2004	Texas Public Utility Commission	28840	AEP Texas Central Company (Direct Testimony)
6/1/2004	Texas Public Utility Commission	29526	CenterPoint Energy Houston Electric, LLC, Reliant Energy Retail Services, LLC, and Texas Genco, LP (Direct Testimony)
8/19/2004	Texas Public Utility Commission	28813	Cap Rock Energy Corporation (Affidavit)
8/30/2004	Texas Public Utility Commission	28813	Cap Rock Energy Corporation (Direct Testimony)
1/7/2005	Texas Public Utility Commission	30485	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
3/16/2005	Texas Public Utility Commission	30706	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
6/9/2005	Texas Public Utility Commission	29801	Southwestern Public Service Company (Direct Testimony)
9/2/2005	Texas Public Utility Commission	31056	AEP Texas Central Company and CPL Retail Energy, LP (Direct Testimony)
9/9/2005	State Corporation Commission of Kansas	05-WSEE-981-RTS	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
9/29/2005	Georgia Public Service Commission	20298-U	Atmos Energy Corporation (Direct Testimony)
4/24/2006	Texas Public Utility Commission	32475	AEP Texas Central Company (Cross Answering Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
8/11/2006	Texas Public Utility Commission	32093	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
8/23/2006	Texas Public Utility Commission	32795	Reallocation of Stranded Costs Pursuant to PURA §139.253(f) (Direct Testimony)
8/24/2006	Texas Public Utility Commission	32758	AEP Texas Central Company (Direct Testimony)
12/22/2006	Texas Public Utility Commission	32766	Southwestern Public Service Company (Direct Testimony)
3/13/2007	Texas Public Utility Commission	33309	AEP Texas Central Company (Direct Testimony)
3/19/2007	State Corporation Commission of Kansas	07-AQLG-431-RTS	Aquila Networks-KGO (Direct Testimony)
4/27/2007	Texas Public Utility Commission	33687	Entergy Gulf States, Inc. (Direct Testimony)
7/11/2007	Texas Public Utility Commission	33823	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
7/13/2007	Texas Public Utility Commission	33687	East Texas Cooperatives (Supplemental Testimony)
1/11/2008	Texas Public Utility Commission	35219	Guadalupe Valley Electric Cooperative, Inc. (Direct Testimony)
1/29/2008	Texas Public Utility Commission	35287	Sharyland Utilities, L.P. (Direct Testimony)
7/1/2008	Georgia Public Service Commission	27163	Atmos Energy Corporation (Direct Testimony)
9/16/2008	Texas Public Utility Commission	34442	JD Wind (Direct Testimony)
9/29/2008	State Corporation Commission of Kansas	08-WSEE-1041-RTS	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
10/13/2008	Texas Public Utility Commission	35763	Southwestern Public Services Company (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
11/26/2008	Texas Public Utility Commission	35717	Oncor Electric Delivery Company (Direct Testimony)
6/26/2009	State Corporation Commission of Kansas	09-WSEE-641-GIE	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
6/29/2009	Texas Public Utility Commission	36918	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
9/30/2009	State Corporation Commission of Kansas	09-WSEE-925-RTS	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
7/10/2010	Pennsylvania Public Utility Commission	R-2010-2161575, et. al.	PECO Energy Company (Direct Testimony)
9/3/2010	Texas Public Utility Commission	38324	Oncor Electric Delivery Company, LLC (Direct Testimony)
9/10/2010	Texas Public Utility Commission	38339	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
9/24/2010	Texas Public Utility Commission	38339	CenterPoint Energy Houston Electric, LLC (Cross-Rebuttal Testimony)
9/27/2010	Texas Public Utility Commission	38324	Oncor Electric Delivery Company, LLC (Cross-Rebuttal Testimony)
11/5/2010	Texas Public Utility Commission	38577	Modification of CREZ Transmission Plan (Direct Testimony)
2/4/2011	Texas Railroad Commission	GUD 10038	CenterPoint Energy Texas Gas (Direct Testimony)
3/1/2011	Texas Public Utility Commission	39070	Sharyland Utilities, L.P. (Direct Testimony)
10/19/2011	Texas Public Utility Commission	39856	Guadalupe Valley Electric Cooperative (Direct Testimony)
5/1/2012	Texas Public Utility Commission	40364	Sharyland Utitilies, L.P. (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
5/15/2012	Delaware Public Service Commission	11-528	Delmarva Power & Light Company (Direct Testimony)
11/2/2012	Florida Public Service Commission	120015-EI	Florida Power & Light Company (Direct Testimony)
2/20/2013	Texas Public Utility Commission	40627	Homeowners United for Rate Fairness (Cross-Rebuttal Testimony)
4/30/2013	Texas Public Utility Commission	41438	Sharyland Utilities, L.P. (Direct Testimony)
5/31/2013	Texas Public Utility Commission	41474	Sharyland Utilities, L.P. (Direct Testimony)
8/27/2013	Texas Public Utility Commission	41794	Sharyland Utilities, L.P. (Direct Testimony)
11/7/2013	Texas Public Utility Commission	41474	Sharyland Utilities, L.P. (Rebuttal Testimony)
1/2/2014	Texas Public Utility Commission	42133	Sharyland Utilities, L.P. (Direct Testimony)
1/9/2014	Michigan Public Service Commission	U-17437	DTE Electric Company (Direct Testimony)
5/19/2014	Public Service Commission of West Virginia	14-0344-E-GI	Appalachian Power Co. & Wheeling Power Co. (Direct Testimony)
6/17/2014	Texas Public Utility Commission	42087	Oncor Electric Delivery Company, LLC (Direct Testimony)
7/23/2014	Texas Public Utility Commission	42699	Sharyland Utilities, L.P. (Direct Testimony)
8/6/2014	Virginia State Corporation Commission	2014-00026	Appalachian Power Company (Direct Testimony)
8/15/2014	Texas Public Utility Commission	42767	Sharyland Utilities, L.P. (Direct Testimony)
12/18/2014	Public Service Commission of West Virginia	14-1152-E-42T	Appalachian Power Co. & Wheeling Power Co. (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
1/23/2015	Texas Public Utility Commission	44361	Sharyland Utilities, L.P. (Direct Testimony)
2/10/2015	Texas Public Utility Commission	44438	Sharyland Utilities, L.P. (Direct Testimony)
4/8/2015	Texas Public Utility Commission	44620	Sharyland Utilities, L.P. (Direct Testimony)
5/8/2015	Texas Public Utility Commission	44361	Sharyland Utilities, L.P. (Rebuttal Testimony)
5/13/2015	Regulatory Commission of Alaska	U-14-111	ENSTAR Natural Gas Company (Direct Testimony)
5/19/2015	Public Service Commission of West Virginia	15-0301-E-GI	Appalachian Power Co. & Wheeling Power Co. (Direct Testimony)

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/402

PGE RESPONSE TO ICNU DATA REQUEST NO. 136

June 15, 2015

June 5, 2015

TO: Jesse Gorsuch
Davison Van Cleve (ICNU)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to ICNU Data Request No. 136
Dated May 22, 2015

Request:

Please provide a copy of all PGE Franchise Agreements related to the $46,791,000 included in the 2016 test year revenue requirement for franchise fees. For each agreement, provide the amount of franchise fees paid for 2014 and estimated or budgeted to be paid for 2015.

Response:

Please see Attachment 136-A for all PGE Franchise Agreements currently on file. Please note that some cities do not have a current agreement specifying franchise fees and/or privilege taxes on file, but have a city ordinance requiring payment of franchise fees and/or privilege taxes.

Attachment 136-B provides 2014 and 2015 Franchise Fee and Privilege Tax payments by jurisdiction.

As discussed in PGE Exhibit 200, page 15, PGE's forecasted 2016 franchise fee rate is calculated based on the most recent three-year average of 2012 through 2014 gross revenues by jurisdiction. Additional detail can be found in the PGE Exhibit 200 non-confidential work paper titled "Franchise Fees for 2016".

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/403

SAMPLE FRANCHISE AGREEMENT

June 15, 2015

DUPLICATE ORIGINAL

FRANCHISE AGREEMENT

This Franchise Agreement grants Portland General Electric Company ("Grantee") a non-exclusive franchise for ten years to erect, construct, maintain, repair, update and operate an electric light and power system within the City of Beaverton ("City"), sets the terms and conditions of the franchise and provides an effective date.

WHEREAS, Grantee has been providing electric light and power service within the City; and

WHEREAS, Grantee is duly authorized by the Oregon Public Utility Commission ("OPUC") to supply electric light and power within the City; and

WHEREAS, the City has the authority to regulate the use of the Public ROW (as defined below) within the City and to receive compensation for the use of the Public ROW; and

WHEREAS, the City and Grantee both desire Grantee to continue to be able to provide electrical service within the City and to establish the terms by which Grantee shall use and occupy the Public ROW;

NOW THEREFORE, THE PARTIES AGREE AS FOLLOWS:

SECTION 1. NATURE OF FRANCHISE.

(A) The City hereby grants to Grantee and its successors and assigns, subject to the terms and conditions in this Franchise, a nonexclusive franchise to erect, construct, repair, maintain, upgrade and operate an electric light and power system within the City as it now exists or may be extended in the future, including related communication equipment for Grantee's internal use and Grantee Facilities (as defined below). This Franchise includes the privilege to install, repair, maintain, upgrade and operate Facilities necessary for the operation of Grantee's Electric Light and Power

System (as defined below) upon, over, along, and across the surface of and the space above and below the streets, alleys, roads, highways, sidewalks, bridges, City park property and other public ways (collectively, "Public ROW"), as well as public utility easements ("PUEs") on third party property as shown on recorded final plats that which will be managed by the City thereafter (see Section 9), for the provision of public utility services within the City as Grantee's Electric Light and Power System now exists or is extended or upgraded in the future. The City and Grantee shall mutually agree on the location and design of any new Grantee Facilities constructed in City park property. Nothing in this Franchise limits the City from granting others the right to carry on activities similar to, or different from the ones described in this Franchise. The rights granted herein do not include the right to build or site electric generating facilities in the Public ROW.

(B) All Grantee Facilities in possession of Grantee currently or during the Term (as defined in Section 2(A)) that are located within the Public ROW are covered by this Franchise and are deemed lawfully placed in their current locations. The City may require relocation of Grantee Facilities as further specified in Section 8.

(C) Grantee may provide telecommunications services as defined in ORS 759.005 as it may be amended from time to time via Grantee's Electric Light and Power System if it obtains all necessary and applicable authorizations from the OPUC regarding the provision of telecommunications service to the public and obtains any necessary, lawful and applicable authorization from the City for use of the Public ROW for such provision, including entering into a separate franchise with the City.

<u>SECTION 2. TERM AND EFFECTIVE DATE.</u>

(A) Effective Date. The effective date of this Franchise shall be thirty (30) days after the City Council passes a resolution adopting this Franchise and Grantee accepts this Franchise in writing in accordance with Section 25 herein; and if such written acceptance is not so filed within said period, this Franchise shall be null and void.

(B) Duration of Franchise. The term of this Franchise, and all rights and obligations pertaining thereto, shall be ten years from the effective date of the Franchise ("Term") unless renegotiated or terminated as provided herein. The Term shall automatically renew for two (2) five (5) year Terms, unless either party provides the other party one hundred eighty (180) days advanced written notice of its desire not to renew this Franchise prior to the expiration of the initial Term or renewal Term.

(C) Charter and General Ordinances to Apply. To the extent authorized by law, this Franchise is subject to the Charter of the City of Beaverton and general ordinance provisions passed pursuant thereto, including the applicable provisions of the City Development- and Site Development Codes and the Engineering Design Manual requiring underground utilities in subdivisions or partitions, and state statutes and regulations existing during the Term. Nothing in this Franchise shall be deemed to waive the requirements of the various codes and ordinances of the City regarding permits, fees to be paid that are generally applicable to other similar businesses operating within the City, including but not limited to fees for permits, inspections, and for administrative time spent in review of construction plans, or the manner of construction.

<u>SECTION 3.</u> <u>DEFINITIONS</u>.

(A) Captions. Throughout this Franchise, captions to sections are intended solely to facilitate reading and to reference the provisions of this Franchise. The captions shall not affect the meaning and interpretation of this Franchise.

(B) Definitions. For purposes of this Franchise, the following terms, phrases, and their derivations shall have the meanings given below unless the context indicates otherwise. When not inconsistent with the context, words used in the present tense include the future tense, words in the plural number include the singular number, and words in the singular number include the plural number. The word "shall" is always mandatory and not merely directory.

(1) "City" means the City of Beaverton, Oregon, a municipal corporation, and all of the territory within its corporate boundaries, as such may change from time to time.

(2) "City Council" means the Council of the City.

(3) "City Engineer" means the City Engineer of the City.

(4) "City Recorder" means the Recorder of the City.

(5) "Director of Finance" means the Director of Finance of the City.

(6) "Franchise" means this Franchise Agreement as fully executed by the City and Grantee and adopted by the City Council by Resolution.

(7) "Grantee" means Portland General Electric Company, an Oregon corporation.

(8) "Grantee Facility" means any tangible component of Grantee's Electric Light and Power System, including but not limited to any poles, guy wires, anchors, wire, fixtures, equipment, conduit, circuits, vaults, switch cabinets, transformers, secondary junction cabinets, antennas, communication equipment and other property necessary or convenient to supply electric light and power by Grantee within the City.

(9) "Grantee's Electric Light and Power System" means all real property and Grantee Facilities used by Grantee in the transmission and distribution of its services that are located inside the boundaries of the City.

(10) "Gross Revenues" shall be deemed to include any and all revenues derived by Grantee within the City from Grantee's Electric Light and Power System, and includes, but is not limited to, the sale of and use of electricity and electric service, and the use, rental, or lease of Grantee Facilities, after adjustment for the net write-off of uncollectible accounts. Gross Revenues do not include proceeds from the sale of bonds, mortgages or other evidence of indebtedness, securities or stocks, or sales at wholesale by one public utility to another of electrical energy when the utility purchasing such electrical energy is not the ultimate consumer. Gross Revenues also do not include revenue from joint pole use. For purposes of this Franchise, revenue from joint pole use includes any revenue collected by Grantee from other franchisees, permittees, or licensees of the City for the right to attach wires, cable or other facilities or equipment to Grantee's poles or place them in Grantee's conduits.

(11) "Mayor" means the Mayor of the City.

(12) "NESC" means the National Electrical Safety Code.

(13) "OPUC" means the Oregon Public Utility Commission.

(14) "Person" means any individual, sole proprietorship, partnership, association, corporation, cooperative, People's Utility District, or other form of organization authorized to do business in the State of Oregon, and includes any natural person.

(15) "Public ROW" shall have the meaning described in Section 1.1(A).

(16) "PUE" shall have the meaning described in Section 1.1(A).

(17 "Term" shall have the meaning described in Section 2(A).

(18) Year," "annual," or "annually" means the period consisting of a full calendar year, beginning January 1 and ending December 31, unless otherwise provided in this Franchise.

SECTION 4. CONSTRUCTION

(A) Construction. Subject to the NESC, Grantee's Electric Light and Power System shall be constructed and maintained in such manner as not to interfere with sewers, water pipes, or any other property of the City, or with any other pipes, wires, conduits or other facilities that may have been laid in the Public ROW by or under the City's authority. Grantee and the City shall work together during any design process affecting the Public ROW to establish suitable locations for Grantee's Facilities. Assuming there is sufficient space in the Public ROW, all poles shall be placed between the sidewalk and the edge of the Public ROW unless another location is approved by the City Engineer. If there is not sufficient space in the Public ROW, the City agrees to provide a suitable alternative location that meets Grantee's engineering standards, the NESC and generally applicable standards published by the City in order for Grantee to maintain sufficient service.

(B) Acquisition. Subsequent to the effective date of this Franchise, upon Grantee's acquisition of additional Grantee Facilities in the Public ROW, or upon any addition or annexation to the City of any area in which Grantee retains Grantee Facilities in the Public ROW of such addition or annexation, Grantee shall submit to the City a statement describing all Grantee Facilities involved, whether authorized by a franchise agreement or upon any other form of prior right, together with a map, as described in Section 5, specifying the location of all such Grantee Facilities. Such Grantee Facilities shall immediately be subject to the terms of this Franchise.

(C) Emergency Repairs. In the event emergency repairs to Grantee Facilities are necessary, Grantee shall as soon as reasonably possible notify the City of the need for such repairs. Grantee may immediately initiate such emergency repairs and apply for appropriate permits the next business day or as soon as reasonably possible following discovery of the emergency.

(D) Reasonable Care. All work completed by Grantee within the Public ROW shall be conducted with reasonable care and with the goal of minimizing the risk to those using the Public ROW and to minimize the risk of damage to public and third party property. All work shall be performed in accordance with all applicable laws and regulations, including but not limited to the NESC, the conditions contained in the City permit for the work, and generally applicable standards published by the City. Any work completed by Grantee within the Public ROW may be inspected by the City to determine whether it complies with Grantee's permit issued by the City. If emergency work has been completed by Grantee in the Public ROW and the City determines such work was not completed in a City approved location in accordance with the applicable City permit, the City shall notify Grantee and provide Grantee with sixty (60) days after the emergency has passed to re-perform the work in a City approved location in accordance with the applicable City permit, subject to the NESC.

SECTION 5. **SUPPLYING MAPS.**

Grantee shall maintain maps and data pertaining to the location of Grantee Facilities on file at its corporate offices or at an office in Oregon. After providing Grantee with twenty-four (24) hours prior notice, the City may inspect the maps (excluding Grantee proprietary information) at any time during Grantee's business hours. Upon request of the City and without charge, Grantee shall furnish current maps to the City by electronic data in read-only format showing the general location of Grantee Facilities, excluding Grantee proprietary information. Unless required by law, the City will not sell or provide Grantee prepared maps or data to third parties without written permission from Grantee. Upon request of Grantee, the City will make available to Grantee any relevant City prepared maps or data at no charge to Grantee.

SECTION 6. **EXCAVATION.** Subject to Sections 4 and 7, and after obtaining any permits required by the City, Grantee may make all necessary excavations within the Public ROW for the purpose of installing, repairing, upgrading or maintaining Grantee Facilities. The City shall inform the Grantee through the permitting process or earlier, if possible, of any limitations enacted by the City on excavation in particular geographic areas within the City. Notwithstanding the foregoing two sentences, in the case of an emergency that cannot reasonably be addressed without excavation in the Public ROW, no permit shall be required prior to excavation and no limitations on excavation in particular geographic areas within the City shall apply for the Public ROW affected by such emergency; provided, Grantee complies with Sections 4 and 7. Should there be a direct conflict between any terms or conditions stated in a permit granted by the City and the terms of this Franchise, the terms of this Franchise shall control. All excavations made by Grantee in the Public ROW shall be properly safeguarded for the prevention of accidents. All of Grantee's work under this Section shall be completed in strict compliance with all applicable rules, regulations and ordinances of the City. Should a customer of Grantee be required, pursuant to Grantee's tariff on file with the OPUC, to make excavations that are located in the Public ROW, the City agrees that Grantee shall not be responsible or liable for any failure by such customer to comply with any applicable rules, regulations, ordinances of the City and/or with City standards.

SECTION 7. RESTORATION AFTER EXCAVATION.

Except as otherwise provided for in this Section, Grantee shall restore the surface of the Public ROW disturbed by any excavation by Grantee to at least the same condition that it was in prior to excavation, but in any event to the generally applicable City standards published at the time. If Grantee excavates the surface of the Public ROW, Grantee shall be responsible for restoration of the Public ROW and the area affected by the excavation. If

Grantee fails to restore the Public ROW to at least the same condition that it was in prior to the excavation, the City shall give Grantee written notice and provide Grantee a reasonable period of time, not to exceed thirty (30) days, to restore the Public ROW. If the work of Grantee creates a public safety hazard as determined by the City Engineer, Grantee may be required to repair or restore the Public ROW within twenty-four (24) hours notice from the City, or such time as agreed between the City Engineer and Grantee, taking into consideration weather and other relevant factors. Should Grantee fail to make such repairs or restorations within the aforementioned time frames, the City may, after providing notice to Grantee and a reasonable opportunity to cure, refill or repave any opening made by Grantee in the Public ROW and the expense thereof shall be paid by Grantee. The City reserves the right, after providing notice to Grantee, to remove or repair any work completed by Grantee, which, in the determination of the City Engineer is inadequate, using a qualified contractor in accordance with applicable state and federal safety laws and regulations. The cost thereof, including the cost of inspection and supervision, shall be paid by Grantee. In the event that Grantee's work is coordinated with other construction work in the Public ROW, the City Engineer may excuse Grantee from restoring the surface of the Public ROW, providing that as part of the coordinated work, the Public ROW is restored to good order and condition.

SECTION 8. RELOCATION.

(A) Permanent Relocation Required by City – This subsection covers relocation of overhead Grantee Facilities that will remain overhead, and underground Grantee Facilities that will remain underground. Subject to ORS Chapter 758, the City shall have the right to require Grantee to change the location of Grantee's Electric Light and Power System when necessary or convenient in the interest of the public, and, unless otherwise agreed, the expenses thereof shall be paid by Grantee. However, when the City requests a subsequent relocation of all or part of the same Grantee Facilities less than two years after the initial relocation that is necessary or convenient in the interest of the public, and not at the request of or to accommodate a third party, the subsequent relocation shall be at the expense of the City unless the relocation is necessitated by a natural disaster that is not precipitated by the actions of City or City's agent. The City agrees to provide a suitable location in the Public ROW for Grantee Facilities that meets Grantee's engineering standards, the NESC and generally applicable standards published by the City in order for Grantee to maintain sufficient service. If sufficient space is not available in the Public ROW for Grantee Facilities, Grantee and the City shall cooperate to enable the City to obtain sufficient easements from private property owners to accommodate Grantee Facilities in order to maintain service and permit upgrades of Grantee Facilities. Should Grantee fail to remove or relocate any such Grantee Facilities within sixty (60) days after the date established by the City, or a mutually agreed upon time period which, except in the event of public emergency, absent mutual agreement shall not occur sooner than sixty (60) days after the City provides written notice to remove/relocate to Grantee, the City may cause or effect such removal or relocation, performed by a qualified contractor in accordance with applicable state and federal safety laws and regulations and Grantee's standards, and the expense thereof shall be paid by Grantee.

(B) Notice. The City will endeavor to provide as much notice prior to requiring Grantee to relocate Grantee Facilities as possible. The notice shall specify the date by which the existing Grantee Facilities must be removed or relocated. Nothing in this provision shall prevent the City and Grantee from agreeing, either before or after notice is provided, to a schedule for relocation.

(C) Permanent Relocation - Undergrounding. As permitted by, and in accordance with City ordinance and any applicable law, administrative rule, or regulation, the City may require Grantee to convert any overhead Grantee Facilities to underground Grantee Facilities at the same or different locations, subject to Grantee's engineering and safety standards. This subsection shall not apply to Grantee Facilities used for or in connection with the transmission of electric energy at nominal voltages in excess of 35,000 volts or to pedestals, cabinets or other related above-ground equipment, except that Grantee shall convert specific pedestals, cabinets or other related above-ground equipment to underground if the City agrees to pay a "premium charge" that equals the difference between the cost of the standard above-ground equipment and the cost of the version of such equipment that meets Grantee's engineering and safety standards for placement underground . Any such relocation shall be consistent with applicable long-term development plans or projects of the City, or as approved by the City. The expense of such a conversion shall be paid by Grantee, and Grantee may recover its costs from its customers in accordance with state law, administrative rule, or regulation. The

City may designate that Grantee collect such costs from only a portion of its customers within the boundaries of the City in accordance with OAR 860-022-0046(4) as it may be amended from time to time. The City agrees to provide a suitable location in the Public ROW that meets Grantee's engineering standards, the NESC and generally applicable standards published by the City in order for Grantee to maintain sufficient service. If sufficient space is not available in the Public ROW, then the City will obtain sufficient easements from private property owners to accommodate Grantee Facilities in order to maintain service and permit upgrades of Grantee Facilities. Nothing in this subsection prevents the City and Grantee from agreeing to a different form of cost recovery consistent with applicable statutes, administrative rules, City Code or City Charter and Grantee's tariff on file with the OPUC on a case-by-case basis.

(D) Temporary Relocation at Request of Third Parties. Whenever it is necessary to temporarily relocate or rearrange any Grantee Facility in order to permit the passage of any building, machinery or other object, Grantee shall perform the work after receiving sixty (60) business days written notice from the persons desiring to move the building, machinery or other object. The notice shall: (1) demonstrate that the third party has acquired at its expense all necessary permits from the City; (2) detail the route of movement of the building, machinery, or other object; (3) provide that the person requesting the temporary relocation shall be responsible for Grantee's costs; (4) provide that the requestor shall indemnify and hold harmless the City and Grantee from any and all damages or claims resulting either from the moving of the building, machinery or other object or from the temporary relocation of Grantee Facilities; and (5) be accompanied by a cash deposit or other security acceptable to Grantee for the costs of relocation. Grantee in its sole discretion may waive the security obligation. The cash deposit or other security shall be in an amount reasonably calculated by Grantee to cover Grantee's costs of temporary relocation and restoration. All temporary relocations under this subsection shall comply with ORS 757.805.

(E) Temporary Relocation at Request of City. Subject to ORS Chapter 758, the City may require Grantee to temporarily remove and relocate Grantee Facilities, subject to Grantee's engineering and safety standards, by giving sixty (60) days notice to Grantee. Prior to such relocation, the City agrees to provide a suitable location in the Public ROW, as mutually agreed, or a temporary construction easement that meets Grantee's engineering standards, the NESC and generally applicable standards published by the City, and that allows the Grantee to place its Facilities on the easement in order for Grantee to maintain sufficient service until such time as Grantee moves its Facilities to their permanent location. The City will assist Grantee in acquiring easements from private property owners if a sufficient location is not available in the Public ROW that meets Grantee's engineering standards and NESC requirements, or the City has not obtained construction easements for the public project necessitating the temporary relocation. The cost of removal or relocation of Grantee Facilities that is necessary or convenient for public projects shall be paid by Grantee; however, when relocation is to be temporary and both the initial and the subsequent relocation are necessary or convenient for public projects, including but not limited to those involving installation or relocation of essential government owned services, such as sewer, water and storm drainage, and not at the request of or to accommodate a third party, the initial relocation shall be at the expense of Grantee and subsequent relocations occurring less than two years after the initial relocation shall be at the expense of the City unless the relocation is necessitated by a natural disaster that is not precipitated by the actions of City or City's agent.

(F) Permanent Relocation at Request of Third Party. In the event that any relocation is requested by or is to accommodate a third party, Grantee shall seek reimbursement from the third party and not from the City. Such relocation shall be consistent with any applicable long-term development plan or projection of the City or approved by the City; however, if relocation of Grantee Facilities is caused or required by the conditions placed by the City on approval for projects of third parties, such relocation shall in no event fall under the provisions of subsections (A), (C) or (E) of this Section 8. The City and Grantee agree to cooperate to minimize the economic impact of such relocation on each Party.

SECTION 9. PUBLIC ROW VACATION.

If all or a portion of the Public ROW used by Grantee is vacated by the City during the Term, upon request and if reasonably possible, the City shall either condition the approval of the vacation on the reservation of an easement for Grantee Facilities in their then-current location that prohibits any use of the vacated property that interferes with Grantee's full enjoyment and use of its easement, or permit Grantee Facilities to remain in a PUE. Upon request, the City will cooperate with Grantee to identify alternative locations within the Public ROW for Grantee Facilities if they are not permitted to remain in the vacated area.

SECTION 10. CITY PUBLIC WORKS AND IMPROVEMENTS.

Nothing in this Franchise shall be construed in any way to prevent the City from excavating, grading, paving, planking, repairing, widening, altering, or completing any work that may be needed or convenient in the Public ROW that is consistent with the NESC. The City shall coordinate any such work with Grantee to avoid, to the extent reasonably foreseeable, any obstruction, injury or restrictions on the use by Grantee of any Grantee Facilities, and the City shall be responsible for the costs to repair any damage to Grantee Facilities arising out of such work. Nothing in this Section relieves Grantee from its obligations stated in Section 8.

SECTION 11. USE OF GRANTEE FACILITIES.

City shall enter into attachment agreements with Grantee and obtain permits to string wires on Grantee's poles or run wires in Grantee's trenches and/or conduit for municipal purposes and to attach fire and police alarm and communication equipment to Grantee's poles, provided that such wires and equipment: a) do not unreasonably interfere with Grantee operations; b) conform to the NESC; and c) the City's excess capacity on such wires and equipment is not leased to, sold to or otherwise used by non-governmental third parties. Grantee shall not charge the City for such attachments to its poles or in its conduits; however, the City shall be responsible to pay for any make-ready and inspections Grantee must perform in order to provide access to Grantee Facilities for City wires and equipment in accordance with the NESC. Should any of the City's attachments to Grantee Facilities violate the NESC, the City shall work with Grantee to address and correct such violations in an agreed-upon period of time. The City shall indemnify and hold Grantee harmless from loss or damage resulting from the presence of City's wires and equipment on or in Grantee Facilities. For purposes of this Franchise, "make-ready" shall mean engineering or construction activities necessary to make a pole, conduit, or other support equipment available for a new attachment, attachment modifications, or additional facilities.

SECTION 12. PAYMENT FOR USE OF PUBLIC ROW.

(A) Use of Public ROW. In consideration for its use of the Public ROW in accordance with the terms of this Franchise, Grantee agrees to pay the City an amount equal to 3 1/2 percent of the Gross Revenue received by Grantee from its customers within the City unless such percentage is changed during the Term of this Franchise in accordance with its terms. The payment for each year shall be based on the Gross Revenue collected by Grantee during the previous calendar year from Grantee's customers, and shall be paid on an annual basis. To the maximum extent permissible under state law and regulation, the payment imposed by this subsection shall be considered an operating expense of Grantee and shall not be itemized or billed separately to consumers within the City.

(B) Property Tax Limitations Do Not Apply. The payment described in this Section 12 is not subject to the property tax limitations of Article XI, Sections 11(b) and 11(19) of the Oregon Constitution and is not a fee imposed on property or property owners by fact of ownership.

(C) Privilege Tax. The City shall retain the right, as permitted by Oregon law, to charge a privilege tax based on a percentage of the Gross Revenue earned from Grantee's customers within the City in addition to the payment amounts set forth in subsection (A). The City shall provide Grantee at least ninety (90) days notice prior to such privilege tax becoming effective. Grantee shall follow state regulations regarding the inclusion of such privilege tax as an itemized charge on the electricity bills of its customers within the City. No later than forty-five (45) days following a calendar quarter, Grantee shall remit to the Director of Finance any privilege tax collected during the previous quarter and a statement showing the amount of Gross Revenues for such quarter.

(D) Remittance of Annual Payment. Grantee shall remit to the Director of Finance on or before the first (1st) day of April of each year, the annual franchise fee payment. Payment must be made in immediately available federal funds. With its annual payment, Grantee shall provide the City a statement under oath showing the Gross Revenue for the preceding year.

(E) Acceptance of Payment. Acceptance by the City of any payment due under this Section shall not be a waiver by the City of any breach of this Franchise occurring prior to the acceptance, nor shall the acceptance by the City preclude the City from later establishing that a larger amount was actually due, or from collecting the balance due to the City.

(F) Late Payments. Interest on late payments shall accrue from the due date based on Grantee's cost of debt as approved by the OPUC as of the due date, and shall be computed based on the actual number of days elapsed from the due date until payment. Interest shall accrue without regard to whether the City has provided notice of delinquency. If the late payment is discovered as a result of an audit, Section 13 shall apply.

(G) No Exemption From Other Fees or Taxes. Payment of the amounts described in this Section 12 shall not exempt Grantee from the payment of any other license fee, tax or charge on the business, occupation, property or income of Grantee that may be lawfully imposed by the City or any other taxing authority, including but not limited to charges for plan review and fees for inspection, except as may otherwise be provided in the ordinance or laws imposing such other license fee, tax or charge.

(H) Direct Access and Volumetric Methodologies. The City may, consistent with state law, direct that the payments made under this Section 12 be based on volume-based methodologies as specifically described in ORS 221.655 instead of the formula set out in subsections 12 (A) and (C). Notice must be given to Grantee in writing for the subsequent payments to be made using volume-based methodology. The volumetric calculation shall apply to payments made in one calendar year (based on January 1 to December 31 billings from the previous calendar year). The choice to use volumetric methodology must be renewed annually by the City. No notice is necessary if the City chooses to remain on the revenue-based calculation.

(I) Payment Obligation Survives Franchise. If prior to the expiration of this Franchise the parties do not finish negotiation of a new franchise agreement, the obligation to make the payments imposed by this Section 12 shall survive expiration of this Franchise until a new franchise agreement becomes effective and supersedes this Franchise. In the event this Franchise is terminated before expiration, Grantee shall make the remaining payments owed, if any, within ninety (90) days of the termination date.

SECTION 13. AUDIT.

(A) Audit Notice and Record Access. The City may request a third party audit of Grantee's calculation of Gross Revenues for any time period more recent than the time period covered by the most recent audit . Within ten (10) business days after receiving a written request from the City, or such other time frame as agreed by both parties, Grantee shall furnish the City and any auditor retained by the City: (1) information sufficient to demonstrate that Grantee is in compliance with this Franchise; and (2) access to all books, records, maps and other documents maintained by Grantee with respect to Grantee Facilities that are necessary for the City to perform such audit. Grantee shall provide access to such information to City within the City, or the Portland, Oregon metropolitan area, during regular Grantee business hours.

(B) Audit Payment. If the City's audit shows that the amounts due to the City are higher than those based on the Grantee's calculation of Gross Revenue, then Grantee shall make a payment for the difference within sixty (60) days after the delivery to Grantee of the audit results. In addition to paying any underpayment, Grantee shall pay interest at the statutory rate designated in ORS 82.010 as it may be amended from time to time, but not penalties, as specified in this Franchise, from the original due date. If the City's audit shows that the amounts due to the City are less than those based on Grantee's calculation of Gross Revenue, then the Grantee shall deduct its overpayment from the next franchise fee payment the Grantee makes to the City, including interest at the statutory rate designated in ORS 82.010, as it may be amended from time to time, from the original due date. The City and the Grantee agree that they will split the cost of any third party audit conducted pursuant to this Section 13, and shall cooperate in good faith to select an acceptable third party auditor.

SECTION 14. TERMINATION AND REMEDIES.

(A) By City for Cause. If Grantee ceases to maintain Grantee Facilities in accordance with the maintenance commitments outlined in the Service Quality Measures Review filed with the OPUC, and this causes an increase in the risk to the public of personal injury or property damage, the City shall notify Grantee and Grantee shall have thirty (30) days after the date of the notice to eliminate such risk or, if such risk can not be eliminated within thirty (30) days, such reasonable time period as is required to eliminate such risk and Grantee shall bear all costs related to remedying the risk. If Grantee does not eliminate the risk in accordance with the preceding sentence, the City may then terminate this Franchise by providing Grantee written notice of termination.

(B) By City if City Will Provide Service. The City may terminate this Franchise upon one year's written notice to Grantee in the event that the City decides to engage in public ownership of the electric facilities located in the Public ROW and the public distribution of electric energy to customers throughout the City in accordance with ORS 758.470.

(C) City Reserves Right to Terminate. In addition to any other rights provided for in this Franchise, the City reserves the right, subject to subsections 14 (E) and (F), to terminate this Franchise in the event that:

(1) The Grantee materially violates any material provision of this Franchise;

(2) The Grantee is found by a court of competent jurisdiction to have practiced any material fraud or deceit upon the City;

(3) There is a final determination that Grantee has failed, refused, neglected or is otherwise unable to obtain or maintain Grantee's service territory designation required by any federal or state regulatory body regarding Grantee's operation of Grantee's Electric Light and Power System or

(4) Grantee becomes unable or unwilling to pay its debts, or is adjudged bankrupt.

(D) Material Provisions. For purposes of this Section 14, the following are material provisions of this Franchise, allowing the City to exercise its rights under this Section 14 or as set forth elsewhere in this Franchise:

(1) The invalidation, failure to pay or any suspension of Grantee's payments of franchise fees or privilege taxes to the City for use of the Public ROW under this Franchise;

(2) Any failure by Grantee to submit timely reports as may be requested by the City, regarding the calculation of its franchise fees or privilege taxes paid or to be paid to the City;

(3) Any failure by Grantee to maintain the liability insurance or self insurance required under this Franchise;

(4) Any failure by Grantee to provide copies of requested information as provided under Sections 4, 5, and 13 above; and

(5) Any failure by Grantee to otherwise substantially comply with the requirements of Section 4 through Section 20 of this Franchise, unless otherwise agreed.

(E) Notice and Opportunity to Cure. The City shall provide Grantee thirty (30) days prior written notice of its intent to exercise its rights under this Section 14, stating the reasons for such action. If Grantee cures the basis for termination or if the Grantee initiates efforts satisfactory to the City to remedy the basis for termination and the efforts continue in good faith within the thirty (30) day notice period, the City shall not exercise its remedy rights. If Grantee fails to cure the basis for termination or if the Grantee does not undertake and/or maintain efforts satisfactory to the City to remedy the basis for termination within the thirty (30) day notice period, then the City Council may impose any or all of the remedies available under this Section 14.

(F) Remedies. In determining which remedy or remedies are appropriate, the City shall consider the nature of the violation, the person or persons burdened by the violation, the nature of the remedy required in order to prevent further such violations, and any other matters the City deems appropriate.

(G) Financial Penalty. In addition to any rights set out elsewhere in this Franchise, as well as its rights under the City Code or other law, the City reserves the right at its sole option to impose a financial penalty of up to $500.00 per day per material violation of a material provision of this Franchise when the opportunity to cure has passed.

SECTION 15. ASSIGNMENT OF FRANCHISE.

Grantee shall not sell, assign, transfer, or convey this Franchise to a third party without the City Council giving its consent in a duly passed resolution. Upon obtaining such consent, this Franchise shall inure to and bind such third party. Grantee shall not sell or assign this Franchise to an entity that is not authorized by the OPUC to provide electric service to retail consumers in the City or is not otherwise authorized to provide electric service to retail consumers under Oregon law. Prior to any proposed transfer, Grantee shall be in full compliance with this Franchise and the proposed transferee shall agree in writing to be bound by this Franchise. In the event Grantee is purchased by or merged into another entity and Grantee survives such purchase or merger as a public utility, Grantee shall provide notice to the City of such purchase or merger, but shall have no obligation under this Franchise to obtain the consent of the City Council for such purchase or merger.

SECTION 16. REMOVAL OF FACILITIES.

If this Franchise is terminated or expires on its own terms and is not replaced by a new franchise agreement or similar authorization, the City may determine whether Grantee Facilities are to be removed from the Public ROW or remain in place. The City shall provide written notice of any requirement to remove Grantee Facilities and shall provide Grantee sixty (60) days to comment on such requirement to move Grantee Facilities. Following consideration of any such comments, the Mayor may issue an order requiring removal of Grantee Facilities within nine (9) months after such order is declared.

SECTION 17. NONDISCRIMINATION.

Grantee shall provide service to electric light and power consumers in the City without undue discrimination or undue preference or disadvantage, in accordance with Oregon law.

SECTION 18. INDEMNIFICATION.

To the fullest extent permitted by law, Grantee shall indemnify and hold harmless the City against any and all claims, damages, costs and expenses, including attorney's fees and costs, to which the City may be subjected as a result of any negligent or willful misconduct of Grantee, or its affiliates, officers, employees, agents, contractors or subcontractors, arising out of the rights and privileges granted by this Franchise. The obligations imposed by this Section are intended to survive termination of this Franchise.

SECTION 19. INSURANCE.

Grantee shall obtain and maintain in full force and effect, for the entire Term, the following insurance covering risks associated with Grantee's ownership and use of Grantee Facilities and the Public ROW:

(A) Commercial General Liability insurance covering all operations by or on behalf of Grantee for Bodily Injury and Property Damage, including Completed Operations and Contractors Liability coverage, in an amount not less than Two Million Dollars ($2,000,000.00) per occurrence and in the aggregate.

(B) Business Automobile Liability insurance to cover any vehicles used in connection with its activities under this Franchise, with a combined single limit not less than One Million Dollars ($1,000,000.00) per accident. **(C)** Workers' Compensation coverage as required by law and Employer's Liability Insurance with limits of $1,000,000. With the exception of Workers' Compensation and Employers Liability coverage, Grantee shall name the City as an additional insured on all applicable policies. All insurance policies shall provide that they shall not be canceled or modified unless thirty (30) days prior written notice is provided to the City. Grantee shall provide the City with a certificate of insurance evidencing such coverage as a condition of this Franchise and shall provide updated certificates upon request.

(D) In Lieu of Insurance. In lieu of the insurance policies required by this Section 19, Grantee shall have the right to self-insure any and all of the coverage outlined hereunder. If Grantee elects to self-insure, it shall do so in an amount at least equal to the coverage requirements of this Section 19 in a form acceptable to the City. Grantee shall provide proof of self-insurance to the City before this Franchise takes effect and thereafter upon request by the City.

SECTION 20. DAMAGE TO FACILITIES.

The City shall not be liable for any consequential damages or losses resulting from any damage to or loss of any facility as a result of or in connection with any work by or for the City unless the damage or loss is the direct and proximate result of willful, intentionally tortious, negligent or malicious acts or omissions by the City, its employees, or agents. In such case, the City shall indemnify and hold harmless Grantee against any and all claims, damages, costs and expenses, including attorney's fees and costs, arising therefrom, subject to any applicable limitations in the Oregon Constitution and the Oregon Tort Claims Act. The obligations imposed by this Section are intended to survive termination of this Franchise.

SECTION 21. LIMITATION ON PRIVILEGES.

All rights and authority granted to Grantee by the City under this Franchise are conditioned on the understanding and agreement that the privileges in the Public ROW shall not be an enhancement of Grantee's properties or an asset or item of ownership or property right of Grantee.

SECTION 22. FRANCHISE NOT EXCLUSIVE.

This Franchise is not exclusive and shall not be construed to limit the City from granting rights, privileges and authority to other persons similar to or different from those set forth in this Franchise.

SECTION 23. REMEDIES AND PENALTIES NOT EXCLUSIVE.

All remedies and penalties under this Franchise, including termination, are cumulative and not exclusive, and the recovery or enforcement by one available remedy or imposition of a penalty is not a bar to recovery or enforcement by any other remedy or imposition of any other penalty. The City reserves the right to enforce the penal provisions of any City ordinance or resolution and to avail itself to any and all remedies available at law or in equity. Failure to enforce any term, condition or obligation of this Franchise shall not be construed as a waiver of a breach of any term, condition or obligation of this Franchise. A specific waiver of a particular breach of any term, condition or obligation of this Franchise shall not be a waiver of any other, subsequent or future breach of the same or any other term, condition or obligation of this Franchise.

SECTION 24. SEVERABILITY CLAUSE.

If any section, subsection, sentence, clause, phrase, or other portion of this Franchise is, for any reason, held to be invalid or unconstitutional by a court of competent jurisdiction, all portions of this Franchise that are not held to be invalid or unconstitutional shall remain in effect until this Franchise is terminated or expired. After any declaration of invalidity or unconstitutionality of a portion of this Franchise, either party may demand that the other party meet to discuss amending the terms of this Franchise to conform to the original intent of the parties. If the parties are unable to agree on a revised franchise agreement within ninety (90) days after a portion of this Franchise is found to be invalid or unconstitutional, either party may terminate this Franchise by delivering one hundred and eighty (180) days notice to the other party.

SECTION 25. ACCEPTANCE.

Within thirty (30) days after the ordinance adopting this Franchise is passed by the City Council, Grantee shall file with the City Recorder its written unconditional acceptance of this Franchise. If Grantee fails to do so, the City may withdraw this Franchise at any time prior to January 1, 2010. If the City elects not to withdraw this Franchise on or before January 1, 2010, the Grantee shall be deemed to accept the terms of this Franchise, whether or not a written acceptance has been filed with the City.

SECTION 26. NOTICE.

Any notice provided for under this Franchise shall be sufficient if in writing and (1) delivered personally to the following addressee, (2) deposited in the United States mail, postage prepaid, certified mail, return receipt requested, (3) sent by overnight or commercial air courier (such as Federal Express or UPS), or (4) sent by facsimile transmission with verification of receipt and a copy deposited in the United States mail, addressed as follows, or to such other address as the receiving party hereafter shall specify in writing:

If to the City: Mayor, City of Beaverton
PO Box 4755
Beaverton, OR 97076-4755

FAX # (503) 526-2479

With a copy to: City Attorney

City of Beaverton

PO Box 4755

Beaverton, OR 97076

FAX # (503) 350-4033

If to the Grantee: Regional Manager

Portland General Electric Company

2213 SW 153rd Drive

Beaverton, OR 97006

FAX: (503) 672-5595

With a copy to: Portland General Electric Company

Attn: General Counsel

One World Trade Center, 17th Floor

121 SW Salmon Street

Portland, Oregon 97204

FAX: (503) 464-2200

Any such notice, communication or delivery shall be deemed effective and delivered upon the earliest to occur of actual delivery, three (3) business days after depositing in the United States mail, one (1) business day after shipment by commercial air courier or the same day as confirmed facsimile transmission (or the first business day thereafter if faxed on a Saturday, Sunday or legal holiday).

IN WITNESS WHEREOF, the parties, through their duly authorized representatives, have executed this Franchise as of the dates indicated below.

PORTLAND GENERAL ELECTRIC COMPANY CU	CITY OF BEAVERTON
By: Stephen R Hawke	By: Denny Doyle

Name: Stephen R. Hawko
Title: Senior VP, Customer Svc. & Delivery
Date: 12/15/2009

Name: Denny Doyle
Title: Mayor
Date: 12/3/09

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/404

COMPARISON OF ALLOCATION OF FRANCHISE FEES

June 15, 2015

UE 294

Comparison of Allocation of Franchise Fees
($ x 1,000)

Line No	Customer Class	PGE's Proposed Allocation (1)	ICNU's Recommended Allocation (2)	Difference
1	Schedule 7	$ 23,760	$ 28,101	$ 4,341
2	Schedule 15	91	182	91
3	Schedule 32	4,566	5,264	698
4	Schedule 38	140	215	75
5	Schedule 47	140	267	127
6	Schedule 49	363	649	286
7	Schedule 83-S	6,373	5,143	(1,229)
8	Schedule 85 201-4,000 kW	6,755	4,614	(2,142)
9	Schedule 89 GT 4 MW	1,873	971	(902)
10	Schedule 90-P	2,382	748	(1,633)
11	Schedules 91/95	341	630	289
12	Schedule 92	7	5	(1)
13	TOTALS	46,791	46,791	-

Sources:

(1) Exhibit PGE / 1404, Page 8

(2) Exhibit ICNU / 405, Page 6

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/405

SUMMARY OF ICNU RATE SPREAD MODEL

June 15, 2015

UE 294

SUMMARY OF ICNU RATE SPREAD MODEL

Line No.	Customer Class	Allocated Cost of Service Before Carty	Allocated Carty Revenue Requirement	Total Cost of Service with Carty
1	Schedule 7	$ 950,285	$ 38,748	$ 989,032
2	Schedule 15	3,676	64	3,740
3	Schedule 32	180,590	7,477	188,068
4	Schedule 38	5,548	201	5,750
5	Schedule 47	5,721	97	5,818
6	Schedule 49	14,806	323	15,129
7	Schedule 83	248,970	12,733	261,703
8	Schedule 85	253,607	13,992	267,599
9	Schedule 89 GT 4 MW	63,326	3,771	67,096
10	Schedule 90	88,200	5,873	94,073
11	Schedule 91/95	13,642	293	13,935
12	Schedule 92	251	13	264
13	**Total**	**$ 1,828,622**	**$ 83,585**	**$ 1,912,207**

PORTLAND GENERAL ELECTRIC
ALLOCATION OF GENERATION REVENUE REQUIREMENT TO COS CUSTOMERS
2016

Schedules	COS Calendar Energy	Marginal Energy Costs ($000)	Generation Capacity Allocation	Marginal Capacity Costs ($000)	Marginal Capacity & Energy Costs ($000)	Capacity & Energy Allocation Percent	Allocated Capacity & Energy Costs ($000)	Cycle Basis Costs ($000)
Schedule 7	7,619,638	$336,729	50.73%	$277,868	$614,597	46.26%	$515,295	$515,374
Schedule 15	16,308	$664	0.06%	$353	$1,017	0.08%	$853	$853
Schedule 32	1,602,033	$70,370	8.77%	$48,035	$118,406	8.91%	$99,275	$99,145
Schedule 38	39,222	$1,764	0.16%	$892	$2,656	0.20%	$2,227	$2,216
Schedule 47	20,716	$935	0.17%	$944	$1,879	0.14%	$1,576	$1,585
Schedule 49	62,812	$2,739	0.54%	$2,961	$5,700	0.43%	$4,779	$4,769
Schedule 83	2,800,415	$122,673	14.56%	$79,763	$202,436	15.24%	$169,728	$169,410
Schedule 85	2,261,238	$99,235	11.05%	$60,505	$159,741	12.02%	$133,931	$132,820
Schedule 85 1-4 MW	914,212	$39,618	4.12%	$22,563	$62,181	4.68%	$52,134	$53,333
Schedule 89 GT 4 MW	932,806	$39,494	3.70%	$20,245	$59,738	4.50%	$50,086	$50,174
Schedule 90	1,503,848	$63,583	5.82%	$31,894	$95,477	7.19%	$80,051	$79,740
Schedule 91/95	74,544	$3,034	0.29%	$1,616	$4,650	0.35%	$3,898	$3,898
Schedule 92	3,243	$139	0.01%	$65	$204	0.02%	$171	$171
TOTAL	17,851,036	$780,977	100.0%	$547,704	$1,328,682	100.00%	$1,114,003	$1,113,490
Simple Cycle Proxy Plant $/kW				$163.17		**TARGET**	**$1,114,003**	
Projected Peak Load				3,357				
Marginal Capacity Costs ($000)				$547,704				

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT
2016

Schedules	Transmission Allocation Percent	Class Revenue Requirement
Schedule 7	48.53%	$16,232
Schedule 15	0.05%	$16
Schedule 32	8.70%	$2,910
Schedule 38	0.18%	$62
Schedule 47	0.12%	$40
Schedule 49	0.36%	$122
Schedule 83	15.21%	$5,087
Schedule 85	11.80%	$3,945
Schedule 85 1-4 MW	4.45%	$1,487
Schedule 89 GT 4 MW	4.05%	$1,353
Schedule 90-P	6.32%	$2,112
Schedules 91/95	0.22%	$73
Schedule 92	0.01%	$4
Target	100.00%	$33,444

PORTLAND GENERAL ELECTRIC
ALLOCATION OF ANCILLARY SERVICE REVENUE REQUIREMENT
2016

Schedules	Production Allocation Percent	Class Revenue Requirement
Schedule 7	46.26%	$2,289
Schedule 15	0.08%	$4
Schedule 32	8.91%	$441
Schedule 38	0.20%	$10
Schedule 47	0.14%	$7
Schedule 49	0.43%	$21
Schedule 83	15.24%	$754
Schedule 85	12.02%	$595
Schedule 85 1-4 MW	4.68%	$232
Schedule 89 GT 4 MW	4.50%	$222
Schedule 90-P	7.19%	$356
Schedules 91/95	0.35%	$17
Schedule 92	0.02%	$1
TOTAL	100.00%	$4,948
	TARGET	$4,948

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TROJAN DECOMMISSIONING COSTS
2016

Schedules	Cycle Generation Revenues	Allocation Percent	Class Revenue Requirement
Schedule 7	$516,292,637	43.00%	$1,504
Schedule 15	$854,050	0.07%	$2
Schedule 32	$99,628,906	8.30%	$290
Schedule 38	$2,684,403	0.22%	$8
Schedule 47	$1,298,009	0.11%	$4
Schedule 49	$4,310,331	0.36%	$13
Schedule 83	$169,656,301	14.13%	$494
Schedule 85-S	$141,264,182	11.76%	$412
Schedule 85-S 1-4 MW	$29,836,297	2.48%	$87
Schedule 89-S GT 4 MW	$798,911	0.07%	$2
Schedule 85-P	$17,621,400	1.47%	$51
Schedule 85-P 1-4 MW	$39,124,364	3.26%	$114
Schedule 89-P GT 4 MW	$74,432,577	6.20%	$217
Schedule 89-T	$20,630,080	1.72%	$60
Schedule 90-P	$78,257,383	6.52%	$228
Schedule 91/95	$3,903,891	0.33%	$11
Schedule 92	$171,646	0.01%	$1
TOTAL	$1,200,765,367		$3,499
		TARGET	$3,499

PORTLAND GENERAL ELECTRIC
ALLOCATION OF FRANCHISE FEES
2016

Schedules	Distribution Allocations	Transmission Allocations	Generation Allocations	Schedule 129 Allocations	Subtotal Allocations	Distribution Fran. Fee Allocations	Transmission Fran. Fee Allocations	Generation Fran. Fee Allocations	Schedule 129 Fran. Fee Allocations	Total Fran. Fee Allocations
Schedule 7	$388,250	$18,520			$406,771	$26,826	$1,280			$28,106
Schedule 15	$2,621	$20			$2,641	$181	$1			$182
Schedule 32	$72,836	$3,351			$76,187	$5,033	$232			$5,264
Schedule 38	$3,045	$72			$3,117	$210	$5			$215
Schedule 47	$3,821	$47			$3,868	$264	$3			$267
Schedule 49	$9,244	$143			$9,388	$639	$10			$649
Schedule 83-S	$68,591	$5,841			$74,432	$4,739	$404			$5,143
Schedule 85 201-4,000 kW	$60,495	$6,258			$66,754	$4,180	$432			$4,612
Schedule 89 GT 4 MW	$12,456	$1,576			$14,032	$861	$109			$970
Schedule 90-P	$8,345	$2,468			$10,812	$577	$171			$747
Schedules 91/95	$9,025	$90			$9,115	$624	$6			$630
Schedule 92	$70	$5			$75	$5	$0			$5
TOTALS	$638,799	$38,392	$0	$0	$677,191	$44,138	$2,653	$0	$0	$46,791

Franchise Fee Revenue Requirement **$46,791**

Schedules	Distribution MWh	Distribution mills/kWh	Transmission MWh	Transmission mills/kWh	Generation MWh	Generation mills/kWh	Schedule 129 MWh	Schedule 129 mills/kWh	Total COS mills/kWh	Total DA mills/kWh
Schedule 7	7,620,805	3.52	7,620,805	0.17	7,620,805	0.00	0		3.69	
Schedule 15	16,308	11.11	16,308	0.08	16,308	0.00	0		11.19	11.11
Schedule 32	1,599,950	3.15	1,599,950	0.14	1,599,950	0.00	0		3.29	3.15
Schedule 38	39,036	5.39	39,036	0.13	39,036	0.00	0		5.52	5.39
Schedule 47	20,845	12.66	20,845	0.16	20,845	0.00	0		12.82	
Schedule 49	62,677	10.19	62,677	0.16	62,677	0.00	0		10.35	10.19
Schedule 83-S	2,795,179	1.70	2,795,179	0.14	2,795,179	0.00	0		1.84	1.70
Schedule 85-S 201-4,000 kW	2,902,903	1.08	2,464,564	0.14	2,464,564	0.00	438,339	0.00	1.22	1.08
Schedule 89-S GT 4 MW	14,393	0.49	0	0.12	0	0.00	14,393	0.00	0.61	0.49
Schedule 85-P 201-4,000 kW	986,738	1.06	713,162	0.13	713,162	0.00	273,576	0.00	1.19	1.06
Schedule 89-P GT 4 MW	1,384,519	0.48	851,370	0.12	851,370	0.00	533,149	0.00	0.60	0.48
Schedule 89-T	389,052	0.48	83,072	0.12	83,072	0.00	305,980	0.00	0.59	0.48
Schedule 90-P	1,498,007	0.38	1,498,007	0.11	1,498,007	0.00			0.50	0.38
Schedule 91/95	74,544	8.36	74,544	0.08	74,544	0.00	0		8.45	8.36
Schedule 92	3,243	1.48	3,243	0.11	3,243	0.00	0		1.60	1.48
TOTALS	19,408,200		17,842,764		17,842,764		1,565,436			

Revenues

Schedules	MWh	Fran. Fee mills/kWh	Fran. Fee Revenues
Schedule 7	7,620,805	3.69	$28,106
Schedule 15	16,308	11.19	$182
Schedule 32	1,599,950	3.29	$5,264
Schedule 38	39,036	5.52	$215
Schedule 47	20,845	12.82	$267
Schedule 49	62,677	10.35	$649
Schedule 83-S	2,795,179	1.84	$5,143
Schedule 85-S 201-4,000 kW	2,464,564	1.22	$2,998
Schedule 485-S 201-4,000 kW	438,339	1.08	$473
Schedule 89-S GT 4 MW	0	0.61	$0
Schedule 489-S GT 4 MW	14,393	0.49	$7
Schedule 85-P 201-4,000 kW	713,162	1.19	$851
Schedule 485-P 201-4,000 kW	273,576	1.06	$290
Schedule 89-P GT 4 MW	851,370	0.60	$510
Schedule 489-P GT 4 MW	533,149	0.48	$257
Schedule 89-T	83,072	0.59	$49
Schedule 489-T	305,980	0.48	$146
Schedule 90-P	1,498,007	0.50	$747
Schedule 91/95	74,544	8.45	$630
Schedule 92	3,243	1.60	$5
TOTALS	19,408,200		$46,791

PORTLAND GENERAL ELECTRIC
ALLOCATION OF SCHEDULE 129 TRANSITION ADJUSTMENT
2016

Schedules	Cycle Energy	Percent	Allocations ($000)
Schedule 85-S	2,395,416	33.4%	($2,352)
Schedule 85-S 1-4 MW	507,487	7.1%	($498)
Schedule 89-S GT 4 MW	14,393	0.2%	($14)
Schedule 85-P	305,855	4.3%	($300)
Schedule 85-P 1-4 MW	680,883	9.5%	($669)
Schedule 89-P GT 4 MW	1,384,519	19.3%	($1,359)
Schedule 90-P	1,498,007	20.9%	($1,471)
Schedule 89-T	389,052	5.4%	($382)
TOTAL	7,175,612	100.00%	($7,046)
		TARGET	($7,046)

ALLOCATION OF TRANSITION ADJUSTMENT FOR POST 2013 VINTAGE CUSTOMERS

Schedules	Cycle Energy	Percent	Allocations ($000)
Schedule 7	7,620,805	39.3%	($708)
Schedule 15	16,308	0.1%	($2)
Schedule 32	1,599,950	8.2%	($149)
Schedule 38	39,036	0.2%	($4)
Schedule 47	20,845	0.1%	($2)
Schedule 49	62,677	0.3%	($6)
Schedule 83	2,795,179	14.4%	($260)
Schedule 85-S	2,395,416	12.3%	($223)
Schedule 85-S 1-4 MW	507,487	2.6%	($47)
Schedule 89-S GT 4 MW	14,393	0.1%	($1)
Schedule 85-P	305,855	1.6%	($28)
Schedule 85-P 1-4 MW	680,883	3.5%	($63)
Schedule 89 GT 4 MW	1,384,519	7.1%	($129)
Schedule 89-T	389,052	2.0%	($36)
Schedule 90-P	1,498,007	7.7%	($139)
Schedules 91/95	74,544	0.4%	($7)
Schedule 92	3,243	0.0%	($0)
TOTAL	19,408,200	100.00%	($1,804)
		TARGET	($1,804)

Note: does not include partial requirements customers

PORTLAND GENERAL ELECTRIC
ALLOCATION OF UNCOLLECTIBLES
2016

Grouping	Marginal Cost Allocation Percent	Class Revenue Requirement
Schedule 7		
Single Phase	93.32%	$7,371
Three Phase	0.02%	$1
Schedule 15		
Residential	0.30%	$24
Commercial	0.47%	$37
Schedule 32		
Single Phase	2.53%	$200
Three Phase	1.64%	$130
Schedule 38		
Single Phase	0.00%	$0
Three Phase	0.00%	$0
Schedule 47		
Single Phase	0.00%	$0
Three Phase	0.03%	$3
Schedule 49		
Single Phase	0.00%	$0
Three Phase	0.05%	$4
Schedule 83		
Single Phase	0.05%	$4
Three Phase	0.83%	$66
Schedule 85		
Secondary	0.61%	$48
Primary	0.07%	$6
Schedule 85 1-4 MW		
Secondary	0.04%	$3
Primary	0.04%	$3
Schedule 89 GT 4 MW		
Secondary	0.00%	$0
Primary	0.00%	$0
Subtransmission	0.00%	$0
Schedule 90-P	0.00%	$0
Schedules 91/95	0.00%	$0
Schedule 92	0.00%	$0
TOTAL	100.00%	$7,899
	TARGET	$7,899

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2016

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7 Residential							
CUSTOMER	Meters						
		Single-Phase Customers	748,270	Customers	$20.22	$15,130	$19,930
		Three-Phase Customers	143	Customers	$57.47	$8	$11
	Service Design & Transformer						
		Single-Phase Customers	748,270	Customers	$73.98	$55,357	$72,919
		Three-Phase Customers	143	Customers	$130.73	$19	$25
FACILITIES	Feeder Backbone						
		Single-Phase Customers	1,996,443	kW, rateclass peak	$23.97	$47,855	$63,037
		Three-Phase Customers	382	kW, rateclass peak	$23.97	$9	$12
	Feeder Local Facilities						
		Single-Phase Customers	2,993,080	Design Demand	$16.18	$48,428	$63,792
		Three-Phase Customers	573	Design Demand	$16.18	$9	$12
DEMAND	Subtransmission		2,025,779	kW, rateclass peak	$12.38	$25,079	$33,036
	Substation		1,996,825	kW, rateclass peak	$11.39	$22,744	$29,960
SUBTOTAL						$214,638	$282,734
Schedule 15 Residential Outdoor Area Lighting							
CUSTOMER	Customer Service		9,464	Lights	$3.88	$37	$48
	Service Design & Transformer		9,464	Lights	$5.44	$51	$68
FACILITIES	Feeder Backbone		952	kW, rateclass peak	$24.76	$24	$31
	Feeder Local Facilities		952	Design Demand	$16.86	$16	$21
DEMAND	Subtransmission		965	kW, rateclass peak	$12.38	$12	$16
	Substation		952	kW, rateclass peak	$11.39	$11	$14
FIXED	Luminaires & Poles						$390
SUBTOTAL						$151	$589
Schedule 15 Commercial Outdoor Area Lighting							
CUSTOMER	Customer Service		11,053	Lights	$3.88	$43	$57
	Service Design & Transformer		11,053	Lights	$5.44	$60	$79
FACILITIES	Feeeder Backbone		3,206	kW, rateclass peak	$24.76	$79	$105
	Feeder Local Facilities		3,206	Design Demand	$16.86	$54	$71
DEMAND	Subtransmission		3,253	kW, rateclass peak	$12.38	$40	$53
	Substation		3,206	kW, rateclass peak	$11.39	$37	$48
FIXED	Luminaires & Poles						$1,316
SUBTOTAL						$313	$1,729
Schedule 15 Outdoor Area Lighting							
CUSTOMER	Customer Service						$105
	Service Design & Transformer						$147
FACILITIES	Feeeder Backbone						$136
	Feeder Local Facilities						$92
DEMAND	Subtransmission						$69
	Substation						$62
FIXED	Luminaires & Poles						$1,706
SUBTOTAL							$2,317

Schedule 32 Small Non-residential General Service							
CUSTOMER	Meters						
		Single-Phase Customers	54,838	Customers	$18.32	$1,005	$1,323
		Three-Phase Customers	35,546	Customers	$70.94	$2,522	$3,322
	Service Design & Transformer						
		Single-Phase Customers	54,838	Customers	$105.18	$5,768	$7,598
		Three-Phase Customers	35,546	Customers	$224.71	$7,988	$10,522
FACILITIES	Feeder Backbone						
		Single-Phase Customers	129,376	kW, rateclass peak	$27.91	$3,611	$4,756
		Three-Phase Customers	197,185	kW, rateclass peak	$27.91	$5,503	$7,249
	Feeder Local Facilities						
		Single-Phase Customers	274,188	Design Demand	$23.61	$6,474	$8,527
		Three-Phase Customers	408,783	Design Demand	$9.43	$3,855	$5,078
DEMAND	Subtransmission		331,297	kW, rateclass peak	$12.38	$4,101	$5,403
	Substation		326,561	kW, rateclass peak	$11.39	$3,720	$4,900
SUBTOTAL						$44,545	$58,678
Schedule 38 General Service							
CUSTOMER	Meters						
		Single-Phase Customers	66	Customers	$52.41	$3	$5
		Three-Phase Customers	482	Customers	$125.41	$60	$80
	Service Design & Transformer						
		Single-Phase Customers	66	Customers	$149.42	$10	$13
		Three-Phase Customers	482	Customers	$507.27	$245	$322
FACILITIES	Feeder Backbone						
		Single-Phase Customers	653	kW, rateclass peak	$34.05	$22	$29
		Three-Phase Customers	16,196	kW, rateclass peak	$34.05	$551	$726
	Feeder Local Facilities						
		Single-Phase Customers	2,303	Design Demand	$19.37	$45	$59
		Three-Phase Customers	44,496	Design Demand	$13.45	$598	$788
DEMAND	Subtransmission		17,094	kW, rateclass peak	$12.38	$212	$279
	Substation		16,849	kW, rateclass peak	$11.39	$192	$253
SUBTOTAL						$1,939	$2,554
Schedule 47 Irrigation & Drainage Service - < 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	231	Customers	$57.42	$13	$17
		Three-Phase Customers	2,921	Customers	$81.34	$238	$313
	Service Design & Transformer						
		Single-Phase Customers	231	Customers	$10.05	$2	$3
		Three-Phase Customers	2,921	Customers	$19.03	$56	$73
FACILITIES	Feeder Backbone						
		Single-Phase Customers	557	kW, rateclass peak	$73.00	$41	$54
		Three-Phase Customers	13,325	kW, rateclass peak	$73.00	$973	$1,281
	Feeder Local Facilities						
		Single-Phase Customers	2,310	Design Demand	$49.64	$115	$151
		Three-Phase Customers	29,210	Design Demand	$25.88	$756	$996
DEMAND	Subtransmission		14,083	kW, rateclass peak	$12.38	$174	$230
	Substation		13,882	kW, rateclass peak	$11.39	$158	$208
SUBTOTAL						$2,525	$3,326

Schedule 49 Irrigation & Drainage Service - > 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	3	Customers	$59.88	$0	$0
		Three-Phase Customers	1,346	Customers	$69.56	$94	$123
	Service Design & Transformer						
		Single-Phase Customers	3	Customers	$130.10	$0	$1
		Three-Phase Customers	1,346	Customers	$130.10	$175	$231
FACILITIES	Feeder Backbone						
		Single-Phase Customers	94	kW, rateclass peak	$76.09	$7	$9
		Three-Phase Customers	41,996	kW, rateclass peak	$76.09	$3,196	$4,209
	Feeder Local Facilities						
		Single-Phase Customers	188	Design Demand	$32.76	$6	$8
		Three-Phase Customers	84,394	Design Demand	$26.05	$2,198	$2,896
DEMAND	Subtransmission		42,701	kW, rateclass peak	$12.38	$529	$696
	Substation		42,090	kW, rateclass peak	$11.39	$479	$632
SUBTOTAL						$6,685	$8,805
Schedule 83 General Service (31-200 kW)							
CUSTOMER	Meters						
		Single-Phase Customers	645	Customers	$52.33	$34	$44
		Three-Phase Customers	10,384	Customers	$124.16	$1,289	$1,698
	Service Design & Transformer						
		Single-Phase Customers	645	Customers	$334.66	$216	$284
		Three-Phase Customers	10,384	Customers	$937.19	$9,732	$12,819
FACILITIES	Feeder Backbone						
		Single-Phase Customers	16,303	kW, rateclass peak	$24.36	$397	$523
		Three-Phase Customers	554,539	kW, rateclass peak	$24.36	$13,509	$17,794
	Feeder Local Facilities						
		Single-Phase Customers	24,633	Design Demand	$19.94	$491	$647
		Three-Phase Customers	836,944	Design Demand	$8.96	$7,499	$9,878
DEMAND	Subtransmission		579,119	kW, rateclass peak	$12.38	$7,169	$9,444
	Substation		570,842	kW, rateclass peak	$11.39	$6,502	$8,565
SUBTOTAL						$46,838	$61,697
Schedule 85 General Service (201-1,000 kW)							
CUSTOMER	Meters						
		Secondary Customers	1,343	Customers	$163.10	$219	$288
		Primary Customers	156	Customers	$1,781.36	$278	$366
	Service Design & Transformer						
		Secondary Customers	1,343	Customers	$1,840.38	$2,471	$3,255
		Primary Customers	156	Customers	$727.30	$114	$150
FACILITIES	Feeder Backbone		519,565	kW, rateclass peak	$20.95	$10,885	$14,338
	Feeder Local Facilities		671,590	Design Demand	$6.84	$4,594	$6,051
DEMAND	Subtransmission		527,099	kW, rateclass peak	$12.38	$6,525	$8,596
	Substation		519,565	kW, rateclass peak	$11.39	$5,918	$7,795
SUBTOTAL						$31,003	$40,840

Schedule 85 General Service (1,001-4,000 kW)						
CUSTOMER	Meters					
	Secondary Meters	79	Customers	$186.22	$15	$19
	Primary Meters	80	Customers	$1,794.23	$144	$189
	Service Design & Transformer					
	Secondary Customers	79	Customers	$4,112.80	$325	$428
	Primary Customers	80	Customers	$864.59	$69	$91
FACILITIES	Feeder Backbone	210,952	kW, rateclass peak	$21.35	$4,504	$5,933
	Feeder Local Facilities	277,074	Design Demand	$4.89	$1,355	$1,785
DEMAND	Subtransmission	214,011	kW, rateclass peak	$12.38	$2,649	$3,490
	Substation	210,952	kW, rateclass peak	$11.39	$2,403	$3,165
SUBTOTAL					$11,463	$15,100
Schedule 89 General Service (4,000 plus kW)						
CUSTOMER	Meters					
	Secondary Meters	1	Customers	$195.47	$0	$0
	Primary Meters	27	Customers	$1,785.30	$48	$63
	Substation Meters	8	Customers	$17,752.55	$142	$187
	Service Design & Transformer					
	Secondary Customers	1	Customers	$13,785.61	$14	$18
	Primary Customers	27	Customers	$2,566.49	$69	$91
FACILITIES	Feeder Backbone					
	Secondary Customers	1	Customers	$85,119.00	$85	$112
	Primary Customers	27	Customers	$85,119.00	$2,298	$3,027
	Subtransmission 115 kV Feeder	8	Customers	$86,451.00	$692	$911
DEMAND	Subtransmission	260,625	kW, rateclass peak	$12.38	$3,227	$4,250
	Substation (Sec. & Prim. Only)	201,536	kW, rateclass peak	$11.39	$2,295	$3,024
SUBTOTAL					$8,870	$11,685
Schedule 90 Primary Voltage Service						
CUSTOMER	Meters					
	Primary Meters	4	Customers	$1,773.01	$7	$9
	Service Design & Transformer					
	Primary Customers	4	Customers	$2,566.49	$10	$14
FACILITIES	Feeder Backbone					
	Primary Customers	4	Customers	$269,070.00	$1,076	$1,418
DEMAND	Subtransmission	208,777	kW, rateclass peak	$12.38	$2,585	$3,405
	Substation (Sec. & Prim. Only)	205,793	kW, rateclass peak	$11.39	$2,344	$3,088
SUBTOTAL					$6,022	$7,933
Schedules 91 & 95 Streetlighting & Highway Lighting						
CUSTOMER	Customer Service	155,359	Lights	$3.88	$604	$795
	Service Design & Transformer	155,359	Lights	$3.28	$510	$671
FACILITIES	Feeder Backbone	19,006	kW, rateclass peak	$24.76	$471	$620
	Feeder Local Facilities	19,006	Design Demand	$16.86	$320	$422
DEMAND	Subtransmission	19,281	kW, rateclass peak	$12.38	$239	$314
	Substation	19,006	kW, rateclass peak	$11.39	$216	$285
FIXED	Luminaires & Poles					**$5,592**
SUBTOTAL					$2,359	$8,700

Schedule 92 Traffic Signals

CUSTOMER	Service Design & Transformer	1,721	Intersections	$8.06	$14	$18
FACILITIES	Feeder Backbone	381	kW, rateclass peak	$24.76	$9	$12
	Feeder Local Facilities	381	Design Demand	$9.16	$3	$5
DEMAND	Subtransmission	387	kW, rateclass peak	$12.38	$5	$6
	Substation	381	kW, rateclass peak	$11.39	$4	$6
SUBTOTAL					$36	$47

Summary

CUSTOMER	Meters	856,573	Customers	$21,249	$27,990
	Service Design & Transformer		Customers	$83,274	$109,693
	Customer Service	175,876	Lights	$683	$900
FACILITIES	Feeder Backbone	3,721,111	kW, rateclass peak	$95,797	$126,189
	Feeder Local Facilities	5,673,311	Design Demand	$76,817	$101,188
DEMAND	Subtransmission	4,244,471	kW, rateclass peak	$52,547	$69,217
	Substation	4,128,440	kW rateclass peak	$47,023	$61,941
FIXED	Luminaires & Poles				$7,298
TOTALS				$377,389	$504,416
				TARGET	$504,416
				EQUAL PERCENT	131.7%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF METERING REVENUE REQUIREMENT
2016

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	748,270	$0.43	$322	$5,675
Three Phase	143	$0.43	$0	$1
Schedule 15				
Residential	882	$0.00	$0	$0
Commercial	1,372	$0.00	$0	$0
Schedule 32				
Single Phase	54,838	$0.94	$52	$909
Three Phase	35,546	$0.94	$33	$589
Schedule 38				
Single Phase	66	$12.91	$1	$15
Three Phase	482	$12.91	$6	$110
Schedule 47				
Single Phase	231	$0.78	$0	$3
Three Phase	2,921	$0.78	$2	$40
Schedule 49				
Single Phase	3	$1.30	$0	$0
Three Phase	1,346	$1.30	$2	$31
Schedule 83				
Single Phase	645	$4.81	$3	$55
Three Phase	10,384	$4.81	$50	$881
Schedule 85				
Secondary	1,343	$13.62	$18	$323
Primary	156	$13.62	$2	$37
Schedule 85 1-4 MW				
Secondary	79	$13.62	$1	$19
Primary	80	$13.62	$1	$19
Schedule 89 GT 4 MW				
Secondary	1	$0.40	$0	$0
Primary	27	$0.40	$0	$0
Subtransmission	8	$0.40	$0	$0
Schedule 90-P	4	$0.29	$0	$0
Schedules 91/95	205	$0.00	$0	$0
Schedule 92	17	$0.00	$0	$0
TOTAL	859,049		$494	$8,708
			TARGET	$8,708
		EQUAL PERCENT		1764%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF BILLING REVENUE REQUIREMENT
2016

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	748,270	$48.85	$36,553	$53,490
Three Phase	143	$48.85	$7	$10
Schedule 15				
Residential	882	$50.05	$44	$65
Commercial	1,372	$37.52	$51	$75
Schedule 32				
Single Phase	54,838	$40.66	$2,230	$3,263
Three Phase	35,546	$40.66	$1,445	$2,115
Schedule 38				
Single Phase	66	$121.80	$8	$12
Three Phase	482	$121.80	$59	$86
Schedule 47				
Single Phase	231	$48.36	$11	$16
Three Phase	2,921	$48.36	$141	$207
Schedule 49				
Single Phase	3	$48.64	$0	$0
Three Phase	1,346	$48.64	$65	$96
Schedule 83				
Single Phase	645	$63.81	$41	$60
Three Phase	10,384	$63.81	$663	$970
Schedule 85				
Secondary	1,343	$144.06	$193	$283
Primary	156	$144.06	$22	$33
Schedule 85 1-4 MW				
Secondary	79	$144.06	$11	$17
Primary	80	$144.06	$12	$17
Schedule 89 GT 4 MW				
Secondary	1	$125.35	$0	$0
Primary	27	$125.35	$3	$5
Subtransmission	8	$125.35	$1	$1
Schedule 90-P	4	$22.76	$0	$0
Schedules 91/95	205	$813.18	$167	$244
Schedule 92	17	$764.67	$13	$19
TOTAL	859,049		$41,742	$61,084
			TARGET	$61,084
		EQUAL PERCENT		146%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF CONSUMER REVENUE REQUIREMENT
2016

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	748,270	$19.60	$14,666	$37,455
Three Phase	143	$19.60	$3	$7
Schedule 15				
Residential	882	$18.19	$16	$41
Commercial	1,372	$16.93	$23	$59
Schedule 32				
Single Phase	54,838	$28.86	$1,583	$4,042
Three Phase	35,546	$28.86	$1,026	$2,620
Schedule 38				
Single Phase	66	$186.66	$12	$31
Three Phase	482	$186.66	$90	$230
Schedule 47				
Single Phase	231	$27.49	$6	$16
Three Phase	2,921	$27.49	$80	$205
Schedule 49				
Single Phase	3	$85.74	$0	$1
Three Phase	1,346	$85.74	$115	$295
Schedule 83				
Single Phase	645	$154.95	$100	$255
Three Phase	10,384	$154.95	$1,609	$4,109
Schedule 85				
Secondary	1,343	$728.57	$978	$2,498
Primary	156	$728.57	$114	$290
Schedule 85 1-4 MW				
Secondary	79	$728.57	$58	$147
Primary	80	$728.57	$58	$149
Schedule 89 GT 4 MW				
Secondary	1	$5,272.21	$5	$13
Primary	27	$5,272.21	$142	$364
Subtransmission	8	$5,272.21	$42	$108
Schedule 90-P	4	$17,960.45	$72	$183
Schedule 91/95	205	$132.80	$27	$70
Schedule 92	17	$65.07	$1	$3
TOTAL	859,049		$20,828	$53,192
			TARGET	$53,192
		EQUAL PERCENT		255%

PORTLAND GENERAL ELECTRIC
Allocation of Carty Revenue Requirements

Schedule	Cycle MWh	Generation Revenues	Carty Allocation	Carty Price	Cycle Revenues
Schedule 7	7,620,805	$516,292,637	$38,747,827.80	5.08	$38,713,692
Schedule 15	16,308	$854,050	$64,097	3.93	$64,090
Schedule 32	1,599,950	$99,628,906	$7,477,162	4.67	$7,471,768
Schedule 38	39,036	$2,684,403	$201,465	5.16	$201,425
Schedule 47	20,845	$1,298,009	$97,416	4.67	$97,346
Schedule 49	62,677	$4,310,331	$323,491	5.16	$323,416
Schedule 83	2,795,179	$169,656,301	$12,732,727	4.56	$12,746,018
Schedule 85S	2,464,564	$145,424,883	$10,914,156	4.43	$10,918,020
Schedule 85P	713,162	$41,004,036	$3,077,358	4.32	$3,080,859
Schedule 89S	0	$0	$0	4.11	$0
Schedule 89P	851,370	$45,772,538	$3,435,235	4.03	$3,431,019
Schedule 89T	83,072	$4,469,742	$335,455	4.04	$335,611
Schedule 90P	1,498,007	$78,257,383	$5,873,227	3.92	$5,872,189
Schedule 91/95	74,544	$3,903,891	$292,987	3.93	$292,960
Schedule 92	3,243	$171,646	$12,882	3.97	$12,874
Totals	17,842,764	$1,113,728,757	$83,585,484		$83,561,287
Calendar Revenue Requirement			$83,583,000		
Add: Employee Discount			$41,235		
Revenue Requirement			$83,624,235		
Adjusted for Cycle			$83,585,484		

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/406

SUMMARY COMPARISON OF PGE AND ICNU RATE SPREAD

June 15, 2015

UE 294

Comparison of PGE and ICNU Rate Spread Proposals - Including Carty Revenue Requirement

($ x 1,000)

		Customer Classes												
Line No.	**Description**	**Schedule 7**	**Schedule 15**	**Schedule 32**	**Schedule 38**	**Schedule 47**	**Schedule 49**	**Schedule 83-S**	**Schedule 85 201-4,000 kW**	**Schedule 89 GT 4 MW**	**Schedule 90-P**	**Schedules 91/95**	**Schedule 92**	**Total**
1	Current Revenues	$ 913,144	$ 3,628	$ 175,073	$ 5,251	$ 3,692	$ 7,829	$ 248,442	$ 262,216	$ 73,402	$ 91,891	$ 14,055	$ 251	$ 1,798,875
2	PGE Proposed Revenues with CIO	$ 936,834	$ 3,458	$ 181,839	$ 5,845	$ 3,702	$ 8,804	$ 256,033	$ 258,708	$ 67,147	$ 92,359	$ 13,598	$ 259	$ 1,828,586
3	Carty Revenue Requirement (Net Sch. 129 Revenues)	38,028	66	7,472	197	97	316	12,774	14,158	3,981	6,052	300	13	83,453
4	**PGE Proposed Revenues Including Carty**	**$ 974,861**	**$ 3,523**	**$ 189,310**	**$ 6,042**	**$ 3,799**	**$ 9,120**	**$ 268,807**	**$ 272,866**	**$ 71,128**	**$ 98,411**	**$ 13,898**	**$ 272**	**$ 1,912,039**
5	Proposed Increase ($)	$ 61,717	$ (105)	$ 14,237	$ 791	$ 107	$ 1,291	$ 20,365	$ 10,650	$ (2,274)	$ 6,520	$ (157)	$ 21	$ 113,164
6	Proposed Increase (%)	6.76%	-2.88%	8.13%	15.06%	2.91%	16.49%	8.20%	4.06%	-3.10%	7.10%	-1.12%	8.33%	6.29%
7	PGE Allocated Cost of Service	$ 936,837	$ 3,606	$ 180,009	$ 5,538	$ 5,534	$ 14,306	$ 251,203	$ 258,350	$ 67,149	$ 92,363	$ 13,450	$ 259	$ 1,828,603
8	Carty Revenue Requirement (Net Sch. 129 Revenues)	38,028	66	7,472	197	97	316	12,774	14,158	3,981	6,052	300	13	83,453
9	**PGE Allocated Cost of Service Including Carty**	**$ 974,865**	**$ 3,672**	**$ 187,481**	**$ 5,735**	**$ 5,631**	**$ 14,621**	**$ 263,977**	**$ 272,508**	**$ 71,130**	**$ 98,415**	**$ 13,750**	**$ 272**	**$ 1,912,056**
10	Increase/(Decrease) from Current Revenues ($)	$ 61,721	$ 44	$ 12,408	$ 484	$ 1,939	$ 6,792	$ 15,535	$ 10,291	$ (2,272)	$ 6,524	$ (305)	$ 21	$ 113,181
11	Increase/(Decrease) from Current Revenues (%)	6.76%	1.20%	7.09%	9.22%	52.52%	86.76%	6.25%	3.92%	-3.10%	7.10%	-2.17%	8.32%	6.29%
12	Difference from Proposed Revenues ($)	$ 3	$ 148	$ (1,829)	$ (307)	$ 1,832	$ 5,501	$ (4,830)	$ (358)	$ 2	$ 4	$ (148)	$ (0)	$ 17
13	ICNU Allocated Cost of Service	$ 950,285	$ 3,676	$ 180,590	$ 5,548	$ 5,721	$ 14,806	$ 248,970	$ 253,607	$ 63,326	$ 88,200	$ 13,642	$ 251	$ 1,828,622
14	ICNU Carty Revenue Requirement	38,637	64	7,456	201	97	323	12,718	13,967	3,757	5,857	292	13	83,383
15	**ICNU Allocated Cost of Service Including Carty**	**$ 988,922**	**$ 3,740**	**$ 188,046**	**$ 5,749**	**$ 5,818**	**$ 15,128**	**$ 261,688**	**$ 267,574**	**$ 67,083**	**$ 94,057**	**$ 13,934**	**$ 264**	1,912,005
16	Increase/(Decrease) from Current Revenues ($)	$ 37,141	$ 48	$ 5,517	$ 297	$ 2,029	$ 6,977	$ 528	$ (8,609)	$ (10,076)	$ (3,691)	$ (413)	$ (0)	$ 113,130
17	Increase/(Decrease) from Current Revenues (%)	4.07%	1.32%	3.15%	5.66%	54.95%	89.11%	0.21%	-3.28%	-13.73%	-4.02%	-2.94%	-0.01%	6.29%
18	Increase/(Decrease) from PGE Proposed Revenues ($)	$ 13,451	$ 218	$ (1,248)	$ (297)	$ 2,019	$ 6,001	$ (7,063)	$ (5,101)	$ (3,821)	$ (4,159)	$ 44	$ (8)	$ 36
19	Increase/(Decrease) from PGE Proposed Revenues (%)	1.44%	6.31%	-0.69%	-5.08%	54.53%	68.16%	-2.76%	-1.97%	-5.69%	-4.50%	0.32%	-2.95%	0.00%
20	ICNU Proposed Revenues with CIO	$ 950,322	$ 3,676	$ 182,621	$ 5,845	$ 3,712	$ 8,804	$ 254,272	$ 253,939	$ 63,324	$ 88,202	$ 13,813	$ 251	$ 1,828,782
21	ICNU Carty Revenue Requirement	38,637	64	7,456	201	97	323	12,718	13,967	3,757	5,857	292	13	83,383
22	Carty-Related Adjustment to CIO				(201)		(323)	475	32					(17)
23	**ICNU Proposed Revenue Including Carty**	**$ 988,960**	**$ 3,740**	**$ 190,076**	**$ 5,845**	**$ 3,809**	**$ 8,804**	**$ 267,465**	**$ 267,938**	**$ 67,081**	**$ 94,059**	**$ 14,105**	**$ 264**	**$ 1,912,148**
20	Increase/(Decrease) from Current Revenues ($)	$ 75,816	$ 112	$ 15,003	$ 594	$ 117	$ 975	$ 19,023	$ 5,722	$ (6,321)	$ 2,168	$ 50	$ 13	$ 113,273
24	Increase/(Decrease) from Current Revenues (%)	8.30%	3.08%	8.57%	11.31%	3.18%	12.46%	7.66%	2.18%	-8.61%	2.36%	0.35%	5.10%	6.30%
25	PGE Allocated Cost of Service Including Carty (Line 9)													$ 1,912,056
26	Less: Carty Revenue Requirement (Line 8)													83,453
27	Less: Cycle Adjustment													(802)
28	Less: Other Revenues/Discounts[1]													(8,356)
29	**PGE 2016 Functionalized Revenue Requirement (Line 25 - Sum Lines 26, 27, 28)**													**$ 1,837,761**
30	ICNU Allocated Cost of Service Including Carty (Line 15)													$ 1,912,005
31	Less: Carty Revenue Requirement (Line 14)													83,383
32	Less: Cycle Adjustment													(800)
33	Less: Other Revenues/Discounts[1]													(8,340)
34	**ICNU 2016 Functionalized Revenue Requirement (Line 30 - Sum Lines 31, 32, 33)**													**$ 1,837,762**

[1] Direct Access Schedule 129 Revenues, Employee Discount, Partial Requirements Transmission, Partial Requirements Distribution. Difference between PGE and ICNU Other Revenues/Discounts is due to difference in allocation of costs to Generation.

ICNU/406
Daniel/2

UE 294
Comparison of PGE and ICNU Rate Spread Proposals - Not Inclucing Carty Revenue Requirement
($ x 1,000)

Line No.	Description	Schedule 7	Schedule 15	Schedule 32	Schedule 38	Schedule 47	Schedule 49	Schedule 83-S	Schedule 85 201-4,000 kW	Schedule 89 GT 4 MW	Schedule 90-P	Schedules 91/95	Schedule 92	Total
		Customer Classes												
1	Current Revenues	$ 913,144	$ 3,628	$ 175,073	$ 5,251	$ 3,692	$ 7,829	$ 248,442	$ 262,216	$ 73,402	$ 91,891	$ 14,055	$ 251	$ 1,798,875
2	**PGE Proposed Revenues with CIO**	**$ 936,834**	**$ 3,458**	**$ 181,839**	**$ 5,845**	**$ 3,702**	**$ 8,804**	**$ 256,033**	**$ 258,708**	**$ 67,147**	**$ 92,359**	**$ 13,598**	**$ 259**	**$ 1,828,586**
3	Proposed Increase ($)	$ 23,690	$ (170)	$ 6,766	$ 594	$ 10	$ 975	$ 7,591	$ (3,508)	$ (6,255)	$ 468	$ (457)	$ 8	$ 29,711
4	Proposed Increase (%)	2.59%	-4.69%	3.86%	11.31%	0.27%	12.46%	3.06%	-1.34%	-8.52%	0.51%	-3.25%	3.03%	1.65%
5	**PGE Allocated Cost of Service**	**$ 936,837**	**$ 3,606**	**$ 180,009**	**$ 5,538**	**$ 5,534**	**$ 14,306**	**$ 251,203**	**$ 258,350**	**$ 67,149**	**$ 92,363**	**$ 13,450**	**$ 259**	**$ 1,828,603**
6	Increase over Current Revenues ($)	$ 23,693	$ (22)	$ 4,936	$ 287	$ 1,842	$ 6,477	$ 2,761	$ (3,867)	$ (6,253)	$ 472	$ (605)	$ 8	$ 29,728
7	Increase over Current Revenues (%)	2.59%	-0.60%	2.82%	5.47%	49.88%	82.72%	1.11%	-1.47%	-8.52%	0.51%	-4.30%	3.02%	1.65%
8	Difference from Proposed Revenues ($)	$ 3	$ 148	$ (1,829)	$ (307)	$ 1,832	$ 5,501	$ (4,830)	$ (358)	$ 2	$ 4	$ (148)	$ (0)	$ 17
9	**ICNU Allocated Cost of Service**	**$ 950,285**	**$ 3,676**	**$ 180,590**	**$ 5,548**	**$ 5,721**	**$ 14,806**	**$ 248,970**	**$ 253,607**	**$ 63,326**	**$ 88,200**	**$ 13,642**	**$ 251**	**$ 1,828,622**
10	Increase/(Decrease) from Current Revenues ($)	$ 37,141	$ 48	$ 5,517	$ 297	$ 2,029	$ 6,977	$ 528	$ (8,609)	$ (10,076)	$ (3,691)	$ (413)	$ (0)	$ 29,747
11	Increase/(Decrease) from Current Revenues (%)	4.07%	1.32%	3.15%	5.66%	54.95%	89.11%	0.21%	-3.28%	-13.73%	-4.02%	-2.94%	-0.01%	1.65%
12	Increase/(Decrease) from PGE Proposed Revenues ($)	$ 13,451	$ 218	$ (1,248)	$ (297)	$ 2,019	$ 6,001	$ (7,063)	$ (5,101)	$ (3,821)	$ (4,159)	$ 44	$ (8)	$ 36
13	Increase/(Decrease) from PGE Proposed Revenues (%)	1.44%	6.31%	-0.69%	-5.08%	54.53%	68.16%	-2.76%	-1.97%	-5.69%	-4.50%	0.32%	-2.95%	0.00%
14	**ICNU Proposed Revenues with CIO**	**$ 950,322**	**$ 3,676**	**$ 182,621**	**$ 5,845**	**$ 3,712**	**$ 8,804**	**$ 254,272**	**$ 253,939**	**$ 63,324**	**$ 88,202**	**$ 13,813**	**$ 251**	**$ 1,828,782**
15	Increase/(Decrease) from Current Revenues ($)	$ 37,178	$ 48	$ 7,548	$ 594	$ 20	$ 975	$ 5,830	$ (8,277)	$ (10,078)	$ (3,689)	$ (242)	$ (0)	$ 29,907
16	Increase/(Decrease) from Current Revenues (%)	4.07%	1.32%	4.31%	11.31%	0.54%	12.46%	2.35%	-3.16%	-13.73%	-4.01%	-1.72%	0.00%	1.66%
17	PGE Allocated Cost of Service (Line 5)													$ 1,828,603
18	Less: Cycle Adjustment													(802)
19	Less: Other Revenues/Discounts[1]													(8,356)
20	**PGE Functionalized Revenue Requirement (Line 17 - Sum Lines 18,19)**													**$ 1,837,761**
21	ICNU Allocated Cost of Service (Line 9)													$ 1,828,622
22	Less: Cycle Adjustment													(800)
23	Less: Other Revenues/Discounts[1]													(8,340)
24	**ICNU Functionalized Revenue Requirement (Line 21 - Sum Lines 22-23)**													**$ 1,837,762**

[1]Schedule 129, Employee Discount, Partial Requirements Transmission, Partial Requirements Distribution. Difference between PGE and ICNU Other Revenues/Discounts is due to difference in allocation of costs to Generation.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

EXHIBIT ICNU/407

REVISED CIO ADJUSTMENT

June 15, 2015

UE 294

ICNU Revised Customer Impact Offset

Grouping	Cycle MWH	Revenues at Current Prices ($000)	2016 Allocated Costs ($000)	Percent Change	Maximum Change	Impact Offset Cap	Spread Offset Net Cap	CIO Revenues	CIO Rev Without Carty	Carty CIO Rev Increase
Schedule 7	7,620,805	$ 913,144	$ 988,922	8.3%	12.0%	$ -	$ -	$ -	$ -	$ -
Schedule 15	16,308	3,628	3,740	3.1%	12.0%	-	-	(171)	(171)	-
Schedule 32	1,599,950	175,073	188,046	7.4%	12.0%	-	-	-	-	-
Schedule 38	39,036	5,251	8,012	52.6%	12.0%	(2,132)	-	(2,132)	(1,931)	(201)
Schedule 47	20,845	3,692	5,818	57.6%	12.0%	-	-	-	-	-
Schedule 49	62,677	7,829	12,865	64.3%	12.0%	(4,096)	-	(4,097)	(3,774)	(323)
Schedule 83-S	2,795,179	248,442	261,688	5.3%	12.0%	-	5,792	5,786	5,311	475
Schedule 85	3,177,726	262,216	272,914	4.1%	12.0%	-	356	350	318	32
Schedule 89	934,442	73,402	70,593	-3.8%	12.0%	-	-	-	-	-
Schedule 90	1,498,007	91,891	94,057	2.4%	12.0%	-	-	-	-	-
Schedules 91 & 95	74,544	14,055	13,934	-0.9%	12.0%	-	-	171	171	-
Schedule 92	3,243	251	264	5.4%	12.0%	-	-	-	-	-
COS TOTALS	17,842,764									
Sch 485 Energy	711,915						80	78	-	78
Sch 489 Energy	853,521							-	-	-
Totals	**19,408,200**	**$ 1,798,875**	**$ 1,920,854**	**6.8%**		**$ (6,228)**	**$ 6,228**	**$ (15)**	**$ (76)**	**$ 61**

Cap on Rate Change	12.0%
Cap on CIO (mills/kWh)	(100.00)
Schedule 83 CIO Percent	93.0%
Schedule 85 CIO Percent	7.0%