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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

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OPENING TESTIMONY OF BRADLEY G. MULLINS**

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EXHIBIT LIST

- Exhibit ICNU/201—Revenue Requirement Calculations
- Exhibit ICNU/202—Rate Spread Impact of Generation Marginal Cost Adjustments
- Exhibit ICNU/203—Northwest Power and Conservation Council Planning Documents
- Conf. Exhibit ICNU/204—Company Responses to Data Requests
- Exhibit ICNU/205—Rate Spread Impact of Load Following Credit Allocation
- Conf. Exhibit ICNU/206—Capital Expenditure Review
- Exhibit ICNU/207—Selections from PGE Investor Presentations on Rate Base Additions
- Conf. Exhibit ICNU/208—Select Capital Addition Project Justification Forms
- Exhibit ICNU/209—Proposed Redline to Schedule 75

I. INTRODUCTION

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

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

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

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

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

23 **(3) Capital Additions:** I have performed an audit of the capital forecast proposed by
24 the Company in this proceeding. Based on my review, I recommend a \$
25 million reduction to the Company’s capital forecast, resulting in a revenue
26 requirement reduction of \$9.5 million.

27 **(4) Rate Schedule Issues:**

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

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

1 **Q. HAVE YOU PREPARED A SUMMARY TABLE DETAILING THE IMPACT OF**
2 **ICNU’S REVENUE REQUIREMENT RECOMMENDATIONS?**

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

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

| <u>ln</u> | <u>Base</u> | <u>Base w/ Carty</u> |
|-----------|------------------|--------------------------|
| 1 | \$ 38,752 | \$ 122,335 |
| 2 | (22,264) | (24,966) |
| 3 | (9,455) | (9,455) |
| 4 | \$ 7,033 | \$ 87,915 |

II. GENERATION MARGINAL COST STUDY

8
9 **Q. PLEASE PROVIDE AN OVERVIEW OF YOUR RECOMMENDATION ON THE**
10 **GENERATION MARGINAL COST STUDY.**

11 A. I recommend three changes to the generation marginal cost study. First, consistent with the
12 Company’s use of the Carty Generating Station as the marginal energy resource, Port
13 Westward II should be used as the marginal capacity resource. Second, the marginal cost of
14 energy should reflect the dispatchability of the marginal energy resource, which results in
15 lower energy costs as a result of the option to generate in some hours and purchase from the
16 market in others. Third, the calculation of capitalized energy costs should reflect fixed fuel
17 transportation costs for both the marginal energy and capacity resources, as those costs are

1 currently excluded from the marginal capacity resource in the Company’s calculation. The
 2 combined rate spread impact of all of these changes, as well as the generation marginal cost
 3 calculations, have been detailed in Exhibit ICNU/202. In addition, Table 2, below,
 4 summarizes the rate spread impact of these three adjustments, along with an alternative
 5 adjustment for the marginal capacity resource. These percentages are based on the revenue
 6 requirement proposed in the Company’s initial filing and do not reflect the partial stipulation,
 7 ICNU’s remaining revenue requirement adjustments, nor the adjustments proposed in Mr.
 8 Daniel’s Opening Testimony.

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

| <u>ln</u> | (a) Rate Class | (b) Company Proposed (Table 5) | (c) Capacity Resource PWII | (d) Dispatch-ability Credit | (e) Capitalized Energy | (f) = Σ (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% |

9 **a. Marginal Capacity Resource**

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

12 **A.** The marginal capacity resource proposed by the Company is an F-Class Combustion Turbine
 13 (“Frame CT”), a type of Simple Cycle Combustion Turbine (“SCCT”) that is characterized by

1 its inflexibility and low capital cost. The use of the proposed Frame CT, based on an Energy
2 Information Administration (“EIA”) report, produces a real levelized marginal capacity cost of
3 \$127.44/kW-yr.^{1/} I disagree with using a Frame CT in the generation marginal cost study.
4 Because of its inflexibility, it is not consistent with the type of capacity resource that the
5 Company would actually build to meet incremental peak loads. In addition, it is based on EIA
6 cost data that is inconsistent with the use of the Carty Generating Station as the marginal
7 energy resource, the cost of which was established in a request for proposal (“RFP”) process.
8 Rather, my recommendation is that the marginal capacity costs should be based on Port
9 Westward II, which was selected in the same RFP process as the Carty Generating Station.
10 This recommendation will produce a real levelized marginal capacity cost of \$[REDACTED]/kW-yr.

11 **Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?**

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

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

21 A. There are four primary resource types considered by utilities in resource planning today. These
22 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, dual 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) |

1 Table 3 is based largely on the preliminary resource assumptions the Northwest Power and
 2 Conservation Council (“Planning Council”) is using for the Seventh Power Plan.^{2/} The source
 3 documents for most of this data have been attached as Exhibit ICNU/203. As can be noted
 4 from the figure, the Frame CT is the least flexible and has the highest heat rate of any of the
 5 peaker resource options. No Frame CT has been constructed in the Northwest since at least
 6 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

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

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

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

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

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

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

^{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).

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

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

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

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

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

22 **Q. DOES THE FRAME CT MEET THESE CRITERIA?**

23 A. No. As discussed below, the Company has repeatedly indicated that a Frame CT is not a
24 peaker resource that it would consider for meeting its peak load obligations. This creates

1 inconsistency between the Company’s marginal energy and marginal capacity resources in
2 terms of the cost data it uses. While the Company uses cost data developed in the 2012
3 Request for Proposals for Capacity and Baseload Energy Resources (“2012 RFP”) for the
4 marginal energy resource, it is forced to rely on an EIA report titled “Updated Capital Cost
5 Estimates for Utility Scale Electricity Generating Plants” to price its marginal capacity
6 resource because it has no comparable Company-specific data for a Frame CT.^{4/} Based on the
7 Company’s workpapers, for resource attributes not presented in the EIA report, the Company
8 relied on the IRP of another regional utility to acquire those attributes.

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

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

18 **Q. DID THE COMPANY EVALUATE A FRAME CT IN ITS 2013 INTEGRATED**
19 **RESOURCE PLAN (“IRP”)?**

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

^{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”).

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

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

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

17 **Q. WHAT CAPACITY RESOURCE DO YOU RECOMMEND?**

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

^{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).

^{7/} https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp_appG.pdf
Id.

^{8/} Id. at 152.

^{9/} PGE/1300 at 3:22

^{10/} EIA Report at A-10.

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

8 **Q. WHAT IS YOUR ALTERNATIVE RECOMMENDATION?**

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

17 **b. Dispatchability Credit**

18 **Q. WHAT IS YOUR RECOMMENDATION RELATED TO DISPATCHABILITY?**

19 A. The Company calculated the variable energy component of marginal thermal energy costs
20 based solely on fuel costs. Because the thermal energy resource, however, is dispatchable, its
21 fuel cost does not represent the true cost of energy from that resource. Rather, in some hours,
22 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).

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

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

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

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

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

19 **Q. HOW DOES DISPATCHABILITY REDUCE ENERGY COSTS?**

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

1 dispatch option is a reduction of the overall cost of energy relative to the fuel cost of the
2 marginal energy resource.

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

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

13 **Q. WHAT IS THE IMPACT OF THIS DISPATCHABILITY CREDIT?**

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

17 **c. Capitalized Energy Cost**

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

20 A. Capitalized energy costs, a component of the marginal thermal energy costs, are based on the
21 difference between the fixed cost of the marginal energy resource and the fixed cost of the
22 marginal capacity resource. The Company's calculation of these capitalized energy costs
23 included the fixed cost of fuel transportation for the marginal energy resource but excluded the
24 fixed cost of fuel transportation for the marginal capacity resource. My recommendation is to

1 include the fixed cost of fuel transportation for both the marginal energy and marginal capacity
2 resources when calculating capitalized energy costs. Adopting this recommendation will
3 reduce marginal energy costs by \$3.72/MWH.

4 **Q. WHAT IS CAPITALIZED ENERGY COST?**

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

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

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

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

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

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

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

16 III. LOAD FOLLOWING CREDIT

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

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

^{12/} PGE/1400 at 22:1-8.

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

3 **Q. WHAT IS THE LOAD FOLLOWING CREDIT?**

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

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

17 A. The Company proposed to allocate all of the cost of the load following credit solely to
18 Schedule 89 customers. This is in contrast to how the Company allocated the cost of the load
19 following credit in the last two rate cases, where it allocated the cost of the credit to all
20 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).

1 **Q. WHAT WAS THE COMPANY’S JUSTIFICATION FOR CHANGING THE**
2 **ALLOCATION?**

3 A. The Company stated that the allocation change was made “in order to better equalize the base
4 rate price impacts across the major rate schedules.”^{16/} In other words, the Company has
5 proposed to use the allocation of the load following credit in a manner that is similar to the
6 customer impact offset adjustment.

7 **Q. DO YOU AGREE WITH THE CHANGE?**

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

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

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

^{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.

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

3 **Q. WHAT DO YOU RECOMMEND?**

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

8 **IV. CAPITAL ADDITIONS**

9 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATION ON CAPITAL ADDITIONS.**

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

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

2 A. The Company has undertaken a capital program that increased gross plant from approximately
3 \$7.2 billion^{18/} in the 2013 general rate case to approximately \$9.2 billion in this proceeding,^{19/}
4 an approximate \$2.0 billion increase over a three year period. This is a substantial amount of
5 new capital, which is concerning given utilities' incentive to over-build their systems. Thus,
6 capital additions deserve particular attention in this proceeding.

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

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

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

15 A. The Company developed rate base in this proceeding based on an end-of-period December 31,
16 2015 calculation.^{22/} The rate base amount was forecasted based on actual plant in service on
17 December 31, 2014, adjusted for capital additions forecast over calendar year 2015.^{23/} Finally,
18 the Company added the rate base associated with the Carty Generation Station, which will be
19 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

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

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

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

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

17 **Q. ARE THE PROJECT JUSTIFICATION FORMS ADEQUATE DOCUMENTATION**
18 **FOR THE COMPANY’S PROPOSED CAPITAL PROJECTS?**

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

^{25/} See Confidential ICNU/206 at Workpaper A2.

^{26/} Id.

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

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

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

11 **Q. WHAT WAS THE RESULT OF YOUR REVIEW?**

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

1 framework, my workpapers support reducing the Company's capital forecast, for the top 20
2 projects, by approximately \$ [REDACTED] million.

3 **Q. WHAT IS YOUR RECOMMENDATION RELATED TO THE REMAINING [REDACTED]**
4 **PROJECTS?**

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

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

18 A. In total, I am proposing an adjustment of approximately \$ [REDACTED] million to the Company's
19 \$ [REDACTED] million capital addition forecast. The revenue requirement impact of this adjustment is
20 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).

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

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

9 **Q. WHAT IS YOUR ADJUSTMENT RELATED TO THE [REDACTED]**
10 **[REDACTED]?**

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

16 **Q. WHAT IS YOUR ADJUSTMENT RELATED TO THE [REDACTED]**
17 **[REDACTED]?**

18 A. [REDACTED]
19 [REDACTED].
20 The Company proposes a capital budget of approximately \$ [REDACTED] million for these activities. I
21 have several concerns with both the nature and amount of expenditures forecast under this
22 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).

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

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

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

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

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

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

4 As a result of the fact that virtually no [REDACTED] activities have been
5 performed to date in calendar year 2015, this capital project should be removed from the
6 Company's capital forecast, reducing its rate base request by \$ [REDACTED] million.

7 **Q. WHAT IS YOUR ADJUSTMENT RELATED TO [REDACTED]**
8 **[REDACTED]?**

9 A. The Company has proposed a capital budget of approximately \$ [REDACTED] million, which, based
10 solely on the project description, appears to be related to [REDACTED]

11 [REDACTED] The Company, however, did not produce a Project Justification Form for this
12 capital project in response to Staff DR 178, so the actual nature of the project is not entirely
13 clear.

14 Notwithstanding, the amount of capital requested for this project far exceeds the
15 amounts actually expended on this capital category in prior years. For example, in calendar
16 year 2014 the Company spent only \$ [REDACTED] million on this capital category.^{32/} In calendar year
17 2013 the Company spent only \$ [REDACTED] million.^{33/} In addition, through April of 2015, the
18 Company spent only \$ [REDACTED] million on this capital category, or approximately \$ [REDACTED] million less
19 than it forecast over the same period.^{34/}

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

^{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)

1 average actual monthly plant placed in service in calendar year 2014 for the remaining months
2 in calendar year 2015. I use this same methodology for adjusting the capital budgets of several
3 other capital categories, which, as applied to the [REDACTED] project, will
4 result in a \$ [REDACTED] million reduction to the Company's capital forecast.

5 **Q. WHAT IS YOUR ADJUSTMENT RELATED TO THE [REDACTED]**

6 **[REDACTED]?**

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

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

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

1 allows the Company to modify the customer's baseload demand if it determines that this level
2 does not match the customer's load, adjusted for actual customer generation.^{36/}

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

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

9 **Q. PLEASE DESCRIBE SCHEDULE 75.**

10 A. Schedule 75 is a Partial Requirements Service tariff that is available to nonresidential
11 customers with a load over 30 kW and that self-generate all or a portion of their own power.^{37/}
12 Under the tariff, the Company provides a baseline level of energy that is priced under Schedule
13 89, the Company's large industrial cost-of-service tariff.^{38/} The Company and the customer
14 determine a Baseline Demand level that is defined as "the Demand normally supplied by the
15 Company to the Large Nonresidential Customer when the Customer's generator is operating as
16 planned by the Customer."^{39/} The difference between the baseline level of energy supplied by
17 the Company under Schedule 89 and the customer's total demand is either provided by the
18 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.

1 **Q. PLEASE DESCRIBE SCHEDULE 76R.**

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

12 **Q. HOW IS BASELINE DEMAND DETERMINED UNDER SCHEDULE 75?**

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

15 The Customer’s Baseline Demand may be increased or decreased as requested
16 by the Customer for planned, long-term load changes including changes
17 resulting from the addition of long-term energy efficiency measures, load
18 shedding, the addition or removal of equipment or the permanent removal of
19 generating capacity from the Customer location. Such changes will be effective
20 upon verification of the change by the Company. “Long-term” or “permanent”
21 mean changes that are implemented with the purpose of being in place
22 indefinitely.^{44/}
23

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

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

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

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

5 A. The Company has proposed to add the following sentence at the end of Special Condition 8:

6 "The Customer's Baseline Demand may be modified by the Company if the Company
7 determines that the level does not reflect load adjusted for the actual Customer generation."^{47/}

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

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

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

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

^{45/}

Id.

^{46/}

Id.

^{47/}

PGE/1401 at 17.

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

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

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

16 **b. Schedule 77**

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

19 A. Schedule 77 is the Company's Firm Load Reduction Program, which was implemented as a
20 permanent program through Advice No. 13-08 and approved by the Commission on August 6,
21 2013. The program provides the Company with the opportunity to interrupt certain non-
22 residential customer loads in consideration of a \$3/kW-mo or \$6/kW-mo Reservation Payment,

^{48/} PGE Schedule 76R at 1.

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

9 **Q. WHAT IS YOUR RECOMMENDATION RELATED TO SCHEDULE 77?**

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

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

17 A. The current Reservation Payment on Schedule 77 is \$3.00/kW-mo for customers that require
18 18 hours' advance notice and \$6.00/kW-mo for customers that only require 4 hours' advance
19 notice of a Load Reduction Event. These reservation payment rates were established through
20 Advice No. 13-08. No economic justification was provided to support the level of the
21 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.

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

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

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

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

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

19 A. The impact of relying on the marginal cost of capacity to establish the Reservation Payment
20 will depend on the marginal capacity resource ultimately selected in the generation marginal
21 cost study in this proceeding. If my recommendation to use Port Westward II is adopted, the
22 marginal cost of capacity will be \$[REDACTED]/kW-yr, which equates to a reservation payment of
23 \$[REDACTED]/kW-mo. If the Frame CT, as proposed in the Company's initial filing, is selected, the

1 marginal cost of capacity will be \$127.44/kW-yr,^{52/} which equates to a Reservation Payment of
2 \$10.62/kW-mo. Either way, then, participants in the Firm Load Reduction Program are not
3 currently receiving the full value of their capacity contributions to the system.

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

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

14 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

15 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 (12) | Carty Rev. Change For COC (13) | Carty Rev. Change For COC (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 (15) | Adjustment (16) | Adjusted ROO (17) | Rev. Change for ROE (18) | Adjusted ROO at ROE (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 useful 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**

| CATEGORY | RATE SCHEDULE | Forecast SDEC14E16 | | TOTAL ELECTRIC BILLS | | Change | | | |
|---|------------------|-----------------------|--------------|---|---|---------------|-------|-------|-------|
| | | CUSTOMERS | MWH SALES | CURRENT | PROPOSED | AMOUNT | PCT. | FILED | DELTA |
| | | | | with all supplementals except LIA & PPC | with all supplementals except LIA & PPC | | | | |
| 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 | | TOTAL ELECTRIC BILLS | | Change | | | |
|---|------------------|-----------------------|--------------|---|---|---------------|-------|-------|-------|
| | | CUSTOMERS | MWH SALES | CURRENT | PROPOSED | AMOUNT | PCT. | FILED | DELTA |
| | | | | with all supplementals except LIA & PPC | with all supplementals except LIA & PPC | | | | |
| 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 | | TOTAL ELECTRIC BILLS | | Change | | | |
|---|------------------|-----------------------|--------------|---|---|---------------|-------|-------|-------|
| | | CUSTOMERS | MWH SALES | CURRENT | PROPOSED | AMOUNT | PCT. | FILED | DELTA |
| | | | | with all supplementals except LIA & PPC | with all supplementals except LIA & PPC | | | | |
| 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 | | TOTAL ELECTRIC BILLS | | Change | | | |
|---|------------------|-----------------------|--------------|---|---|---------------|-------|-------|-------|
| | | CUSTOMERS | MWH SALES | CURRENT | PROPOSED | AMOUNT | PCT. | FILED | DELTA |
| | | | | with all supplementals except LIA & PPC | with all supplementals except LIA & PPC | | | | |
| 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

Phil Rockefeller
Chair
Washington

Tom Karier
Washington

Henry Lorenzen
Oregon

Bill Bradbury
Oregon



**Northwest Power and
Conservation Council**

W. Bill Booth
Vice Chair
Idaho

James Yost
Idaho

Pat Smith
Montana

Jennifer Anders
Montana

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/>.

2/9/2015

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.

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* Power Plan Narratives | CO ₂ Sequestration |
| | | Storage Technologies* |

2/9/2015

Langley Gulch, 300 MW, Idaho, 2012

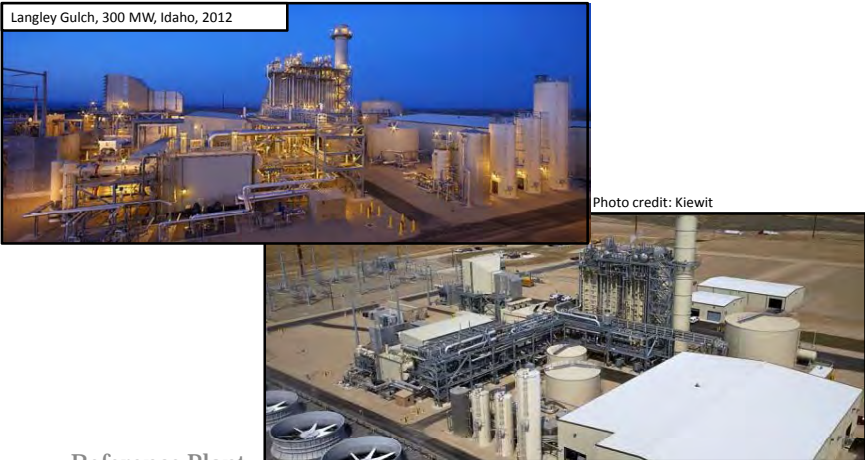


Photo credit: Kiewit

Reference Plant

COMBINED CYCLE COMBUSTION TURBINE

Northwest Power and Conservation Council

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SEVENTH NORTHWEST POWER PLAN

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

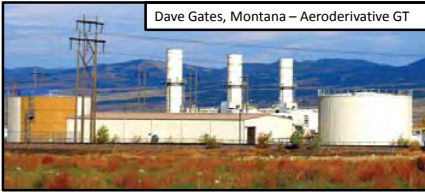
- Expected plant size consistent a 1x1 configuration (1 gas-turbine coupled with 1 HRSG)
- Requested configurations for both Wet-Cooled, and Dry-Cooled

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 |




Dave Gates, Montana – Aero derivative GT

Photo credit: PowerMag.com




Danskin, Idaho – Frame GT

Photo credit: Tim Bondy



Port Westward II – Recip

Photo credit: PGE flickr



Port Westward II – Recip

Photo credit: PGE flickr

Reference Plants

GAS PEAKERS – SINGLE CYCLE AND RECIPROCATING ENGINES

Northwest Power and Conservation Council

10

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.
- **Reciprocating Engine** – One or more compression spark or spark-ignition reciprocating 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 S-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) |

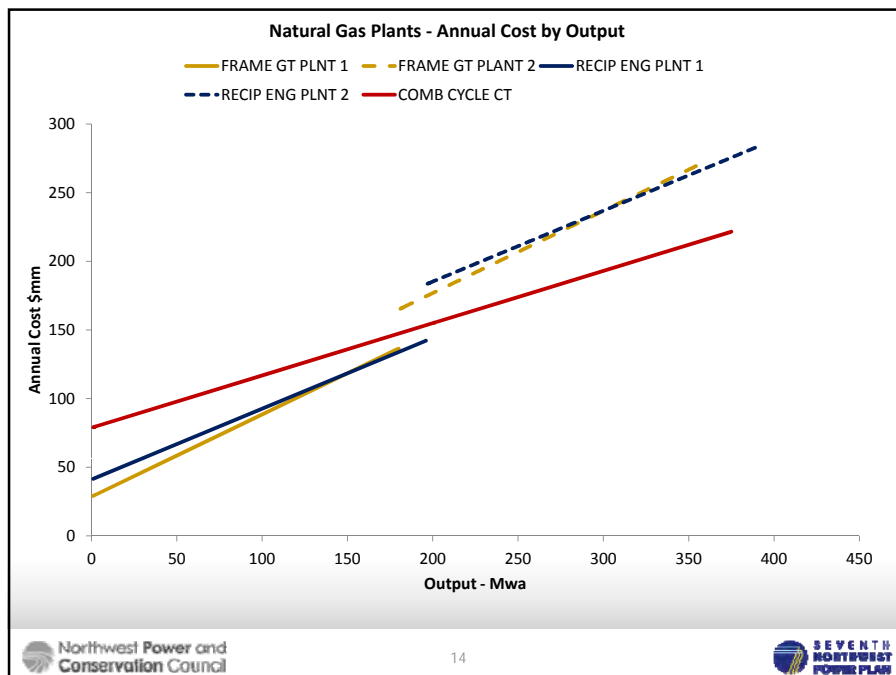
All costs represented in 2012 \$

12

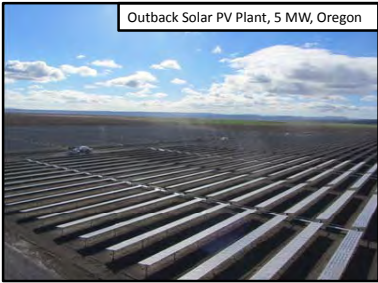
Black = Draft 7th Plan Assumption
Red = Final 6th Plan Assumption

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?




2/9/2015




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


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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

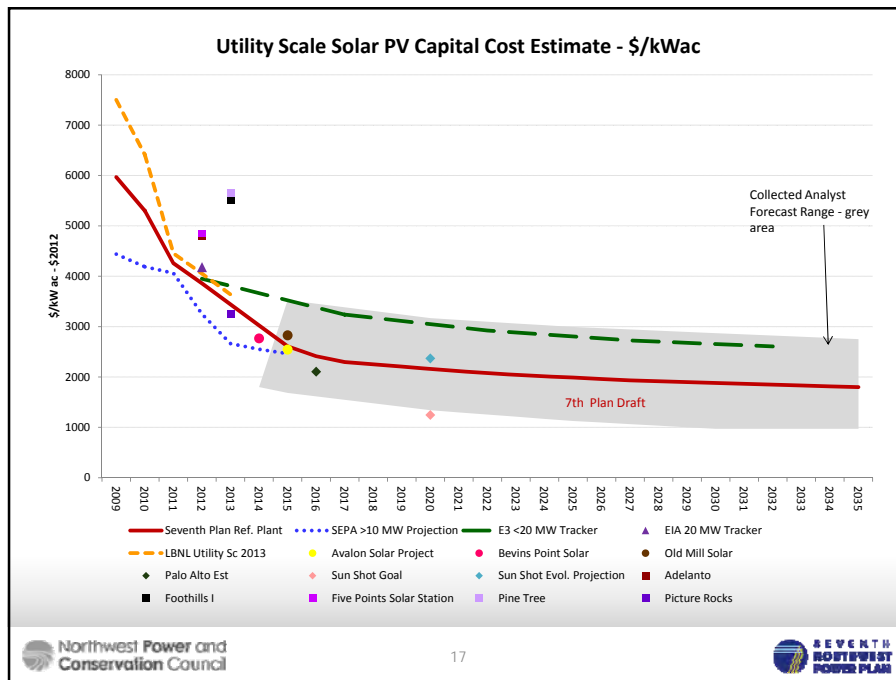
Importance/Relevance to PNW: Although there is a limited presence in the region, activity has recently picked up in Southern Idaho – which is probably the best solar resource region for the Northwest.

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.

2/9/2015



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

2/9/2015



Tucannon River Wind Farm, 267 MW, 2014

Photo credit: PGE flickr

Reference Plant

ONSHORE-WIND

Northwest Power and Conservation Council

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SEVENTH NORTHWEST POWER PLAN

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.

2/9/2015

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) |

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 |

2/9/2015

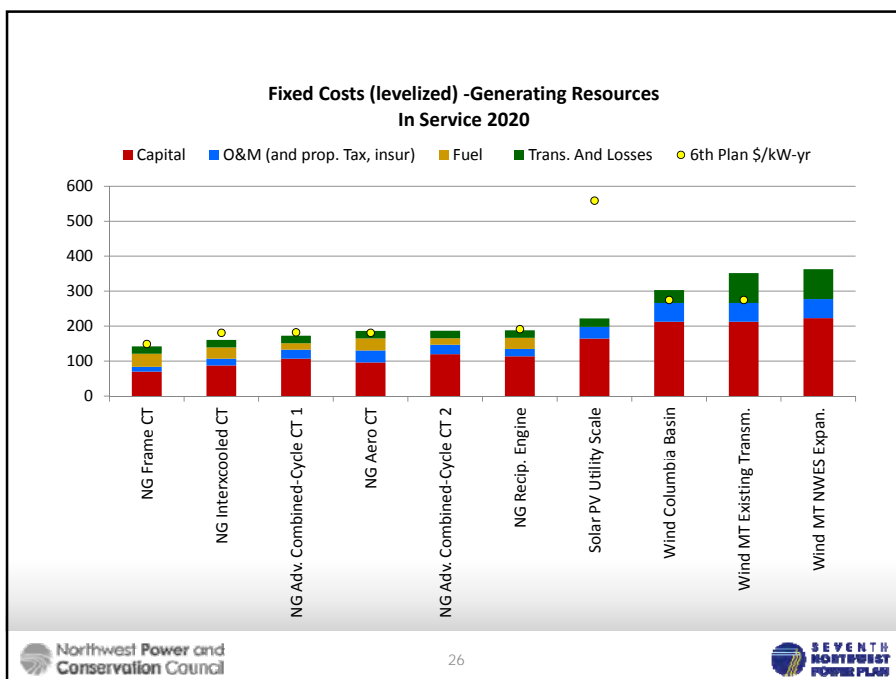
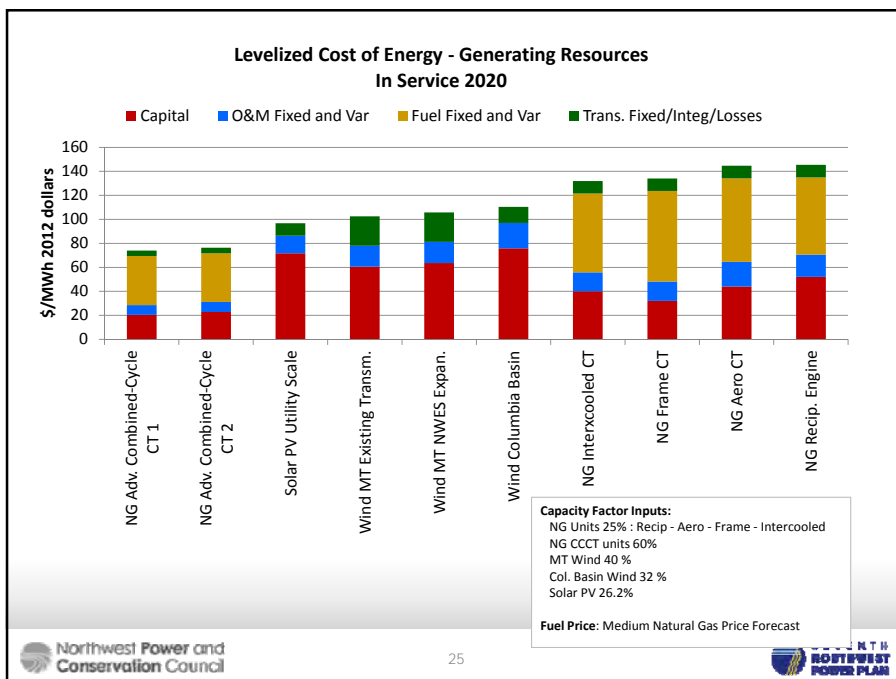
Fixed (\$/kW-yr) and full (\$/MWh)– annualized cost of capital and operation across the lifecycle

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



2/9/2015

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

| <h2>Properties of Peaking Technologies</h2> | |
|---|---|
| <p>Frame (80MW – 250 MW units)</p> <ul style="list-style-type: none"> • 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) | <p>Aeroderivative (15 – 60 MW units)</p> <ul style="list-style-type: none"> • 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 |
| <p>Intercooled (100 MW units)</p> <ul style="list-style-type: none"> • 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 | <p>Reciprocating Engine (2 - 20 MW units)</p> <ul style="list-style-type: none"> • Largest gas engines in world – 4 stroke • Strengths – highly modular; very rapid response, low heat rate, dual 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 |

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

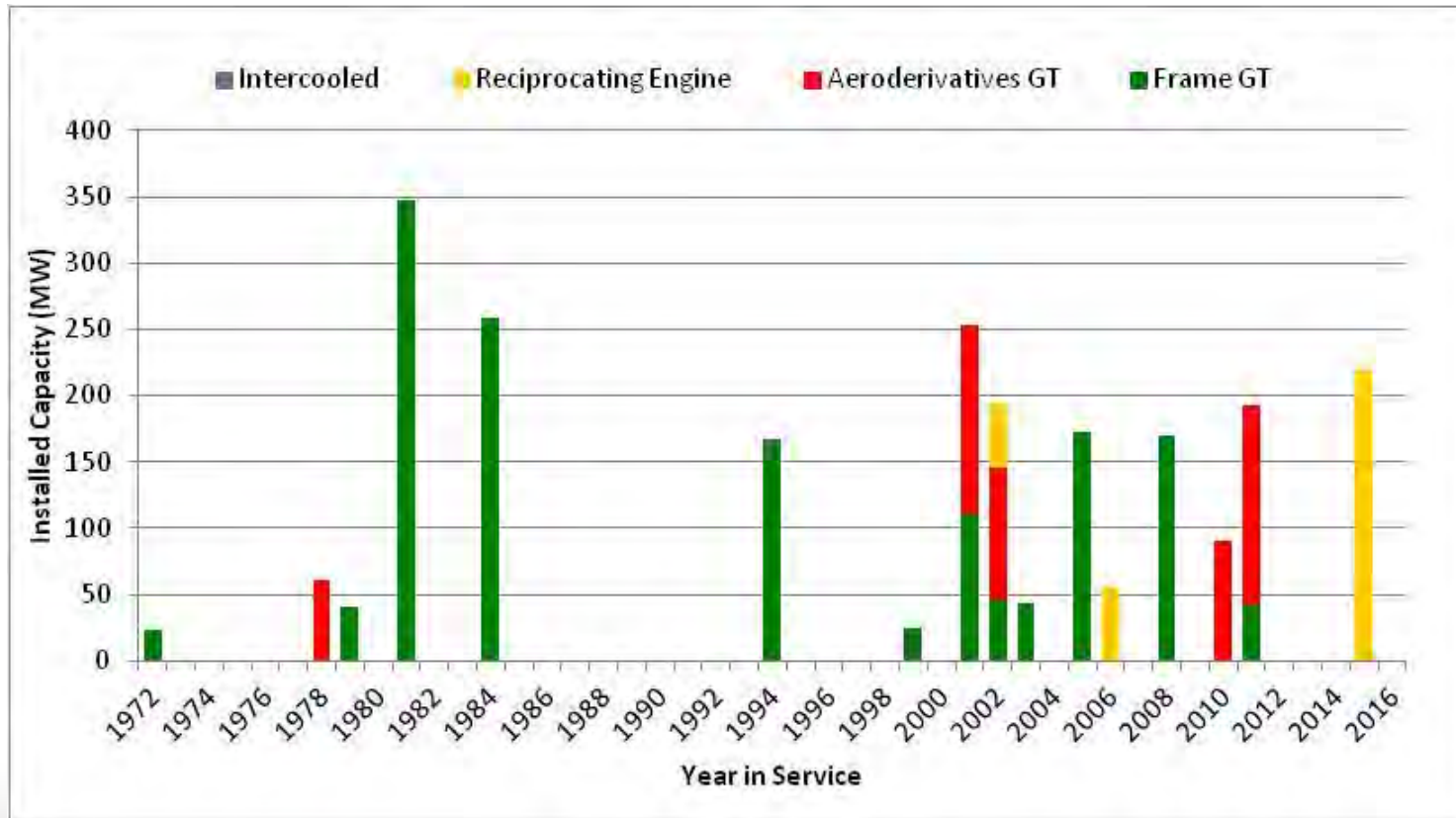
Definitions

- 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+ | |

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 |

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

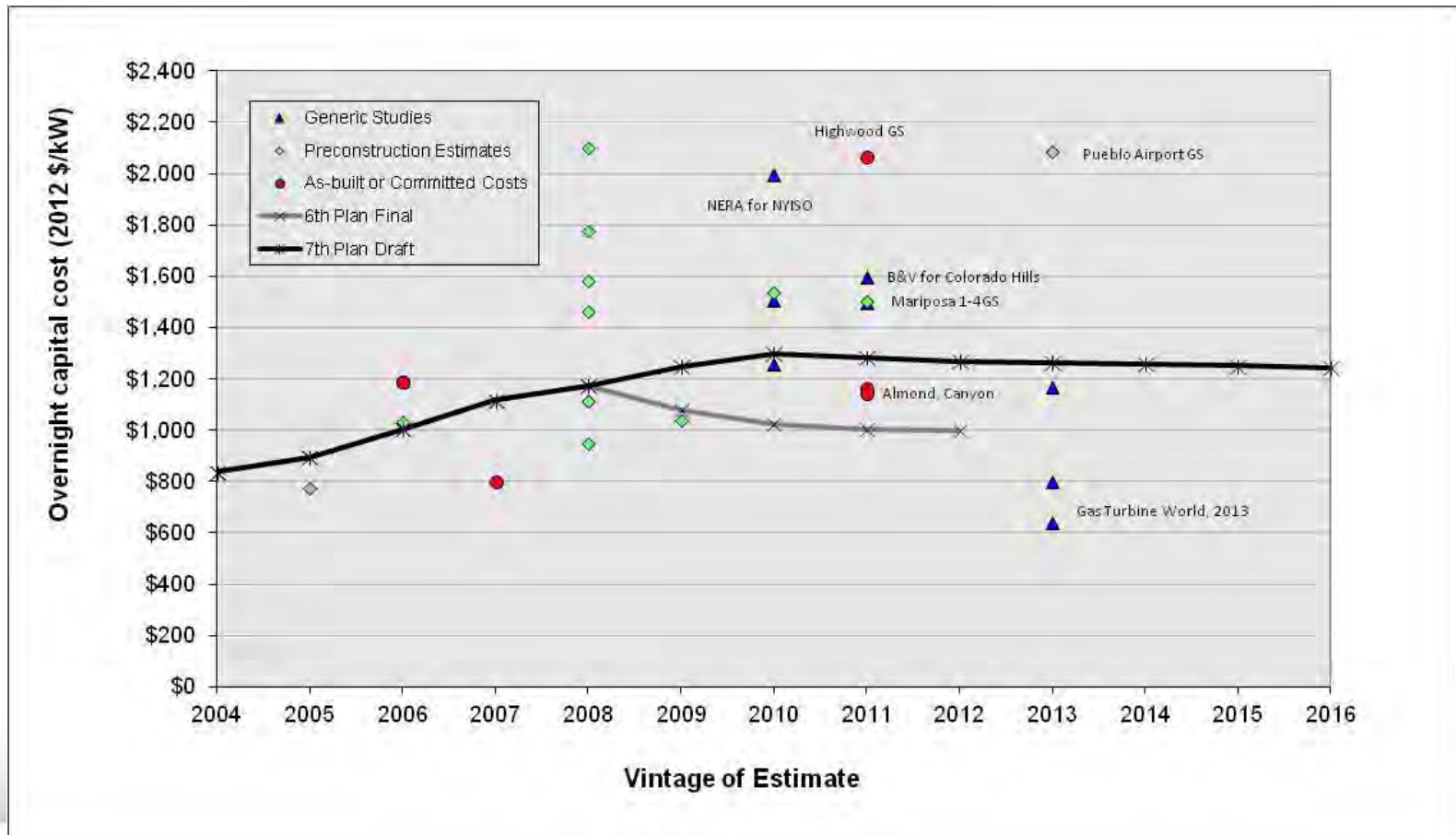
Proposed Aeroderivative Reference Plant (1)

- **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 |

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)

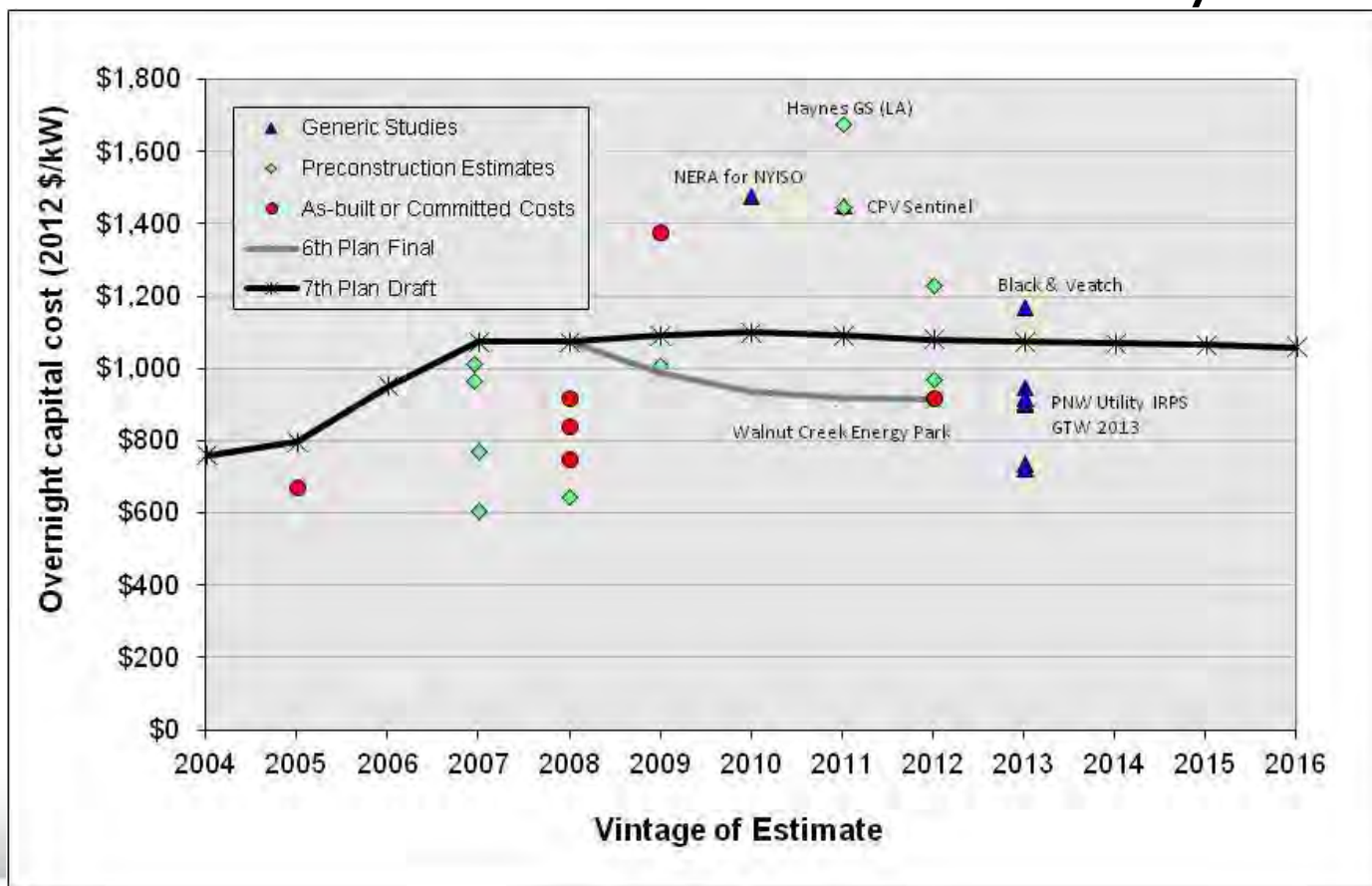
GE LMS100 PB

- 99.4 MW output (103.5 MW PA)
- Available starting in 2010
- Similar to PA, but with DLE instead of water injection for NO_x 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 |

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

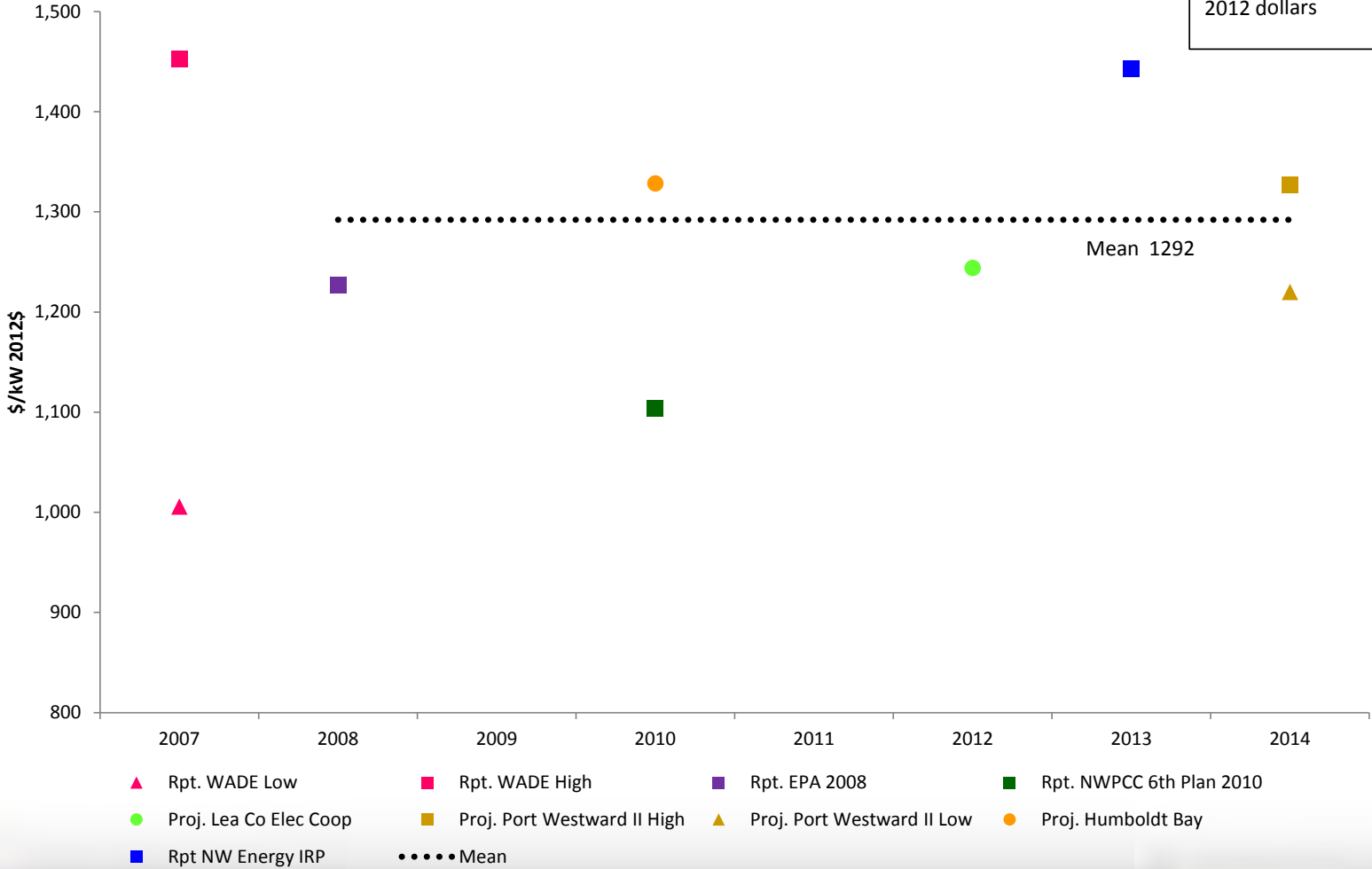
1. Northwest Power & Conservation Council
6th Plan – 2010
2. EPA Tech. Char. Of
Recip. Eng. – 2008
3. World Alliance for
Decentralized Energy
(WADE) 2007

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



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.

UE 294 PGE Response to ICNU DR 021
April 13, 2015
Page 2

- 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.

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.

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.

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.

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.

UE 294 PGE Response to OPUC DR No. 176
March 20, 2015
Page 3

- 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 | | TOTAL ELECTRIC BILLS | | Change | | | |
|---|---------------|-----------------------|------------|---|---|---------------|-------|-------|-------|
| | | CUSTOMERS | MWH SALES | CURRENT | PROPOSED | AMOUNT | PCT. | FILED | DELTA |
| | | | | with all supplementals except LIA & PPC | with all supplementals except LIA & PPC | | | | |
| 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



Investor Presentation

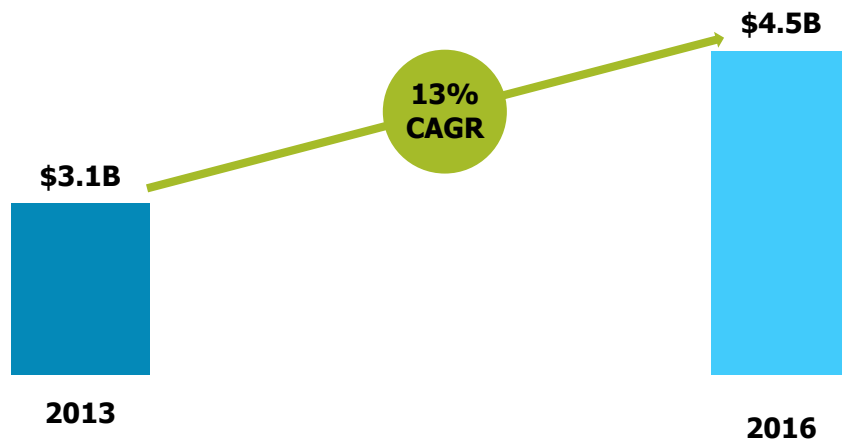
March 2015





Rate Base and Capital Expenditures

\$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



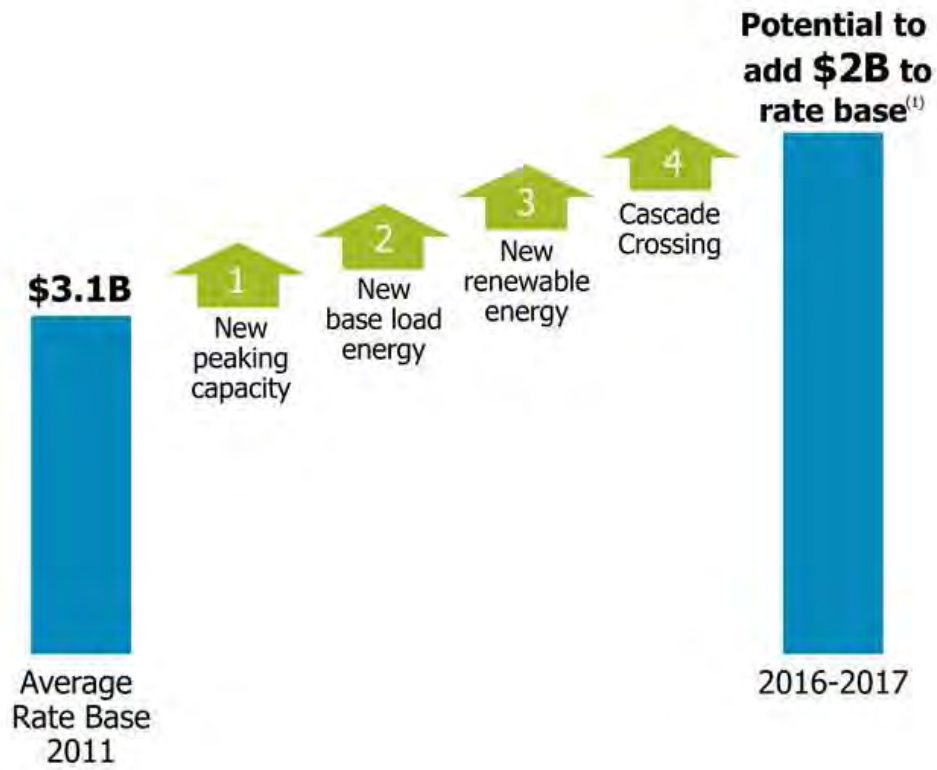
Investor Presentation

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

Portland General Electric Company ~~Ninth~~Tenth Revision of Sheet No. 75-1
P.U.C. Oregon No. E-18 Canceling ~~Eighth~~Ninth Revision of Sheet No. 75-1

**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 | |
| <u>Basic Charge</u> | \$5,1302,670 .00 | \$4,5801,6 20.00 | \$5,2803,090.00 | (H) |
| <u>Transmission and Related Services Charge</u> per kW of monthly On-Peak Demand | \$0.8979 | \$0.77 | \$0.76 | (R) |
| <u>Distribution Charges</u> The sum of the following: per kW of Facility Capacity | | | | (R) |
| First 4,000 kW | \$1,850.99 | \$1,820.96 | \$1,820.96 | |
| Over 4,000 kW | \$1,260.99 | \$1,230.96 | \$1,230.96 | |
| per kW of monthly On-Peak Demand | \$2.1238 | \$2.0632 | \$0.781.21 | (R) |
| <u>Generation Contingency Reserves Charges</u> | | | | (R) |
| Spinning Reserves per kW of Reserved Capacity > 2,000 kW | \$0.234 | \$0.234 | \$0.234 | (X)(R) |
| Supplemental Reserves per kW of Reserved Capacity > 2,000 kW | \$0.234 | \$0.234 | \$0.234 |) |
| <u>System Usage Charge</u> per kWh | 0.084083 ¢ | 0.078080 ¢ | 0.075077 ¢ | (U) |
| <u>Energy Charge</u> per kWh | See Energy Charge Below | | | |

* See Schedule 100 for applicable adjustments.

Advice No. ~~14-2715-02~~
Issued ~~December~~February 12, 20142015
James F. Lobdell, Senior Vice President

Effective for service
on and after ~~January 1~~March 16, 2015

Portland General Electric Company
P.U.C. Oregon No. E-18

Original Sheet No. 75-2

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.

Advice No. 07-01
Issued January 16, 2007
Pamela Grace Lesh, Vice President

Effective for service
on and after January 17, 2007

Portland General Electric Company
P.U.C. Oregon No. E-18

Original Sheet No. 75-3

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.

Advice No. 07-01
Issued January 16, 2007
Pamela Grace Lesh, Vice President

Effective for service
on and after January 17, 2007

Portland General Electric Company
P.U.C. Oregon No. E-18

Original Sheet No. 75-4

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.

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Issued January 16, 2007
Pamela Grace Lesh, Vice President

Effective for service
on and after January 17, 2007

Portland General Electric Company
P.U.C. Oregon No. E-18

~~Fifth~~^{Sixth} Revision of Sheet No. 75-5
Canceling ~~Fourth~~^{Fifth} Revision of Sheet No. 75-5

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)

Advice No. ~~14-2715-02~~
Issued ~~December~~^{February} 12, ~~2014~~²⁰¹⁵
James F. Lobdell, Senior Vice President

Effective for service
on and after ~~January 1~~^{March 16}, 2015

Portland General Electric Company
P.U.C. Oregon No. E-18

Third Revision of Sheet No. 75-6
Canceling Second Revision of Sheet No. 75-6

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.

Advice No. 14-27
Issued December 12, 2014
James F. Lobdell, Senior Vice President

Effective for service
on and after January 1, 2015

Portland General Electric Company
P.U.C. Oregon No. E-18

Original Sheet No. 75-7

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.

Advice No. 07-01
Issued January 16, 2007
Pamela Grace Lesh, Vice President

Effective for service
on and after January 17, 2007

Portland General Electric Company First Revision of Sheet No. 75-8
P.U.C. Oregon No. E-18 Canceling Original Sheet No. 75-8

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 generationCustomer's generating capacity.
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.

(N)
|
(N)

Advice No. 07-0415-02
Issued ~~January 16, 2007~~ February 12, 2015

Effective for service

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| ~~Pamela Grace Lesh~~, James F. Lobdell, Senior Vice President on 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

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OPENING TESTIMONY OF MICHAEL P. GORMAN**

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EXHIBIT ICNU/317 – CAPM RETURN

EXHIBIT ICNU/318 – STANDARD & POOR’S CREDIT METRICS

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

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

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

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

11 **Q. WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?**

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

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

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

18 **I. SUMMARY**

19 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS**
20 **ON PGE’S RATE OF RETURN.**

21 **A.** I recommend the Public Utility Commission of Oregon (the “Commission”) award PGE a
22 return on common equity of 9.25%, which is the midpoint of my recommended range of
23 8.90% to 9.60%. My recommended return on equity will fairly compensate PGE for its
24 current market cost of common equity, and it will mitigate the claimed revenue

1 deficiency in this proceeding by providing PGE fair compensation with the lowest cost to
2 customers.

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

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

10 **II. RATE OF RETURN**

11 **Q. PLEASE DESCRIBE THIS SECTION OF YOUR TESTIMONY.**

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

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

1 under greater rating pressure. Recent consolidation among independent
2 gencos has added scale and diversity, and is a credit positive.^{2/}

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

4 Our outlook for the US regulated utilities industry is stable. This
5 outlook reflects our expectation for the fundamental business
6 conditions in the industry over the next 12 to 18 months.

7 » **Regulatory support is the most important driver of our stable**
8 **outlook.** Our stable outlook for the US regulated utility industry is
9 based on our expectation that regulators will continue to help utilities
10 recover costs and maintain stable cash flow, such that the ratio of cash
11 flow from operations (CFO) to debt will remain close to 20%, on
12 average, for the industry.

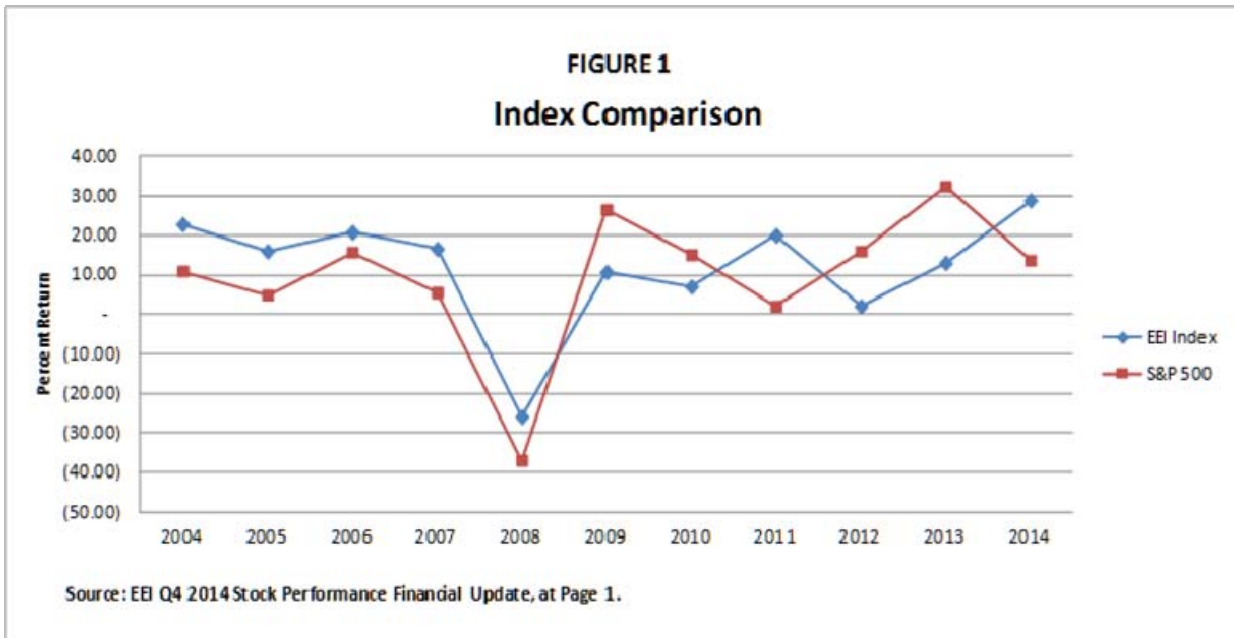
13 » **Capital spending will decline in 2015, which reduces borrowing**
14 **needs.** The credit profiles of large, integrated utilities that generate,
15 transmit and distribute power will benefit from a drop in capital
16 spending in 2015, because most of the heavy capital expenditures for
17 environmental compliance have been made. This will reduce the
18 industry's debt needs and stabilize financial metrics, at least for the
19 next two years.^{3/}

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

22 **A.** As shown in the graph below, the Edison Electric Institute ("EEI") has recorded utility
23 stock price performance compared to the market. The EEI data shows that its Utility
24 Index has outperformed the market in downturns and trailed the market during recovery.
25 This supports my conclusion that utility stock investments are regarded by market
26 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.



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

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

10 **II.B. PGE Investment Risk**

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

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

1 Moody's are BBB and A-, and A- and A1, respectively.^{4/} Both rating agencies have a
2 Stable outlook for PGE.

3 Specifically, S&P states the following:

4 **Business Risk: Strong**

5 Our assessment of Portland General's business risk profile is "strong," as
6 defined in our criteria, based on the company's "satisfactory" competitive
7 position, "very low" industry risk derived from the regulated utility
8 industry, and "very low" country risk of the U.S. Portland General's
9 competitive position reflects the company's low-risk regulated operations
10 under a generally constructive regulatory environment, a midsize customer
11 base, and competitive rates across customer classes. Portland General's
12 reliance on power purchases and its exposure to hydroelectric power
13 variability result in the careful management of power resources and
14 collateral needs.

15 Portland General serves roughly 840,000 customers, or 46% of Oregon's
16 population, including the Portland and Salem regions. This concentration
17 makes the company dependent on successfully managing regulatory
18 relationships in Oregon, including navigating state energy policy
19 initiatives and environmental mandates, which have become increasingly
20 complex in recent years. Regulatory mechanisms such as forecast test
21 periods help reduce regulatory lag since the costs are projected and
22 recovered on a timely basis. Power cost costs are recovered through the
23 power cost adjustment mechanism and a renewable adjustment clause
24 mechanism enables Portland General to recover the revenue requirements
25 of new renewable resources.

26 **Financial Risk: Significant**

27 We base our financial risk profile assessment of "significant" on the
28 medial volatility financial ratio benchmarks. Our assessment takes into
29 consideration the mostly steady cash flows from the utility business. Our
30 base case indicates that discretionary cash flow, or operating cash flow
31 less capital spending and dividends, will turn positive after 2015 when the
32 Carty gas plant construction is largely completed. In 2015, the negative
33 discretionary cash flow will be partially reduced through proceeds from
34 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.

1 **II.C. PGE's Proposed Capital Structure**

2 **Q. WHAT IS PGE'S PROPOSED CAPITAL STRUCTURE?**

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

| TABLE 1 | |
|--|----------------------|
| <u>PGE's Proposed Capital Structure</u> | |
| (Test Year 2016) | |
| <u>Description</u> | <u>Weight</u> |
| Long-Term Debt | 50.00% |
| Common Equity | <u>50.00%</u> |
| Total Regulatory Capital Structure | 100.00% |

Source: Direct Testimony of Patrick Hager and Brett Greene.

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

6 **II.D. Embedded Cost of Debt**

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

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

1 **II.E. Return on Equity**

2 **Q. PLEASE DESCRIBE WHAT IS MEANT BY A “UTILITY’S COST OF**
3 **COMMON EQUITY.”**

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

7 **Q. PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A**
8 **REGULATED UTILITY’S COST OF COMMON EQUITY.**

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

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

18 **Q. PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE PGE’S**
19 **COST OF COMMON EQUITY.**

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

1 **II.F. Risk Proxy Group**

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

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

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

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

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

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

1 **II.G. Discounted Cash Flow Model**

2 **Q. PLEASE DESCRIBE THE DCF MODEL.**

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

6
$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \dots \frac{D_\infty}{(1+K)^\infty} \quad (\text{Equation 1})$$

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

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

14
$$K = D_1/P_0 + G \quad (\text{Equation 2})$$

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

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

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

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

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

26 **A.** I relied on the average of the weekly high and low stock prices of the utilities in the proxy
27 group over a 13-week period ending on May 15, 2015. An average stock price is less
28 susceptible to market price variations than a spot price. Therefore, an average stock price

1 is less susceptible to aberrant market price movements, which may not reflect the stock's
2 long-term value.

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

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

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

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

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

21 As predictors of future returns, security analysts' growth estimates have been
22 shown to be more accurate than growth rates derived from historical data.^{7/} That is,
23 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

1 **II.H. Sustainable Growth DCF**

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

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

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

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

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

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

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

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

7 **II.I. Multi-Stage Growth DCF Model**

8 **Q. HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?**

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

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

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

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

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

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

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

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

23 **A.** Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the
24 economy in which they sell services. Utilities' earnings/dividend growth is created by

1 increased utility investment or rate base. Such investment, in turn, is driven by service
2 area economic growth and demand for utility service. In other words, utilities invest in
3 plant to meet sales demand growth, and sales growth, in turn, is tied to economic growth
4 in their service areas.

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

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

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

18 The constant growth model is most appropriate for mature companies with
19 a stable history of growth and stable future expectations. Expected growth
20 rates vary somewhat among companies, but dividends for mature firms are
21 often expected to grow in the future at about the same rate as nominal
22 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.

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

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

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

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

16 **A.** I relied on the consensus analysts' projections of long-term GDP growth. *Blue Chip*
17 *Economic Indicators* publishes consensus economists' GDP growth projections twice a
18 year. These consensus analysts' GDP growth outlooks are the best available measure of
19 the market's assessment of long-term GDP growth. These analyst projections reflect all
20 current outlooks for GDP, as reflected in analyst projections, and are likely the most
21 influential on investors' expectations of future growth outlooks. The consensus
22 economists' published GDP growth rate outlook is 4.7% to 4.4% over the next
23 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.

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

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

11 **A.** Yes, and these sources corroborate my consensus analysts’ projections. The U.S. EIA in
12 its *Annual Energy Outlook* projects real GDP out until 2040. In its 2015 Annual Report,
13 the EIA projects real GDP through 2040 to be in the range of 1.8% to 2.9%, with a
14 midpoint or reference case of 2.4%, and a long-term GDP price inflation projection of
15 1.8%. The EIA data supports a long-term nominal GDP growth outlook of 4.2%.^{13/}

16 Also, the Congressional Budget Office (“CBO”) makes long-term economic
17 projections. The CBO is projecting real GDP growth of 2.5% to 2.1% during the next 5
18 and 10 years, respectively, with a GDP price inflation outlook of 2.0%.^{14/} The CBO’s
19 real GDP and GDP inflation projections are slightly lower than the consensus
20 economists. The five- and 10-year outlooks for nominal GDP based on these projections
21 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.

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

6 The Social Security Administration makes long-term economic projections out to
7 2090. The Social Security Administration’s nominal GDP projections, under its
8 intermediate cost scenario for 30 and 75 years, ranges from 4.7% to 4.5%, respectively.^{16/}
9 These projections are in line with the consensus economists.

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

16 The real GDP and nominal GDP growth projections made by these independent
17 sources support the use of the consensus economist 5-year and 10-year projected GDP
18 growth outlooks as a reasonable estimate of market participants’ long-term GDP growth
19 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.

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

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

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

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

16 **Q. PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.**

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

| TABLE 2 | |
|--|-----------------------------------|
| <u>Summary of DCF Results</u> | |
| <u>Description</u> | <u>Proxy Group Average</u> |
| Constant Growth DCF Model (Analysts' Growth) | 8.87% |
| Constant Growth DCF Model (Sustainable Growth) | 8.93% |
| Multi-Stage Growth DCF Model | <u>8.47%</u> |
| Average | 8.76% |

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

3 **II.J. Risk Premium Model**

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

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

12 This risk premium model is based on two estimates of an equity risk premium.
13 First, I estimated the difference between the required return on utility common equity
14 investments and U.S. Treasury bonds. The difference between the required return on

1 common equity and the Treasury bond yield is the risk premium. I estimated the risk
2 premium on an annual basis for each year over the period 1986 through March 2015.
3 The common equity required returns were based on regulatory commission-authorized
4 returns for electric utility companies. Authorized returns are typically based on expert
5 witnesses' estimates of the contemporary investor-required return.

6 The second equity risk premium estimate is based on the difference between
7 regulatory commission-authorized returns on common equity and contemporary
8 "A" rated utility bond yields by Moody's. I selected the period 1986 through March
9 2015 because public utility stocks consistently traded at a premium to book value during
10 that period. This is illustrated in Exhibit ICNU/311, which shows that the market to book
11 ratio since 1986 for the electric utility industry was consistently above a multiple of 1.0x.
12 Over this period, regulatory authorized returns were sufficient to support market prices
13 that at least exceeded book value. This is an indication that regulatory authorized returns
14 on common equity supported a utility's ability to issue additional common stock without
15 diluting existing shares. It further demonstrates that utilities were able to access equity
16 markets without a detrimental impact on current shareholders.

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

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

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

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

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

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

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

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

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

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

1 A current 13-week average “A” rated utility bond yield of 3.82%, when compared
2 to the current Treasury bond yield of 2.67% as shown in Exhibit ICNU/315, page 1,
3 implies a yield spread of around 115 basis points. This current utility bond yield spread
4 is lower than the 36-year average spread for “A” rated utility bonds of 1.52%. Similarly,
5 the current spread for the “Baa” rated utility bond yield of 1.90% is lower than the
6 36-year average spread of 1.95%.

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

10 **Q. HOW DID YOU ESTIMATE PGE’S COST OF COMMON EQUITY WITH THIS**
11 **RISK PREMIUM MODEL?**

12 **A.** I added a projected long-term Treasury bond yield to my estimated equity risk premium
13 over Treasury yields. The 13-week average 30-year Treasury bond yield, ending May 15,
14 2015, was 2.67%, as shown in Exhibit ICNU/315, page 1. *Blue Chip Financial*
15 *Forecasts* projects the 30-year Treasury bond yield to be 3.70%, and a 10-year Treasury
16 bond yield to be 3.20%.^{18/} Using the projected 30-year Treasury bond yield of 3.70%,
17 and a Treasury bond risk premium of 4.25% to 6.62%, as developed above, produces an
18 estimated common equity return in the range of 7.95% (3.70% + 4.25%) to 10.32%
19 (3.70% + 6.62%). My risk premium estimates fall in the range of 7.95% to 10.32%.

20 I next added my equity risk premium over utility bond yields to a current 13-week
21 average yield on “Baa” rated utility bonds for the period ending May 15, 2015, of 4.57%.
22 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.

1 “Baa” rated bond yield of 4.57%, produces a cost of equity in the range of 7.45% (4.57%
2 + 2.88%) to 10.11% (4.57% + 5.54%).

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

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

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

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

^{19/} See Exhibit ICNU/314.

^{20/} *Id.*

1 market interest rate risk. This results in a risk premium estimate over Treasury bond
2 yields of 9.73%,^{21/} and a risk premium estimate over Baa utility bond yields of 9.45%.^{22/}

3 My risk premium analyses produce a return estimate in the range of 9.45% to
4 9.73%, with a midpoint of 9.59%, rounded to 9.60%.

5 **II.K. Capital Asset Pricing Model (“CAPM”)**

6 **Q. PLEASE DESCRIBE THE CAPM.**

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

$$11 \quad R_i = R_f + B_i \times (R_m - R_f) \text{ where:}$$

12 R_i = Required return for stock i

13 R_f = Risk-free rate

14 R_m = Expected return for the market portfolio

15 B_i = Beta - Measure of the risk for stock

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

22 The risks that cannot be eliminated when held in a diversified portfolio are non-
23 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%.

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

7 **Q. PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.**

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

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

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

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

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

^{23/} *Blue Chip Financial Forecasts*, May 1, 2015 at 2.

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

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

9 **Q. WHAT BETA DID YOU USE IN YOUR ANALYSIS?**

10 **A.** As shown in Exhibit ICNU/316, the proxy group average *Value Line* beta estimate is
11 0.75.

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

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

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

20 Morningstar's *Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook* estimates
21 the historical arithmetic average real market return over the period 1926 to 2014 as
22 8.9%.^{24/} A current consensus analysts' inflation projection, as measured by the

^{24/} *Morningstar, Inc., Ibbotson SBBI 2015 Classic Yearbook* at 92.

1 Consumer Price Index, is 2.4%.^{25/} Using these estimates, the expected market return is
2 11.51%.^{26/} The market risk premium then is the difference between the 11.51% expected
3 market return, and my 3.70% risk-free rate estimate, or approximately 7.8%.

4 The historical estimate of the market risk premium was also estimated by
5 Morningstar in *Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook*. Over the
6 period 1926 through 2014, Morningstar's study estimated that the arithmetic average of
7 the achieved total return on the S&P 500 was 12.1%,^{27/} and the total return on long-term
8 Treasury bonds was 6.10%.^{28/} The indicated market risk premium is 6.0% (12.1% - 6.1%
9 = 6.0%). The average of my market risk premium estimates is 6.90% (6.0% to 7.8%).

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

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

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

^{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.*

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

7 Morningstar's range is based on several methodologies. First, Morningstar
8 estimates a market risk premium of 7.0% based on the difference between the total
9 market return on common stocks (S&P 500) less the income return on Treasury bond
10 investments. Second, Morningstar found that if the New York Stock Exchange
11 ("NYSE") was used as the market index rather than the S&P 500, that the market risk
12 premium would be 6.8%, not 7.0%. Third, if only the two deciles of the largest
13 companies included in the NYSE were considered, the market risk premium would be
14 6.3%.^{30/}

15 Finally, Morningstar found that the 7.0% market risk premium based on the S&P
16 500 was influenced by an abnormal expansion of price-to-earnings ("P/E") ratios relative
17 to earnings and dividend growth during the period 1980 through 2001. Morningstar
18 believes this abnormal P/E expansion is not sustainable.^{31/} Therefore, Morningstar
19 adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be
20 more in line with the growth in dividends and earnings. Based on this alternative

^{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.

1 methodology, Morningstar published a long-horizon supply-side market risk premium of
2 6.1%.^{32/}

3 **Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?**

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

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

15 **II.L. Return on Equity Summary**

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

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

^{32/} *Id.* at 157.

| <u>Description</u> | <u>Results</u> |
|---------------------------|-----------------------|
| DCF | 8.90% |
| Risk Premium | 9.60% |
| CAPM | 9.20% |

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

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

8 **II.M. Financial Integrity**

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

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

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

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

1 expanded its matrix criteria by including additional business and financial risk
2 categories.^{33/}

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

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

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

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

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

^{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.

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

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

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

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

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

22 **A.** The S&P financial metric calculations for PGE at a 9.25% return are developed on
23 Exhibit ICNU/318, page 1. S&P currently rates PGE's business risk as "Strong" and
24 financial risk as "Significant." The credit metrics produced below, with this financial and

1 business risk outlook by S&P, will be used to assess the strength of the credit metrics
2 based on PGE's retail operations in Oregon.

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

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

14 PGE's retail operations FFO to total debt coverage at a 9.25% equity return is
15 24%, which is also within S&P's "Intermediate" metric guideline range of 23% to 35%.
16 This FFO/total debt ratio will support an investment grade bond rating.

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

^{35/} *Id.*

III. RESPONSE TO PGE WITNESS DR. VILLADSEN

1
2 **Q. WHAT RETURN ON COMMON EQUITY IS PGE PROPOSING IN THIS**
3 **PROCEEDING?**

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

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

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

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

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

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

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

TABLE 4

Summary of Dr. Villadsen's Results

| <u>Model</u> | <u>Model ROE Results</u> (1) | <u>ATWACC ROE Adder</u> (2) | <u>Recommended ROE</u> (3) | <u>Adjusted ROE</u> (4) |
|------------------------------------|---|--|---|--|
| <u>DCF</u> | | | | |
| 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% | <u>8.7%</u> 8.9% |
| <u>CAPM</u> | | | | |
| 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% | <u>Reject</u> 9.2% |
| <u>Risk Premium</u> | | | | |
| 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

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

5 She then increases her market return on equity estimate by adding a return on
6 equity adder in the range of 0.6% to 1.8% based on an After-Tax Weighted Average Cost
7 of Capital ("ATWACC") adder methodology. This ATWACC adder increases her

1 recommended range up to 9.8% to 11.2%. Dr. Villadsen asserts this ATWACC return on
2 equity adder is necessary to properly recognize PGE's financial risk when applying a
3 market return on equity to its book value common equity.

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

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

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

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

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

21 Finally, all of Dr. Villadsen's risk premium studies are based on a risk premium
22 of approximately 6% relative to Treasury bond yields. The current Treasury bond yield
23 is around 2.67%, and projected yield is around 3.8%. Without taking issue with her
24 estimated equity risk premiums, Dr. Villadsen's own risk premium studies show that a

1 return on equity for PGE in this proceeding based on her risk premium studies should be
2 in the range of 8.7% to 9.7%.

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

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

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

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

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

24 Dr. Villadsen's general assessment is that a return on equity should be higher
25 based on book value because book value has more financial risk than does the market

1 value of common equity. She is in effect suggesting that firms have a different level of
2 financial risk, depending on whether one is observing its market value capital structure or
3 the book value capital structure.

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

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

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

19 *Value Line* on the other hand provides information to the market participants to
20 help them assess the total investment risk including both financial risk and business risk
21 for the utilities and other stock investments. The data *Value Line* provides to investors
22 concerning these investment risk characteristics relates to book value factors including
23 book value capital structure, book value cash flows, and book value earnings. All these
24 book value factors are then used by investors to assess investment risk which allows them

1 to derive market value stock prices. The book value parameters are an integral part of
2 assessing risk and allowing investors to produce market valuations. There is not a
3 difference in financial risk for a company if you are examining its book financial risk or
4 market value financial risk. Rather, the book value and market value financial risks for
5 the same company are interconnected to one another, and produce a single level of
6 financial risk for the company.

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

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

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

22 Second, book value capital structure weights permit the utility to hedge or lock-in
23 a large portion of capital market costs in arriving at the rate of return used to set rates.
24 This rate of return cost hedge stabilizes the utility's cost of service, which in turn helps

1 stabilize utility rates. A stable method of setting rates also allows investors to more
2 accurately assess the future earnings and cash flow outlooks for the utility, which will
3 reduce the business risk of the utility. The ATWACC, on the other hand, will produce an
4 overall rate of return which will change based on both changes to market value capital
5 structure weights and also based on changes to market capital costs. Hence, a major
6 component of the cost structure of the utility (i.e., the overall rate of return) will vary
7 based on market forces from rate case to rate case. This rate of return variability will
8 introduce significant instability in the utility's cost of service (via rate of return changes)
9 and hence instability in tariff rates. Introducing additional instability in the utility's cost
10 structure and rates will not benefit either investors or ratepayers.

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

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

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

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

- 1 3. Is an unproven and never used methodology that is not reliable for setting rates.
2 (Ohio Public Utilities Commission, Cause Nos. 07-551-EL-AIR *et al.*, Ohio Edison
3 Company *et al.*, January 2009).
- 4 4. The Commission was not persuaded that the ATWACC methodology was appropriate
5 for setting rates and declined to use it in the rate proceeding. (Public Service
6 Commission of Wisconsin, Wisconsin Electric Power Company, 5-UR-103).

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

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

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

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

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

^{36/} PGE/1100, Villadsen/42, footnote 56.

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

3 In her third risk premium analysis, Dr. Villadsen relies on earned returns on
4 equity relative to long-term Treasury yield to produce the historical equity risk premium
5 over the same 1997-2014 time period. This analysis produced an average equity risk
6 premium of 5.93%. Dr. Villadsen then adds to her average risk premium “her” projected
7 20-year Treasury yield of 4.64%. This produces a return estimate of 10.57% (4.64% +
8 5.93%), rounded to 10.6%.

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

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

19 In the 1980s, equity risk premiums were inversely related to interest rates, but that
20 was likely attributable to the interest rate volatility that existed at that time. When
21 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.

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

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

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

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

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

^{38/} Morningstar SBBI, 2009 Classic Yearbook at 95-96.

^{39/} *Blue Chip Financial Forecasts*, May 1, 2015 at 2.

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

3 **Q. DO YOU HAVE ANY COMMENTS ON DR. VILLADSEN'S SECOND RISK**
4 **PREMIUM ANALYSIS BASED ON ALLOWED RETURNS ON EQUITY**
5 **RELATIVE TO LONG-TERM TREASURY BOND RATES OVER THE PERIOD**
6 **1997 THROUGH 2014?**

7 **A.** Yes. My primary issue with Dr. Villadsen's second risk premium study is her use of a
8 4.0% Treasury bond yield. As noted above, current observable and current forecasted
9 Treasury bond rates are much lower than the rates used by Dr. Villadsen. Reflecting a
10 3.7% long-term 30-year Treasury bond rate, rather than the 4.0% used in her study,
11 would lower her risk premium estimate from 10.0% down to 9.7%. This single
12 adjustment reduces her risk premium study toward the high-end of my estimated return
13 on equity range for PGE in this proceeding.

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

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

22 Second, Dr. Villadsen produces a risk premium estimate by developing her own
23 projected Treasury bond yield of 4.64%. Her projection of a Treasury bond risk premium
24 appears to be based by adding a 0.64% premium to the 10-year Treasury bond rate of
25 4.0%. The 4.0% rate initially overstates current market outlooks for cost of capital.
26 Further, her claim of a 10-year yield spread between 20-year and 10-year bonds of 0.64%

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

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

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

11 **A.** Risk premium models are producing rather high return on equity estimates in this
12 proceeding. All three of her analyses are based on risk premium estimates of around 6%.
13 These risk premium studies can be applied to current observable Treasury bond yields of
14 2.67% (Exhibit ICNU/315) and updated projected Treasury bond yields of 3.7% (Exhibit
15 ICNU/317). These Treasury bond yields and Dr. Villadsen's risk premium of 6.0%
16 suggest the return on equity falls in the range of 8.7% up to 9.7% (with a midpoint
17 estimate of 9.2%). This risk premium range and midpoint are useful in estimating PGE's
18 current market cost of equity.

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

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

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

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

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

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

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

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

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

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

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

12 **Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?**

13 **A.** Yes, it does.

**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/301

QUALIFICATIONS OF MICHAEL P. GORMAN

June 15, 2015

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

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

4 **Q PLEASE STATE YOUR OCCUPATION.**

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

7 **Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK**
8 **EXPERIENCE.**

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

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

20 In 1987, I was promoted to Director of the Financial Analysis Department. In this
21 position, I was responsible for all financial analyses conducted by the Staff. Among
22 other things, I conducted analyses and sponsored testimony before the ICC on rate of
23 return, financial integrity, financial modeling and related issues. I also supervised the
24 development of all Staff analyses and testimony on these same issues. In addition, I

1 supervised the Staff's review and recommendations to the Commission concerning utility
2 plans to issue debt and equity securities.

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

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

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

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

3 **Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?**

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

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

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

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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.)
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EXHIBIT ICNU/302

RATE OF RETURN

June 15, 2015

Portland General Electric

Rate of Return

| <u>Line</u> | <u>Description</u> | <u>Amount</u> ¹ (1) | <u>Weight</u> ^{1/a} (2) | <u>Cost</u> ^{2/1} (3) | <u>Weighted</u> <u>Cost</u> (4) |
|-------------|--------------------|-----------------------------------|-------------------------------------|-----------------------------------|---------------------------------------|
| 1 | Common Equity | \$ 2,443,817 | 50.00% | 9.25% | 4.63% |
| 2 | Long-Term Debt | <u>\$ 2,441,400</u> | <u>50.00%</u> | 5.43% | <u>2.72%</u> |
| 3 | Total | \$ 4,885,217 | 100.00% | | 7.34% |

Source:

¹Hager-Greene Direct at 2.

²Gorman Direct Testimony, at 2.

^aThe 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.

**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/303

PROXY GROUP

June 15, 2015

Portland General Electric Company

Proxy Group

| <u>Line</u> | <u>Company</u> | <u>Credit Ratings¹</u> | | <u>Common Equity Ratios</u> | |
|-------------|--|-----------------------------------|-----------------------|-------------------------------|--------------------------------------|
| | | <u>S&P</u> (1) | <u>Moody's</u> (2) | <u>SNL¹</u> (3) | <u>Value Line²</u> (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 Capital Corporation | 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 | BBB³ | 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.

**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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EXHIBIT ICNU/304

CONSENSUS ANALYSTS' GROWTH RATES

June 15, 2015

Portland General Electric Company

Consensus Analysts' Growth Rates

| <u>Line</u> | <u>Company</u> | <u>Zacks</u> | | <u>SNL</u> | | <u>Reuters</u> | | <u>Average of Growth Rates</u> |
|-------------|--|---------------------------------------|----------------------------|---------------------------------------|----------------------------|---------------------------------------|----------------------------|--------------------------------|
| | | <u>Estimated Growth %¹</u> | <u>Number of Estimates</u> | <u>Estimated Growth %²</u> | <u>Number of Estimates</u> | <u>Estimated Growth %³</u> | <u>Number of Estimates</u> | |
| | | (1) | (2) | (3) | (4) | (5) | (6) | |
| 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)
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PORTLAND GENERAL ELECTRIC)
COMPANY)
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Request for a General Rate Revision.)
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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)

| <u>Line</u> | <u>Company</u> | <u>13-Week AVG Stock Price¹</u> (1) | <u>Analysts' Growth²</u> (2) | <u>Annualized Dividend³</u> (3) | <u>Adjusted Yield</u> (4) | <u>Constant Growth DCF</u> (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**

UE 294

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

EXHIBIT ICNU/306

PAYOUT RATIOS

June 15, 2015

Portland General Electric Company

Payout Ratios

| <u>Line</u> | <u>Company</u> | <u>Dividends Per Share</u> | | <u>Earnings Per Share</u> | | <u>Payout Ratio</u> | |
|-------------|--|----------------------------|-------------------------|---------------------------|-------------------------|---------------------|-------------------------|
| | | <u>2014</u> (1) | <u>Projected</u> (2) | <u>2014</u> (3) | <u>Projected</u> (4) | <u>2014</u> (5) | <u>Projected</u> (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**

UE 294

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

EXHIBIT ICNU/307

SUSTAINABLE GROWTH RATE

June 15, 2015

Portland General Electric Company

Sustainable Growth Rate

| Line | Company | 3 to 5 Year Projections | | | | | | | | | | Sustainable |
|------|--|-------------------------|------------------|------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------------|--------------|
| | | Dividends | Earnings | Book Value | Book Value | | Adjustment | Adjusted | Payout | Retention | Internal | Growth |
| | | Per Share (1) | Per Share (2) | Per Share (3) | Growth (4) | ROE (5) | Factor (6) | ROE (7) | Ratio (8) | Rate (9) | Growth Rate (10) | 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 | 2014 | Market | Common Shares | | Growth | S Factor ³ | V Factor ⁴ | S * V |
|------|--|--------------------------|------------------------|-------------|--|---------------|--------------|-----------------------|-----------------------|--------------|
| | | Average | Book Value | to Book | Outstanding (in Millions) ² | | | | | |
| | | Stock Price ¹ | Per Share ² | Ratio | 2013 | 3-5 Years | (6) | (7) | (8) | (9) |
| | | (1) | (2) | (3) | (4) | (5) | | | | |
| 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 Incorporated | \$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
OF OREGON**

UE 294

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

EXHIBIT ICNU/308

**CONSTANT GROWTH DCF MODEL
(SUSTAINABLE GROWTH RATE)**

June 15, 2015

Portland General Electric Company

Constant Growth DCF Model (Sustainable Growth Rate)

| <u>Line</u> | <u>Company</u> | <u>13-Week AVG Stock Price¹</u> (1) | <u>Sustainable Growth²</u> (2) | <u>Annualized Dividend³</u> (3) | <u>Adjusted Yield</u> (4) | <u>Constant Growth DCF</u> (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.

**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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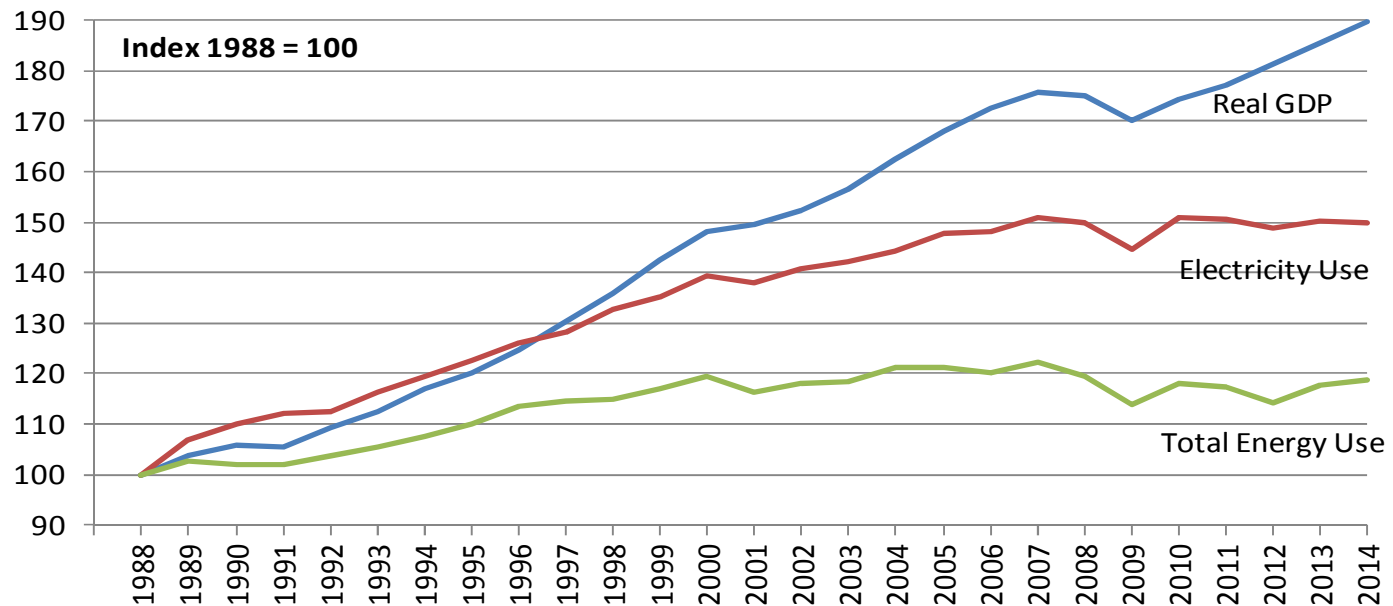
EXHIBIT ICNU/309

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
OF OREGON**

UE 294

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

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 | Annualized | First Stage | Second Stage Growth | | | | | Third Stage | Multi-Stage |
|------|--|---------------------------------|------------------------------|----------------------------|---------------------|---------------|---------------|---------------|----------------|----------------------------|-------------------|
| | | <u>Stock Price</u> ¹ | <u>Dividend</u> ² | <u>Growth</u> ³ | <u>Year 6</u> | <u>Year 7</u> | <u>Year 8</u> | <u>Year 9</u> | <u>Year 10</u> | <u>Growth</u> ⁴ | <u>Growth DCF</u> |
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (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 Incorporated | \$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)
)
Request for a General Rate Revision.)
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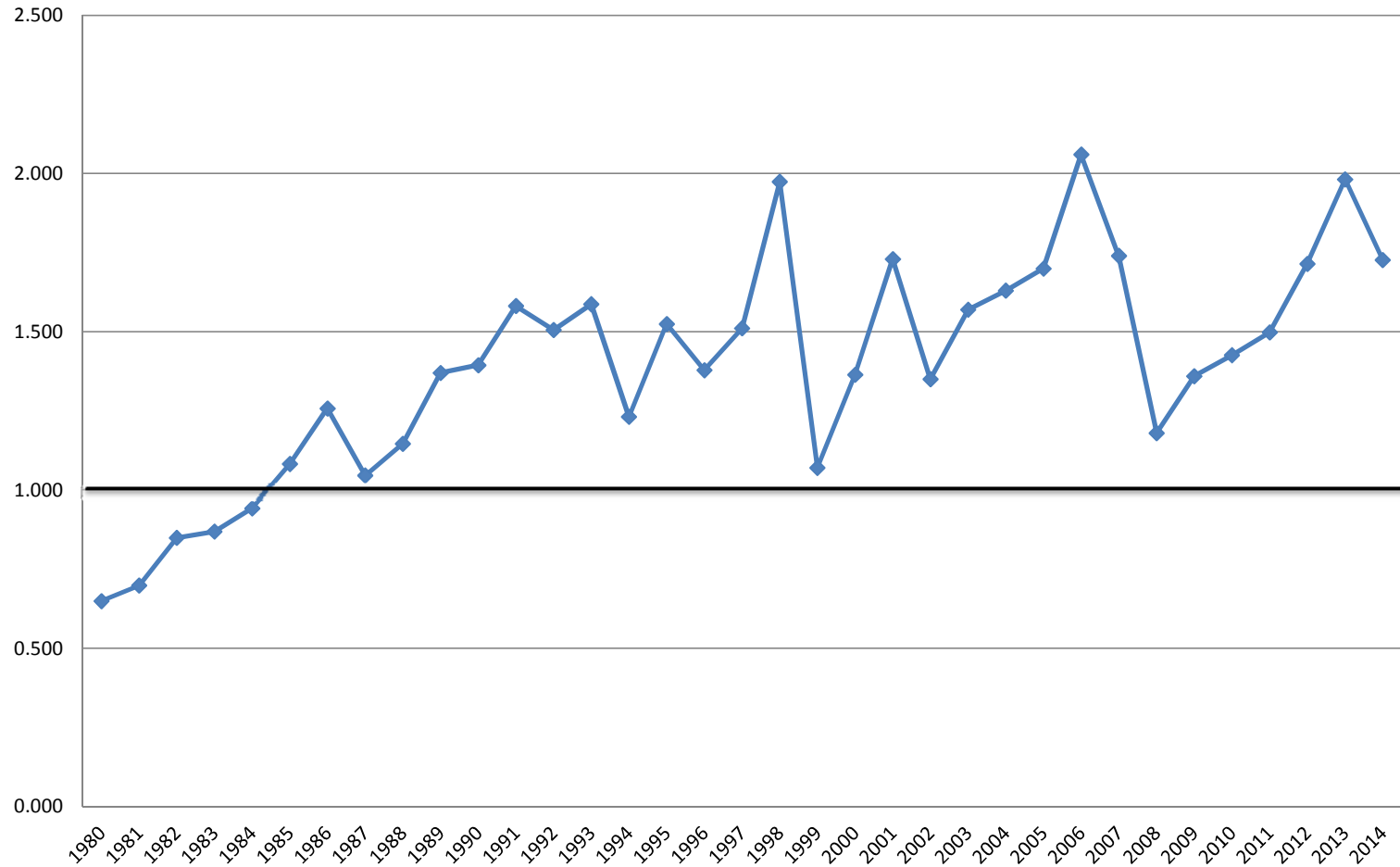
EXHIBIT ICNU/311

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
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/312

EQUITY RISK PREMIUM – TREASURY BOND

June 15, 2015

Portland General Electric Company

Equity Risk Premium - Treasury Bond

| <u>Line</u> | <u>Year</u> | <u>Authorized Electric Returns¹</u> (1) | <u>Treasury Bond Yield²</u> (2) | <u>Indicated Risk Premium</u> (3) | <u>Rolling 5 - Year Average</u> (4) | <u>Rolling 10 - Year Average</u> (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**

UE 294

In the Matter of)
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PORTLAND GENERAL ELECTRIC)
COMPANY)
)
Request for a General Rate Revision.)
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EXHIBIT ICNU/313

EQUITY RISK PREMIUM – UTILITY BOND

June 15, 2015

Portland General Electric Company

Equity Risk Premium - Utility Bond

| <u>Line</u> | <u>Year</u> | <u>Authorized Electric Returns¹</u> (1) | <u>Average "A" Rated Utility Bond Yield²</u> (2) | <u>Indicated Risk Premium</u> (3) | <u>Rolling 5 - Year Average</u> (4) | <u>Rolling 10 - Year Average</u> (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
OF OREGON**

UE 294

In the Matter of)
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PORTLAND GENERAL ELECTRIC)
COMPANY)
)
Request for a General Rate Revision.)
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EXHIBIT ICNU/314

BOND YIELD SPREADS

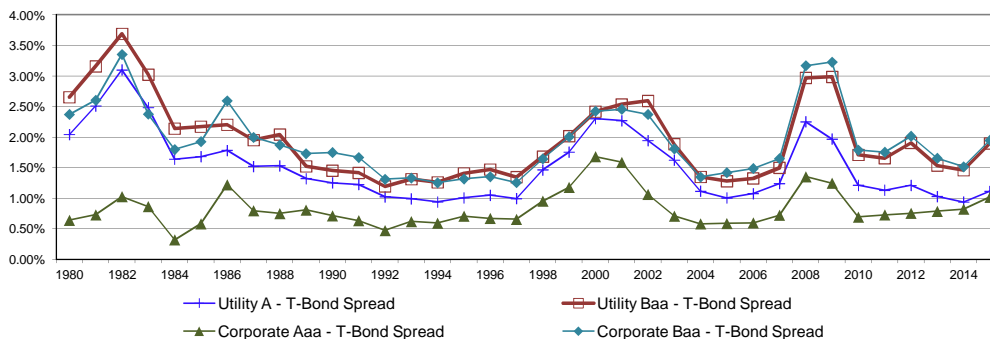
June 15, 2015

Portland General Electric Company

Bond Yield Spreads

| Line | Year | Public Utility Bond | | | | | Corporate Bond | | | | Utility to Corporate | |
|------|-------------------|----------------------------------|-----------------------|-------------------------|------------------------|--------------------------|-------------------------|-------------------------|--------------------------|--------------------------|----------------------|----------------------|
| | | 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

In the Matter of)
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PORTLAND GENERAL ELECTRIC)
COMPANY)
)
Request for a General Rate Revision.)
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EXHIBIT ICNU/315

TREASURY AND UTILITY BOND YIELDS

June 15, 2015

Portland General Electric Company

Treasury and Utility Bond Yields

| <u>Line</u> | <u>Date</u> | <u>Treasury Bond Yield¹</u> (1) | <u>"A" Rated Utility Bond Yield²</u> (2) | <u>"Baa" Rated Utility Bond Yield²</u> (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% |

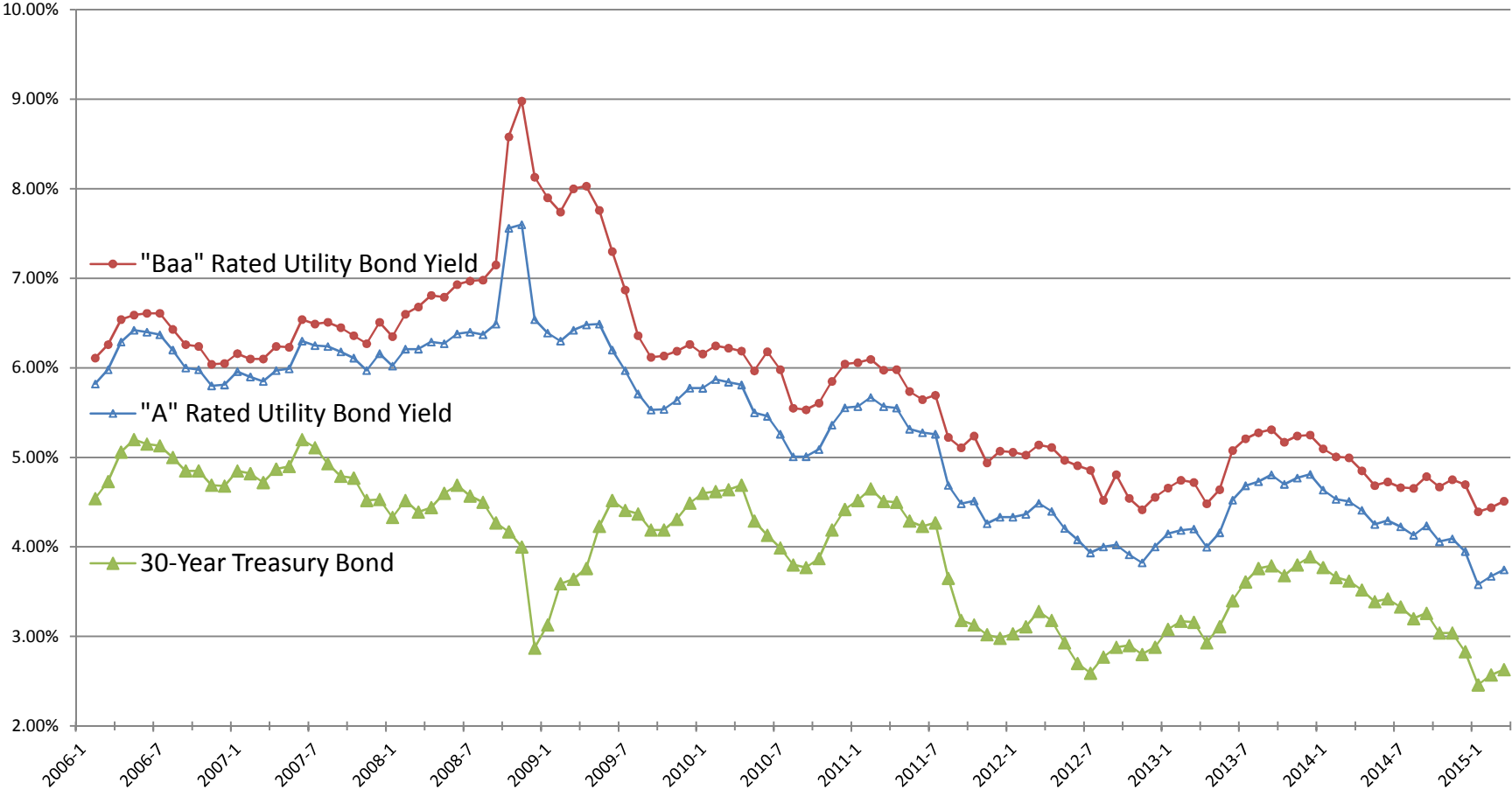
Sources:

¹ St. Louis Federal Reserve: Economic Research, <http://research.stlouisfed.org>.

² <http://credittrends.moody.com/>.

Portland General Electric Company

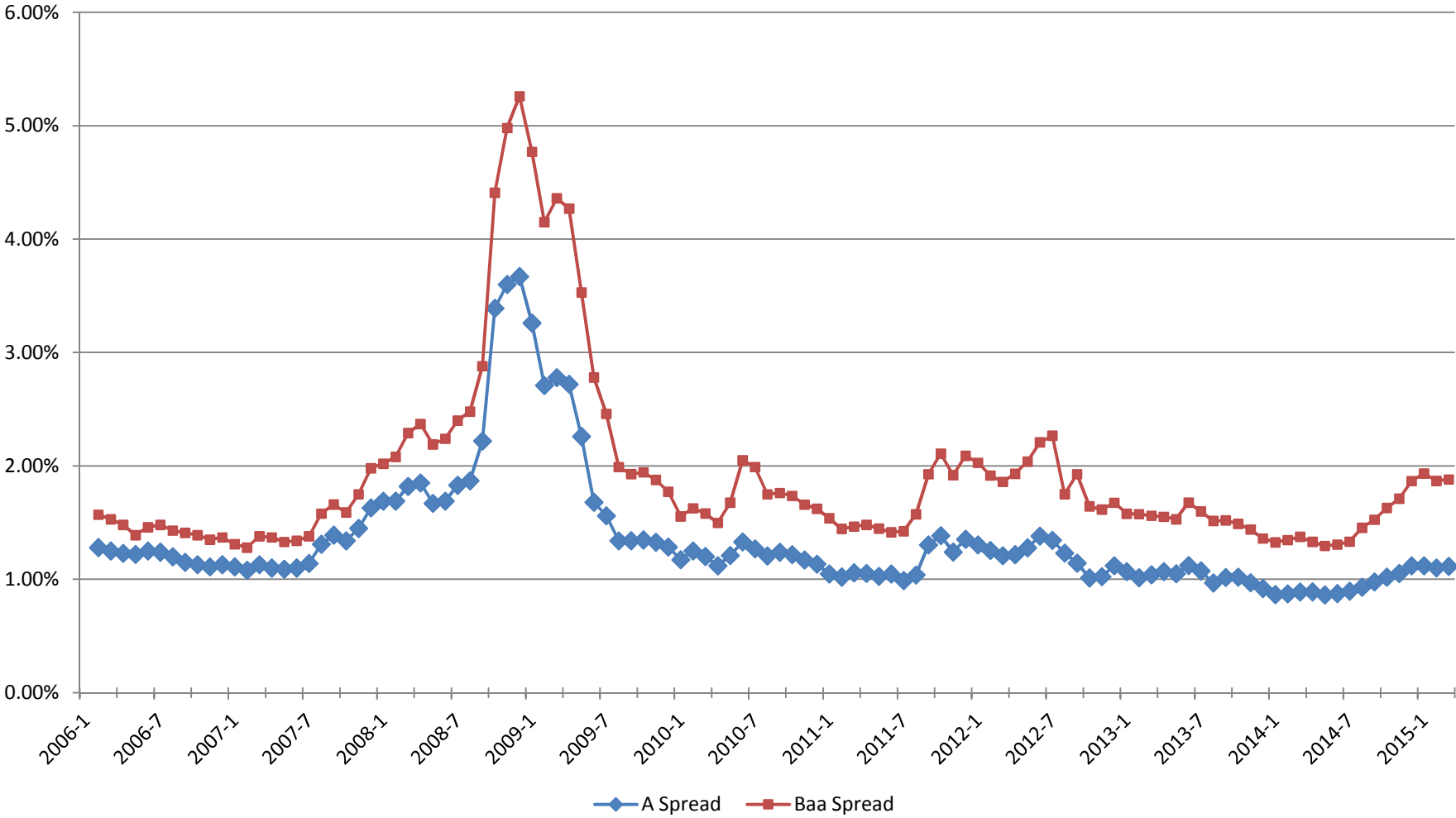
Trends in Bond Yields



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)
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PORTLAND GENERAL ELECTRIC)
COMPANY)
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Request for a General Rate Revision.)
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EXHIBIT ICNU/316

VALUE LINE BETA

June 15, 2015

Portland General Electric Company

Value Line Beta

| <u>Line</u> | <u>Company</u> | <u>Beta</u> |
|-------------|--|-------------|
| 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.

**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/317

CAPM RETURN

June 15, 2015

Portland General Electric Company

CAPM Return

| <u>Line</u> | <u>Description</u> | <u>High Market Risk Premium (1)</u> | <u>Low Market Risk Premium (2)</u> |
|-------------|-----------------------------|---|--|
| 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.

**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/318

STANDARD & POOR'S CREDIT METRICS

June 15, 2015

Portland General Electric

Standard & Poor's Credit Metrics

Thousands of Dollars

| <u>Line</u> | <u>Description</u> | Retail | <u>S&P Benchmark (Medial Volatility)^{1/2}</u> | | | <u>Reference</u> |
|-------------|--|--|--|---------------------------|--------------------------|---|
| | | <u>Cost of Service</u> <u>Amount</u> (1) | <u>Intermediate</u> (2) | <u>Significant</u> (3) | <u>Aggressive</u> (4) | |
| 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)

| <u>Line</u> | <u>Description</u> | <u>Weight</u> ¹ (1) | <u>Cost</u> (2) | <u>Weighted Cost</u> (3) | <u>Pre-Tax Weighted Cost</u> (4) |
|-------------|------------------------------------|-----------------------------------|--------------------|-----------------------------|-------------------------------------|
| 1 | Common Equity | 50.0% | 9.25% | 4.63% | 7.93% |
| 2 | Long-Term Debt | <u>50.0%</u> | 5.43% | <u>2.72%</u> | <u>2.72%</u> |
| 3 | Total | 100.0% | | 7.34% | 10.65% |
| 4 | Tax Conversion Factor ² | | | | 1.72 |

Sources:

¹Exhibit ICNU/302.

²Exhibit PGE 201.

Portland General Electric

Standard & Poor's Credit Metrics (Financial Capital Structure)

Thousands of Dollars

| <u>Line</u> | <u>Description</u> | <u>Amount</u> ¹ (1) | <u>Weight</u> (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 | <u>\$ 146,700</u> | <u>2.8%</u> |
| 4 | Total Long-Term Debt | \$ 2,707,318 | 52.6% |
| 5 | Common Equity | <u>\$ 2,443,817</u> | <u>47.4%</u> |
| 6 | Total | \$ 5,151,135 | 100.0% |

Sources:

¹Exhibit ICNU/302.

²S&P Global Credit Portal, accessed on June 9, 2015.

Portland General Electric

Electric Industry Credit Metrics

| <u>Line</u> | <u>Description</u> | <u>FFO/Debt (%)</u> (1) | <u>Debt / EBITDA (x)</u> (2) | <u>Debt/Debt plus Equity (%)</u> (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.)
)
_____)

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**

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EXHIBITS

- ICNU/401 – List of Regulatory Proceedings
- ICNU/402 – PGE Response to ICNU Data Request No. 136
- ICNU/403 – Sample Franchise Agreement
- ICNU/404 – Comparison of Allocation of Franchise Fees
- ICNU/405 – Summary of ICNU Rate Spread Model
- ICNU/406 – Summary Comparison of PGE and ICNU Rate Spread
- ICNU/407 – Revised CIO Adjustment

I. INTRODUCTION

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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

1 requirements, cost of service, and rate design studies as well as the preparation and
2 submittal of testimony and exhibits in utility rate proceedings on behalf of publicly-
3 owned utilities, industrial customers and other customer groups. Since February 1986, I
4 have held the position of Manager of GDS' office in Austin, Texas. In April 2000, I was
5 elected as a Vice President of GDS. While at GDS, I have provided testimony in
6 numerous regulatory proceedings involving electric, natural gas, and water utilities, I
7 have participated in generic rulemaking proceedings, I have prepared retail rate studies
8 on behalf of publicly-owned utilities, I have prepared utility valuation analyses, I have
9 prepared economic feasibility studies, and I have procured and contracted for wholesale
10 and retail energy supplies.

11 **Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?**

12 A. I have testified many times before regulatory commissions. I have submitted testimony
13 before the following state regulatory authorities: the Public Utility Commission of Texas
14 ("PUC" or the "Commission"), the Texas Commission on Environmental Quality, the
15 Texas Railroad Commission, the Alaska Regulatory Commission, the Arkansas Public
16 Service Commission, the Arizona Corporation Commission, the Delaware Public Service
17 Commission, the Florida Public Service Commission, the Georgia Public Service
18 Commission, the Illinois Commerce Commission, the State Corporation Commission of
19 Kansas, the Louisiana Public Service Commission, the New Mexico Public Service
20 Commission, the Oklahoma Corporation Commission, the Pennsylvania Public Utility
21 Commission, the South Dakota Public Utilities Commission, the Virginia State
22 Corporation Commission, and the West Virginia Public Service Commission. I have also
23 testified before the Federal Energy Regulatory Commission ("FERC"), and two

1 Condemnation Courts appointed by the Supreme Court of Nebraska, and I have
2 submitted an expert opinion report before the United States Tax Court on utility issues.
3 A list of regulatory proceedings in which I have presented expert testimony is provided as
4 ICNU/401.

5 **Q. WOULD YOU PLEASE DESCRIBE GDS?**

6 A. GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin,
7 Texas; Auburn, Alabama; Manchester, New Hampshire; Madison, Wisconsin, and
8 Orlando Florida. GDS has over 175 employees with backgrounds in engineering,
9 accounting, management, economics, finance, and statistics. GDS provides rate and
10 regulatory consulting services in the electric, natural gas, water, storm, and telephone
11 utility industries. GDS also provides a variety of other services in the electric utility
12 industry including power supply planning, generation support services, energy
13 procurement and contracting, energy efficiency program development, financial analysis,
14 load forecasting, and statistical services. Our clients are primarily privately-owned
15 utilities, publicly-owned utilities, municipalities, customers of investor-owned utilities,
16 groups or associations of customers, and government agencies.

17 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

18 A. I am testifying on behalf of the Industrial Customers of Northwest Utilities (“ICNU”).
19 ICNU includes several large industrial customers of Portland General Electric Company
20 (“PGE” or “Company”).

1 **Q. WHAT ARE THE BASIC STEPS FOR PREPARING A CLASS COSS?**

2 A. Typically, there are three steps. These are the functionalization, classification, and
3 allocation of costs. Some utilities which provide service in more than one jurisdiction
4 also perform a jurisdictional allocation step.

5 **Q. PLEASE DESCRIBE THE FUNCTIONALIZATION, CLASSIFICATION, AND**
6 **ALLOCATION STEPS.**

7 A. As stated in my previous answer, cost of service studies are typically developed in three
8 distinct steps. First the various components of the utility's overall revenue requirements
9 are assigned to their functional use, e.g., generation, transmission, distribution, and
10 customer service. Next, the functionalized costs are classified based on cost causation
11 factors to the cost categories of fixed or capacity-related, variable or commodity- related,
12 and customer-related. Finally, the classified costs are directly assigned or allocated to
13 customer classes using allocation factors developed for each classified cost category.
14 Various methodologies or approaches exist for conducting each step in the cost of service
15 study.

16 **Q. PLEASE DESCRIBE THE ALLOCATED COST OF SERVICE STUDY**
17 **INCLUDED IN PGE'S RATE INCREASE APPLICATION.**

18 A. PGE's allocated COSS is sponsored by PGE witness Marc Cody. A summary of Mr.
19 Cody's allocated COSS is attached to his direct testimony as PGE Exhibit 1404. The
20 COSS is also referred to as the rate spread model or exhibit. In my direct testimony, I
21 will use the terms class COSS and rate spread model interchangeably.

22 **Q. ARE THERE DIFFERENT COST BASES FOR DETERMINING A CUSTOMER**
23 **CLASS' ALLOCATED COST OF SERVICE?**

24 A. Yes. There are two different cost bases that can be used for an allocated COSS. First,
25 the COSS can be based on the utility's average embedded costs. Average embedded

1 costs are the utility's booked costs, as revised for known and measurable adjustments.
2 Average embedded costs can be based on an historic test year or on a projected test year.
3 Second, the COSS can be based on the utility's marginal costs. PGE's proposed COSS is
4 based on its marginal costs. The Public Utility Commission of Oregon ("OPUC" or
5 "Commission") is one of the state regulatory agencies that allows the use of marginal
6 costs as the basis for determining the class COSS.

7 **Q. ARE THERE ANY ADDITIONAL STEPS OR CALCULATIONS THAT MUST**
8 **BE MADE WHEN USING MARGINAL COSTS AS THE BASIS FOR A COSS?**

9 A. Yes. A utility's marginal costs are typically greater than the utility's actual or embedded
10 costs used to set its revenue requirements. In some instances, the marginal costs may be
11 lower than the embedded costs. Therefore, it is necessary to adjust the allocated marginal
12 costs downward or upward so that the allocated costs in the COSS will equal the overall
13 Company revenue requirement.

14 **Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING MARGINAL**
15 **COST-BASED COST OF SERVICE STUDIES?**

16 A. Yes. Marginal cost-based COSSs typically classify more of a utility's costs as energy-
17 related. In general, this results in more costs being allocated to high load factor
18 customers or customer classes.

19 **IV. ALLOCATION OF PRODUCTION COSTS**

20 **Q. IS ICNU RECOMMENDING ANY ADJUSTMENT TO PGE'S PROPOSED**
21 **MARGINAL GENERATION COSTS?**

22 A. Yes. ICNU witness Bradley Mullins is presenting testimony on the proper marginal
23 generation costs to be used in this case.

1 **Q. HAVE YOU INCLUDED ICNU'S RECOMMENDED MARGINAL**
2 **GENERATION COSTS IN YOUR CLASS COSS?**

3 A. Yes.

4 **Q. DOES THIS REVISION TO PGE'S MARGINAL GENERATION COSTS**
5 **IMPACT THE ALLOCATION OF OTHER COSTS?**

6 A. Yes. Other costs in PGE's rate spread model are allocated on the basis of the allocated
7 marginal generation costs. For example, ancillary services costs are allocated to
8 customer classes based on their allocated generation costs. Therefore, this change in
9 PGE's marginal generation costs will directly impact the allocation of test year ancillary
10 services costs. Another example is the allocation of PGE's proposed revenue
11 requirement for Carty. The allocation of some general costs and other revenues are also
12 indirectly affected by this change in marginal generation costs. My revised COSS or rate
13 spread model also reflects these other cost allocations impacted by ICNU's revised
14 marginal generation costs.

15 **V. FUNCTIONALIZATION OF FRANCHISE FEES**

16 **Q. IS PGE PROPOSING TO RECOVER TEST YEAR FRANCHISE FEES IN ITS**
17 **PROPOSED BASE RATES?**

18 A. Yes. As shown on PGE Exhibit 1404, the Company is proposing to recover \$46,809,000
19 in franchise fees in its proposed rates. The amount adjusted to cycle is \$46,791,000.

20 **Q. PLEASE DESCRIBE THE PURPOSE OF A PUBLIC UTILITY FRANCHISE**
21 **AND THE RELATED FRANCHISE FEES.**

22 A. A public utility franchise agreement is an agreement between a governmental entity
23 (usually a municipality) and a public utility that typically provides for:

- 24
 - The public utility's use of public right-of-ways ("ROWs) within the governmental
25 entity's jurisdiction,

- 1 • Determines the obligations of the public utility,
- 2 • Sets forth the rules for the use of public ROWs, and
- 3 • Provides for compensation by the public utility for use of the public ROWs.

4 The franchise fee establishes the basis for the compensation to be paid to the
5 governmental entity by the public utility. Usually the basis for the franchise fee is a set
6 percentage of the revenues received by the public utility for the utility services provided
7 within the jurisdiction of the governmental entity.

8 **Q. ARE THE FRANCHISE FEES PAID BY PGE CONSISTENT WITH YOUR**
9 **GENERAL DESCRIPTION?**

10 A. Yes. According to PGE’s response to ICNU data request 136, the Company has
11 franchise agreements with 51 municipalities in its service territory (ICNU/402). In some
12 instances, the terms of the franchise are set forth in a city ordinance rather than in a
13 franchise agreement. The franchise fees paid by PGE under these franchise agreements is
14 primarily based on a percent of the revenues collected by PGE for electric service within
15 the municipality’s city limits. In some situations where customers have chosen direct
16 access service, the franchise fee may be based on an amount per kWh delivered to the
17 direct access customers. A sample of a typical franchise fee agreement for the Company
18 is included as Exhibit ICNU/403.

19 **Q. IS THE FRANCHISE FEE ALSO COMPENSATION FOR THE RIGHT TO**
20 **SERVE CUSTOMERS WITHIN THE MUNICIPALITY’S CITY LIMITS?**

21 A. No. Typically the franchise agreement does not convey to the public utility the exclusive
22 right to serve the customers within the city limits. Instead, as previously stated, the
23 franchise fee is only for the use of public ROWs within the city by the utility. This is true
24 for PGE’s franchise agreements. Below is language from page 17, ICNU/403, which is

1 standard language in many PGE franchise agreements regarding the purpose of the
2 franchise fee:

3 SECTION 12: PAYMENT FOR USE OF PUBLIC ROW.

4 A. Use of Public ROW. In consideration for its use of the Public
5 ROW in accordance with the terms of this Franchise, Grantee agrees to
6 pay the City an amount equal to 3½ percent of the Gross Revenue
7 received by Grantee from its customers within the City unless such
8 percentage is changed during the Term of this Franchise in accordance
9 with its terms.

10
11 **Q. SHOULD THE FRANCHISE FEE BE CONSIDERED AS A TAX?**

12 A. No, it is not a tax. A franchise fee is a rental payment or use fee for the utility's right to
13 use the municipality's public ROWs.

14 **Q. HOW ARE PUBLIC ROWS DEFINED IN FRANCHISE AGREEMENTS?**

15 A. Public ROWs are generally described as space on, above and below streets, alleys, roads,
16 highways, sidewalks, bridges, parks and other public property. In some agreements,
17 public utility easements (PUEs) are also included as public ROWs.

18 **Q. HOW CAN THE UTILITY USE THE PUBLIC ROWS?**

19 A. The franchise agreement will specify how the utility can use the public ROWs. Typically
20 the franchise agreement will allow the utility to install, operate, and maintain poles,
21 conduit, overhead and underground conductors, transformers, communications
22 equipment, and other facilities necessary to deliver electricity to customers in the city.

23 Pages 1-2 of Exhibit ICNU/403, for instance, contains the following standard language in
24 many of PGE's franchise agreements:

25 SECTION 1. NATURE OF FRANCHISE.

26 (A) The City hereby grants to Grantee and its successors and assigns,
27 subject to the terms and conditions in this Franchise, a nonexclusive
28 franchise to erect, construct, repair, maintain, upgrade and operate an

1 electric light and power system within the City as it now exists or may
2 be extended in the future, including related communication equipment
3 for Grantee's internal use and Grantee Facilities. This Franchise
4 includes the privilege to install, repair, maintain, upgrade and operate
5 Facilities necessary for the operation of Grantee's Electric Light and
6 Power System (as defined below) upon, over, along, and across the
7 surface of and the space above and below the streets, alleys, roads,
8 highways, sidewalks, bridges, City park property and other public
9 ways (collectively, "Public ROW"), as well as public utility easements
10 ("PUEs") on third party property as shown on recorded final plats that
11 which will be managed by the City thereafter ... for the provision of
12 public utility services within the City as Grantee's Electric Light and
13 Power System now exists or is extended or upgraded in the future.

14 **Q. HOW IS "GRANTEE'S ELECTRIC LIGHT AND POWER SYSTEM" DEFINED**
15 **IN PGE'S FRANCHISE AGREEMENTS?**

16 A. Not all of PGE's franchise agreements are identical. However, page 6 of Exhibit
17 ICNU/403 contains the most common definition, which is as follows:

18 (9) "Grantee's Electric Light and Power System" means all real
19 property and Grantee Facilities used by Grantee in the transmission
20 and distribution of its services that are located inside the boundaries of
21 the City.

22 **Q. AS THIS DEFINITION SUGGESTS, ARE THE PUBLIC ROWS PRIMARILY**
23 **USED FOR DISTRIBUTION FACILITIES?**

24 A. Yes. Electric utilities primarily use public ROWs for their distribution system facilities.
25 In some cities, public ROWs may also be used for transmission facilities.

26 **Q. ARE THE PUBLIC ROWS ALSO USED FOR GENERATION FACILITIES?**

27 A. No. Typically, utilities own the land where generation facilities are located. Also, most
28 generation facilities are located outside of municipalities' city limits. In addition, as the
29 definition of "Grantee's Electric Light and Power System" demonstrates, the PGE
30 franchise agreements only provide for delivery system facilities on public ROWs.

1 **Q. HOW HAS PGE FUNCTIONALIZED ITS TEST YEAR FRANCHISE FEES?**

2 A. PGE is proposing to functionalize its franchise fees of \$46,791,000 to the generation,
3 transmission and distribution functions. As shown on page 8 of PGE/1400, the amount
4 assigned to each function is based on the total revenue requirement for each function.
5 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.

6

7 **Q. DOES PGE INITIALLY INCLUDE THE ENTIRE FRANCHISE FEE AMOUNT**
8 **IN THE DISTRIBUTION FUNCTION?**

9 A. Yes. As stated on page 30 of PGE/200, the direct testimony of PGE witnesses Alex
10 Tooman and Rebeca Brown, the test year franchise fees are initially assigned entirely to
11 the distribution function, consistent with OAR 860-038-0200(9)(c)(B)(i)(IV). However,
12 in the PGE rate spread model, as shown on PGE Exhibit 1404, page 2, the Company later
13 removes franchise fees from the distribution function and re-functionalizes the franchise
14 fees as shown above.

15 **Q. DO YOU AGREE WITH PGE'S PROPOSED FUNCTIONALIZATION OF**
16 **FRANCHISE FEES?**

17 A. No. As previously discussed, franchise fees are incurred for PGE's transmission and
18 distribution delivery system. Therefore, in order to functionalize franchise fees based on

1 cost causation, they should only be functionalized to the transmission and distribution
2 functions. Using PGE's approach for assigning franchise fees to functions, the table
3 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 |

4 Source: ICNU Exhibit 405, page 6.

5 **Q. DOES YOUR RECOMMENDED FUNCTIONALIZATION OF FRANCHISE**
6 **FEES MAINTAIN CONSISTENCY WITH COMMISSION ORDER 12-500?**

7 A. Yes. While my revised functionalization of franchise fees will increase or decrease the
8 franchise fee rate element in each rate schedule, the change is consistent with the
9 requirements of Order 12-500.

10 **Q. HAVE YOU PREPARED AN EXHIBIT THAT COMPARES THE AMOUNT OF**
11 **FRANCHISE FEES ALLOCATED TO CUSTOMER CLASSES UNDER PGE'S**
12 **PROPOSED AND YOUR RECOMMENDED FUNCTIONALIZATION OF**
13 **FRANCHISE FEES?**

14 A. Yes. My Exhibit ICNU/404 compares the amount of franchise fees allocated to customer
15 classes under both PGE's and my recommended functionalization methodologies.

16 **Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING PGE'S PROPOSED**
17 **FUNCTIONALIZATION AND ALLOCATION OF FRANCHISE FEES?**

18 A. Yes. PGE's proposed functionalization appears to be based on how the amount of the
19 franchise fee payment to cities is calculated rather than on the cause of the franchise fee.
20 Although the franchise fee payment is based on a percentage of total revenue, this should
21 not influence how the franchise fee amount should be functionalized and allocated.

1 Instead, the cause for the fee, i.e., the utility's transmission and distribution costs, should
2 be the basis used for functionalizing the fee. If the basis for the franchise fee, i.e., total
3 revenues or revenue requirement, is used to functionalize franchise fees, then the logical
4 allocation of franchise fees would be to only allocate this cost to customers inside city
5 limits. I am not suggesting or proposing this allocation. I am just pointing out that to
6 consistently allocate franchise fees with PGE's proposed functionalization of franchise
7 fees would be to not allocate and charge franchise fees to customers located outside of
8 city limits since the franchise fee is not based on their revenues.

9 **VI. RECOMMENDED RATE SPREAD**

10 **Q. HAVE YOU PREPARED A REVISED REVENUE SPREAD MODEL THAT**
11 **REFLECTS THE RECOMMENDED ADJUSTMENTS OF ICNU WITNESS**
12 **BRADLEY MULLINS AND YOURSELF?**

13 A. Yes. A summary of my revised rate spread model is provided as ICNU/405.

14 **Q. HOW DO THE RESULTS OF YOUR REVISED REVENUE SPREAD MODEL**
15 **COMPARE TO PGE'S PROPOSED REVENUE SPREAD MODEL?**

16 A. My Exhibit ICNU/406 provides several summary comparisons by customer class under
17 PGE's current and proposed revenues and allocated cost of service and under my
18 recommended proposed revenues and allocated cost of service. The first page of this
19 exhibit includes the Company's proposed revenue requirement increase for Carty. The
20 second page of this exhibit excludes the amounts for Carty should the Commission
21 disallow the Company's Carty proposal. Lines 15 and 9 on page 1 of ICNU/406 shows
22 the cost of service allocated to the customer classes under my revised revenue spread
23 model and the allocated cost of service amounts under PGE's proposed revenue spread
24 model. Both rate spread models are based on the Company's proposed revenue
25 requirement of approximately \$1,921,056,000 with Carty. The table below compares the

1 results of PGE’s rate spread model with the results of my revised rate spread model for
2 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) |

3 Source: ICNU/406

4 **Q. HOW DO THE RESULTS OF YOUR REVISED REVENUE SPREAD MODEL**
5 **COMPARE WITH TEST YEAR REVENUES UNDER CURRENT RATES?**

6 A. A comparison of the customer class revenues under current revenues with the results of
7 my revised revenue spread model is provided in ICNU/406. The table below summarizes
8 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 |

1 Source: ICNU/406

2 **Q. WHAT DOES THE COMPARISON IN TABLE 4 ABOVE INDICATE**
3 **REGARDING INTER-CLASS SUBSIDIES?**

4 A. This table shows that under current rates significant subsidies are being paid from the
5 Schedule 89 customer class to other customer classes.

6 **Q. HAVE YOU ALSO COMPARED THE RESULTS OF YOUR REVISED**
7 **REVENUE SPREAD MODEL WITH TEST YEAR REVENUES UNDER PGE'S**
8 **PROPOSED RATES?**

9 A. Yes. A comparison of the customer class revenues under PGE's proposed rates with the
10 results of my revised revenue spread model is provided in my Exhibit ICNU/406. The
11 table below summarizes this comparison for PGE's proposed revenue requirement with
12 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) |

1 Source: ICNU/406

2 **Q. WHAT DOES THE COMPARISON IN TABLE 5 ABOVE INDICATE**
3 **REGARDING INTER-CLASS SUBSIDIES UNDER PGE'S PROPOSED RATES?**

4 A. As shown in the column on the right, significant inter-class subsidies among the customer
5 classes will result from PGE's proposed rates. This is true even with consideration of
6 PGE's proposed CIO adjustments.

7 **VII. CONSUMER IMPACT OFFSET**

8 **Q. SHOULD THE CUSTOMER CLASS RATES ESTABLISHED IN THIS**
9 **PROCEEDING BE SET EQUAL TO THE CLASS' ALLOCATED COST OF**
10 **SERVICE?**

11 A. While setting class revenue responsibility equal to its cost of service is the proper
12 objective, it could be unreasonable to correct some inter-class subsidy problems entirely
13 in one rate case. To do that could cause significant rate impacts on some customer
14 classes. In that situation, the inter-class subsidies should be eliminated over two or three
15 rate cases in order to gradually phase in the rate impacts. This process is commonly
16 referred to as the gradualism principle.

1 **Q. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE NEED TO**
2 **GRADUALLY ELIMINATE INTER-CLASS SUBSIDIES, IF NECESSARY TO**
3 **AVOID SIGNIFICANT RATE IMPACTS?**

4 A. Yes, in prior PGE rate cases, the Commission has approved a CIO adjustment for this
5 purpose. As stated on page 12 of the Commission’s Order No. 14-422 in UE 283, the
6 CIO is a mechanism that is designed to mitigate the effects of cost-justified increases that
7 greatly exceed the overall average system percent increase.

8 **Q. IS PGE PROPOSING A CIO ADJUSTMENT IN THIS CASE?**

9 A. Yes. PGE’s proposed CIO adjustment is described at page 25, line 14 through page 26,
10 line 16 of PGE/1400, the direct testimony of PGE witness Marc Cody. As discussed in
11 that testimony, PGE is proposing to mitigate the cost of service-based rate increases for
12 the combined Schedules 38 and 49, and that Schedules 83 and 85 pay for the resulting
13 revenue reductions. Under the Company’s proposal, the rate increase before
14 consideration of Carty for the combined group of Schedules 38 and 49 is limited to 12%
15 above current rate revenues. The results of PGE’s proposed CIO adjustment is provided
16 on PGE/1403.

17 **Q. DO YOU HAVE ANY ISSUES WITH PGE’S PROPOSED CIO ADJUSTMENT?**

18 A. While I do not have a problem with applying a CIO in this case, the 12% rate increase
19 cap should be applied to the proposed rate increases including Carty. The Direct
20 Testimony of James J. Piro and Jim Lobdell (PGE/100 at 6:18) makes clear that “[t]he
21 current case is necessary due primarily to the addition of Carty ...” Since most of PGE’s
22 proposed revenue increase is related to Carty, the CIO adjustment should consider the
23 impact of Carty.

1 **Q. SHOULD AN ALTERNATIVE CIO BE MADE BASED ON THE RESULTS OF**
2 **YOUR REVISED RATE SPREAD MODEL?**

3 A. As shown on ICNU/406, setting rates equal to my allocated class cost of service amounts
4 with Carty would result in substantial rate increases for some customer classes. Given
5 this result, a revised CIO adjustment should be made.

6 **Q. PLEASE DESCRIBE YOUR RECOMMENDED CIO ADJUSTMENT.**

7 A. Under the Company's CIO proposal, the rate increase for each customer class before
8 consideration of Carty is limited to 12%. I am utilizing this same threshold for my CIO
9 recommendation except I apply this limit or threshold to customer class rate increases
10 with the increase for Carty.

11 **Q. HOW DO YOU PROPOSE TO ASSIGN TO THE OTHER CUSTOMER**
12 **CLASSES THE REDUCED REVENUE INCREASES THAT ARE CAPPED BY**
13 **THE 12% THRESHOLD?**

14 A. Under my revised application of PGE's proposed CIO, the rate increases for the Schedule
15 38 and 49 customer classes would be reduced. Similar to PGE's CIO adjustment, the
16 reduced revenue amounts from the Schedule 38 and 49 customer classes should be spread
17 to the Schedule 83 and 85 customer classes proportionate to the Schedule 49 historic
18 consumption of customers below or above 200 kW.

19 **Q. WHAT IS THE AMOUNT OF YOUR PROPOSED CIO ADJUSTMENT?**

20 A. My Exhibit ICNU/407 provides the calculation of my revised CIO adjustment at PGE's
21 proposed revenue requirement with Carty. As shown on that exhibit, the cost-based
22 revenue increase for the combined Schedule 38 and 49 customer classes should be
23 reduced by \$6,228,000 in order to limit the rate increase to 12%.

1 **VIII. SUMMARY AND RECOMMENDATIONS**

2 **Q. PLEASE SUMMARIZE THE CONCLUSIONS YOU HAVE REACHED AND**
3 **THE RECOMMENDATIONS YOU ARE MAKING TO THE COMMISSION.**

4 A. I have reached the following conclusions and recommendations.

5 (1) PGE's generation marginal costs should be determined per the recommendation
6 of ICNU witness Bradley Mullins.

7 (2) Franchise fees are not related to generation and should only be assigned to the
8 transmission and distribution functions.

9 (3) ICNU's revised rate spread model should be used to allocate the cost of service to
10 customer classes.

11 (4) A CIO should be implemented in this proceeding that limits rate increases to
12 customer classes by 12%. The 12% cap should be applied based on customer class
13 rate increases after the inclusion of the increase for Carty.

14 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

15 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 Utilities, 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

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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

1 System (as defined below) upon, over, along, and across the
2 surface of and the space above and below the streets, alleys,
3 roads, highways, sidewalks, bridges, City park property and other
4 public ways (collectively, "Public ROW"), as well as public utility
5 easements ("PUEs") on third party property as shown on recorded
6 final plats that which will be managed by the City thereafter (see
7 Section 9), for the provision of public utility services within the City
8 as Grantee's Electric Light and Power System now exists or is
9 extended or upgraded in the future. The City and Grantee shall
10 mutually agree on the location and design of any new Grantee
11 Facilities constructed in City park property. Nothing in this
12 Franchise limits the City from granting others the right to carry on
13 activities similar to, or different from the ones described in this
14 Franchise. The rights granted herein do not include the right to
15 build or site electric generating facilities in the Public ROW.

16 (B) All Grantee Facilities in possession of Grantee currently or
17 during the Term (as defined in Section 2(A)) that are located within
18 the Public ROW are covered by this Franchise and are deemed
19 lawfully placed in their current locations. The City may require
20 relocation of Grantee Facilities as further specified in Section 8.

21 (C) Grantee may provide telecommunications services as defined
22 in ORS 759.005 as it may be amended from time to time via
23 Grantee's Electric Light and Power System if it obtains all
24 necessary and applicable authorizations from the OPUC regarding
25 the provision of telecommunications service to the public and
26 obtains any necessary, lawful and applicable authorization from the
27 City for use of the Public ROW for such provision, including
28 entering into a separate franchise with the City.

29 **SECTION 2. TERM AND EFFECTIVE DATE.**

30 (A) **Effective Date.** The effective date of this Franchise shall be
31 thirty (30) days after the City Council passes a resolution adopting

1 this Franchise and Grantee accepts this Franchise in writing in
2 accordance with Section 25 herein; and if such written acceptance
3 is not so filed within said period, this Franchise shall be null and
4 void.

5 **(B) Duration of Franchise.** The term of this Franchise, and all
6 rights and obligations pertaining thereto, shall be ten years from the
7 effective date of the Franchise ("Term") unless renegotiated or
8 terminated as provided herein. The Term shall automatically renew
9 for two (2) five (5) year Terms, unless either party provides the
10 other party one hundred eighty (180) days advanced written notice
11 of its desire not to renew this Franchise prior to the expiration of the
12 initial Term or renewal Term.

13 **(C) Charter and General Ordinances to Apply.** To the extent
14 authorized by law, this Franchise is subject to the Charter of the
15 City of Beaverton and general ordinance provisions passed
16 pursuant thereto, including the applicable provisions of the City
17 Development- and Site Development Codes and the Engineering
18 Design Manual requiring underground utilities in subdivisions or
19 partitions, and state statutes and regulations existing during the
20 Term. Nothing in this Franchise shall be deemed to waive the
21 requirements of the various codes and ordinances of the City
22 regarding permits, fees to be paid that are generally applicable to
23 other similar businesses operating within the City, including but not
24 limited to fees for permits, inspections, and for administrative time
25 spent in review of construction plans, or the manner of construction.

26 **SECTION 3. DEFINITIONS.**

27 **(A) Captions.** Throughout this Franchise, captions to sections are
28 intended solely to facilitate reading and to reference the provisions
29 of this Franchise. The captions shall not affect the meaning and
30 interpretation of this Franchise.

1 **(B) Definitions.** For purposes of this Franchise, the following
2 terms, phrases, and their derivations shall have the meanings given
3 below unless the context indicates otherwise. When not
4 inconsistent with the context, words used in the present tense
5 include the future tense, words in the plural number include the
6 singular number, and words in the singular number include the
7 plural number. The word "shall" is always mandatory and not
8 merely directory.

9 (1) "City" means the City of Beaverton, Oregon, a municipal
10 corporation, and all of the territory within its corporate
11 boundaries, as such may change from time to time.

12 (2) "City Council" means the Council of the City.

13 (3) "City Engineer" means the City Engineer of the City.

14 (4) "City Recorder" means the Recorder of the City.

15 (5) "Director of Finance" means the Director of Finance of
16 the City.

17 (6) "Franchise" means this Franchise Agreement as fully
18 executed by the City and Grantee and adopted by the City
19 Council by Resolution.

20 (7) "Grantee" means Portland General Electric Company, an
21 Oregon corporation.

22 (8) "Grantee Facility" means any tangible component of
23 Grantee's Electric Light and Power System, including but not
24 limited to any poles, guy wires, anchors, wire, fixtures,
25 equipment, conduit, circuits, vaults, switch cabinets,
26 transformers, secondary junction cabinets, antennas,
27 communication equipment and other property necessary or

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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.

1 **(14) "Person"** means any individual, sole proprietorship,
2 partnership, association, corporation, cooperative, People's
3 Utility District, or other form of organization authorized to do
4 business in the State of Oregon, and includes any natural
5 person.

6 **(15) "Public ROW"** shall have the meaning described in
7 Section 1.1(A).

8 **(16) "PUE"** shall have the meaning described in Section
9 1.1(A).

10 **(17) "Term"** shall have the meaning described in Section
11 2(A).

12 **(18) Year," "annual," or "annually"** means the period
13 consisting of a full calendar year, beginning January 1 and
14 ending December 31, unless otherwise provided in this
15 Franchise.

16 **SECTION 4. CONSTRUCTION**

17 **(A) Construction.** Subject to the NESC, Grantee's Electric Light
18 and Power System shall be constructed and maintained in such
19 manner as not to interfere with sewers, water pipes, or any other
20 property of the City, or with any other pipes, wires, conduits or other
21 facilities that may have been laid in the Public ROW by or under the
22 City's authority. Grantee and the City shall work together during any
23 design process affecting the Public ROW to establish suitable
24 locations for Grantee's Facilities. Assuming there is sufficient space
25 in the Public ROW, all poles shall be placed between the sidewalk
26 and the edge of the Public ROW unless another location is
27 approved by the City Engineer. If there is not sufficient space in the
28 Public ROW, the City agrees to provide a suitable alternative

1 location that meets Grantee's engineering standards, the NESC
2 and generally applicable standards published by the City in order
3 for Grantee to maintain sufficient service.

4 **(B) Acquisition.** Subsequent to the effective date of this
5 Franchise, upon Grantee's acquisition of additional Grantee
6 Facilities in the Public ROW, or upon any addition or annexation to
7 the City of any area in which Grantee retains Grantee Facilities in
8 the Public ROW of such addition or annexation, Grantee shall
9 submit to the City a statement describing all Grantee Facilities
10 involved, whether authorized by a franchise agreement or upon any
11 other form of prior right, together with a map, as described in
12 Section 5, specifying the location of all such Grantee Facilities.
13 Such Grantee Facilities shall immediately be subject to the terms of
14 this Franchise.

15 **(C) Emergency Repairs.** In the event emergency repairs to
16 Grantee Facilities are necessary, Grantee shall as soon as
17 reasonably possible notify the City of the need for such repairs.
18 Grantee may immediately initiate such emergency repairs and
19 apply for appropriate permits the next business day or as soon as
20 reasonably possible following discovery of the emergency.

21 **(D) Reasonable Care.** All work completed by Grantee within the
22 Public ROW shall be conducted with reasonable care and with the
23 goal of minimizing the risk to those using the Public ROW and to
24 minimize the risk of damage to public and third party property. All
25 work shall be performed in accordance with all applicable laws and
26 regulations, including but not limited to the NESC, the conditions
27 contained in the City permit for the work, and generally applicable
28 standards published by the City. Any work completed by Grantee

1 within the Public ROW may be inspected by the City to determine
2 whether it complies with Grantee's permit issued by the City. If
3 emergency work has been completed by Grantee in the Public
4 ROW and the City determines such work was not completed in a
5 City approved location in accordance with the applicable City
6 permit, the City shall notify Grantee and provide Grantee with sixty
7 (60) days after the emergency has passed to re-perform the work in
8 a City approved location in accordance with the applicable City
9 permit, subject to the NESC.

10 **SECTION 5. SUPPLYING MAPS.**

11 Grantee shall maintain maps and data pertaining to the location of
12 Grantee Facilities on file at its corporate offices or at an office in
13 Oregon. After providing Grantee with twenty-four (24) hours prior
14 notice, the City may inspect the maps (excluding Grantee
15 proprietary information) at any time during Grantee's business
16 hours. Upon request of the City and without charge, Grantee shall
17 furnish current maps to the City by electronic data in read-only
18 format showing the general location of Grantee Facilities, excluding
19 Grantee proprietary information. Unless required by law, the City
20 will not sell or provide Grantee prepared maps or data to third
21 parties without written permission from Grantee. Upon request of
22 Grantee, the City will make available to Grantee any relevant City
23 prepared maps or data at no charge to Grantee.

24 **SECTION 6. EXCAVATION.** Subject to Sections 4 and 7, and after obtaining

25 any permits required by the City, Grantee may make all necessary
26 excavations within the Public ROW for the purpose of installing,
27 repairing, upgrading or maintaining Grantee Facilities. The City
28 shall inform the Grantee through the permitting process or earlier, if

1 possible, of any limitations enacted by the City on excavation in
2 particular geographic areas within the City. Notwithstanding the
3 foregoing two sentences, in the case of an emergency that cannot
4 reasonably be addressed without excavation in the Public ROW, no
5 permit shall be required prior to excavation and no limitations on
6 excavation in particular geographic areas within the City shall apply
7 for the Public ROW affected by such emergency; provided, Grantee
8 complies with Sections 4 and 7. Should there be a direct conflict
9 between any terms or conditions stated in a permit granted by the
10 City and the terms of this Franchise, the terms of this Franchise
11 shall control. All excavations made by Grantee in the Public ROW
12 shall be properly safeguarded for the prevention of accidents. All of
13 Grantee's work under this Section shall be completed in strict
14 compliance with all applicable rules, regulations and ordinances of
15 the City. Should a customer of Grantee be required, pursuant to
16 Grantee's tariff on file with the OPUC, to make excavations that are
17 located in the Public ROW, the City agrees that Grantee shall not
18 be responsible or liable for any failure by such customer to comply
19 with any applicable rules, regulations, ordinances of the City and/or
20 with City standards.

21 **SECTION 7. RESTORATION AFTER EXCAVATION.**

22 Except as otherwise provided for in this Section, Grantee shall
23 restore the surface of the Public ROW disturbed by any excavation
24 by Grantee to at least the same condition that it was in prior to
25 excavation, but in any event to the generally applicable City
26 standards published at the time. If Grantee excavates the surface
27 of the Public ROW, Grantee shall be responsible for restoration of
28 the Public ROW and the area affected by the excavation. If

1 Grantee fails to restore the Public ROW to at least the same
2 condition that it was in prior to the excavation, the City shall give
3 Grantee written notice and provide Grantee a reasonable period of
4 time, not to exceed thirty (30) days, to restore the Public ROW. If
5 the work of Grantee creates a public safety hazard as determined
6 by the City Engineer, Grantee may be required to repair or restore
7 the Public ROW within twenty-four (24) hours notice from the City,
8 or such time as agreed between the City Engineer and Grantee,
9 taking into consideration weather and other relevant factors.
10 Should Grantee fail to make such repairs or restorations within the
11 aforementioned time frames, the City may, after providing notice to
12 Grantee and a reasonable opportunity to cure, refill or repave any
13 opening made by Grantee in the Public ROW and the expense
14 thereof shall be paid by Grantee. The City reserves the right, after
15 providing notice to Grantee, to remove or repair any work
16 completed by Grantee, which, in the determination of the City
17 Engineer is inadequate, using a qualified contractor in accordance
18 with applicable state and federal safety laws and regulations. The
19 cost thereof, including the cost of inspection and supervision, shall
20 be paid by Grantee. In the event that Grantee's work is coordinated
21 with other construction work in the Public ROW, the City Engineer
22 may excuse Grantee from restoring the surface of the Public ROW,
23 providing that as part of the coordinated work, the Public ROW is
24 restored to good order and condition.

25 **SECTION 8. RELOCATION.**

26 **(A) Permanent Relocation Required by City** – This subsection
27 covers relocation of overhead Grantee Facilities that will remain
28 overhead, and underground Grantee Facilities that will remain

1 underground. Subject to ORS Chapter 758, the City shall have the
2 right to require Grantee to change the location of Grantee's Electric
3 Light and Power System when necessary or convenient in the
4 interest of the public, and, unless otherwise agreed, the expenses
5 thereof shall be paid by Grantee. However, when the City
6 requests a subsequent relocation of all or part of the same Grantee
7 Facilities less than two years after the initial relocation that is
8 necessary or convenient in the interest of the public, and not at the
9 request of or to accommodate a third party, the subsequent
10 relocation shall be at the expense of the City unless the relocation
11 is necessitated by a natural disaster that is not precipitated by the
12 actions of City or City's agent. The City agrees to provide a
13 suitable location in the Public ROW for Grantee Facilities that
14 meets Grantee's engineering standards, the NESC and generally
15 applicable standards published by the City in order for Grantee to
16 maintain sufficient service. If sufficient space is not available in the
17 Public ROW for Grantee Facilities, Grantee and the City shall
18 cooperate to enable the City to obtain sufficient easements from
19 private property owners to accommodate Grantee Facilities in order
20 to maintain service and permit upgrades of Grantee Facilities.
21 Should Grantee fail to remove or relocate any such Grantee
22 Facilities within sixty (60) days after the date established by the
23 City, or a mutually agreed upon time period which, except in the
24 event of public emergency, absent mutual agreement shall not
25 occur sooner than sixty (60) days after the City provides written
26 notice to remove/relocate to Grantee, the City may cause or effect
27 such removal or relocation, performed by a qualified contractor in
28 accordance with applicable state and federal safety laws and

1 regulations and Grantee's standards, and the expense thereof shall
2 be paid by Grantee.

3 **(B) Notice.** The City will endeavor to provide as much notice prior
4 to requiring Grantee to relocate Grantee Facilities as possible. The
5 notice shall specify the date by which the existing Grantee Facilities
6 must be removed or relocated. Nothing in this provision shall
7 prevent the City and Grantee from agreeing, either before or after
8 notice is provided, to a schedule for relocation.

9 **(C) Permanent Relocation - Undergrounding.** As permitted by,
10 and in accordance with City ordinance and any applicable law,
11 administrative rule, or regulation, the City may require Grantee to
12 convert any overhead Grantee Facilities to underground Grantee
13 Facilities at the same or different locations, subject to Grantee's
14 engineering and safety standards. This subsection shall not apply
15 to Grantee Facilities used for or in connection with the transmission
16 of electric energy at nominal voltages in excess of 35,000 volts or
17 to pedestals, cabinets or other related above-ground equipment,
18 except that Grantee shall convert specific pedestals, cabinets or
19 other related above-ground equipment to underground if the City
20 agrees to pay a "premium charge" that equals the difference
21 between the cost of the standard above-ground equipment and the
22 cost of the version of such equipment that meets Grantee's
23 engineering and safety standards for placement underground . Any
24 such relocation shall be consistent with applicable long-term
25 development plans or projects of the City, or as approved by the
26 City. The expense of such a conversion shall be paid by Grantee,
27 and Grantee may recover its costs from its customers in
28 accordance with state law, administrative rule, or regulation. The

1 City may designate that Grantee collect such costs from only a
2 portion of its customers within the boundaries of the City in
3 accordance with OAR 860-022-0046(4) as it may be amended from
4 time to time. The City agrees to provide a suitable location in the
5 Public ROW that meets Grantee's engineering standards, the
6 NESC and generally applicable standards published by the City in
7 order for Grantee to maintain sufficient service. If sufficient space
8 is not available in the Public ROW, then the City will obtain
9 sufficient easements from private property owners to accommodate
10 Grantee Facilities in order to maintain service and permit upgrades
11 of Grantee Facilities. Nothing in this subsection prevents the City
12 and Grantee from agreeing to a different form of cost recovery
13 consistent with applicable statutes, administrative rules, City Code
14 or City Charter and Grantee's tariff on file with the OPUC on a
15 case-by-case basis.

16 **(D) Temporary Relocation at Request of Third Parties.**

17 Whenever it is necessary to temporarily relocate or rearrange any
18 Grantee Facility in order to permit the passage of any building,
19 machinery or other object, Grantee shall perform the work after
20 receiving sixty (60) business days written notice from the persons
21 desiring to move the building, machinery or other object. The
22 notice shall: (1) demonstrate that the third party has acquired at its
23 expense all necessary permits from the City; (2) detail the route of
24 movement of the building, machinery, or other object; (3) provide
25 that the person requesting the temporary relocation shall be
26 responsible for Grantee's costs; (4) provide that the requestor shall
27 indemnify and hold harmless the City and Grantee from any and all
28 damages or claims resulting either from the moving of the building,

1 machinery or other object or from the temporary relocation of
2 Grantee Facilities; and (5) be accompanied by a cash deposit or
3 other security acceptable to Grantee for the costs of relocation.
4 Grantee in its sole discretion may waive the security obligation.
5 The cash deposit or other security shall be in an amount
6 reasonably calculated by Grantee to cover Grantee's costs of
7 temporary relocation and restoration. All temporary relocations
8 under this subsection shall comply with ORS 757.805.

9 **(E) Temporary Relocation at Request of City.** Subject to
10 ORS Chapter 758, the City may require Grantee to temporarily
11 remove and relocate Grantee Facilities, subject to Grantee's
12 engineering and safety standards, by giving sixty (60) days notice
13 to Grantee. Prior to such relocation, the City agrees to provide a
14 suitable location in the Public ROW, as mutually agreed, or a
15 temporary construction easement that meets Grantee's engineering
16 standards, the NESC and generally applicable standards published
17 by the City, and that allows the Grantee to place its Facilities on the
18 easement in order for Grantee to maintain sufficient service until
19 such time as Grantee moves its Facilities to their permanent
20 location. The City will assist Grantee in acquiring easements from
21 private property owners if a sufficient location is not available in the
22 Public ROW that meets Grantee's engineering standards and
23 NESC requirements, or the City has not obtained construction
24 easements for the public project necessitating the temporary
25 relocation. The cost of removal or relocation of Grantee Facilities
26 that is necessary or convenient for public projects shall be paid by
27 Grantee; however, when relocation is to be temporary and both the
28 initial and the subsequent relocation are necessary or convenient

1 for public projects, including but not limited to those involving
2 installation or relocation of essential government owned services,
3 such as sewer, water and storm drainage, and not at the request of
4 or to accommodate a third party, the initial relocation shall be at the
5 expense of Grantee and subsequent relocations occurring less than
6 two years after the initial relocation shall be at the expense of the
7 City unless the relocation is necessitated by a natural disaster that
8 is not precipitated by the actions of City or City's agent.

9 **(F) Permanent Relocation at Request of Third Party.** In the
10 event that any relocation is requested by or is to accommodate a
11 third party, Grantee shall seek reimbursement from the third party
12 and not from the City. Such relocation shall be consistent with any
13 applicable long-term development plan or projection of the City or
14 approved by the City; however, if relocation of Grantee Facilities is
15 caused or required by the conditions placed by the City on approval
16 for projects of third parties, such relocation shall in no event fall
17 under the provisions of subsections (A), (C) or (E) of this Section 8.
18 The City and Grantee agree to cooperate to minimize the economic
19 impact of such relocation on each Party.

20 **SECTION 9. PUBLIC ROW VACATION.**

21 If all or a portion of the Public ROW used by Grantee is vacated by
22 the City during the Term, upon request and if reasonably possible,
23 the City shall either condition the approval of the vacation on the
24 reservation of an easement for Grantee Facilities in their then-
25 current location that prohibits any use of the vacated property that
26 interferes with Grantee's full enjoyment and use of its easement, or
27 permit Grantee Facilities to remain in a PUE. Upon request, the
28 City will cooperate with Grantee to identify alternative locations

1 within the Public ROW for Grantee Facilities if they are not
2 permitted to remain in the vacated area.

3 **SECTION 10. CITY PUBLIC WORKS AND IMPROVEMENTS.**

4 Nothing in this Franchise shall be construed in any way to prevent
5 the City from excavating, grading, paving, planking, repairing,
6 widening, altering, or completing any work that may be needed or
7 convenient in the Public ROW that is consistent with the NESC.
8 The City shall coordinate any such work with Grantee to avoid, to
9 the extent reasonably foreseeable, any obstruction, injury or
10 restrictions on the use by Grantee of any Grantee Facilities, and the
11 City shall be responsible for the costs to repair any damage to
12 Grantee Facilities arising out of such work. Nothing in this Section
13 relieves Grantee from its obligations stated in Section 8.

14 **SECTION 11. USE OF GRANTEE FACILITIES.**

15 City shall enter into attachment agreements with Grantee and
16 obtain permits to string wires on Grantee's poles or run wires in
17 Grantee's trenches and/or conduit for municipal purposes and to
18 attach fire and police alarm and communication equipment to
19 Grantee's poles, provided that such wires and equipment: a) do not
20 unreasonably interfere with Grantee operations; b) conform to the
21 NESC; and c) the City's excess capacity on such wires and
22 equipment is not leased to, sold to or otherwise used by non-
23 governmental third parties. Grantee shall not charge the City for
24 such attachments to its poles or in its conduits; however, the City
25 shall be responsible to pay for any make-ready and inspections
26 Grantee must perform in order to provide access to Grantee
27 Facilities for City wires and equipment in accordance with the
28 NESC. Should any of the City's attachments to Grantee Facilities

1 violate the NESC, the City shall work with Grantee to address and
2 correct such violations in an agreed-upon period of time. The City
3 shall indemnify and hold Grantee harmless from loss or damage
4 resulting from the presence of City's wires and equipment on or in
5 Grantee Facilities. For purposes of this Franchise, "make-ready"
6 shall mean engineering or construction activities necessary to make
7 a pole, conduit, or other support equipment available for a new
8 attachment, attachment modifications, or additional facilities.

9 **SECTION 12. PAYMENT FOR USE OF PUBLIC ROW.**

10 **(A) Use of Public ROW.** In consideration for its use of the Public
11 ROW in accordance with the terms of this Franchise, Grantee
12 agrees to pay the City an amount equal to 3 1/2 percent of the
13 Gross Revenue received by Grantee from its customers within the
14 City unless such percentage is changed during the Term of this
15 Franchise in accordance with its terms. The payment for each year
16 shall be based on the Gross Revenue collected by Grantee during
17 the previous calendar year from Grantee's customers, and shall be
18 paid on an annual basis. To the maximum extent permissible
19 under state law and regulation, the payment imposed by this
20 subsection shall be considered an operating expense of Grantee
21 and shall not be itemized or billed separately to consumers within
22 the City.

23 **(B) Property Tax Limitations Do Not Apply.** The payment
24 described in this Section 12 is not subject to the property tax
25 limitations of Article XI, Sections 11(b) and 11(19) of the Oregon
26 Constitution and is not a fee imposed on property or property
27 owners by fact of ownership.

1 **(C) Privilege Tax.** The City shall retain the right, as permitted by
2 Oregon law, to charge a privilege tax based on a percentage of the
3 Gross Revenue earned from Grantee's customers within the City in
4 addition to the payment amounts set forth in subsection (A). The
5 City shall provide Grantee at least ninety (90) days notice prior to
6 such privilege tax becoming effective. Grantee shall follow state
7 regulations regarding the inclusion of such privilege tax as an
8 itemized charge on the electricity bills of its customers within the
9 City. No later than forty-five (45) days following a calendar quarter,
10 Grantee shall remit to the Director of Finance any privilege tax
11 collected during the previous quarter and a statement showing the
12 amount of Gross Revenues for such quarter.

13 **(D) Remittance of Annual Payment.** Grantee shall remit to the
14 Director of Finance on or before the first (1st) day of April of each
15 year, the annual franchise fee payment. Payment must be made in
16 immediately available federal funds. With its annual payment,
17 Grantee shall provide the City a statement under oath showing the
18 Gross Revenue for the preceding year.

19 **(E) Acceptance of Payment.** Acceptance by the City of any
20 payment due under this Section shall not be a waiver by the City of
21 any breach of this Franchise occurring prior to the acceptance, nor
22 shall the acceptance by the City preclude the City from later
23 establishing that a larger amount was actually due, or from
24 collecting the balance due to the City.

25 **(F) Late Payments.** Interest on late payments shall accrue from
26 the due date based on Grantee's cost of debt as approved by the
27 OPUC as of the due date, and shall be computed based on the
28 actual number of days elapsed from the due date until payment.
29 Interest shall accrue without regard to whether the City has

1 provided notice of delinquency. If the late payment is discovered as
2 a result of an audit, Section 13 shall apply.

3 **(G) No Exemption From Other Fees or Taxes.** Payment of the
4 amounts described in this Section 12 shall not exempt Grantee
5 from the payment of any other license fee, tax or charge on the
6 business, occupation, property or income of Grantee that may be
7 lawfully imposed by the City or any other taxing authority, including
8 but not limited to charges for plan review and fees for inspection,
9 except as may otherwise be provided in the ordinance or laws
10 imposing such other license fee, tax or charge.

11 **(H) Direct Access and Volumetric Methodologies.** The City
12 may, consistent with state law, direct that the payments made under
13 this Section 12 be based on volume-based methodologies as
14 specifically described in ORS 221.655 instead of the formula set out
15 in subsections 12 (A) and (C). Notice must be given to Grantee in
16 writing for the subsequent payments to be made using volume-
17 based methodology. The volumetric calculation shall apply to
18 payments made in one calendar year (based on January 1 to
19 December 31 billings from the previous calendar year). The choice
20 to use volumetric methodology must be renewed annually by the
21 City. No notice is necessary if the City chooses to remain on the
22 revenue-based calculation.

23 **(I) Payment Obligation Survives Franchise.** If prior to the
24 expiration of this Franchise the parties do not finish negotiation of a
25 new franchise agreement, the obligation to make the payments
26 imposed by this Section 12 shall survive expiration of this Franchise
27 until a new franchise agreement becomes effective and supersedes
28 this Franchise. In the event this Franchise is terminated before
29 expiration, Grantee shall make the remaining payments owed, if
30 any, within ninety (90) days of the termination date.

31 **SECTION 13. AUDIT.**

1 **(A) Audit Notice and Record Access.** The City may request a
2 third party audit of Grantee's calculation of Gross Revenues for any
3 time period more recent than the time period covered by the most
4 recent audit . Within ten (10) business days after receiving a written
5 request from the City, or such other time frame as agreed by both
6 parties, Grantee shall furnish the City and any auditor retained by
7 the City: (1) information sufficient to demonstrate that Grantee is in
8 compliance with this Franchise; and (2) access to all books,
9 records, maps and other documents maintained by Grantee with
10 respect to Grantee Facilities that are necessary for the City to
11 perform such audit. Grantee shall provide access to such
12 information to City within the City, or the Portland, Oregon
13 metropolitan area, during regular Grantee business hours.

14 **(B) Audit Payment.** If the City's audit shows that the amounts due
15 to the City are higher than those based on the Grantee's calculation
16 of Gross Revenue, then Grantee shall make a payment for the
17 difference within sixty (60) days after the delivery to Grantee of the
18 audit results. In addition to paying any underpayment, Grantee
19 shall pay interest at the statutory rate designated in ORS 82.010 as
20 it may be amended from time to time, but not penalties, as specified
21 in this Franchise, from the original due date. If the City's audit
22 shows that the amounts due to the City are less than those based
23 on Grantee's calculation of Gross Revenue, then the Grantee shall
24 deduct its overpayment from the next franchise fee payment the
25 Grantee makes to the City, including interest at the statutory rate
26 designated in ORS 82.010, as it may be amended from time to
27 time, from the original due date. The City and the Grantee agree
28 that they will split the cost of any third party audit conducted
29 pursuant to this Section 13, and shall cooperate in good faith to
30 select an acceptable third party auditor.

31 **SECTION 14. TERMINATION AND REMEDIES.**

1 **(A) By City for Cause.** If Grantee ceases to maintain Grantee
2 Facilities in accordance with the maintenance commitments
3 outlined in the Service Quality Measures Review filed with the
4 OPUC, and this causes an increase in the risk to the public of
5 personal injury or property damage, the City shall notify Grantee
6 and Grantee shall have thirty (30) days after the date of the notice
7 to eliminate such risk or, if such risk can not be eliminated within
8 thirty (30) days, such reasonable time period as is required to
9 eliminate such risk and Grantee shall bear all costs related to
10 remedying the risk. If Grantee does not eliminate the risk in
11 accordance with the preceding sentence, the City may then
12 terminate this Franchise by providing Grantee written notice of
13 termination.

14 **(B) By City if City Will Provide Service.** The City may terminate
15 this Franchise upon one year's written notice to Grantee in the
16 event that the City decides to engage in public ownership of the
17 electric facilities located in the Public ROW and the public
18 distribution of electric energy to customers throughout the City in
19 accordance with ORS 758.470.

20 **(C) City Reserves Right to Terminate.** In addition to any other
21 rights provided for in this Franchise, the City reserves the right,
22 subject to subsections 14 (E) and (F), to terminate this Franchise in
23 the event that:

24 (1) The Grantee materially violates any material provision of
25 this Franchise;

26 (2) The Grantee is found by a court of competent jurisdiction
27 to have practiced any material fraud or deceit upon the City;

28 (3) There is a final determination that Grantee has failed,
29 refused, neglected or is otherwise unable to obtain or
30 maintain Grantee's service territory designation required by

1 any federal or state regulatory body regarding Grantee's
2 operation of Grantee's Electric Light and Power System or
3 **(4) Grantee becomes unable or unwilling to pay its debts, or**
4 **is adjudged bankrupt.**

5 **(D) Material Provisions.** For purposes of this Section 14, the
6 following are material provisions of this Franchise, allowing the City
7 to exercise its rights under this Section 14 or as set forth elsewhere
8 in this Franchise:

9 **(1) The invalidation, failure to pay or any suspension of**
10 **Grantee's payments of franchise fees or privilege taxes to**
11 **the City for use of the Public ROW under this Franchise;**

12 **(2) Any failure by Grantee to submit timely reports as may be**
13 **requested by the City, regarding the calculation of its**
14 **franchise fees or privilege taxes paid or to be paid to the**
15 **City;**

16 **(3) Any failure by Grantee to maintain the liability insurance**
17 **or self insurance required under this Franchise;**

18 **(4) Any failure by Grantee to provide copies of requested**
19 **information as provided under Sections 4, 5, and 13 above;**
20 **and**

21 **(5) Any failure by Grantee to otherwise substantially comply**
22 **with the requirements of Section 4 through Section 20 of this**
23 **Franchise, unless otherwise agreed.**

24 **(E) Notice and Opportunity to Cure.** The City shall provide
25 Grantee thirty (30) days prior written notice of its intent to exercise
26 its rights under this Section 14, stating the reasons for such action.
27 If Grantee cures the basis for termination or if the Grantee initiates
28 efforts satisfactory to the City to remedy the basis for termination

1 and the efforts continue in good faith within the thirty (30) day
2 notice period, the City shall not exercise its remedy rights. If
3 Grantee fails to cure the basis for termination or if the Grantee does
4 not undertake and/or maintain efforts satisfactory to the City to
5 remedy the basis for termination within the thirty (30) day notice
6 period, then the City Council may impose any or all of the remedies
7 available under this Section 14.

8 **(F) Remedies.** In determining which remedy or remedies are
9 appropriate, the City shall consider the nature of the violation, the
10 person or persons burdened by the violation, the nature of the
11 remedy required in order to prevent further such violations, and any
12 other matters the City deems appropriate.

13 **(G) Financial Penalty.** In addition to any rights set out elsewhere
14 in this Franchise, as well as its rights under the City Code or other
15 law, the City reserves the right at its sole option to impose a
16 financial penalty of up to \$500.00 per day per material violation of a
17 material provision of this Franchise when the opportunity to cure
18 has passed.

19 **SECTION 15. ASSIGNMENT OF FRANCHISE.**

20 Grantee shall not sell, assign, transfer, or convey this Franchise to
21 a third party without the City Council giving its consent in a duly
22 passed resolution. Upon obtaining such consent, this Franchise
23 shall inure to and bind such third party. Grantee shall not sell or
24 assign this Franchise to an entity that is not authorized by the
25 OPUC to provide electric service to retail consumers in the City or
26 is not otherwise authorized to provide electric service to retail
27 consumers under Oregon law. Prior to any proposed transfer,
28 Grantee shall be in full compliance with this Franchise and the

1 proposed transferee shall agree in writing to be bound by this
2 Franchise. In the event Grantee is purchased by or merged into
3 another entity and Grantee survives such purchase or merger as a
4 public utility, Grantee shall provide notice to the City of such
5 purchase or merger, but shall have no obligation under this
6 Franchise to obtain the consent of the City Council for such
7 purchase or merger.

8 **SECTION 16. REMOVAL OF FACILITIES.**

9 If this Franchise is terminated or expires on its own terms and is not
10 replaced by a new franchise agreement or similar authorization, the
11 City may determine whether Grantee Facilities are to be removed
12 from the Public ROW or remain in place. The City shall provide
13 written notice of any requirement to remove Grantee Facilities and
14 shall provide Grantee sixty (60) days to comment on such
15 requirement to move Grantee Facilities. Following consideration of
16 any such comments, the Mayor may issue an order requiring
17 removal of Grantee Facilities within nine (9) months after such
18 order is declared.

19 **SECTION 17. NONDISCRIMINATION.**

20 Grantee shall provide service to electric light and power consumers
21 in the City without undue discrimination or undue preference or
22 disadvantage, in accordance with Oregon law.

23 **SECTION 18. INDEMNIFICATION.**

24 To the fullest extent permitted by law, Grantee shall indemnify and
25 hold harmless the City against any and all claims, damages, costs
26 and expenses, including attorney's fees and costs, to which the City
27 may be subjected as a result of any negligent or willful misconduct
28 of Grantee, or its affiliates, officers, employees, agents, contractors

1 or subcontractors, arising out of the rights and privileges granted by
2 this Franchise. The obligations imposed by this Section are
3 intended to survive termination of this Franchise.

4 **SECTION 19. INSURANCE.**

5 Grantee shall obtain and maintain in full force and effect, for the
6 entire Term, the following insurance covering risks associated with
7 Grantee's ownership and use of Grantee Facilities and the Public
8 ROW:

9 **(A) Commercial General Liability insurance covering all operations**
10 **by or on behalf of Grantee for Bodily Injury and Property Damage,**
11 **including Completed Operations and Contractors Liability coverage,**
12 **in an amount not less than Two Million Dollars (\$2,000,000.00) per**
13 **occurrence and in the aggregate.**

14 **(B) Business Automobile Liability insurance to cover any vehicles**
15 **used in connection with its activities under this Franchise, with a**
16 **combined single limit not less than One Million Dollars**
17 **(\$1,000,000.00) per accident. (C) Workers' Compensation**
18 **coverage as required by law and Employer's Liability Insurance**
19 **with limits of \$1,000,000. With the exception of Workers'**
20 **Compensation and Employers Liability coverage, Grantee shall**
21 **name the City as an additional insured on all applicable policies.**

22 **All insurance policies shall provide that they shall not be canceled**
23 **or modified unless thirty (30) days prior written notice is provided to**
24 **the City. Grantee shall provide the City with a certificate of**
25 **insurance evidencing such coverage as a condition of this**
26 **Franchise and shall provide updated certificates upon request.**

27 **(D) In Lieu of Insurance. In lieu of the insurance policies required**
28 **by this Section 19, Grantee shall have the right to self-insure any**

1 and all of the coverage outlined hereunder. If Grantee elects to
2 self-insure, it shall do so in an amount at least equal to the
3 coverage requirements of this Section 19 in a form acceptable to
4 the City. Grantee shall provide proof of self-insurance to the City
5 before this Franchise takes effect and thereafter upon request by
6 the City.

7 **SECTION 20. DAMAGE TO FACILITIES.**

8 The City shall not be liable for any consequential damages or
9 losses resulting from any damage to or loss of any facility as a
10 result of or in connection with any work by or for the City unless the
11 damage or loss is the direct and proximate result of willful,
12 intentionally tortious, negligent or malicious acts or omissions by
13 the City, its employees, or agents. In such case, the City shall
14 indemnify and hold harmless Grantee against any and all claims,
15 damages, costs and expenses, including attorney's fees and costs,
16 arising therefrom, subject to any applicable limitations in the
17 Oregon Constitution and the Oregon Tort Claims Act. The
18 obligations imposed by this Section are intended to survive
19 termination of this Franchise.

20 **SECTION 21. LIMITATION ON PRIVILEGES.**

21 All rights and authority granted to Grantee by the City under this
22 Franchise are conditioned on the understanding and agreement
23 that the privileges in the Public ROW shall not be an enhancement
24 of Grantee's properties or an asset or item of ownership or property
25 right of Grantee.

26 **SECTION 22. FRANCHISE NOT EXCLUSIVE.**

1 This Franchise is not exclusive and shall not be construed to limit
2 the City from granting rights, privileges and authority to other
3 persons similar to or different from those set forth in this Franchise.

4 **SECTION 23. REMEDIES AND PENALTIES NOT EXCLUSIVE.**

5 All remedies and penalties under this Franchise, including
6 termination, are cumulative and not exclusive, and the recovery or
7 enforcement by one available remedy or imposition of a penalty is
8 not a bar to recovery or enforcement by any other remedy or
9 imposition of any other penalty. The City reserves the right to
10 enforce the penal provisions of any City ordinance or resolution and
11 to avail itself to any and all remedies available at law or in equity.
12 Failure to enforce any term, condition or obligation of this Franchise
13 shall not be construed as a waiver of a breach of any term,
14 condition or obligation of this Franchise. A specific waiver of a
15 particular breach of any term, condition or obligation of this
16 Franchise shall not be a waiver of any other, subsequent or future
17 breach of the same or any other term, condition or obligation of this
18 Franchise.

19 **SECTION 24. SEVERABILITY CLAUSE.**

20 If any section, subsection, sentence, clause, phrase, or other
21 portion of this Franchise is, for any reason, held to be invalid or
22 unconstitutional by a court of competent jurisdiction, all portions of
23 this Franchise that are not held to be invalid or unconstitutional
24 shall remain in effect until this Franchise is terminated or expired.
25 After any declaration of invalidity or unconstitutionality of a portion
26 of this Franchise, either party may demand that the other party
27 meet to discuss amending the terms of this Franchise to conform to

1 the original intent of the parties. If the parties are unable to agree
2 on a revised franchise agreement within ninety (90) days after a
3 portion of this Franchise is found to be invalid or unconstitutional,
4 either party may terminate this Franchise by delivering one hundred
5 and eighty (180) days notice to the other party.

6 **SECTION 25. ACCEPTANCE.**

7 Within thirty (30) days after the ordinance adopting this Franchise is
8 passed by the City Council, Grantee shall file with the City
9 Recorder its written unconditional acceptance of this Franchise. If
10 Grantee fails to do so, the City may withdraw this Franchise at any
11 time prior to January 1, 2010. If the City elects not to withdraw this
12 Franchise on or before January 1, 2010, the Grantee shall be
13 deemed to accept the terms of this Franchise, whether or not a
14 written acceptance has been filed with the City.

15 **SECTION 26. NOTICE.**

16 Any notice provided for under this Franchise shall be sufficient if in
17 writing and (1) delivered personally to the following addressee,
18 (2) deposited in the United States mail, postage prepaid, certified
19 mail, return receipt requested, (3) sent by overnight or commercial
20 air courier (such as Federal Express or UPS), or (4) sent by
21 facsimile transmission with verification of receipt and a copy
22 deposited in the United States mail, addressed as follows, or to
23 such other address as the receiving party hereafter shall specify in
24 writing:

25 **If to the City: Mayor, City of Beaverton**
26 **PO Box 4755**
27 **Beaverton, OR 97076-4755**

1 **FAX # (503) 526-2479**

2 **With a copy to: City Attorney**

3 **City of Beaverton**

4 **PO Box 4755**

5 **Beaverton, OR 97076**

6 **FAX # (503) 350-4033**

7 **If to the Grantee: Regional Manager**

8 **Portland General Electric Company**

9 **2213 SW 153rd Drive**

10 **Beaverton, OR 97006**

11 **FAX: (503) 672-5595**

12 **With a copy to: Portland General Electric Company**

13 **Attn: General Counsel**

14 **One World Trade Center, 17th Floor**

15 **121 SW Salmon Street**

16 **Portland, Oregon 97204**

17 **FAX: (503) 464-2200**

18 Any such notice, communication or delivery shall be deemed effective and
19 delivered upon the earliest to occur of actual delivery, three (3) business days
20 after depositing in the United States mail, one (1) business day after shipment by
21 commercial air courier or the same day as confirmed facsimile transmission (or
22 the first business day thereafter if faxed on a Saturday, Sunday or legal holiday).

23 IN WITNESS WHEREOF, the parties, through their duly authorized
24 representatives, have executed this Franchise as of the dates indicated below.

PORTLAND GENERAL ELECTRIC
COMPANY *(u)*

CITY OF BEAVERTON

By:

Stephen R. Hawke

By:

Denny Doyle

| | |
|---|--------------------------|
| Name: <u>Stephen R. Hawko</u> | Name: <u>Denny Doyle</u> |
| Title: <u>Senior VP. Customer Svc. & Delivery</u> | Title: <u>Mayor</u> |
| Date: <u>12/15/2009</u> | Date: <u>12/3/09</u> |

1

**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 | | 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 | Feeder 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 | Feeder 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)

| Line No. | Description | Customer Classes | | | | | | | | | | | | Total |
|----------|--|-------------------|-----------------|-------------------|-----------------|-----------------|------------------|-------------------|--------------------------|---------------------|------------------|------------------|---------------|---------------------|
| | | 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 | |
| 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 |
| 24 | 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.

UE 294
Comparison of PGE and ICNU Rate Spread Proposals - Not Including Carty Revenue Requirement
(\$ x 1,000)

| Line No. | Description | Customer Classes | | | | | | | | | | | | Total |
|----------|--|-------------------|-----------------|-------------------|-----------------|-----------------|------------------|-------------------|--------------------------|---------------------|------------------|------------------|---------------|---------------------|
| | | 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 | |
| 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 |

¹Schedule 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 | | | | | | 80 | 78 | - | 78 |
| Sch 485 Energy | 711,915 | | | | | | | | | |
| 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 | | | | | | | | | | |
| Cap on CIO (mills/kWh) | | | | | | | | | | |
| Schedule 83 CIO Percent | | | | | | | | | | |
| Schedule 85 CIO Percent | | | | | | | | | | |

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%