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Suite 400
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June 11, 2014

Via Electronic Mail and Federal Express

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

Re: PORTLAND GENERAL ELECTRIC
Request for a General Rate Revision
Docket No. UE 283

Dear Filing Center:

Enclosed for filing in the above-referenced docket, please find the original and five (5) copies of the redacted Opening Testimony and Exhibits of Bradley G. Mullins on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). Also enclosed are the original and five (5) copies of the Opening Testimony and Exhibits of Michael P. Gorman on behalf of ICNU. The confidential pages of Mr. Mullins' testimony and exhibits are being filed under seal in accordance with Protective Order No. 14-043.

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

Sincerely,

Jesse O. Gorsuch

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the attached **Opening Testimony and Exhibits of Bradley G. Mullins and Michael P. Gorman** upon all parties in this proceeding by sending a copy via electronic mail, and by sending the confidential pages of same via U.S. Mail, postage prepaid, to the following parties at the following addresses.

Dated at Portland, Oregon, this 11th day of June, 2014.

Sincerely,

Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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 11, 2014

OPENING TESTIMONY OF BRADLEY G. MULLINS

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ATTACHED EXHIBITS

I. INTRODUCTION AND SUMMARY

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. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent consultant representing industrial customers throughout the western United States. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU"), a non-profit trade association whose members are large customers served by electric utilities throughout the Pacific Northwest, including Portland General Electric Company (the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I received Bachelor of Science degrees in Finance and in Accounting from the University of Utah. I also received a Master of Science degree in Accounting from the University of Utah. After receiving my Master of Science degree, I worked at Deloitte Tax, LLP, where I was a Tax Senior providing tax consulting services to multi-national corporations and investment fund clients. Subsequently, I worked at PacifiCorp Energy as an analyst involved in regulatory matters, primarily involving power supply costs. I began performing independent consulting services in September 2013. A further description of my educational background and work experience can be found in Exhibit ICNU/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the Company's 2014 Request for a General Rate Revision (the "2014 GRC"). Specifically, my testimony will address issues related to policy and revenue requirement. In addition, my testimony also will address several issues that are relevant to the Company's 2015 Net Variable Power Costs ("NVPC") and Annual Power Cost Update ("APCU"), which was originally included in this proceeding, but later bifurcated into a new proceeding, Docket No. UE 286.

Q. ARE ANY OTHER WITNESSES SPONSORING TESTIMONY ON BEHALF OF ICNU?

A Yes. Mr. Michael P. Gorman will provide testimony addressing issues related to cost of capital in this proceeding. The revenue requirement impact of his recommendation is summarized in ICNU/102 and in Table 1, below.

Q. WILL YOU PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY?

A. I make the following recommendations and my testimony is organized respectively:

1. **RPS Carve-out.** The Commission should reject the Company's proposed RPS Carve-out power cost tracking mechanism on the basis that it a) is inconsistent with Senate Bill 838 ("SB 838"); b) conflicts with the Commission's resolution in Docket No. UE 246 regarding recovery of RPS resource-related costs in a PCAM; c) violates the design criteria for a power cost adjustment mechanism established in Docket Nos. UE 165 / UM 1187; and d) is structurally flawed.

2. **Port Westward II.** The Commission should not allow Port Westward II to be included in base rates until the Company is capable of self-integrating all of its owned wind resources. Until then, Port Westward II is not used and useful, nor a prudent investment in rate base. This adjustment, which is related to a similar adjustment proposed in the 2015 APCU proceeding, reduces revenue requirement by approximately $49.7 million.

3. **Deferred Production Tax Credits.** The Commission should require the Company to remove deferred production tax credits associated with Tucannon River and Biglow from rate base. The Company's normalized taxes will be sufficient to utilize the entire amount of production tax credits related to Tucannon River and Biglow in the test period. This adjustment reduces the revenue requirement by $8.3 million.

4. **Power Resources Cooperative Transaction.** The Commission should require the Company to return to customers the entire amount of the $[redacted] gain related to its transaction with Power Resources Cooperative ("PRC") to purchase an additional share of the Boardman generating station. The gain should be returned to customers in 2015 as a credit in Schedule 105.

5. **Prepaid Pension Asset.** The Commission should deny the Company's request to recover its prepaid pension asset in rate base and should provide pension cost recovery consistent with previous rate cases. This adjustment reduces revenue requirement by $5.4 million.

6. **Environmental Remediation Costs.** The Commission should disallow the Company's proposed inclusion of a contingent liability related to environmental remediation activities at the Downtown Reach site. These costs are not known and measurable, and including them now, either as a one-time cost or, as the Company has proposed, over a 20-year period, will not incentivize the Company to pursue collection of these costs from entities other than its customers. Eliminating this contingent liability reduces revenue requirement by $3.2 million.

7. **MC Initiative Expenditures.** The Commission should deny the Company's proposal to include rate base and expenses related to participation in the Northwest Power Pool ("NWPP") Members' Market Assessment and Coordination Committee ("MC") Initiative in this proceeding, as those expenditures are not used and useful. This adjustment will reduce revenue requirement by $476,457.

8. **Depreciation Study.** The Commission should incorporate the final depreciation study that will be approved in Docket UM 1679 into revenue requirement in this proceeding. A settlement in principle was reached in Docket UM 1679, which is expected to reduce revenue requirement by approximately $19 million.

Q. HAVE YOU PREPARED A TABLE TO PRESENT YOUR REVENUE REQUIREMENT RECOMMENDATION IN THIS PROCEEDING?

A. Yes. Table 1, below, details my overall revenue requirement recommendation in this proceeding. It also includes the revenue requirement impact associated with Mr. Gorman's cost-of-capital analysis.

TABLE 1
REVENUE REQUIREMENT RECOMMENDATION

	Revenue Requirement ($000)	
	Increase / (decrease)	%
Filed Base Revenue*	110,529	6.39%
Revenue Requirement Adjustments:		
1. Rate of Return	(21,143)	-1.22% **
2. Port Westward II	(49,695)	-2.87% ***
3. Deferred PTCs	(8,287)	-0.48%
4. PRC Transaction	[redacted]	[redacted]
5. Prepaid Pension Asset	(5,381)	-0.31%
6. Environmental Remediation	(3,223)	-0.19%
7. MC Initiative Expenditures	(476)	-0.03%
8. Depreciation Study (approx.)	(19,000)	-1.10%
Total Adjustments	[redacted]	[redacted]
Recommended	[redacted]	[redacted]

* Base revenue increase including Tucannon River and Port Westward II, excluding Trojan fuel and BPA residential exchange credits
** Supported by ICNU witness Mr. Gorman
*** Until determined to be used and useful and prudent investment in rate base

II. RENEWABLE PORTFOLIO STANDARD CARVE-OUT

Q. PLEASE DESCRIBE THE COMPANY'S RPS CARVE-OUT PROPOSAL.

A. The Company currently recovers the variable power costs and benefits associated with resources used to comply with Oregon's Renewable Portfolio Standard ("RPS") through its APCU and power cost adjustment mechanism ("PCAM"). The Company also recovers the variable tax benefits associated with production tax credits from RPS resources in base rates. Between these regulatory frameworks, however, and, in particular, as a result of the dead bands, sharing bands, and earnings test included in its

PCAM calculation, the Company argues that it is not recovering all of its costs associated with RPS resources in rates.[1/] Accordingly, it proposes to create a new "automatic adjustment clause," as defined in ORS 757.210(1), that will allow it to true-up, on a dollar-for-dollar basis, variances in the market value of energy, integration costs and production tax credits associated with renewable resources. The Company argues that Senate Bill ("SB") 838, the Oregon Renewable Energy Act, authorizes its proposal.[2/] The Company refers to its proposal as an "RPS carve-out" because it would allegedly remove from the Company's PCAM only the variable costs and benefits of RPS resources.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal is inconsistent with the type of cost recovery for RPS resources allowed in SB 838. The policy established by the Commission in Docket No. UE 246 affirms that SB 838 does not require dollar-for-dollar recovery of RPS costs. Rather, the Commission has stated that those costs, as well as other power costs, should be recovered through a "well-designed" PCAM satisfying the design principals established in Order No. 07-015.[3/] The Company's proposal is also based on a flawed design that does not reflect the costs associated with RPS compliance and does not accurately isolate the variations in the costs and benefits attributable solely to RPS resources. For these reasons, the Commission should reject the Company's proposal.

1/ PGE/500 at 44:1-18.

2/ Id. at 43:9-16; ORS § 469A.120.

3/ In re PacifiCorp, dba Pacific Power, Request for a General Rate Revision, Docket UE 246, Order No. 12-493 at 13 (Dec. 20, 2012); see also, In re PGE Request for a General Rate Revision, Docket No. UE 180, In re PGE Annual Adjustments to Schedule 125, Docket No. UE 181, and In re Request for a General Rate Revision Relating to the Port Westward Plant, Docket No. UE 184, Order No. 07-015 at 26-27 (Jan. 12, 2007).

Q. PLEASE PROVIDE SOME BACKGROUND ON SB 838.

A. Section 13 of SB 838, which was signed into law on June 6, 2007, directed the Commission to establish an automatic adjustment clause or other mechanism that allows timely recovery of costs prudently incurred by an electric company to construct or acquire renewable resources, and for associated transmission.[4/] Separately, SB 838 also provided that other prudently incurred costs associated with RPS compliance are recoverable in rates, but did not make any mention of an automatic adjustment clause.[5/]

Q. WHY DO YOU BELIEVE THE COMPANY'S PROPOSED RPS CARVE-OUT IS INCONSISTENT WITH SB 838?

A. While SB 838 did allow for an automatic adjustment clause mechanism for RPS costs, that mechanism was limited to the costs to construct or otherwise acquire renewable resources, and for associated transmission.[6/] Variances in power costs were excluded from the mechanism. Instead, under SB 838, such power costs simply "are recoverable."[7/] Because SB 838 established an automatic adjustment clause specifically for construction and acquisition costs, it should be inferred that no other costs, including variable power and production tax credit costs, should receive such treatment within the context of SB 838. Rather, those costs should be subject to standard cost recovery principles.

Q. IS THIS INTERPRETATION CONSISTENT WITH PRIOR COMMISSION ORDERS?

A. Yes. In Docket No. UE 246, PacifiCorp requested dollar-for-dollar recovery of its net power costs because it claimed it could not accurately forecast costs associated with

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4/ ORS § 469A.120(2).
5/ Id at (1).
6/ Id at (2).
7/ Id. at (1).

renewable resources, and therefore, was under-recovering net power costs. Instead, the Commission determined that all of PacifiCorp's net power costs, including costs associated with RPS compliance, should be recovered through a PCAM with dead bands, sharing bands, and an earnings test.[8/] The Commission held that "the most prudent way to accomplish proper recovery [of net power costs] is through a well-designed PCAM."[9/]

Q. DOES THE COMPANY'S PROPOSED RPS CARVE-OUT SATISFY THE DESIGN CRITERIA ESTABLISHED BY THE COMMISSION FOR A WELL-DESIGNED PCAM?

A. No. The Commission has established five general principles that form the basis of a well-designed PCAM.[10/] The design criteria are:

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

Because it will not be subject to sharing bands, dead bands, and an earnings test, the proposed RPS carve-out mechanism fails to conform to these principles.

Q. HAS THE COMPANY PRESENTED ANY EVIDENCE TO SUGGEST THAT THE PCAM'S DESIGN CRITERIA SHOULD NOT APPLY TO ITS PROPOSED MECHANISM?

A. Not beyond its argument that SB 838 authorizes the Company to obtain dollar-for-dollar recovery of its RPS compliance costs. As discussed, however, this argument is flawed.

8/ Docket UE 246, Order No. 12-493 at 14.
9/ Id.
10/ Id. at 13.
11/ Id.; see also Docket Nos. UE 180, UE 181, UE 184, Order No. 07-015 at 26-27 (establishing PCAM for PGE based on similar design criteria).

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE COMPANY'S RPS CARVE-OUT PROPOSAL?

A. Yes. The Company's proposed mechanism is structurally flawed for at least three reasons. First, market prices, which have nothing to do with RPS compliance, will have a material impact on the deferrals calculated under the Company's proposal. Second, it is not possible to isolate the variability of individual resources from the Company's resource portfolio without ignoring the diversification benefits that the Company receives as a result of procuring its power supply from many different fuel and resource types. Third, system re-dispatch associated with isolating wind from the Company's resource portfolio cannot be accurately measured in actual operations.

Q. PLEASE EXPLAIN HOW MARKET PRICES ARE INCORPORATED INTO THE COMPANY'S RPS CARVE-OUT PROPOSAL.

A. In the Company's proposed RPS carve-out, variability in market prices may result in a deferral, despite having little to do with the Company's obligation to comply with RPS requirements. If market prices are lower in actual operation than in the Company's forecast, for example, the Company's proposed mechanism will likely result in a deferral, notwithstanding the fact that lower market prices should result in a reduction to overall NVPC. This scenario is demonstrated in Table 2, below.

TABLE 2
MARKET PRICE IMPACT ON RPS CARVE-OUT PROPOSAL

	Base NVPC	Actual NVPC	RPS Carve-out Deferral
	(A)	(B)	(A) - (B)
RPS Generation (MWH)	100	100	-
Market Price ($/MWH)	35.00	30.00	5.00
Value of RPS Generation ($)	3,500	3,000	**500**

As shown in Table 2, the Company's recovery is not solely related to its ability to accurately forecast the energy output of its RPS-compliant resources. If the Company perfectly forecasts such output, it may still collect dollar-for-dollar recovery as a result of inaccurately forecasting the market price for that energy. Variances in market price fall within the Company's authorized PCAM and are not appropriate for dollar-for-dollar recovery through an RPS carve-out mechanism.

Q. PLEASE STATE WHY THE COMPANY'S PROPOSAL IGNORES THE DIVERSIFICATION BENEFITS ASSOCIATED WITH OPERATING A DIVERSE RESOURCE PORTFOLIO?

A. In general, a diversified portfolio will have less risk than the aggregate risk associated with each asset in the portfolio. For purposes of utility planning, this means that a utility will benefit from procuring power supplies that are dependent on many different fuel and resource types. Because the risks associated with different fuel types are based, all or in part, on independent risk variables, the utility's overall risk profile will decline as a result of the offsetting nature of each of the fuel or resource types in its portfolio. For example, in a diversified resource portfolio, such as the Company's, low wind output in any given year may be offset by higher hydro generation or lower gas prices resulting in more stability in overall NVPC. By attempting to isolate only the variability associated with renewable output, the Company is ignoring the fact that its overall system is benefiting as a result of the diverse nature of all resources in its portfolio.

To illustrate this concept, consider if the Company's resource portfolio were the equivalent of an investment portfolio consisting of Fortune 500 stocks. Under this scenario, the RPS carve-out mechanism would be similar to the Company requesting a deferral mechanism for losses, or gains, associated with a single stock holding, independent of how its overall investment portfolio performed in the period.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THAT SYSTEM RE-DISPATCH IS NOT ACCURATELY REPRESENTED IN THE COMPANY'S PROPOSED RPS CARVE-OUT?

A. In actual operations, the level of wind output in any given hour will impact how every other dispatchable resource will be operated. To accurately isolate the costs and benefits associated solely with renewable resources, the Company must determine how its other resources would have dispatched in actual operation but for the RPS generation that it is attempting to isolate. The Company's proposal only focuses on the variability of wind and does not account for this system re-dispatch.

Q. PLEASE SUMMARIZE WHY YOU THINK THE COMPANY SHOULD CONTINUE TO RECOVER THE COSTS OF ITS RPS RESOURCES THROUGH EXISTING REGULATORY MECHANISMS.

A. Continued recovery of renewable resource variable costs through existing regulatory mechanisms best balances the interests of the utility and the consumer and ensures that the Company continues to bear normal business risks for which it earns an appropriate return on its investments. If the costs of the Company's RPS resources are truly extraordinary, they will be reflected in its PCAM and eligible for recovery subject to the dead bands, sharing bands, and earnings test.

III. PORT WESTWARD II

Q. PLEASE DESCRIBE YOUR RECOMMENDATION RELATED TO PORT WESTWARD II.

A. The development of Port Westward II has been justified on the basis that it would be used to self-integrate Company-owned wind resources.[12/] As the Company acknowledges in testimony, the Port Westward II flexible capacity is needed as a result of "*the growth in renewable energy supplies, mostly in the form of wind energy …*"[13/] However, the Company will likely be incapable of self-integrating its owned wind resources by the time Port Westward II is placed into service. I recommend that the facility, and its associated costs and benefits, be excluded from rates until it can be used to self-integrate both the Biglow and Tucannon River wind resources. This adjustment is an alternative to one of my proposals in the 2015 APCU proceeding (UE 286) to reflect the self-integration benefits associated with Biglow and Tucannon River in NVPC. That is, if the Commission determines not to include self-integration benefits of Port Westward II for the full test period, it should remove this resource from rates until such time as it is actually being used for self-integration.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF THIS RECOMMENDATION?

A. This adjustment will result in no change to the Company's proposed base revenues, but will delay the approximate $49.7 million rate increase attributable to Port Westward II until the Company can demonstrate that customers are receiving the benefits associated with self-integration.

12/ See e.g. PGE/400 at 18:4-15.
13/ Id.

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN PGE'S 2015 AUT PROCEEDING.

A. My testimony in Docket UE 286 demonstrates that, in addition to not being used and useful, Port Westward II is not a prudent investment in rate base until it can be used to self-integrate wind.[14/] To summarize, the Company justified the cost of the Port Westward II facility on the basis that it would be used to self-integrate wind, yet it has failed to take the necessary steps to self-integrate by the time the facility will be placed into service. Additionally, despite parties' promptings in Docket No. UE 266 for the Company to develop a more cost-effective wind integration paradigm, the Company did not properly analyze, and plan for, its April 4, 2014 balancing service election with BPA. Exhibit ICNU/103 includes the relevant portion of my testimony in Docket UE 286 discussing the prudence of the Company's efforts to self-integrate wind.

Q. HOW DOES YOUR TESTIMONY IN THE AUT PROCEEDING IMPACT YOUR TESTIMONY IN THIS DOCKET?

A. My testimony in the AUT proceeding demonstrates that the Company has not prudently planned for the Port Westward II addition. Thus, if self-integration benefits from this resource are not imputed for the 2015 test year, Port Westward II should not be included in rates until the associated benefits of self-integration are also included in rates. Until such a date that it can be used for its intended purpose of self-integrating wind, Port Westward II is unneeded flexible capacity that is not used and useful and is not a prudent investment in rate base.

[14/] Docket No. UE 286, ICNU/100 at 4-11.

Q. WHY IS PORT WESTWARD II NOT A USED AND USEFUL RESOURCE IN THE TEST PERIOD?

A. Port Westward II was built for the purpose of providing flexible capacity, namely to integrate wind. This flexible capacity, however, will not be used and will provide no benefit to customers in the test period. This is evident by the fact that in its 2012 Request for Proposals for Capacity and Baseload Energy Resources ("Capacity RFP"), the Company assumed Port Westward II would dispatch in 74 percent of hours in 2015 in order to satisfy the reserve requirements outlined in its Wind Integration Study.[15/] In the test period, however, the Company forecasts Port Westward II to operate at only a 10 percent capacity factor, providing no net economic benefit to customers.

Q. CAN YOU DEMONSTRATE THAT PORT WESTWARD II, AS CURRENTLY MODELED, DOES NOT PROVIDE A NET ECONOMIC BENEFIT TO CUSTOMERS?

A. Yes. Table 3, below, demonstrates that, absent the self-integration benefits promised from the facility, the Port Westward II investment will provide no net economic benefits to ratepayers, and therefore is not used and useful, in the test period.

TABLE 3
PORT WESTWARD II
NET ECONOMIC BENEFIT IN TEST PERIOD
($000)

Dispatch Benefit	$ 1,213
BPA Wheeling Cost	(4,605)
Production O&M	(1,479)
A&G, Ins/Bene., & Gen. Plant	(347)
Net Economic Benefit / (Loss)	**$ (5,218)**

15/ Docket No. UM 1535, PGE's Final Draft Request for Proposal for Power Supply Resources at 81 (Jan. 25, 2012).

As can be seen from Table 3, given the low dispatch benefits and high wheeling, production O&M, and other costs, it is more beneficial for customers if the Company does not operate Port Westward II at all during the test period.

Q. PLEASE SUMMARIZE YOUR PROPOSAL RELATED TO PORT WESTWARD II.

A. Either the Company's NVPC should be reduced to reflect the self-integration benefits of Port Westward II, as discussed in my APCU testimony, or, in the alternative, Port Westward II should be excluded from base rates under the used and useful and prudence rate making principles. This rate treatment should apply until the Company can demonstrate that it is using Port Westward II to self-integrate both Biglow and Tucannon River, and the benefits associated with that self-integration are reflected in rates.

IV. DEFERRED PRODUCTION TAX CREDITS

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR RECOMMENDATION RELATED TO DEFERRED PRODUCTION TAX CREDITS.

A. The Company's filing includes approximately $75.6 million[16] in rate base associated with deferred production tax credits generated from the Tucannon River and Biglow wind facilities. The deferred production tax credits are intended to represent the credit amounts that the Company is not capable of utilizing in the test period and that must be carried-forward to a future tax year. Based on the Company's normalized tax forecast in this proceeding, however, the Company should be capable of utilizing the entire amount of production tax credits generated from both Tucannon River and Biglow in the test period. I recommend that the $75.6 million in deferred production tax credits be removed

16/ Approximately $48.1 million and $27.5 million of deferred tax credits related to Tucannon River and Biglow, respectively.

from rate base, which will result in an approximate $8.3 million reduction to revenue requirement, detailed in Exhibit ICNU/104.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE LIMITATIONS FOR UTILIZING PRODUCTION TAX CREDITS.

A. Production tax credits, which are governed by Internal Revenue Code ("I.R.C.") § 45,[17/] are a general business credit and must be utilized in accordance with the rules outlined in I.R.C. § 38.[18/] These rules impose two limitations on a firm's ability to utilize general business credits. First, a general business credit may not reduce a firm's tax liability below 25 percent of its regular tax liability in excess of $25,000.[19/] Second, a general business credit may not reduce tax liability below a firm's tentative minimum tax, the tax computed for purposes of the alternative minimum tax.[20/] With regard to the production tax credit, however, the second limitation regarding the tentative minimum tax does not apply in the first four years of an eligible resource's useful life.[21/]

Q. CAN YOU DEMONSTRATE THAT THE COMPANY WILL BE CAPABLE OF UTILIZING THE ENTIRE AMOUNT OF PRODUCTION TAX CREDITS IN THE TEST PERIOD ON A NORMALIZED BASIS?

A. Yes. Table 4, below, demonstrates that the Company's normalized taxable income is sufficient to utilize the credits generated from both Tucannon River and Biglow in the test period. Note that the second limitation, discussed above related to the alternative minimum tax, has been excluded from this analysis since it will not be applicable in the first four years of Tucannon River's useful life, nor is alternative minimum tax reflected on a normalized tax basis.

17/ 26 U.S.C. § 45
18/ 26 U.S.C. § 38.
19/ I.R.C. § 38(c)(1)(B).
20/ I.R.C. § 38(c)(1)(A).
21/ See I.R.C. § 38(c)(4)(B)(iii), § 38(c)(4)(A)

TABLE 4
NORMALIZED PRODUCTION TAX CREDIT UTILIZATION

Description	Reference	Amount ($000)
(a) Current Taxes	PGE/301	97,382
(b) Deferred Taxes	PGE/301	(10,574)
(d) Normalized Taxes Payable	(a) + (b)	86,808
(e) Tax Payable In Excess of $25,000	(d) - $25k	86,783
(f) 25 % of Tax Payable in Excess of $25,000	(e) * 25%	21,696
(g) PTC Credit Utilization Limit (I.R.C. § 45(c)(1)(B))	(d) - (f)	65,087
(h) Tucannon PTC	PGE/301	19,782
(i) Biglow PTC	PGE/301	28,929
(j) Total PTC	∑ (h), (i)	48,711
(k) Normalized Credit Utilized	Min (g), (j)	48,711
(l) Deferred Tax Asset (Credit Carry-forward)	(j) - (k)	-

Q. PLEASE SUMMARIZE TABLE 4.

A. To the extent that the amount in row (j) is less than the limitation detailed in row (g), as is the case here, the Company can utilize all of the production tax credits generated at both Tucannon River and Biglow.

Q. WHY SHOULD NORMALIZED TAXES, RATHER THAN ACTUAL TAXES, BE USED TO CALCULATE DEFERRED TAX ATTRIBUTES RELATED TO PRODUCTION TAX CREDIT CARRY-FORWARDS?

A. Normalized tax reflects the requirement in IRC § 168(f)(2)[22/] that prohibits a utility from including the deferred tax benefits associated with accelerated depreciation in rates. To the extent that accelerated depreciation, or other temporary book-tax difference, reduces actual taxable income and results in the inability of the Company to not fully utilize production tax credits, it would be inconsistent to include the tax credit carry-forwards in a normalized rate base account. Because ratepayers do not receive the benefits associated

22/ 26 U.S.C. § 168.

with accelerated depreciation and other similar temporary book-tax differences, it follows that ratepayers should not be required to supply funding for a tax attribute that has arisen as a result of tax benefits that they have not received.

Q. HAVE YOU IDENTIFIED ANY OTHER ISSUES WITH THE DEFERRED PRODUCTION TAX CREDITS RELATED TO TUCANNON RIVER IN THE COMPANY'S FILING?

A. Yes. The Company forecasts that it will generate $19.8 million in production tax credits related to Tucannon River in the test period, yet it includes a $48.1 million deferred tax asset related to Tucannon River production tax credits, over double the amount generated in the test period. Because production tax credits are generated ratably over the course of the year, in no circumstance should the average rate base associated with a potential deferred production tax credit asset for Tucannon River in the test period exceed greater than one-half of the amount generated in the test period or $9.9 million ($19.8 million ÷ 2).

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT RELATED TO TUCANNON RIVER DEFERRED PRODUCTION TAX CREDITS.

A. The Company's normalized taxes are sufficient to utilize the entire amount of credits associated with Tucannon River and Biglow. Accordingly, no deferred production tax credit should be reflected in rate base, and in no circumstance should the tax asset associated with Tucannon exceed $9.9 million.

V. POWER RESOURCES COOPERATIVE TRANSACTION

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR ADJUSTMENT RELATED TO THE PRC TRANSACTION.

A. The Company will recognize a $[redacted] cash gain as a result of the transaction with Power Resources Cooperative ("PRC") to purchase an additional ten percent share of

Boardman. Instead of passing this gain back to customers immediately, however, the Company has proposed a complex system of regulatory accounting that will result in amortizing the gain over a number of years. Rather than adopt the accounting that the Company has proposed, I recommend that the entire amount of the $[redacted] gain related to the PRC transaction be refunded to customers as a one-time credit in 2015 through Schedule No. 105.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE COMPANY'S ACQUISITION OF A SHARE OF BOARDMAN FROM PRC.

A. When the Company made its initial filing in this proceeding, it indicated that it was in discussions with PRC to acquire PRC's 10 percent ownership share of Boardman.[23] On April 1, 2014, the Company filed supplemental testimony indicating that it had fully negotiated an agreement with PRC, which it intended to close on by the end of 2014.[24] Under the agreement, PRC agreed to pay the Company a total of $[redacted] in exchange for PGE assuming PRC's obligations related to decommissioning, environmental costs, and station service. The Company also assumed PRC's power purchase agreement with the Turlock Irrigation District, which extends through 2018.[25]

Q. HOW HAVE YOU CALCULATED THE GAIN ASSOCIATED WITH THE PRC TRANSACTION?

A. The cash flows related to the transaction were detailed in PGE/1500. From these cash flows, the total amount of gain realized as a result of acquiring the additional ten percent share of the Boardman facility can be calculated. This gain amount has been represented in Table 5, below.

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[23] PGE/100 at 15:3-11.
[24] PGE/1500 at 4:8-11.
[25] Id. at 4:13-19 and 6:10-11.

TABLE 5
CALCULATION OF GAIN RESULTING FROM PRC TRANSACTION

Description	Cash Flow Receipt / (Payment)	Total Gain	Explanation
Boardman Payment	[redacted]	[redacted]	
Inventory Purchase	[redacted]	[redacted]	*Exclude from gain, included in rate base*
Operating Risk Premium	[redacted]	[redacted]	
2011 PPA Settlement	[redacted]	[redacted]	
Two Power Lines	[redacted]	[redacted]	*Exclude from gain, included in rate base*
Total	[redacted]	[redacted]	
Less: Amount already included in Sch. 105 per PGE/1502:		[redacted]	
Total adjustment to Sch. 105:		[redacted]	

As can be seen from Table 5, PGE paid PRC for certain inventory and the cost of two power lines. However, the cash flows related to these purchases should not reduce the total gain. Instead, these payments should simply be excluded from the total gain, as I reflect in the "Total Gain" column of Table 5.

Q. WHY SHOULD THE COST OF INVENTORY PURCHASES AND POWER LINES NOT REDUCE THE GAIN CALCULATION?

A. The amounts related to inventory purchases, which include fuel, supplies, and other working capital items, are not properly deducted from the realized gain amount because the associated inventory items will be reflected in rate base and later expensed. The costs underlying the inventory items will eventually be expensed through net variable power cost or supply expense as the items are used, so separately deducting those amounts from the gain calculation would serve to double-count the profit and loss impact of those items. Similarly, the power lines will be reflected in rate base, where they will be recovered through depreciation expense, so including their associated cost in the gain calculation would double-count the cost recovery associated with them.

Q. WHY SHOULD THIS GAIN BE RETURNED TO CUSTOMERS IN AS A ONE-TIME CREDIT IN 2015 RATHER THAN THROUGH THE COMPANY'S PROPOSED ACCOUNTING?

A. The Company has received an up-front lump sum payment from PRC to acquire an additional share of Boardman and its associated decommissioning costs. The vast majority of these costs will be borne by the Company's customers. Thus, they should realize an equivalent up-front lump sum payment. Yet, under the Company's proposal, the majority of the gain related to the PRC transaction will not be passed back to customers until 2026, the year that the Company proposes to credit the $[redacted] operating risk premium. In the test period, the Company proposes to pass a credit to customers of only $[redacted], or about five percent of the total gain that it has recognized.[26]

Additionally, the Company has requested that customers begin paying now for the additional operational and decommissioning burdens associated with the additional share of Boardman through a $1.2 million increase to the annual collections under Schedule 145.[27] Nevertheless, over 75 percent of the gain associated with this transaction, under the Company's proposed accounting, will not be credited to customers until after 2019. In order to match the burden assumed by customers related to the additional share of Boardman with the gain recognized in the PRC transaction, it is most appropriate to refund the gain as a one-time credit in 2015, rather than passing the majority of it back in the future under the Company's complex accounting proposal.

26/ See Exhibit PGE/1501

27/ Id.

Q. PLEASE SUMMARIZE YOUR PROPOSED TREATMENT FOR THE GAINS ASSOCIATED WITH THE PRC BOARDMAN TRANSACTION.

A. Just as the Company was paid a one-time gain for assuming the additional burden associated with Boardman, if the Company intends to pass that burden on to customers, they too should receive the benefit of the one-time gain recognized in the PRC transaction. Accordingly, the Company's proposed accounting should be rejected and the entire $[redacted] gain associated with the PRC transaction should be credited to customers in 2015 through Schedule 105.

VI. PREPAID PENSION ASSET

Q. HOW IS THE COMPANY REQUESTING TO RECOVER ITS PENSION COSTS IN THIS CASE?

A. The Company has requested authorization to recover its 2015 pension expense, and to include its prepaid pension asset in rate base so it can earn a return on that asset.[28]

Q. IS THIS CONSISTENT WITH HOW THE COMPANY HAS HISTORICALLY COLLECTED ITS PENSION COSTS FROM CUSTOMERS?

A. No. In the past, as with other Commission-regulated utilities, the Company has collected costs related to its pension program based on its expenses under Financial Accounting Standard 87 ("FAS 87"). FAS 87 is an accrual accounting method. Thus, the actual costs of funding the Company's pension program in any given year may not line up with the Company's FAS 87 expense – sometimes FAS 87 expense is greater than those costs, and sometimes it is less. Although FAS 87 expense will ultimately equal the total costs of funding the Company's pension program over time, the Company claims that its cash contributions over the past few years have exceeded its FAS 87 expense. It is the

28/ PGE/600 at 31:3-7.

difference between these cash contributions and FAS 87 expense that has created the prepaid pension asset PGE seeks to include in rate base and earn a return on.

Q. WHY DOES THE COMPANY ARGUE THAT IT SHOULD BE ALLOWED TO EARN A RETURN ON ITS PREPAID PENSION ASSET?

A. The Company states that earning a return on its prepaid pension asset will compensate the Company for the costs it assumes in financing that asset.[29/]

Q. DO YOU BELIEVE THE COMPANY SHOULD BE ALLOWED TO EARN A RETURN ON ITS PREPAID PENSION ASSET IN THIS PROCEEDING?

A. No. Regardless of the merits of the Company's proposal, which I do not accept, this proposal is being considered as a policy matter in Docket No. UM 1633. The Commission recently suspended the procedural schedule in that case, which makes it unlikely that this matter will be resolved until after the conclusion of this rate case.[30/] It is not appropriate for the Company to prejudge the outcome of UM 1633.

Q. WHAT DO YOU RECOMMEND?

A. The Company should continue to recover its pension-related costs in the same manner that was approved in its last rate case.[31/] This treatment will result in a $5.4 million reduction to revenue requirement, which is detailed in Exhibit ICNU/105

VII. CONTINGENT ENVIRONMENTAL REMEDIATION COSTS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO CONTINGENT ENVIRONMENTAL REMEDIATION COSTS.

A. The Company has included a contingent liability of approximately $3.1 million in the test period to cover for environmental remediation costs at the Downtown Reach area of the

29/ Id. at 32:13-17.
30/ See Docket No. UM 1633, Law Judge Ruling Suspending Procedural Schedule (May 8, 2014).
31/ Docket No. UE 262, Order No. 13-459 at 11-12.

Willamette River.[32/] I recommend that this contingent liability be excluded from rates on the basis that it not known and measurable. Eliminating this contingency reduces revenue requirement by $3.2 million, as detailed in Exhibit ICNU/106.

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST FOR AN ACCOUNTING ORDER REGARDING REMEDIATION ACTIVITIES.

A. The Company states that it expects the Oregon Department of Environmental Quality ("ODEQ") to require remediation of sediment contamination at River Miles 13.1 and 13.5.[33/] The Company has proposed an accounting order that would reclassify the $3.1 million in contingent environmental remediation costs to a regulatory asset and amortize those costs over 20 years, which would reduce the $3.1 million contingent liability by $2.9 million.[34/] The Company would still collect the full $3.1 million in rates over the 20-year period, however.[35/]

Q. WHY DOES THE COMPANY BELIEVE IT WILL BE LIABLE FOR REMEDIATION EXPENSES?

A. After sampling outfalls at River Miles 13.1 and 13.5 in 2008, which found elevated levels of various hazardous substances, the ODEQ required the Company, in 2010, to conduct a remedial investigation study ("RIS").[36/] The Company finished the required study in December 2011, an excerpt of which is included as ICNU/108. That study identified a number of potential sources for the hazardous substances, including the following:

[32/] PGE/700 at 14:3-17:11.
[33/] Id. at 14:8-11.
[34/] Id. at 15:13-20.
[35/] Id.
[36/] Exhibit ICNU/108 (Excerpt of the RIS, included in PGE Resp. to ICNU DR 54, Attachment A).

- The Hawthorne Building – this building has been continuously owned by the Company or a predecessor since 1905 and was identified as an historical and potentially current source of contamination;[37]
- The Rexel Taylor Property – this property was owned by the Rexel Taylor Electric company and burned to the ground in 2006. The fire spread to three Company transformers, which leaked oil into an outfall that discharged to the river. The Remedial Investigation Study identifies this property as a potential current source of contamination, though this contamination appears to be coming from the building, not the Company's transformers;[38]
- The Holman Building – this building was identified by the RIS as a potential current source of contamination. It is owned by Rivers East, LLC, and the property is owned by the State of Oregon;[39]
- The Inman-Poulsen Property and Station L – this property was the site of the Inman-Poulsen lumber mill until 1954 when it was sold to the Company and became part of the Station L Southern Yard. The RIS identifies it as an historical source of contamination. The Oregon Museum of Science and Industry is now part of the Station L property ;[40]
- The RIS also identifies stormwater outfalls owned by the City of Portland and the Oregon Department of Transportation ("ODOT") as current sources of contamination.[41]

[37] Id. § 3.2.1.1.
[38] Id. § 3.2.1.2.
[39] Id. § 3.2.1.3.
[40] Id. § 3.2.2.1.
[41] Id. § 3.2.1.

Because the Company is a past or current owner of a number of sites identified as potential sources of contamination at Downtown Reach, it may be liable for remediation costs.

Q. WHAT IS THE RIS' CONCLUSION REGARDING CONTAMINATION AT DOWNTOWN REACH FROM THESE SITES?

A. The RIS states that the Hawthorne Building, the Rexel Taylor Building, and the Holman Building are historical and likely current sources of contamination at River Mile 13.1.[42/] It also identifies ODOT and City of Portland outfalls as current sources. The RIS identifies the Inman-Poulsen property and Station L as historical sources of contamination at River Mile 13.5, and ODOT and City of Portland outfalls as current sources.[43/]

Q. HAS THE COMPANY ATTEMPTED TO RECOVER REMEDIATION COSTS FROM ITS INSURERS OR FROM THIRD PARTY OWNERS OF SITES THE RIS IDENTIFIES AS PAST AND CURRENT SOURCES OF CONTAMINATION?

A. Not yet. To date, the Company has only incurred costs of *investigating* these sites. It has incurred no *remediation* costs, which are the costs the Company is seeking to include in rates in this case.[44/] For this reason, in responses to data requests, the Company indicated that it was "premature to negotiate reimbursement" with insurance companies[45/] and that it "has not taken action to recover remediation costs" from potentially responsible parties.[46/]

42/ Id. §§ 4.1.1-4.1.2.
43/ Id. §§ 4.2.1-4.2.2.
44/ ICNU/107 at 3 (PGE Resp. to ICNU DR 71).
45/ Id.
46/ ICNU/107 at 4 (PGE Resp. to ICNU DR 73).

Q. DO YOU AGREE THAT IT IS APPROPRIATE FOR THE COMPANY TO INCLUDE REMEDIATION COSTS AT DOWNTOWN REACH IN ITS RATES IN THIS CASE?

A. No. The Company has stated that the $3.1 million in costs it anticipates it will incur for remediation activities at Downtown Reach is based on its "best estimate."[47/] The inclusion of such a contingent liability, as one commentator has stated, "is unfair, because such a practice would shift the risk associated with the contingent event wholly to the ratepayer."[48/]

In its testimony, the Company states that it "continues to receive 45% of undisputed costs associated with the defense and investigation from two insurers regarding the Portland Harbor and Downtown Reach areas."[49/] The Company provides no indication that it cannot obtain reimbursement for at least this much of its remediation costs as well. Furthermore, the Company has stated that it considers the City of Portland and the Oregon Department of Transportation to be potentially responsible parties with regard to the Downtown Reach site and that it may have contribution claims against these parties.[50/] Other owners of the contamination sources identified above may also be potentially responsible parties from whom the Company may be able to seek contribution.

Given that there is a significant chance that a large portion of the Company's remediation costs associated with Downtown Reach could be covered by insurance and/or contributions from other potentially responsible parties, the amount the Company will spend on remediation at this site is not currently known and measurable.

47/ ICNU/107 at 6 (PGE 2013 10-K at 119).
48/ Leonard Saul Goodman, The Process of Ratemaking, Vol. I at 319 (1998).
49/ PGE/700 at 15:4-5.
50/ ICNU/107 at 4 (PGE Resp. to ICNU DR 73).

Furthermore, any amount of these costs that the Company could reasonably collect from insurance and other parties are not prudently incurred costs that should be passed on to ratepayers. Allowing the Company to include these costs in rates, either as a one-time cost or amortized over 20 years, will not incentivize the Company to aggressively seek reimbursement of its costs from entities other than its customers.

Q. IS THE COMMISSION CURRENTLY CONSIDERING HOW TO PROVIDE FOR RECOVERY OF OTHER UTILITIES' ENVIRONMENTAL REMEDIATION COSTS?

A. Yes. In UM 1635, the Commission is examining a number of proposals for Northwest Natural Gas Company's environmental remediation costs. In general, these proposals have recommended that Northwest Natural's recovery of remediation costs be subject to sharing percentages between the utility and its customers, as well as an earnings test.[51/]

Q. DO YOU BELIEVE A SIMILAR RECOVERY MECHANISM THAT IS DEVELOPED FOR NORTHWEST NATURAL WOULD BE APPROPRIATE FOR THE COMPANY?

A. Not at this time. While I agree that any recovery of environmental remediation costs that the Company is ultimately entitled to should be subject to the types of regulatory safeguards proposed in UM 1635, including sharing percentages and an earnings test, the recovery mechanisms ultimately approved for Northwest Natural are not currently necessary for the Company. The Company is not in the same position as Northwest Natural, which has significant deferred balances of remediation costs and is projected to incur additional significant costs in the future.[52/] Conversely, I do not understand the Company to have any deferred balance of remediation costs, and it is only seeking recovery of $3.1 million in anticipated remediation costs in this case. While the

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51/ See, e.g., Docket No. UM 1635, Staff/200 at 20-21 (May 2, 2014) and NWIGU/100 at 14-18 (May 2, 2014).

52/ Docket No. UG 221, Order No. 12-437 at 26.

Company has indicated that it may have additional exposure to remediation costs related to the Portland Harbor Superfund site, those costs are simply too speculative at this point to plan for.[53/]

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSAL TO RECOVER ITS ENVIRONMENTAL REMEDIATION COSTS ASSOCIATED WITH THE DOWNTOWN REACH SITE.

A. The Commission should disallow the Company's inclusion of its contingent remediation costs related to the Downtown Reach site. The Company has not demonstrated that these costs are known and measurable such that they should be included in rates for the test period. Allowing the Company to include them now may disincentivize it from seeking reimbursement of these costs from its insurers, as well as other potentially responsible parties. If and when the Company does incur remediation costs, interested parties should be able to propose whether and how the Company recovers those costs from its customers, which may include any customer safeguards for recovery that the Commission ultimately approves for Northwest Natural in UM 1635.

VIII. MC INITIATIVE EXPENDITURES

Q. WHAT IS YOUR RECOMMENDATION RELATED TO MC INITIATIVE EXPENDITURES?

A. The Commission should not allow the Company to include in rates at this time, nor defer, any capital or expenditures related to the Company's participation in the Northwest Power Pool ("NWPP") Members' Market Assessment and Coordination Committee ("MC") Initiative. At this point, the nature of the work in the MC initiative is exploratory in nature and does not rise to the level of being used and useful for ratemaking purposes.

[53/] ICNU/107 at 1 (PGE Resp. to ICNU DR 53).

For this reason, all expenditures, capital and expense, should be eliminated from revenue requirement. This adjustment, which is detailed in Exhibit ICNU/109, will result in a $476,457 reduction to revenue requirement.

Q. WHAT IS THE COMPANY'S PROPOSED TREATMENT OF MC INITIATIVE COSTS?

A. The Company projects that it will incur an initial investment of $1.5 million associated with its participation in the MC Initiative in the test period. The Company has proposed to capitalize these expenditures and amortize them over five years.[54/] The Company has also included $300,000 of expenses related to the MC initiative in the test period.[55/]

Q. WHY DO YOU BELIEVE THAT THE COMPANY SHOULD NOT BE ALLOWED TO INCLUDE THE COSTS ASSOCIATED WITH MC INITIATIVE PARTICIPATION AT THIS TIME?

A. The Company has made no commitment to join an energy imbalance market ("EIM") at this time. Thus, its exploratory costs are not related to any used and useful investment, nor has the Company shown that they otherwise benefit customers. Moreover, the MC Initiative is a phased process sponsored by a group of NWPP members to develop improvements to balancing practices throughout the Northwest. While the Company has maintained a prominent role in the process, the Bonneville Power Administration is the principal participant, and its public power customers are concerned over the implementation of a market similar to an EIM in the Northwest. Given the possibility of controversy involved with the MC Initiative and any resulting centralized market dispatch mechanism, it is premature to include the costs associated with MC Initiative activities in rates at this time.

54/ PGE/800 at 26:20-27:2.
55/ ICNU/109 at 3 (Company's response to OPUC Staff DR 358, Attachment B).

IX. DEPRECIATION STUDY

Q. HAVE PARTIES REACHED A SETTLEMENT IN PRINCIPAL IN DOCKET UM 1679 RELATED TO THE COMPANY'S DEPRECIATION STUDY?

A. Yes. On June 3, 2014, Commission Staff requested a suspension of the schedule in that proceeding on the basis that the parties intended to submit a stipulation resolving all issues related to the Company's depreciation study.[56/] The stipulation will be submitted, along with testimony, by June 20, 2014.[57/]

Q. HAVE YOU REVIEWED THE IMPACT OF THIS SETTLEMENT ON THE REVENUE REQUIREMENT IN THIS RATE PROCEEDING?

A. Yes. Based on my estimates, which are detailed in ICNU/110, the proposed stipulation will result in an overall reduction to revenue requirement of approximately $19 million in this proceeding.

Q. HOW DO YOU PROPOSE THAT THE DEPRECIATION STUDY RESULTS BE INCORPORATED INTO RATES IN THIS PROCEEDING?

A. The Company should include in its rebuttal filing a comprehensive update to its revenue requirement calculations to include the updated depreciation study and any other known corrections, errors or omissions. This will provide parties the opportunity to review how the depreciation study, and other changes, impact customers.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

56/ Docket No. UM 1679, Motion to Suspend Procedural Schedule (June 3, 2014).
57/ Id.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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

EXHIBIT ICNU/101

QUALIFICATIONS OF BRADLEY G. MULLINS

June 11, 2014

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Bradley G. Mullins. My business address is 333 S.W. Taylor Street, Suite 400, Portland, OR 97204.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am an independent consultant representing industrial customers throughout the western United States.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I received Bachelor of Science degrees in Finance and in Accounting from the University of Utah. I also received a Master of Science degree in Accounting from the University of Utah. After receiving my Master of Science degree, I worked at Deloitte Tax, LLP, where I was a Tax Senior providing tax consulting services to multi-national corporations and investment fund clients. Subsequently, I worked at PacifiCorp Energy as an analyst involved in regulatory matters primarily involving power supply costs. I began performing independent consulting services in September 2013 and have been engaged with industrial organizations located throughout the western United States, including regulatory proceedings in Oregon, Washington and Wyoming. In Oregon, I am engaged to testify on behalf of ICNU before the Oregon Public Utility Commission in ongoing rate proceedings with Portland General Electric and PacifiCorp. In Washington, I am engaged to testify on behalf of ICNU before the Washington Utilities and Transportation Commission in the general rate proceeding of Avista. In Wyoming, I am engaged to provide non-testifying services related to various matters before the Wyoming Public Service Commission.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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

EXHIBIT ICNU/102

REVENUE REQUIREMENT IMPACT OF MICHAEL P. GORMAN'S COST OF CAPITAL RECOMMENDATIONS

June 11, 2014

Exhibit ICNU/102
2015 Results of Operations
Adjustment 1 - Rate of Return: Revenue Requirement Impact
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Operating Revenues										
Sales to Consumers (Rev. Req.)	1,730,004	(4,264)	1,725,740	1,725,740	49,695	1,775,435	1,725,740	43,956	1,769,695	1,819,390
Sales for Resale	-	-	-	-	-	-	-	-	-	-
Other Operating Revenues	23,521	-	23,521	23,521	-	23,521	23,521	-	23,521	23,521
Total Operating Revenues	1,753,525	(4,264)	1,749,260	1,749,260	49,695	1,798,955	1,749,260	43,956	1,793,216	1,842,911
Operation & Maintenance										
Net Variable Power Cost	593,425	-	593,425	592,212	-	592,212	577,002	-	577,002	575,789
Operations O&M	246,227	-	246,227	247,706	-	247,706	254,700	-	254,700	256,179
Support O&M	233,650	(35)	233,615	233,962	404	234,366	234,050	357	234,407	235,158
Total Operation & Maintenance	1,073,302	(35)	1,073,267	1,073,880	404	1,074,283	1,065,752	357	1,066,109	1,067,125
Depreciation & Amortization	280,008	-	280,008	293,596	-	293,596	303,679	-	303,679	317,267
Other Taxes / Franchise Fee	110,280	(107)	110,174	111,637	1,243	112,880	117,124	1,099	118,224	120,930
Income Taxes	59,601	(1,646)	57,954	48,342	19,186	67,528	23,513	16,970	40,484	50,057
Total Oper. Expenses & Taxes	1,523,191	(1,788)	1,521,403	1,527,454	20,833	1,548,287	1,510,069	18,427	1,528,496	1,555,380
Utility Operating Income	230,333	(2,477)	227,857	221,806	70,529	250,668	239,191	62,383	264,720	287,531
Rate of Return	7.531%		7.450%	6.594%		7.450%	6.733%		7.450%	7.450%
Return on Equity	9.562%		9.400%	7.687%		9.400%	7.966%		9.400%	9.400%

* 2014 Rates per approved UE 262 and UE 266

Exhibit ICNU/102
2015 Results of Operations
Adjustment 1 - Rate of Return: Revenue Requirement Impact
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Rate Base										
Plant in Service	7,293,364	-	7,293,364	7,603,781	-	7,603,781	7,803,401	-	7,803,401	8,113,818
Accumulated Depreciation	(3,805,842)	-	(3,805,842)	(3,812,518)	-	(3,812,518)	(3,817,676)	-	(3,817,676)	(3,824,352)
Accumulated Def. Income Taxes	(579,549)	-	(579,549)	(574,257)	-	(574,257)	(631,267)	-	(631,267)	(625,975)
Accumulated Def. Inv. Tax Credit	-	-	-	(3,835)	-	(3,835)	48,058	-	48,058	44,222
Net Utility Plant	2,907,972	-	2,907,972	3,213,170	-	3,213,170	3,402,515	-	3,402,515	3,707,713
Misc Deferred Debits	30,852	-	30,852	30,852	-	30,852	30,852	-	30,852	30,852
Operating Materials & Fuel	75,103	-	75,103	75,103	-	75,103	75,103	-	75,103	75,103
Misc. Deferred Credits	(11,740)	-	(11,740)	(11,740)	-	(11,740)	(11,740)	-	(11,740)	(11,740)
Working Cash	56,358	(66)	56,292	56,516	771	57,287	55,873	682	56,554	57,549
Total Rate Base	3,058,545	(66)	3,058,479	3,363,901	771	3,364,672	3,552,603	682	3,553,284	3,859,477
Income Tax Calculations										
Book Revenues	1,753,525	(4,264)	1,749,260	1,749,260	49,695	1,798,955	1,749,260	43,956	1,793,216	1,842,911
Book Expenses	1,463,590	(141)	1,463,449	1,479,113	1,647	1,480,759	1,486,556	1,457	1,488,012	1,505,323
Interest Rate Base @ Weighted Cost of Debt	84,110	(2)	84,108	92,507	21	92,528	97,697	19	97,715	106,136
Production Deduction	-	-	-	-	-	-	-	-	-	-
Permanent Sch M Differences	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)
Temporary Sch M Differences	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)
State Taxable Income	252,972	(4,121)	248,851	224,788	48,027	272,816	212,156	42,480	254,636	278,601
State Income Tax	16,252	(314)	15,938	14,106	3,657	17,763	13,144	3,234	16,379	18,203
Federal Taxable Income	236,720	(3,808)	232,913	210,682	44,371	255,053	199,012	39,246	238,258	260,398
Fed Income Tax	82,852	(1,333)	81,520	73,739	15,530	89,269	69,654	13,736	83,390	91,139
Deferred Taxes	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)
Federal Tax Credits	(28,929)	-	(28,929)	(28,929)	-	(28,929)	(48,711)	-	(48,711)	(48,711)
Total Income Tax	59,601	(1,646)	57,954	48,342	19,186	67,528	23,513	16,970	40,484	50,057
Adjusted Revenue Requirement		(4,264)			49,695			43,956		
Filed Base Revenue Requirement (PGE/301)		12,496			51,371			46,663		
Revenue Requirement Adjustment		**(16,760)**			**(1,675)**			**(2,707)**		
∑ Adjustment col (2), (5), (8):		**(21,143)**								

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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

EXHIBIT ICNU/103

SELECTION FROM OPENING TESTIMONY OF BRADLEY G. MULLINS IN DOCKET NO. UE 286

June 11, 2014

II. WIND INTEGRATION

Q. WHAT ADJUSTMENT ARE YOU PROPOSING RELATED TO WIND INTEGRATION?

A. I propose that the Commission require the Company to assume in its NVPC calculations that it had elected the most cost-effective method to integrate wind for the entire test period. Specifically, I propose that NVPC be calculated as if the Company had elected to self-integrate the Biglow and Tucannon River facilities, resulting in a $5.0 million reduction to NVPC.

Q. WHAT IS YOUR BASIS FOR PROPOSING THIS ADJUSTMENT?

A. The evidence shows that the Company has not prudently managed its integration costs. There are two fact patterns that lead to this conclusion. First, the Company justified the cost of the Port Westward II facility on the basis that it would be used to self-integrate wind, yet it has failed to take the necessary steps to self-integrate by the time the facility will be placed into service. Second, despite parties' promptings in the prior APCU proceeding for the Company to develop a more cost-effective wind integration paradigm, the Company did not properly analyze, and plan for, its April 4, 2014 balancing service election, which impacts the first nine months in the test period. In fact, the Company has not shown that it has made sufficient progress in preparing its systems to self-integrate wind in time for BPA's next balancing service election.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE OPTIONS AVAILABLE TO THE COMPANY TO INTEGRATE WIND.

A. Both the Biglow and Tucannon River wind facilities are located in BPA's balancing area. Thus, the Company must pay BPA ancillary service charges, including charges for both Variable Energy Resource Balancing Service ("VERBS") and Generation Imbalance

("GI"), to integrate these wind resources on its behalf. Over the past five years, and in particular following the settlement approved in the BP-14 rate proceeding on May 15, 2013, BPA has given companies that own variable energy resources, such as wind resources, additional flexibility regarding how they procure integration services. These companies, including PGE, now have the option to pay discounted VERBS rates in return for electing to schedule on a sub-hourly basis,[2/] and also have the option to self-supply integration services for VERBS and/or GI.

The election for these integration options traditionally occurs every two years, corresponding to BPA's rate periods; however, in BP-14, entities were given the option to make a special, mid-rate-period election outside of the two-year window, which occurred on April 4, 2014, and will be effective for BPA's fiscal year 2015 (October 2014 – September 2015). The next election will occur for the BP-16 rate period in April 2015, and unless a similar mid-rate-period election is given, it will be in effect for the entire BP-16 rate period – BPA fiscal years 2016 and 2017 (October 2015 – September 2017).

Q. WAS THE COMPANY AWARE OF ITS ABILITY TO ELECT TO SELF-SUPPLY IN THE APRIL 4, 2014 MID-RATE-PERIOD ELECTION?

A. Yes. In the Company's prior APCU filing, Renewable Northwest ("RNW") witnesses Yourkowski, Lindsay, and Dubson criticized the Company for not electing the most cost-effective method to integrate wind in its April 2013 balancing service election and called attention to the Company's ability to make a new, more cost-effective election in its April

[2/] While discounted rates only apply to the VERBS ancillary service charges, it is expected that an entity electing sub-hourly scheduling will likely also incur fewer GI charges as a result of using sub-hourly forecasts.

4, 2014 mid-rate-period election.[3/] While no NVPC adjustment was incorporated into the final settlement in that proceeding, the Company agreed to perform a comprehensive study of its April 4, 2014 election and present its analysis to parties prior to making the election.[4/]

Q. DID THE COMPANY FULFILL ITS OBLIGATION TO ANALYZE AND SELECT THE MOST COST-EFFECTIVE METHOD TO INTEGRATE WIND IN ITS APRIL 4, 2014 ELECTION?

A. No. While the stipulation required the Company to perform a comprehensive review of both the costs and benefits of each alternative method, the Company only performed quantitative analysis on one alternative option, the thirty-minute scheduling election.[5/] Confidential Exhibit ICNU/102 contains the presentation that the Company provided to parties prior to its April 4, 2014 balancing service election.[6/] Notably, the presentation fails to provide a comprehensive review of the Company's wind integration options. In addition, despite the thirty-minute scheduling option being more cost-effective than the sixty-minute scheduling election, the Company did not pursue it for the benefit of customers. The Company viewed the benefits associated with the thirty-minute scheduling option, which amounted to nearly $[redacted] per year, to be inadequate to justify participation.[7/] Other options were not even quantified on an analytical basis.[8/] The Company stated that it did not analyze a fifteen-minute scheduling election as a

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[3/] Docket No. UE 266, RNP/100 Yourkowski-Lindsay-Dubson at 5:8-6:3 and 9:21-10:4 (May 21, 2013).
[4/] Docket No. UE 266, Order No. 13-280 at 8-9.
[5/] See Confidential Exhibit ICNU/102 at 9.
[6/] It should be noted that the March 18, 2013 date detailed on the slide deck is incorrect. The actual date of the presentation was March 18, 2014.
[7/] See Confidential Exhibit ICNU/102 at 14; see Confidential Table 2 below.
[8/] See Confidential Exhibit ICNU/102 at 4, 13.

result of "modeling difficulties"[9/] and that it did not analyze the self-integration option because the necessary system upgrades were not in place to make such an election.[10/]

Q. PLEASE DESCRIBE WHAT ELECTION THE COMPANY MADE IN ITS MID-RATE-PERIOD ELECTION AND WHY YOU BELIEVE THAT ELECTION WAS NOT THE MOST COST-EFFECTIVE OPTION?

A. In its April 4, 2014 mid-rate-period election on balancing services, the Company elected to purchase all wind integration services from BPA under a sixty-minute scheduling paradigm. This election represents no change in how the Company has traditionally procured wind integration. Table 2, below, demonstrates why this election is not the most cost-effective method to integrate wind. As can be seen in the table, the election that the Company made is the most expensive option available.

CONFIDENTIAL TABLE 2
ESTIMATED TEST PERIOD WIND INTEGRATION COSTS
Under alternative balancing service elections ($million)

[redacted]

9/ Id. at 13.
10/ Id. at 9.

Q. WHY IS THE FACT THAT THE COMPANY DID NOT HAVE THE PROPER SYSTEM UPGRADES IN PLACE INSUFFICIENT TO JUSTIFY ITS DECISION NOT TO ANALYZE THE SELF-INTEGRATION OPTION?

A. The various hurdles that allegedly prevented the Company from making a cost-effective election should have been resolved well in advance of its mid-rate-period election. It is not sufficient to say that an option was not viable on the basis that the Company did not know how to analyze it, and if system upgrades were indeed necessary, those upgrades should have been identified and quantified early enough to provide time to place them in service prior to the effective date of the mid-rate-period election. I will note that the Company would not have been the first entity to pursue a self-integration option. Iberdrola Renewables, LLC has successfully self-integrated its variable energy resources in BPA's balancing area since October 2010, and is seeking to expand its self-integration program to other entities.[11/] Thus, it is clear that self-integration is achievable.

Q. WHAT OTHER FACTORS SUGGEST THAT THE COMPANY SHOULD HAVE BEEN CAPABLE OF SELF-INTEGRATING ITS VARIABLE ENERGY RESOURCES IN TIME FOR THE APRIL 4, 2014 ELECTION?

A. A major reason why the Company should have been preparing to self-integrate its variable energy resources in time for the April 4, 2014 election is that Port Westward II was justified based on its ability to be used to self-integrate wind. In fact, a significant factor in the Company's decision to select Port Westward II through its 2012 Request for Proposals for Capacity and Baseload Energy Resources ("Capacity RFP") was Port Westward II's ability to allow the Company to self-integrate.

[11/] See FERC Docket No. ER13-1058-000.

The Capacity RFP assumed a need for a resource "that will fill the dual function of providing capacity to maintain supply reliability … *while also providing needed flexibility to address variable load requirements and increasing levels of intermittent energy resources*."[12/] The Company also modeled the flexible capacity bids in the Capacity RFP under the assumption that all wind would be self-integrated: "Flexible Capacity bids will be subject to a reliability based dispatch required to follow expected load or wind deviations …."[13/]

Without wind-integration, MONET only models Port Westward II to dispatch in 13 percent of the hours of the year. In contrast, the Capacity RFP assumed Port Westward II would dispatch in 74 percent of hours in 2015.[14/] Had the Company modeled Port Westward II solely on economic dispatch, the results of the Capacity RFP likely could have been different. Flexible capacity bids from combined cycle combustion turbine ("CCCT") technologies were not accepted in the Capacity RFP on the basis that they did not meet the Company's flexible capacity needs, yet, because a CCCT has a lower variable cost, it is possible that such a resource would have been selected over Port Westward II if the need to self-integrate wind was not considered.[15/] It, therefore, appears that the economics of Port Westward II are dependent on it being used for self-integration. Thus, I believe that the Company has the obligation to ensure that customers receive the full benefits of Port Westward II on the same basis that its cost was justified in the Capacity RFP. This means the Company's NVPC should be reduced to reflect the

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12/ Docket No. UM 1535, Capacity RFP at 1 (emphasis added) (Jan. 25, 2012).
13/ Id. at 30.
14/ Id. at 81.
15/ Id. at 2.

benefits customers would be receiving if the Company had elected to self-integrate. If these benefits are not provided for the resource's entire useful life, customers are effectively over-paying for Port Westward II.

Q. DOES THE COMPANY ASSUME SELF-INTEGRATION AT ANY POINT DURING THE TEST YEAR?

A. Yes. At PGE/500, Page 12, lines 12-16, the Company states that it will self-integrate starting in Q4 of the test year. By proposing such an adjustment, the Company tacitly acknowledges the need to include self-integration benefits in rates as a result of the Port Westward II acquisition. Unfortunately, a Q4 benefit is too little too late, given the low dispatch rate of Port Westward II without self-integration. Further, even the Q4 adjustment proposed by the Company does not adequately pass the full amount of benefits back to customers.

Q. WHY DO YOU BELIEVE THAT THE COMPANY'S Q4 PORT WESTWARD II INTEGRATION ADJUSTMENT IS INADEQUATE?

A. In MONET, the Company only included self-integration benefits for the Biglow facility and excluded Tucannon River. This reduces benefits to customers by $828,886, despite the fact that, with Port Westward II online, the Company has sufficient flexible capacity to integrate both wind facilities. Given the magnitude of the benefits to ratepayers, the Company should have been working with BPA to ensure that it is capable of self-integrating Tucannon River when that resource comes online.

Q. ARE THERE ANY OTHER DEFICIENCIES WITH THE COMPANY'S Q4 SELF-INTEGRATION MODELING?

A. Yes. The Company used the wind integration rate for 2018, not the wind integration rate for 2015. Wind integration rates typically possess a relationship to gas prices. Because gas prices included in the test period are approximately 22 percent lower than 2018 gas prices assumed in the 2013 Wind Integration Study included in the Company's 2013 IRP, wind integration costs in the test period should also be lower. Based on this 22 percent difference in gas prices, the wind integration cost for 2015 is likely approximately \$3.13/MWH, compared to \$3.99/MWH calculated for 2018.

Q. PLEASE SUMMARIZE HOW YOU HAVE CALCULATED YOUR ADJUSTMENT.

A. My adjustment, which is detailed in Confidential Exhibit ICNU/103, removes all BPA wind integration costs from the test period and replaces those costs with the cost of self-integrating all of the Company's wind resources (Biglow and Tucannon River) as calculated in the Company's 2013 Wind Integration Study. Rather than using the wind integration rate for 2018, however, I have used a rate estimated for 2015 of \$3.13/MWH. In total, this reduces NVPC by \$5,075,904.

III. BEAVER POINT-TO-POINT CONTRACT

Q. WHAT ADJUSTMENT YOU ARE PROPOSING RELATED TO THE BEAVER POINT-TO-POINT CONTRACT?

A. I propose an adjustment that removes the costs associated with the unused portion of the Beaver PTP transmission contract on the basis that it is not used and useful. This adjustment results in a \$6.7 million reduction to NVPC.

Q. WHAT IS YOUR BASIS FOR SUGGESTING THAT THE BEAVER PTP TRANSMISSION CONTRACT IS NOT USED AND USEFUL?

A. The Company originally used the Beaver PTP transmission contract to deliver power from the Beaver generating station to load. Following the construction of Port Westward, the Company reterminated the Beaver power facility to the Trojan transmission substation. This connected Beaver directly into the Company's system and eliminated the

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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

EXHIBIT ICNU/104

REVENUE REQUIREMENT IMPACT OF DEFERRED PRODUCTION TAX CREDITS

June 11, 2014

Exhibit ICNU/104
2015 Results of Operations
Adjustment 3 - Deferred Prodution Tax Credits: Revenue Requirement Impact
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Operating Revenues										
Sales to Consumers (Rev. Req.)	1,730,004	(7,287)	1,722,717	1,722,717	49,695	1,772,412	1,722,717	38,692	1,761,408	1,811,104
Sales for Resale	-	-	-	-	-	-	-	-	-	-
Other Operating Revenues	23,521	-	23,521	23,521	-	23,521	23,521	-	23,521	23,521
Total Operating Revenues	1,753,525	(7,287)	1,746,237	1,746,237	49,695	1,795,933	1,746,237	38,692	1,784,929	1,834,624
Operation & Maintenance										
Net Variable Power Cost	593,425	-	593,425	592,212	-	592,212	577,002	-	577,002	575,789
Operations O&M	246,227	-	246,227	247,706	-	247,706	254,700	-	254,700	256,179
Support O&M	233,639	(59)	233,580	233,927	404	234,331	234,015	314	234,329	235,080
Total Operation & Maintenance	1,073,292	(59)	1,073,232	1,073,845	404	1,074,248	1,065,717	314	1,066,032	1,067,048
Depreciation & Amortization	280,008	-	280,008	293,596	-	293,596	303,679	-	303,679	317,267
Other Taxes / Franchise Fee	110,280	(182)	110,098	111,562	1,243	112,805	117,049	968	118,016	120,723
Income Taxes	59,907	(2,813)	57,094	47,481	19,186	66,667	23,180	14,938	38,118	47,692
Total Oper. Expenses & Taxes	1,523,487	(3,055)	1,520,432	1,526,483	20,833	1,547,316	1,509,625	16,220	1,525,846	1,552,730
Utility Operating Income	230,038	(4,232)	225,805	219,755	70,529	248,617	236,612	54,912	259,083	281,895
Rate of Return	7.589%		7.450%	6.587%		7.450%	6.805%		7.450%	7.450%
Return on Equity	9.679%		9.400%	7.673%		9.400%	8.110%		9.400%	9.400%

* 2014 Rates per approved UE 262 and UE 266

Exhibit ICNU/104
2015 Results of Operations
Adjustment 3 - Deferred Prodution Tax Credits: Revenue Requirement Impact
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Rate Base										
Plant in Service	7,293,364	-	7,293,364	7,603,781	-	7,603,781	7,803,401	-	7,803,401	8,113,818
Accumulated Depreciation	(3,805,842)	-	(3,805,842)	(3,812,518)	-	(3,812,518)	(3,817,676)	-	(3,817,676)	(3,824,352)
Accumulated Def. Income Taxes	(607,048)	-	(607,048)	(601,755)	-	(601,755)	(658,765)	-	(658,765)	(653,473)
Accumulated Def. Inv. Tax Credit	-	-	-	(3,835)	-	(3,835)	-	-	-	(3,835)
Net Utility Plant	2,880,474	-	2,880,474	3,185,672	-	3,185,672	3,326,959	-	3,326,959	3,632,157
Misc Deferred Debits	30,852	-	30,852	30,852	-	30,852	30,852	-	30,852	30,852
Operating Materials & Fuel	75,103	-	75,103	75,103	-	75,103	75,103	-	75,103	75,103
Misc. Deferred Credits	(11,740)	-	(11,740)	(11,740)	-	(11,740)	(11,740)	-	(11,740)	(11,740)
Working Cash	56,369	(113)	56,256	56,480	771	57,251	55,856	600	56,456	57,451
Total Rate Base	3,031,058	(113)	3,030,945	3,336,367	771	3,337,138	3,477,030	600	3,477,630	3,783,823
Income Tax Calculations										
Book Revenues	1,753,525	(7,287)	1,746,237	1,746,237	49,695	1,795,933	1,746,237	38,692	1,784,929	1,834,624
Book Expenses	1,463,580	(241)	1,463,338	1,479,002	1,647	1,480,649	1,486,445	1,282	1,487,727	1,505,038
Interest Rate Base @ Weighted Cost of Debt	83,354	(3)	83,351	91,750	21	91,771	95,618	17	95,635	104,055
Production Deduction	-	-	-	-	-	-	-	-	-	-
Permanent Sch M Differences	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)
Temporary Sch M Differences	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)
State Taxable Income	253,739	(7,043)	246,696	222,633	48,027	270,661	211,322	37,393	248,715	272,680
State Income Tax	16,310	(536)	15,774	13,942	3,657	17,599	13,081	2,847	15,928	17,752
Federal Taxable Income	237,428	(6,506)	230,922	208,691	44,371	253,062	198,241	34,546	232,787	254,927
Fed Income Tax	83,100	(2,277)	80,823	73,042	15,530	88,572	69,384	12,091	81,476	89,225
Deferred Taxes	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)
Federal Tax Credits	(28,929)	-	(28,929)	(28,929)	-	(28,929)	(48,711)	-	(48,711)	(48,711)
Total Income Tax	59,907	(2,813)	57,094	47,481	19,186	66,667	23,180	14,938	38,118	47,692
Adjusted Revenue Requirement		(7,287)			49,695			38,692		
Base Revenue Req. w/ updated ROR (ICNU/102)		(4,264)			49,695			43,956		
Revenue Requirement Adjustment		**(3,023)**			**(0)**			**(5,264)**		
∑ Adjustment col (2), (5), (8):		**(8,287)**								

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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

EXHIBIT ICNU/105

REVENUE REQUIREMENT IMPACT OF PREPAID PENSION ASSET

June 11, 2014

Exhibit ICNU/105
2015 Results of Operations
Adjustment 5 - Prepaid Pension Asset: Revenue Requirement Impact
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Operating Revenues										
Sales to Consumers (Rev. Req.)	1,730,004	(9,645)	1,720,359	1,720,359	49,695	1,770,054	1,720,359	43,956	1,764,314	1,814,010
Sales for Resale	-	-	-	-	-	-	-	-	-	-
Other Operating Revenues	23,521	-	23,521	23,521	-	23,521	23,521	-	23,521	23,521
Total Operating Revenues	1,753,525	(9,645)	1,743,879	1,743,879	49,695	1,793,575	1,743,879	43,956	1,787,835	1,837,530
Operation & Maintenance										
Net Variable Power Cost	593,425	-	593,425	592,212	-	592,212	577,002	-	577,002	575,789
Operations O&M	246,227	-	246,227	247,706	-	247,706	254,700	-	254,700	256,179
Support O&M	233,643	(78)	233,565	233,912	404	234,315	233,999	357	234,356	235,107
Total Operation & Maintenance	1,073,295	(78)	1,073,217	1,073,829	404	1,074,233	1,065,702	357	1,066,059	1,067,075
Depreciation & Amortization	280,008	-	280,008	293,596	-	293,596	303,679	-	303,679	317,267
Other Taxes / Franchise Fee	110,280	(241)	110,039	111,503	1,243	112,746	116,990	1,099	118,089	120,796
Income Taxes	60,142	(3,724)	56,418	46,806	19,186	65,992	21,977	16,970	38,948	48,521
Total Oper. Expenses & Taxes	1,523,726	(4,043)	1,519,682	1,525,733	20,833	1,546,566	1,508,348	18,427	1,526,775	1,553,659
Utility Operating Income	229,799	(5,602)	224,197	218,146	70,529	247,008	235,531	62,383	261,060	283,871
Rate of Return	7.636%		7.450%	6.581%		7.450%	6.723%		7.450%	7.450%
Return on Equity	9.772%		9.400%	7.662%		9.400%	7.946%		9.400%	9.400%

* 2014 Rates per approved UE 262 and UE 266

Exhibit ICNU/105
2015 Results of Operations
Adjustment 5 - Prepaid Pension Asset: Revenue Requirement Impact
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Rate Base										
Plant in Service	7,293,364	-	7,293,364	7,603,781	-	7,603,781	7,803,401	-	7,803,401	8,113,818
Accumulated Depreciation	(3,805,842)	-	(3,805,842)	(3,812,518)	-	(3,812,518)	(3,817,676)	-	(3,817,676)	(3,824,352)
Accumulated Def. Income Taxes	(579,549)	-	(579,549)	(574,257)	-	(574,257)	(631,267)	-	(631,267)	(625,975)
Accumulated Def. Inv. Tax Credit	-	-	-	(3,835)	-	(3,835)	48,058	-	48,058	44,222
Net Utility Plant	2,907,972	-	2,907,972	3,213,170	-	3,213,170	3,402,515	-	3,402,515	3,707,713
Misc Deferred Debits	30,852	-	30,852	30,852	-	30,852	30,852	-	30,852	30,852
Operating Materials & Fuel	75,103	-	75,103	75,103	-	75,103	75,103	-	75,103	75,103
Misc. Deferred Credits	(60,800)	-	(60,800)	(60,800)	-	(60,800)	(60,800)	-	(60,800)	(60,800)
Working Cash	56,378	(150)	56,228	56,452	771	57,223	55,809	682	56,491	57,485
Total Rate Base	3,009,505	(150)	3,009,355	3,314,777	771	3,315,548	3,503,479	682	3,504,161	3,810,353
Income Tax Calculations										
Book Revenues	1,753,525	(9,645)	1,743,879	1,743,879	49,695	1,793,575	1,743,879	43,956	1,787,835	1,837,530
Book Expenses	1,463,584	(320)	1,463,264	1,478,928	1,647	1,480,574	1,486,371	1,457	1,487,827	1,505,138
Interest Rate Base @ Weighted Cost of Debt	82,761	(4)	82,757	91,156	21	91,178	96,346	19	96,364	104,785
Production Deduction	-	-	-	-	-	-	-	-	-	-
Permanent Sch M Differences	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)
Temporary Sch M Differences	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)
State Taxable Income	254,328	(9,321)	245,006	220,943	48,027	268,971	208,311	42,480	250,791	274,756
State Income Tax	16,355	(710)	15,645	13,813	3,657	17,470	12,851	3,234	16,086	17,910
Federal Taxable Income	237,973	(8,612)	229,361	207,130	44,371	251,501	195,460	39,246	234,706	256,846
Fed Income Tax	83,290	(3,014)	80,276	72,496	15,530	88,025	68,411	13,736	82,147	89,896
Deferred Taxes	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)
Federal Tax Credits	(28,929)	-	(28,929)	(28,929)	-	(28,929)	(48,711)	-	(48,711)	(48,711)
Total Income Tax	60,142	(3,724)	56,418	46,806	19,186	65,992	21,977	16,970	38,948	48,521
Adjusted Revenue Requirement		(9,645)			49,695			43,956		
Base Revenue Req. w/ updated ROR (ICNU/102)		(4,264)			49,695			43,956		
Revenue Requirement Adjustment		**(5,381)**			**(0)**			**0**		
∑ Adjustment col (2), (5), (8):		**(5,381)**								

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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

EXHIBIT ICNU/106

REVENUE REQUIREMENT IMPACT OF ENVIRONMENTAL REMEDIATION COSTS

June 11, 2014

Exhibit ICNU/106
2015 Results of Operations
Adjustment 6 - Evironmental Remediation: Revenue Requirement Impact
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Operating Revenues										
Sales to Consumers (Rev. Req.)	1,730,004	(7,488)	1,722,516	1,722,516	49,695	1,772,211	1,722,516	43,956	1,766,472	1,819,386
Sales for Resale	-	-	-	-	-	-	-	-	-	-
Other Operating Revenues	23,521	-	23,521	23,521	-	23,521	23,521	-	23,521	23,521
Total Operating Revenues	1,753,525	(7,488)	1,746,037	1,746,037	49,695	1,795,732	1,746,037	43,956	1,789,992	1,842,907
Operation & Maintenance										
Net Variable Power Cost	593,425	-	593,425	592,212	-	592,212	577,002	-	577,002	575,789
Operations O&M	246,227	-	246,227	247,706	-	247,706	254,700	-	254,700	256,179
Support O&M	230,546	(61)	230,485	230,832	404	231,236	230,920	357	231,277	235,154
Total Operation & Maintenance	1,070,198	(61)	1,070,137	1,070,749	404	1,071,153	1,062,622	357	1,062,979	1,067,121
Depreciation & Amortization	280,008	-	280,008	293,596	-	293,596	303,679	-	303,679	317,267
Other Taxes / Franchise Fee	110,280	(187)	110,093	111,557	1,243	112,800	117,044	1,099	118,143	120,930
Income Taxes	60,842	(2,891)	57,951	48,338	19,186	67,524	23,510	16,970	40,480	50,057
Total Oper. Expenses & Taxes	1,521,328	(3,139)	1,518,189	1,524,240	20,833	1,545,073	1,506,854	18,427	1,525,281	1,555,376
Utility Operating Income	232,197	(4,349)	227,848	221,797	70,529	250,659	239,182	62,383	264,711	287,531
Rate of Return	7.592%		7.450%	6.594%		7.450%	6.733%		7.450%	7.450%
Return on Equity	9.684%		9.400%	7.687%		9.400%	7.966%		9.400%	9.400%

* 2014 Rates per approved UE 262 and UE 266

Exhibit ICNU/106
2015 Results of Operations
Adjustment 6 - Evironmental Remediation: Revenue Requirement Impact
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Rate Base										
Plant in Service	7,293,364	-	7,293,364	7,603,781	-	7,603,781	7,803,401	-	7,803,401	8,113,818
Accumulated Depreciation	(3,805,842)	-	(3,805,842)	(3,812,518)	-	(3,812,518)	(3,817,676)	-	(3,817,676)	(3,824,352)
Accumulated Def. Income Taxes	(579,549)	-	(579,549)	(574,257)	-	(574,257)	(631,267)	-	(631,267)	(625,975)
Accumulated Def. Inv. Tax Credit	-	-	-	(3,835)	-	(3,835)	48,058	-	48,058	44,222
Net Utility Plant	2,907,972	-	2,907,972	3,213,170	-	3,213,170	3,402,515	-	3,402,515	3,707,713
Misc Deferred Debits	30,852	-	30,852	30,852	-	30,852	30,852	-	30,852	30,852
Operating Materials & Fuel	75,103	-	75,103	75,103	-	75,103	75,103	-	75,103	75,103
Misc. Deferred Credits	(11,740)	-	(11,740)	(11,740)	-	(11,740)	(11,740)	-	(11,740)	(11,740)
Working Cash	56,289	(116)	56,173	56,397	771	57,168	55,754	682	56,435	57,549
Total Rate Base	3,058,476	(116)	3,058,360	3,363,782	771	3,364,553	3,552,484	682	3,553,165	3,859,477
Income Tax Calculations										
Book Revenues	1,753,525	(7,488)	1,746,037	1,746,037	49,695	1,795,732	1,746,037	43,956	1,789,992	1,842,907
Book Expenses	1,460,486	(248)	1,460,238	1,475,902	1,647	1,477,548	1,483,345	1,457	1,484,801	1,505,318
Interest Rate Base @ Weighted Cost of Debt	84,108	(3)	84,105	92,504	21	92,525	97,693	19	97,712	106,136
Production Deduction	-	-	-	-	-	-	-	-	-	-
Permanent Sch M Differences	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)
Temporary Sch M Differences	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)
State Taxable Income	256,078	(7,237)	248,842	224,779	48,027	272,806	212,146	42,480	254,627	278,601
State Income Tax	16,488	(551)	15,937	14,105	3,657	17,762	13,143	3,234	16,378	18,203
Federal Taxable Income	239,590	(6,686)	232,904	210,674	44,371	255,044	199,003	39,246	238,249	260,398
Fed Income Tax	83,856	(2,340)	81,516	73,736	15,530	89,266	69,651	13,736	83,387	91,139
Deferred Taxes	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)
Federal Tax Credits	(28,929)	-	(28,929)	(28,929)	-	(28,929)	(48,711)	-	(48,711)	(48,711)
Total Income Tax	60,842	(2,891)	57,951	48,338	19,186	67,524	23,510	16,970	40,480	50,057
Adjusted Revenue Requirement		(7,488)			49,695			43,956		
Base Revenue Req. w/ updated ROR (ICNU/102)		(4,264)			49,695			43,956		
Revenue Requirement Adjustment		**(3,223)**			**(0)**			**(0)**		
∑ Adjustment col (2), (5), (8):		**(3,223)**								

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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

EXHIBIT ICNU/107

PGE STATEMENTS REGARDING ENVIRONMENTAL REMEDIATION ACTIVITIES ALONG THE WILLAMETTE RIVER

June 11, 2014

March 28, 2014

TO: Bradley Van Cleve
Irion Sanger
Bradley Mullins

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to ICNU Data Request No. 053
Dated March 7, 2014

Request:

Please clarify whether PGE's estimated $3.1 million in remediation costs covers all remediation at Downtown Reach and the Portland Harbor remediation sites, or only covers costs expected to be incurred in 2015. If the latter, please identify any estimates PGE has either made or is aware of that cover the total remediation costs for Downtown Reach and the Portland Harbor PGE is expected to incur. Please identify how much PGE has paid already and how much it is estimated to pay going forward. Please provide all related documents.

Response:

PGE objects to this request on the basis that it is overly burdensome. Nevertheless, without waiving its objection, PGE replies as follows:

1. Downtown Reach
   PGE has estimated that $3.1 million in remediation costs will cover potential remediation for specific sites identified as river miles 13.1 and 13.5. PGE anticipates conducting all remediation activities in 2015. Besides river miles 13.1 and 13.5, PGE does not anticipate any other related activities within the Downtown Reach.

   Attachment 054-A provides the Draft Feasibility Report on Downtown Reach Remediation (the file name is "Draft FS Report_V9_2-23-14") and Cost Summary

Table 25 (in the file "Tables 1 through 25") where you can find reference to $3.1 million (Alternative 2) on pages 6-23, 7-16, 8-1 and 8-2.

2. Portland Harbor
   Remediation costs for the federal Environmental Protection Agency (EPA)-governed Portland Harbor Superfund site have not been determined at this time. A Record of Decision is expected from the EPA in late 2015 on the various clean-up alternatives; which, as outlined in the draft Feasibility Study (FS), could take up to 28 years to complete and range in cost from $169 million to $1.8 billion.

   Please see the following link for the FS conducted by the Portland Harbor Lower Willamette Group:
   http://lwgportlandharbor.org/feasibility/index.htm

   The following is a specific link to the page in support of the cost range of $169 million to $1.8 billion:
   http://lwgportlandharbor.org/feasibility/alternatives_analysis01.htm

   It is unclear for what portion, if any, that PGE might be held responsible and PGE does not currently have estimates of its potential liability.

3. Historical and Projected Costs
   Confidential Attachment 053-A provides annual historical and projected costs for Portland Harbor and Downtown Reach through 2015. The costs for Portland Harbor are defense costs while those for Downtown Reach include both defense and remediation costs. These costs do not include any insurance proceeds received.

   Attachment 053-A is confidential and subject to the Protective Order No. 14-043.

April 17, 2014

TO: Bradley Van Cleve
Irion Sanger
Bradley Mullins

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to ICNU Data Request No. 071
Dated April 3, 2014

Request:

Reference PGE's Exhibit 700 at 15:4-7. (a) Why has PGE not been able to reach agreement with insurance companies regarding reimbursement of remediation costs related to River Miles 13.1 and 13.5 of Downtown Reach? (b) Please provide all written communications between PGE and any insurance company related to potential reimbursement of these remediation costs.

Response:

PGE has not incurred remediation costs related to River Miles 13.1 and 13.5 at this time, and therefore does not yet have remediation (damage) claims that can be negotiated with insurance providers. While we anticipate PGE being required to perform remediation activities, it is premature to negotiate reimbursement at this time. We intend to begin such negotiations once the Feasibility Study is final and remedy selection has been made by the Department of Environmental Quality. Costs to date regarding these sites are investigation (defense) related costs, and have been included in costs submitted to and reimbursed by insurance companies.

With respect to part (b) of this request, PGE does not have responsive written communications related to potential reimbursement for remediation of River Miles 13.1 and 13.5; as such costs have not been incurred. PGE has notified its known insurance carriers whose policies could potentially provide coverage that PGE would be seeking coverage for defense and indemnity.

April 17, 2014

TO: Bradley Van Cleve
Irion Sanger
Bradley Mullins

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to ICNU Data Request No. 073
Dated April 3, 2014

Request:

Reference PGE's response to ICNU DR 54, Attachment A. Section 3.1.2 of the Draft Feasibility Report identifies outfalls owned by the Oregon Department of Transportation and the City of Portland as potential sources of contamination of the Downtown Reach site. Please explain whether PGE sees these other entities as potential PRPs with respect to the Downtown Reach site. If yes, please identify any actions PGE has taken to recover remediation costs from these parties. If not, please explain why not.

Response:

PGE does see the City of Portland and Oregon Dept. of Transportation as potential PRPs with respect to the sites at River Miles 13.1 and 13.5 in the Downtown Reach; however, the Oregon Department of Environmental Quality (DEQ) issued a unilateral order to perform investigation tasks only to PGE. As discussed in PGE's response to ICNU Data Request No. 071, PGE has not incurred remediation costs at this time, and therefore has not taken action to recover remediation costs from these parties. Following remediation, PGE may have contribution claims against these parties under applicable environmental clean-up laws, but will need to carefully weigh the costs and benefits before undertaking such actions.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[x] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2013

OR

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition period from ______ to ______

Commission File Number 001-05532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oregon	**93-0256820**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

121 S.W. Salmon Street
Portland, Oregon 97204
(503) 464-8000
(Address of principal executive offices, including zip code, and Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Common Stock, no par value	**New York Stock Exchange**
(Title of class)	(Name of exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [x] No [ ]

DEQ Investigation of Downtown Reach

The Oregon Department of Environmental Quality (DEQ) has executed a memorandum of understanding with the EPA to administer and enforce clean-up activities for portions of the Willamette River that are upriver from the Portland Harbor Superfund site (the Downtown Reach). In January 2010, the DEQ issued an order requiring PGE to perform an investigation of certain portions of the Downtown Reach. PGE completed this investigation in December 2011 and entered into a consent order with the DEQ in July 2012 to conduct a feasibility study of alternatives for remedial action for the portions of the Downtown Reach that were included within the scope of PGE's investigation. The draft feasibility study report, which describes possible remediation alternatives that range in estimated cost from $3 million to $8 million, is expected to be submitted to the DEQ in late February 2014. Using the Company's best estimate of the probable cost for the remediation effort from the set of alternatives provided in the draft feasibility study report, PGE recorded a $3 million reserve for this matter as of December 31, 2013.

Based on the available evidence of previous rate recovery of incurred environmental remediation costs for PGE , as well as for other utilities operating within the same jurisdiction, the Company has concluded that the estimated cost of $3 million to remediate the Downtown Reach is probable of recovery. As a result, the Company also recorded a regulatory asset of $3 million for future recovery in prices as of December 31, 2013. The Company included recovery of the regulatory asset in its 2015 General Rate Case filed with the OPUC in February 2014.

Alleged Violation of Environmental Regulations at Colstrip

On July 30, 2012, PGE received a Notice of Intent to Sue (Notice) for violations of the Clean Air Act (CAA) at Colstrip Steam Electric Station (CSES) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other CSES co-owners, including PPL Montana, LLC, the operator of CSES. PGE has a 20% ownership interest in Units 3 and 4 of CSES. The Notice alleges certain violations of the CAA, including New Source Review, Title V, and opacity requirements, and states that the Sierra Club and MEIC will: i) request a United States District Court to impose injunctive relief and civil penalties; ii) require a beneficial environmental project in the areas affected by the alleged air pollution; and iii) seek reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees.

The Sierra Club and MEIC asserted that the CSES owners violated the Title V air quality operating permit during portions of 2008 and 2009 and that the owners have violated the CAA by failing to timely submit a complete air quality operating permit application to the Montana Department of Environmental Quality (MDEQ). The Sierra Club and MEIC also asserted violations of opacity provisions of the CAA.

On March 6, 2013, the Sierra Club and MEIC sued the CSES co-owners, including PGE, for these and additional alleged violations of various environmental related regulations. The plaintiffs are seeking relief that includes an injunction preventing the co-owners from operating CSES except in accordance with the CAA, the Montana State Implementation Plan, and the plant's federally enforceable air quality permits. In addition, plaintiffs are seeking civil penalties against the co-owners including $32,500 per day for each violation occurring through January 12, 2009, and $37,500 per day for each violation occurring thereafter. On May 3, 2013, the defendants filed a motion to dismiss 36 of the 39 claims in the suit. On September 27, 2013, the plaintiffs filed an amended complaint that deleted the Title V and opacity claims, added claims associated with two 2011 projects, and expanded the scope of certain claims to encompass approximately 40 additional projects. This matter is scheduled for trial in March 2015.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties concerning this matter, PGE cannot predict the outcome or determine whether it would have a material impact on the Company.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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

EXHIBIT ICNU/108

EXCERPT OF DOWNTOWN REACH REMEDIAL INVESTIGATION STUDY

June 11, 2014

FINAL
Sediment Remedial Investigation Report River Miles 13.1 and 13.5

Willamette River
Portland, Oregon

December 2011

Prepared for:
Portland General Electric Company
121 SW Salmon Street
Portland, OR 97204

Prepared by:
URS
111 S.W. Columbia, Suite 1500
Portland, OR 97201-5850

URS Job No. 25697327

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Acronyms and Abbreviations

%	percent
AST	aboveground storage tank
BCF	bioconcentration factor
BERA	baseline ecological risk assessment
BHC	benzene hexachloride
BHHRA	baseline human health risk assessment
Bridgewater	Bridgewater Group, Inc.
bss	below sediment surface
CEM	conceptual exposure model
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
cfs	cubic feet per second
C_{ij}	concentration of COI *i* in medium *j*
COC	chemical of concern
COI	chemical of interest
COPC	chemical of potential concern (human health)
cPAH	carcinogenic polycyclic aromatic hydrocarbon
CPEC	chemical of potential ecological concern
CRBG	Columbia River Basalt Group
CSM	conceptual site model
CSO	combined sewer overflow
DDD	dichlorodiphenyldichloroethane
DDE	dichlorodiphenyldichloroethylene
DDT	dichlorodiphenyltrichloroethane
DDx	sum of DDT and its isomers DDD and DDE
DEQ	Oregon Department of Environmental Quality
DPSC	downtown Portland sediment characterization
DRI	Desert Research Institute
DRO	diesel range organics
ECSI	environmental cleanup site information
ELCR	excess lifetime cancer risk
EMPC	estimated maximum potential concentration
EPC	exposure point concentration
ERA	ecological risk assessment
ESA	environmental site assessments
ft	foot/feet
FS	Feasibility Study
GSI	GSI Water Solutions, Inc.

Acronyms and Abbreviations

HAI	Hahn and Associates, Inc.
HI	hazard index
HHRA	human health risk assessment
HPAH	high molecular weight polycyclic aromatic hydrocarbon
HQ	hazard quotient
$IRAF_{nc}$	infant risk adjustment factor for non-carcinogens
JSCS	Joint Source Control Strategy
$logK_{ow}$	octanol-water partition coefficient
LPAH	low molecular weight polycyclic aromatic hydrocarbon
LWG	Lower Willamette Group
MDC	maximum detected concentration
MDL	method detection limit
mg/kg	milligram per kilogram
mg/L	milligram per liter
mph	miles per hour
MRL	method reporting limit
mya	million years ago
NAVD88	North American Vertical Datum of 1988
ND	not detected
NFA	no further action
ng/kg	nanogram per kilogram
NGVD29	National Geodetic Vertical Datum of 1929
N_{ij}	Total number of *i* COIs in medium *j*
OAR	Oregon Administrative Rule
ODOT	Oregon Department of Transportation
OMSI	Oregon Museum of Science and Industry
ORBIC	Oregon Biodiversity Information Center
PA	preliminary assessment
PAH	polycyclic aromatic hydrocarbon
PCB	polychlorinated biphenyls
PCDD/F	polychlorinated dibenzo-p-dioxins and furans
PeCDF	pentachlorodibenzofuran
PGE	Portland General Electric
Q	receptor designator
QC	quality control
RA	risk assessment
RBC	risk-based concentration

Acronyms and Abbreviations

R_{BAC}	bioaccumulation index
RI	remedial investigation
RM	river mile
ROD	record of decision
RRO	residual range organics
SAP	sampling and analysis plan
SLV	screening level value
SLV_{ij}	screening level value for COI *i* in medium *j*
SLV_{nc}	screening level value for non-carcinogens
SQG	sediment quality guidelines
SVOC	semi volatile organic compound
TCDD	tetrachlorodibenzo-p-dioxin
TCDF	tetrachlorodibenzofuran
TEF	toxic equivalency factor
TEQ	toxicity equivalent quotient
T_{ij}	toxicity ratio for COI *i* in medium *j*
T_j	summation of toxicity ratios for *i* COIs in medium *j*
TPH	total petroleum hydrocarbons
TOC	total organic carbon
UCL	upper confidence limit on the mean
UST	underground storage tank
µg/kg	microgram per kilogram
URS	URS Corporation
USEPA	United State Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compound
WHO	World Health Organization
WRCC	Western Regional Climate Center

1.0 INTRODUCTION

URS Corporation (URS) has prepared this Remedial Investigation (RI) on behalf of Portland General Electric Company (PGE) to evaluate the sediments along the eastern shore of the Willamette River (also referred to as the River) at river miles (RMs) 13.1 and 13.5, hereafter referred to as the study areas. This RI was developed in accordance with the Oregon Department of Environmental Quality (DEQ) No. LQSR-NWR-10-01 Order issued on January 8, 2010.

The impetus for this RI originated from the results of the 2008 Downtown Portland Sediment Characterization (DPSC) data and preliminary screening evaluation (GSI Water Solutions Inc. [GSI], 2009; DEQ, 2009a). The DEQ identified nine Focus Areas with elevated exceedances of conservative risk-based screening levels in surface and subsurface sediment samples, two of which were at RM 13.1 and RM 13.5. These two in-water areas (RM 13.1 and RM 13.5) were identified as Focus Areas based on elevated concentrations of total polychlorinated biphenyls (PCBs), total DDx (sum of dichlorodiphenyltrichloroethane [DDT] and its degradation products dichlorodiphenyldichloroethane [DDD] and dichlorodiphenyldichloroethylene [DDE]), mercury, total chlordanes, and dioxins (DEQ, 2009a).

In response to DEQ's request (DEQ No. LQSR-NWR-10-01), PGE investigated the upland drainage areas adjacent to the study areas that may have contributed to sediment contamination at RMs 13.1 and 13.5. The information obtained by these investigations was summarized in two reports: *Preliminary Assessment for Outfall 33 Drainage Area* (URS, 2010a) and *Preliminary Assessment for RM 13.1 – 13.5 Drainage Areas* (URS, 2010b). Data gaps identified by these preliminary assessments (PAs) led URS to collect further samples from the upland areas, as well as in-water sediment samples at RMs 13.1 and RM 13.5. Samples were collected and analyzed in association with four field efforts conducted in 2010 and detailed in the following documents:

- *Data Report, PGE, Willamette River Sediment Investigation* (URS, 2010c)
- *Data Report, PGE, Station L Southern Yard Upland Assessment* (URS, 2010d)
- *Data Report, PGE, Rexel Taylor Property Upland Assessment* (URS, 2010e)
- *Data Report, PGE, Hawthorne Building Upland Assessment* (URS, 2010f)

This RI presents conceptual site models (CSMs), identifies chemicals of interest (COIs), describes the nature and extent of contamination in the study areas, and identifies chemicals of potential concern (COPCs) for human receptors and chemicals of potential ecological concern (CPECs) in sediments at the two study areas. It also summarizes the histories of the adjacent upland drainage areas of each study area and evaluates the potential for ongoing upland sources of contamination to sediments in these two study areas. It identifies locations where source control actions should be evaluated in order to prevent ongoing contamination of the river sediments.

1.1 Purpose and Scope of the RI Report

The purpose of this RI report is to assess the sources and extent of chemicals observed in the River sediments at RMs 13.1 and 13.5. The adjacent upland areas have already been extensively assessed; therefore, in this report, the upland areas are only evaluated for their potential to be historical and current sources. This RI does not address potential exposure of upland receptors to upland media. Instead, the scope of the RI included the evaluation of river sediment, potential exposure of receptors to the sediment, and identification of potential upland source control opportunities for future evaluation.

The specific objectives of this RI are:

- Characterize the physical attributes of the study areas to support the selection of remedial alternatives and/or source control measures, should they be necessary.
- Identify substances that have been released and transported to sediment at RMs 13.1 and 13.5.
- Determine the nature, extent, and distribution of chemicals in sediment to support the selection of remedial alternatives or source control measures, should they be necessary.
- Evaluate the current potential for adverse human health and environmental effects from bioavailable surface sediments at RMs 13.1 and RM 13.5.
- Evaluate the potential for chemical migration from the adjacent upland areas and upriver sources to the study areas.
- Evaluate the potential for adjacent upland drainage areas to be an ongoing source to the sediments through stormwater runoff, groundwater, or bank erosion.
- Identify locations within the adjacent upland drainage areas where source control actions should be evaluated in order to prevent any ongoing releases to the river sediments.
- Identify any existing data gaps that must be filled to support the selection of remedial alternatives or source control measures, should they be necessary.

Both surface and subsurface sediment data was used to determine nature and extent of contamination, as well as fate and transport of contaminants. The evaluation of potential adverse risk to human health and the environment utilized surface sediment data from the study areas. The surface sediments constitute the biologically active zone and the depth where human and ecological receptors are most likely to be exposed. To assess risk, a screening-level problem formulation human health risk assessment (HHRA) and Level I/Level II ecological risk assessment (ERA) were streamlined and performed. These evaluations used conservative screening level values (SLVs) and exposure/ingestion assumptions. Although PGE does not necessarily concur with the applicability of these conservative SLVs and risk assumptions, they were used in the risk assessments (RAs) at the request of DEQ. For further details on the streamlined approach of the HHRA and ERA, see Sections 9.0 and 10.0, respectively.

1.2 Report Organization

The remainder of this report is organized into the following sections:

- Section 2 describes the study areas' background
- Section 3 describes the adjacent upland background
- Section 4 describes the CSMs
- Section 5 describes the study areas' characteristics
- Section 6 describes the available data within the study areas
- Section 7 describes the nature and extent of contamination
- Section 8 describes the fate and transport of contaminants
- Section 9 presents the problem formulation HHRA
- Section 10 presents the Level I/Level II ERA
- Section 11 presents the upland source control evaluation
- Section 12 presents the summary and recommended next steps in the investigation.
- Section 13 lists references for documents cited in the report text

2.0 STUDY AREAS' BACKGROUND

This section describes the study areas and summarizes the history and previous investigations of the study areas.

2.1 Description of Study Areas

The two study areas are located on the eastern shore of the Willamette River in downtown Portland, Oregon at RMs 13.1 and 13.5 (Figure 1). The RM 13.1 in-water Study Area is approximately 2.61 acres, and the RM 13.5 in-water Area is approximately 2.17 acres. No sandy beaches are present at either study area with the exception of the northern tip of RM 13.1, which includes a very small sandy/gravelly area. This small area is inundated with water during the winter periods. With the above exception, the adjacent river shoreline is covered with large (generally >12 inch diameter) cobbles and rip-rap. A public dock is located within the RM 13.1 Study Area, and a private dock is located within the RM 13.5 Study Area.

The following three upland drainage areas discharge to the two study areas as indicated below (Figure 2):

1. The City of Portland (the City) Outfall 33 drainage area discharges at RM 13.1
2. The RM 13.1 drainage area directly discharges (overand flow) at RM 13.1
3. The RM 13.5 drainage area discharges at RM 13.5

A fourth drainage area at RM 13.3 also drains upland properties into the Willamette River but does not directly drain into either study area. The RM 13.1 Study Area also receives stormwater drainage from the Marquam Bridge access ramp, discharging at Oregon Department of Transportation (ODOT) Outfall WR-319. The two study areas also receive sediment loading from upstream areas of the River.

As previously mentioned, the scope of the RI included the evaluation of river sediment within these two study areas, potential concerns related to the exposure of receptors to the sediment, and identification of potential ongoing sources of contamination.

2.2 History of Study Areas

The following sections describe the history of each study area.

2.2.1 River Mile 13.1 Study Area

Since 2005, a public dock (constructed without creosote treated lumber) has been located within the study area and is used by boaters, especially non-motorized boats. Historically the study area bordered industrial upland properties, whose owners and tenants used wharves and a dock within the in-water study area.

Contamination may be transported to the RM 13.1 Study Area from over-water activities, from activities conducted in upland areas, or from upstream sources. Two drainage basins drain adjacent upland areas to RM 13.1 (Figure 2). Both drainage basins are comprised of multiple upland properties, each of which has unique operational and waste management histories, which are described in the Outfall 33 Drainage Area PA and the RMs 13.1-13.5 Drainage Areas PA (URS, 2010a; 2010b). See Section 3.0 for further information on these adjacent upland areas.

URS was unable to identify information regarding any recent spills that may have occurred from the use of the public dock by boaters (2005-present). URS has not identified specific historical spills directly to the RM 13.1 Study Area. Historical spills to or within the study area likely occurred during the industrial use of the adjacent upland areas and associated in-water uses. These uses have included shoreline floats and ship building by an unknown company (from approximately 1901 to 1904), dock use by the Holman Transfer Company (approximately 1924-1950) and wharves by PGE (PGE and predecessor companies Portland Railway, Light, & Power Company and Portland Electric Power Company). Wharf use by PGE or their predecessor companies occurred from approximately 1909 to 1966 (URS, 2010b).

Information on upstream sources is limited. Upstream sediment and surface water is impaired from a variety of sources that may include contributions from atmospheric deposition, upland overland releases, sewer overflow releases, and over-water releases. These upstream sources may contribute to the chemical deposition in the study areas.

Sections 3.0, 4.0, and 11.0 present a detailed evaluation of the adjacent upland areas as potential historical or current sources for the two study areas.

2.2.2 River Mile 13.5 Study Area

Since 2007, a private steel dock (constructed without creosote treated lumber) has been located within the study area. This private dock is associated with the City Eastside Combined Sewer Overflow (CSO) Project for offloading upland excavated subsurface soils. Historically, the study area bordered industrial upland properties, which used the adjacent in-water study area for boat building, log rafting, and unloading fuel from a historical docking facility.

Contamination may be transported to the RM 13.5 Study Area from over-water activities, from activities conducted in upland areas, or from upstream sources. The RM 13.5 drainage area drains adjacent upland areas to RM 13.5 (Figure 2). This drainage basin is comprised of multiple upland properties, each of which has unique operational and waste management histories, which are described in the PA for RMs 13.1-13.5 Drainage Areas (URS, 2010b). See Section 3.0 for further information on the adjacent upland areas.

URS has not identified specific recent spills from the use of the private dock for the City CSO Project (2007-present) or other specific historical spills to the RM 13.5 Study Area. Historical spills to or within the study area may have occurred during the industrial use of the adjacent upland areas and associated in-water uses, which included boat building and log rafting by the Inman-Poulsen Lumber Company (from approximately 1890 until the mid-1950s) and a fuel-receiving dock by PGE (Station L, from approximately 1957 to 1994).

As discussed in Section 2.2.1, information on upstream sources is limited. Upstream sediment and surface water is impaired from sources that may include contributions from atmospheric deposition, upland/overland transport/releases/erosion, sewer overflow releases, and over-water releases. These upstream sources may contribute to the chemical deposition in the study areas.

Sections 3.0, 4.0, and 11.0 present a detailed evaluation of the adjacent upland areas as potential historical or current sources of contamination for the two study areas.

2.3 Previous Investigations

Analytical sediment results within the study areas from previous investigations are included in the RI data set and were used in the risk assessments (surface sediment only).

Both the RM 13.1 and RM 13.5 Study Areas were sampled during the 2008 DPSC conducted by GSI on behalf of the DEQ and included in the DEQ preliminary screening evaluation (GSI, 2009; DEQ, 2009a). During this evaluation, the DEQ identified nine Focus Areas with the highest apparent exceedances of conservative risk-based screening levels in surface and subsurface sediment samples. Two of the Focus Areas were identified at RM 13.1 and 13.5. The following sections identify the contaminants identified at sample locations within each of the two study areas.

No investigations within the study areas are known to have occurred, other than the DEQ work.

2.3.1 River Mile 13.1

GSI sampling stations DPSC-G048 (surface sediment) and DPSC-C025 (surface and subsurface sediment) are associated with the RM 13.1 Study Area. The DEQ's Focus Area determination of RM 13.1 was based on elevated concentrations of total PCBs, total DDx, total chlordanes, and dioxins in surface sediment grab samples at station DPSC-G048 (DEQ, 2009a). The surface sediment sample from station DPSC-C025, located adjacent to DPSC-G048, had much lower detected concentrations of these constituents, while the subsurface sediment samples from DPSC-C025 had non-detect to low detected concentrations (DEQ, 2009a).

2.3.2 River Mile 13.5

GSI sampling stations DPSC-CO22 (subsurface sediment), DPSC-G039 (surface sediment), and DPSC-G041 (surface sediment) are associated with the RM 13.5 Study Area. The DEQ's Focus Area determination of RM 13.5 was based on elevated concentrations of total PCBs, total DDx, mercury, total chlordanes, and dioxins in samples from stations DPSC-C022 and DPSC-G041 (DEQ, 2009a). Lower concentrations of these constituents were observed at DPSC-G039 (DEQ, 2009a).

3.0 ADJACENT UPLAND BACKGROUND

This section provides a brief description of the adjacent upland drainage areas and summarizes the operational history and likely sources within these areas. These areas are described in detail in the Outfall 33 Drainage Area PA (URS, 2010a) and the RMs 13.1 – 13.5 Drainage Areas PA (URS, 2010b), as well as associated data reports (URS, 2010d; 2010e; 2010f).

3.1 Adjacent Upland Descriptions

Three adjacent upland drainage areas directly discharge to RMs 13.1 and 13.5 (Figure 2), as indicated below:

1. The City Outfall 33 drainage area discharges at RM 13.1.
2. The RM 13.1 drainage area discharges at RM 13.1.
3. The RM 13.5 drainage area discharges at RM 13.5.

Although individual properties in the adjacent upland drainage areas each have unique operational histories, initial development of the entire upland area occurred in the late 1800s. The properties within each drainage area are fully described in the PAs (URS, 2010a; 2010b). Information on the historical ownership and operational activities of properties within the adjacent upland drainage areas was gathered from historical aerial photographs and Sanborn Fire Insurance maps and is provided in the PAs.

The historical uses for each upland property were chronologically summarized and are provided in Table 1 of the PAs (URS, 2010a, 2010b). The PAs also list chemicals generally associated with each property's use. Historical disposal practices may have included disposal of site materials through sewer lines flowing directly to the Willamette River, through surface application, by burning, by depositing at a municipal landfill, or by using locally as fill.

3.2 Adjacent Upland Sources

Those property uses identified in the PAs (URS, 2010a, 2010b) as most likely to have contributed to contamination in river sediments at RMs 13.1 and 13.5 are summarized in the following subsections.

3.2.1 River Mile 13.1 Study Area - Adjacent Upland Drainage Areas

Upland properties with the potential to have discharged to the RM 13.1 Study Area are located in two drainage areas: City Outfall 33 drainage area and RM 13.1 drainage area (Figure 2). Most upland properties are located in the City Outfall 33 drainage area. The City stormwater lines drain this area through a central line that discharges at City Outfall 33.

As described in the Outfall 33 PA (URS, 2010a), the City conducted an investigation of the City Outfall 33 stormwater system in 2009. This investigation included the collection and analysis of in-line stormwater solids samples and a video survey of the section of the pipe from manhole ABU929 (adjacent to the Holman Building) to approximately the top of the riverbank. The investigation and video found that City Outfall 33's stormwater solids appear to be discharged to the interstitial spaces between rip-rap in the riverbank subsurface due to the poor integrity of the outfall pipe (multiple holes along its length). Since an accumulation of fine-grained materials was not observed at the holes in the outfall pipe during the video survey, stormwater solids are likely being deposited within the riverbank.

The smaller RM 13.1 drainage area, which is immediately adjacent to the River, discharges to the River through overland flow and stormwater lines which currently discharge to the River via active non-City outfalls. As indicated in the RMs 13.1-13.5 PA (URS, 2010b), the following stormwater lines and outfalls are located in upland area adjacent to the RM 13.1 Study Area and discharge directly into the study area.

- One stormwater line owned by ODOT drains a portion of the Marquam Bridge access ramp and discharges to the River at ODOT Outfall WR-319.
- Four outfalls (WR 541, 564, 542, and an unnamed outfall of unknown origin) drain the adjacent upland RM 13.1 drainage area properties. The City considers WR-541 and WR-564 to be inactive; however, these were previous discharge locations and may have been a historical source of contaminants to the River. No additional information is available regarding WR-542 and the unnamed outfall.

City Outfall 33 has been confirmed to be the most likely pathway for transport of contaminants to sediments in RM 13.1. The following sections summarize the operational history and site uses of upland properties that are most likely to have contributed to contamination in river sediments at RM 13.1. The current and historical sources at the Hawthorne Building, the Rexel Taylor property, and the Holman Building, and other properties including roadways within the City Outfall 33 drainage area are summarized in the following subsections. In addition to these sources within the City Outfall 33 drainage area, the RM 13.1 Study Area also receives direct stormwater discharge from the Marquam Bridge access ramp at ODOT Outfall WR-319, as well as unknown discharges from WR-541 (historical) and WR-542.

3.2.1.1 Hawthorne Building

This section includes a brief overview of the Hawthorne Building. A detailed description of the ownership and operational history of the Hawthorne Building is discussed in Section 2.2 of the Outfall 33 PA (URS, 2010a). The location of the Hawthorne Building is indicated on Figure 2.

The Hawthorne Building property has been PGE-affiliated since 1905. The two-story building was originally constructed in 1911 by PGE predecessor companies for use as a railway depot and parking garage. Since 1935, various PGE departments have occupied the building for storage and maintenance uses. Between 1935 and 2000, PGE operations in the basement of the Hawthorne Building included bushing repair, automotive repair, a metal shop, a paint booth; cleaning, repair, and maintenance of electrical equipment (e.g., transformers); and the storage of associated supplies/wastes. Since 2000, PGE operations at the Hawthorne Building have been primarily limited to routine maintenance of on-site systems, including HVAC, elevator, compressors, and plumbing filters; and some welding. Additionally, during that time, the Hawthorne Building has been used to store lead cable and lead-containing potheads (on an interim basis), new transformers (with oil containing less than 1 milligrams per liter [mg/L] PCBs), surplus (used) transformers, and maintenance supplies for off-site usage. The surplus transformers were temporarily stored at the Hawthorne Building prior to transfer and testing at the Transformer Shop at the Portland Service Center (located at 3700 SE 17th Avenue, Portland, Oregon). TSCA rules require assuming untested equipment contains between 50-500 mg/L PCBs. Therefore, the surplus transformers temporarily stored at the Hawthorne Building may have contained PCBs. Since December 2010, oil-containing transformers are no longer stored at the Hawthorne Building. DEQ and the City were given a tour of the facility in January 2011 and shown that transformers are no longer stored on site.

The Outfall 33 PA (URS, 2010a) and follow-up data report (URS, 2010f) identified three pathways by which the Hawthorne Building may have been a historical source or may be a current source of contamination to river sediments. These pathways at the Hawthorne Building include:

1. The Hawthorne basement drainage system, which is composed of multiple floor drains and sumps, receives drainage water both from inside the basement and from stormwater that flows down the exterior basement loading ramp from outside the building (Hawthorne Data Report [URS, 2010f]). Prior to its connection with the City's sanitary sewer sometime between 1969 and 1984, the basement drainage system discharged to the stormwater system connected to City Outfall 33. Discharges from historical operations and materials storage within the basement prior to the drainage connection with the sanitary sewer represent a potential historical source of PCB and dioxin/furan discharges to the River near City Outfall 33.

2. The exterior stormwater system is comprised of four catch basins (Hawthorne Data Report [URS, 2010f]). All four catch basins historically and currently discharge to the City's stormwater system and City Outfall 33. Potential releases of PCBs and dioxins/furans to these catch basins and then to the City Outfall 33 stormwater system represent a potential historical (all four catch basins) source to the River at RM 13.1. In 2010, the exterior catch basins and basement drainage system were pressure washed and cleaned out, and filtration liners were installed (URS, 2010f). The filtration liners are removed and replaced with new liners every six months. During removal and replacement of the liners in February 2011, samples of sediment adhering to the liners were collected and analyzed for PCBs. Only Aroclor 1260 was detected in three of the four catch basin liner samples. Only two of the detected concentrations slightly exceeded the Portland Harbor Joint Source Control Strategy (JSCS) SLV of 0.20 milligrams per kilogram (mg/kg). The four external catch basins may be current sources to City Outfall 33; however, the installed filtration liners inhibit the release of solids with relatively low concentrations of PCBs to the City Outfall 33 stormwater system.

3. According to the Outfall 33 PA (URS, 2010a), groundwater discharge to the River was a potentially complete pathway that warranted further consideration in the City Outfall 33 drainage area. Therefore, URS collected groundwater samples near the Hawthorne Building basement drainage system Sump A in order to address this data gap (Hawthorne Data Report [URS, 2010f]). Detected chemicals in the groundwater samples include total PCBs, total and dissolved metals, and several volatile organic compounds (VOCs) (URS, 2010f). The basement drainage system is a possible source of the chemicals detected in the groundwater, or there may be an upstream source. The results of the Outfall 33 PA indicated that groundwater may be a historical and ongoing source to the River. However, the Hawthorne Building is more than 600 feet from the river. Over this distance it is expected that PCBs and metals will be attenuated through adsorption to soil and VOCs will have the potential to volatilize to the vadose zone, and therefore the groundwater pathway is likely an insignificant pathway.

Additional information regarding the Hawthorne Building and the 2010 investigations/sampling details concerning the identification of the sources of contamination is presented in the PA (URS, 2010a), and follow-up Data Report (URS, 2010f).

On behalf of PGE, Bridgewater Group, Inc. (Bridgewater) retained Hahn and Associates, Inc. (HAI) to conduct Phase II Environmental Site Assessment (ESA) activities at the Hawthorne Building property in July and August 2011 (Bridgewater, 2011). The Phase II ESA activities detected a few contaminants (PCBs, benzene, naphthalene, and 1,4-dichlorobenzene) in groundwater. Due to the low level and sporadic nature of the detections, no significant ongoing source for these groundwater impacts appears likely present at the property. The Phase II ESA activities identified PCB contamination of the exterior asphalt surface. The Phase II ESA concluded that the likely source of exterior asphalt surface PCB contamination is likely from vehicle traffic into/out of the Hawthorne Building basement and that PCBs in the asphalt and dust overlying the asphalt may have the potential to erode and migrate via stormwater runoff to the four exterior catch basins, which ultimately discharge to the Willamette River via the City Outfall 33 stormwater system. The Phase II ESA report is currently in draft and not available for submittal to DEQ.

3.2.1.2 Rexel Taylor Property

This subsection includes a brief overview of the Rexel Taylor property. A detailed description of the ownership and operational history of the Rexel Taylor property is discussed in Section 2.2 of the Outfall 33 PA (URS, 2010a). The location of the Rexel Taylor property is indicated on Figure 2.

The Rexel Taylor property was developed as early as 1901. The property was occupied by the Trinidad Asphalt Paving Company Plant in the early 1900s, whose operations included crude oil underground storage tanks (USTs) and dipping tanks. The Standard Fuel Company briefly operated at the facility in 1935. The most recent building was constructed on the property in 1935 by the Loggers and Contractors Machinery Company, for heavy machinery storage and sales. Ingersoll Rand Corporation occupied the property from 1970 to 1991 as an industrial supplier. HMB Corporation purchased the property from Ingersoll Rand in 1991. The property was operated as Rexel Taylor Electric from 1991 until May 17, 2006 when a fire erupted that consumed a large portion of the material inside the building including wiring, forklifts, and other oil-containing heavy equipment and electrical equipment. The Rexel Taylor property is likely an historical and ongoing source of contamination for RM 13.1.

Ingersoll Rand indicated one UST was decommissioned at the property (UST Facility No. 5990) sometime during their ownership of the property (1970 to 1991). The contents of the UST are unknown. No other information was provided regarding the decommissioning. Additionally, Phase I and II ESAs were reportedly completed in 1990 as part of the property transaction to Ingersoll Rand; however, these reports were unavailable for review. These ESAs allegedly identified impacted soil on the site, likely caused by releases of oil from equipment stored on the property prior to 1991. It is possible that the tank contents or contaminated soils contained PCBs or oils. The impacted soil was reportedly excavated and disposed as a result of the Phase II ESA findings.

In addition to consuming a large portion of the material inside the building, the 2006 fire also consumed three PGE-owned electrical transformers that were located on a utility pole outside the building. These three transformers released an estimated volume of less than 10 gallons of oil (the remainder being consumed in the fire). Oil was also reported flowing from the building. Fire suppression water mixed with oil was reported to have flowed from the property to the City Outfall 33 stormwater system, and a sheen was observed on the Willamette River. PGE conducted oil and swab sampling of the burned transformers on May 18, 2006 and detected PCB Aroclors 1242 and 1260. As a result of the fire and release of oil into the City Outfall 33 stormwater system, the property was listed on the Environmental Cleanup Site Information (ECSI) database (File No. 4632). The property has been vacant since the fire.

Following the fire, the City cleaned the main City Outfall 33 line from manhole ABU888 to the top of the bank in 2006. A composite sample of the solids removed from the pipe was analyzed and found to contain 0.510 mg/kg PCBs as Aroclor 1260 along with lead, zinc, polycyclic aromatic hydrocarbons (PAHs), and heavy oil residues. Subsequent sampling conducted on the Rexel Taylor property in 2008 and 2009 by Worley Parsons Komex, and the City, respectively, found PCB contamination in one surface soil sample (6 feet [ft] west of the PGE transformer pole) and in sediment samples from catch basins that drain to the City Outfall 33 stormwater system. As noted in the Outfall 33 PA (URS, 2010a), these findings suggest that stormwater runoff from the vicinity of the Rexel Taylor property is a potential current source of PCBs to the City's Outfall 33 stormwater drainage system.

In May 2010, URS on behalf of PGE completed an Upland Assessment of the Rexel Taylor property (URS, 2010e). The assessment included the sampling of fire residues (soil/debris samples) and stained concrete from the floor of the remaining structure to assist in the evaluation of the historical and current potential for the property to be a source of contamination to RM 13.1. Archive soil/debris samples from the assessment were recently selected for additional laboratory analysis. The most recent updated data tables from the Rexel Taylor Upland Assessment are included in Appendix A of this report. PCBs were detected in the composite soil/debris samples and in the concrete samples. Elevated concentrations of dioxin/furans were also detected in the soil/debris and concrete samples, and elevated concentrations of PAHs were detected in the soil/debris samples. These findings suggest that the Rexel Taylor property, which is currently uncovered, may be a current source of PCB and dioxin/furan contamination via rainwater washing contaminants from the remaining fire debris (burned debris, soil, rubble, etc.) into the City Outfall 33 stormwater system.

The unknown historical operations, material handling, and equipment storage at the Rexel Taylor property represent a significant data gap in fully understanding potential historical sources of contamination from the Rexel Taylor property to RM 13.1. In addition, the fire suppression and cleanup associated with the 2006 fire, in which an unknown nature and quantity of release occurred, represents a data gap that prevents assessing the contributions of this event to RM 13.1. An inventory of equipment present at the time of the fire and fire suppression fluids used to fight the fire would help in determining the potential chemicals present/released at the time of the fire and fill this important information gap.

Additional information regarding the Rexel Taylor Building and the investigations details concerning the identification of the sources of contamination is presented in the PA (URS, 2010a) and follow-up Data Report (URS, 2010e).

3.2.1.3 Holman Building

This section includes a brief overview of the situation at the Holman Building. A detailed description of the ownership and operational history of the Holman Building is discussed in Section 2.2 of the Outfall 33 PA (URS, 2010a). The location of the Holman Building is indicated on Figure 2.

Developed in the early twentieth century, the Holman Building's property has been in continuous operation for most of the last 100 years. In the early 1900s, operations at the property included freight yards, a freight wharf, machine shop, galvanizing furnace, sawing and planing activities, molding loft, and a blacksmith. By 1924, the Caravan Motors Company and Creighton Boiler & Welding Works both occupied the property; operations included auto and truck storage with oil and gas storage in a separate smaller structure. In 1951, the Holman Transfer Company constructed the current building, and operations included a machine shop and auto parking. The Holman Building property, which is currently divided into three parcels, is owned by the State of Oregon, while the building was owned and operated by the Portland Development Commission by at least 1986. According to a 1999 memorandum documenting a conversation with a PGE employee, the Holman parking lot was once purportedly used to store capacitors and salvage transformers. The Holman Building was extensively remodeled in 2004 into office space and a boat house for small water craft by Rivers East, LLC, who was granted a lease for the building, located on the middle and eastern parcels of the property. In 2006, the Portland Development Commission sold the Holman Building to Rivers East, LLC.

Previous investigations were completed at the property in 1993, 1997, and 2004. These investigations are discussed in detail in the Outfall 33 PA (URS, 2010a). The following presents a summary of the findings:

- 1993 – During the decommissioning of a 6,000 gallon heating oil UST and a 500 gallon UST of unknown origin, confirmation soil sample results indicated no detectable concentrations of diesel, gasoline, or heavy oil in the underlying soils. PCBs were not analyzed during these sampling activities.
- 1997 – During an investigation by ODOT, subsurface soil samples had detections of phenol, ethylbenzene, and total xylenes from one boring, located in the southwest corner of the building. PCBs were not analyzed during these sampling activities.
- 2004 – During remodeling activities, Hart Crowser investigated heavy oil staining observed on the concrete pad of the hydraulic levelers in the loading dock. Soil from below the concrete slab in each of the leveler bays was analyzed for TPH and PCBs. The soil sample results had detected concentrations of total petroleum hydrocarbons (TPH); however, PCBs were not detected. The site was therefore listed on the DEQ ECSI database (File No. 4236). At the direction of Hart Crowser, up to 3 ft of contaminated soil was removed. Additional soil beyond 3 ft could not be excavated due to the presence of a concrete beam. Site closure was requested on the grounds that site-impacted soils remaining in place did not pose a risk to human or ecological health due to the lack of complete pathways. Building remodeling activities buried the soil beneath 6 ft of backfilled soil and gravel and capped the entire area with a concrete slab. The DEQ submitted a no further action (NFA) determination on January 6, 2005.

The Outfall 33 PA (URS, 2010a) did not identify any specific potential current or historical sources of contamination at the Holman Building based on the data from these investigations. As noted in the City's 2009 investigation of the City Outfall 33 stormwater system, PCBs were identified in a sample of stormwater system solids from manhole ABU929, located adjacent to the Holman Building. The results of the City's 2009 investigation of the City Outfall 33 stormwater system (including system maps) are included in Appendix G of the Outfall 33 PA (URS, 2010a). The PCBs in the ABU929 manhole sample were three orders of magnitude higher (58 mg/kg) than at any other location within the City Outfall 33 stormwater system, including the ABU881 manhole located upstream of the Holman Building, which was non-detect for PCBs during the City's 2009 investigation. The City maps show multiple potential laterals from the Holman Building to the City Outfall 33 stormwater system immediately upstream of manhole ABU929. In addition, a lateral from the Hawthorne Building, which drains one of the exterior catch basins (CB-3), is also connected to the City Outfall 33 stormwater system immediately upstream of manhole ABU929 (City, 2011a,b).

Since this section of the City Outfall 33 stormwater system was cleaned in 2006 following the Rexel Taylor fire, the high concentration of PCBs observed in 2009 indicates that there is a recent (or ongoing) source of PCBs somewhere within the short section of pipe between manholes ABU881 and ABU929. It is possible that this source may have been discharging PCBs to the stormwater line for many years via laterals to the City Outfall 33 stormwater system. PGE is not aware of any additional data characterizing current or historical discharges from the Holman Building.

3.2.1.4 Other Properties

In addition to the properties discussed above, other discharges to the City Outfall 33 system are likely present from properties within the City Outfall 33 drainage area. Stormwater runoff from streets and parking lots within the two drainage areas also contributes to discharges to the River via City Outfall 33 and the other non-City outfalls. General municipal runoff has been shown at other sites to be a major contributor to river sediment contamination.

3.2.2 River Mile 13.5 Study Area - Adjacent Upland Drainage Area

Upland properties with the potential to have directly discharged to the RM 13.5 Study Area are located in the RM 13.5 drainage area (Figure 2). Property formerly owned by PGE encompasses all but the easternmost and southernmost portions of this drainage area.

The RM 13.5 drainage area includes both current drainage systems and historical stormwater drainage systems that were in operation during much of the last century. Currently and historically, most of the RM 13.5 drainage area is/was drained via infiltration or overland flow to the River. As indicated on Figure 4 of the RM 13.1-13.5 PA (URS, 2010b), only one active outfall (City Outfall ABU956) is currently located in the RM 13.5 Study Area. This City outfall drains only a small portion of the drainage area. Two historical outfalls previously associated with the Station L Southern Yard (the Lincoln Street Outfall and one unnamed outfall just north of active City Outfall ABU956) were located within the RM 13.5 drainage area and have since been removed. Historically the Lincoln Street Outfall discharged stormwater into the River slightly downstream of the RM 13.5 Study Area; while the unnamed outfall discharged stormwater directly into the RM 13.5 Study Area. In the 1990s, stormwater from the Oregon Museum of Science and Industry (OMSI) parking lots was redirected to flow into a series of landscaped bioswales for pretreatment and then discharge to the River through City Outfall 32, which is located downstream of RM 13.5. Therefore, this upland area no longer discharges to RM 13.5.

Almost the entire RM 13.5 drainage area is currently covered with buildings, parking lots, or other impermeable surfaces; therefore, potential current sources of contamination from the RM 13.5 drainage area to river sediments are limited to stormwater runoff, bank erosion, and potentially groundwater discharge to the River. Based on the findings of the RM 13.1-13.5 PA (URS, 2010b), the most significant historical upland sources adjacent to the RM 13.5 Study Area are the Inman-Poulsen Lumber Company and the former Station L Southern Yard. The following subsections summarize the operational history, site uses, and potential sources of contamination from these two historical upland properties, as well as the potential current sources from the active City Outfall ABU956 and from riverbank erosion.

3.2.2.1 Inman-Poulsen Lumber Company

From 1890 to 1954, the Inman-Poulsen Lumber Company's lumber mill (also referred to as Inman-Poulsen) occupied all but the most northern portion of RM 13.5 drainage area. Mill operations generated large amounts of wood waste (hog fuel) that were subsequently burned for power generation at PGE's Stations F and L, and possibly other locations. The hog fuel was historically stored on the northern portion of the RM 13.5 drainage area. Figure 6 of the RM 13.1-13.5 PA shows the coverage of the Inman-Poulsen structures (URS, 2010b).

According to the RM 13.1-13.5 PA, operations at Inman-Poulsen included a planing mill, saw mill, planers, boiler room, lath mill, kilns, lumber storage yards, lumber sheds, carpenter shop, and pipe shop. The historical Sanborn fire insurance maps describe the presence of a transformer room located adjacent to the eastern planing mill in 1950 (URS, 2010b). The transformers in that room may have contained PCBs during the facility's operations. The mill likely used lubricating grease, diesel fuel, hydraulic fluid, and paint in its production processes. The large pieces of equipment used at the mill likely necessitated the use of transformers. PCBs are also historically ubiquitous as a heat transfer medium, in hydraulic fuel and paints, which, based on their period of use, were likely present at the site.

Since the mid-1950s, the parcels formerly occupied by Inman-Poulsen included various commercial and light industrial uses. A large percentage of these parcels were sold to PGE in the mid-1950s, and later became part of the Station L Southern Yard (URS, 2010b).

URS was unable to locate much specific information regarding historical stormwater drainage at the Inman-Poulsen property. Based on standard practices at the time, stormwater from historical Inman-Poulsen operations is expected principally to have infiltrated into the ground, drained to the River by overland flow, or been managed on site through dry wells, ditches, or drains. Additional information regarding the Inman-Poulsen property is provided in the PA (URS, 2010b). Historical overwater activities and historical stormwater runoff through overland flow or stormwater drainage systems may have resulted in the release of contaminants from the Inman-Poulsen property to RM 13.5.

3.2.2.2 Station L Southern Yard

The Station L Southern Yard refers to the Station L-related activities within the RM 13.5 drainage area. Prior to its purchase by PGE in the mid-1950s, the property was developed between 1889 and 1909 for uses associated with the Inman-Poulsen lumber mill. Station L property parcels and site features are shown on various Figures in the PA (URS, 2010b).

Operations within the Station L Southern Yard included the storage of hog fuel, fuel oil, utility power poles, vehicles, transformers, capacitors, and switches, and the operation of offices, maintenance shops, railway lines, fuel oil pipelines, a fuel oil tank farm with a 95,690-barrel aboveground storage tank (AST), a helicopter pad, and an analytical laboratory. The Inman-Poulsen planer building remained within the Station L Southern Yard as a sorting shed or storage building until at least 1986. PGE (or its predecessor companies) acquired, sold, or leased Station

L properties associated with the RM 13.5 drainage area as described in detail in the PA (URS, 2010b).

Since approximately 1957, stormwater that did not infiltrate into the ground in the Station L Southern Yard discharged to the River at two outfalls via catch basins. Stormwater from the central portion of the Station L Southern Yard was collected in several catch basins, treated via an oil/water separator and discharged at the now abandoned Lincoln Street outfall. A second stormwater line, located slightly north of SE Caruthers Street, drained a sump located in a southwest corner of the fuel oil tank farm and discharged stormwater to a now abandoned unnamed outfall just north of the active City Outfall ABU956.

The Station L Southern Yard was extensively investigated and the results documented in a number of reports, which are included in the PGE response to the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) 104(e) information request. Remedial activities were completed through a series of soil removal actions which addressed upland contamination. In November 1993, DEQ issued an Order of Completion for Station L Phase III and in September 1994, PGE received a final NFA determination from DEQ for Station L in the Phase III record of decision (ROD) (URS, 2010b).

When the drainage area was owned by PGE and operated as the Station L Southern Yard, it was largely unpaved. However, the RM 13.5 drainage area was redeveloped in the early 1990s following the Station L remedial activities, and almost the entire drainage area is now covered with asphalt, buildings, or landscaping. Additional information regarding the Station L Southern Yard is in the PA (URS, 2010b) and data report (URS, 2010d). Historical overwater activities and historical stormwater runoff through overland flow or stormwater drainage systems may have resulted in releases from the Station L Southern Yard to RM 13.5.

3.2.2.3 City Outfall ABU956 and Bank Erosion

In May 2010, URS on behalf of PGE completed an Upland Assessment (URS, 2010d) of the RM 13.5 drainage area to evaluate the potential of ongoing releases from the riverbank and the potential sources of contamination to sediments from the stormwater runoff managed by City Outfall ABU956, which drains a small area at the southern end of the RM 13.5 drainage area. The assessment included the sampling of riverbank soils and City Outfall ABU956 sediments. Elevated concentrations of total PCBs, arsenic, lead, mercury, and multiple dioxin/furans were detected in the riverbank soil samples exceeding the JSCS criteria (URS, 2010d; DEQ, 2005). Additionally, elevated concentrations of total PCBs, cadmium, lead, mercury, zinc, multiple dioxin/furans, and two PAH compounds were detected in the City Outfall ABU956 sediment sample exceeding the JSCS SLVs (URS, 2010d).

City Outfall ABU956 and its associated stormwater system were installed in 1998, with additional catch basins and stormwater lines installed at the eastern and northern ends of the system in 2007. Since source control took place at the Station L site prior to installation of this system, the PGE site is not currently the source of contaminants to ABU 956. However, since this is the only active outfall within the RM 13.5 drainage area, the stormwater pathway is relatively limited, but remains as a current source in this drainage basin. Due to its relatively recent installation date, the system does not represent a long term historical source for the RM 13.5 Study Area.

The riverbank is the only large unpaved area within the RM 13.5 drainage area; therefore, bank erosion may be a historical and current potential source. Under current conditions, the riverbank stormwater runoff may transport riverbank soils to river sediments; however, transport to the River is likely limited due to the presence of vegetation and bank armoring.

4.0 CONCEPTUAL SITE MODEL

The purpose of a CSM is to present succinctly the potential sources of contaminants, contaminant transport media, and release pathways. The CSMs presented in this section were developed based on the information gathered from investigations of the study areas and the adjacent upland drainage areas (see Sections 2 and 3, respectively). Because CSMs are 'conceptual' in nature, they are not dependent on the quantification of the chemical nature and extent or fate and transport of contaminants. The CSMs for each of the study areas are discussed in the following sections.

4.1 River Mile 13.1 Study Area

As described in Section 3.2.1, City Outfall 33, which serves the City Outfall 33 drainage area, has been confirmed to be the most likely pathway for transport of contaminants from the RM 13.1 and City Outfall 33 drainage area to sediments in the RM 13.1 Study Area. For a description of the operational history and site uses of adjacent upland properties that are the most likely to have contributed to contamination in river sediments at the RM 13.1 Study Area via City Outfall 33, see Section 3.2.1. Other likely significant sources of contamination to RM 13.1 Study Area include potential releases during overwater activities, direct discharge of stormwater from the Marquam Bridge access ramp at ODOT Outfall WR-319, contamination from upstream sources and activities. Figures 3 and 4, respectively, present the historical and current CSMs for the RM 13.1 Study Area, depicting the release mechanisms and transport media from the RM 13.1 upland drainage area. The potential sources of historical and current contamination, release mechanisms, and transport media are discussed in the following subsections.

4.1.1 Historical Sources, Release Mechanisms, and Transport Media

The following summarizes the most significant historical sources that have been identified to date, and the mechanisms that may have transported contaminants to the sediments at the RM 13.1 Study Area (Figure 3):

- Releases (direct) or transport of solids (e.g., soil or debris) into the City Outfall 33 stormwater system, which discharges to the River, from the following:
    - Hawthorne Building: Releases from basement drains, which directly discharged to the stormwater system (prior to sometime between 1969 and 1980), and transport of soil/solids and potential direct releases into exterior drains, which discharged to the stormwater system.
    - Rexel Taylor property: Transport of debris and residues into the stormwater system following the 2006 fire, as well as likely historical direct releases to the stormwater system.
    - Holman Building property: Releases to the stormwater system.
    - Other properties: Potential transport of contaminated soil via stormwater into the stormwater system, as well as potential direct releases to the stormwater system.

- Chemicals in stormwater may have been released to groundwater through cracks/holes in the City Outfall 33 stormwater system pipes, which discharges to the River.
- Direct discharges to the River from the Marquam Bridge access ramp at ODOT Outfall WR-319.
- Direct discharges to the River from possible spills/releases during historical over-water activities.
- Contamination from upstream sources may have transported contaminants to the study area.

4.1.2 Current Sources, Release Mechanisms, and Transport Media

The following summarizes the primary current sources that have been identified and the mechanisms that may transport contaminants to the sediments at the RM 13.1 Study Area (Figure 4):

- Releases (direct) or transport of solids (e.g., soil or debris) into the City Outfall 33 stormwater system, which discharges to the River, from the following:
  - Hawthorne Building: Transport of stormwater to exterior drains, which discharge to the stormwater system.
  - Rexel Taylor property: Transport of debris and residues into the stormwater system following the 2006 fire.
  - Holman Building property: Releases to the stormwater system.
  - Other properties: Potential transport of contaminated soil via stormwater into the stormwater system, as well as potential direct releases to the stormwater system.
- Chemicals in stormwater may be released to groundwater through cracks/holes in the City Outfall 33 stormwater system pipes, which discharge to the River.
- Direct discharges to the River from the Marquam Bridge access ramp at ODOT Outfall WR-319.
- Direct discharges to the River from possible spills/releases during over-water activities.
- Contamination from upstream sources may be transported to the study area.

4.2 River Mile 13.5 Study Area

As described in Section 3.2.2, releases from the adjacent RM 13.5 drainage area is a likely pathway for transport of contaminants to sediments in the RM 13.5 Study Area. The operational history and site uses of adjacent upland properties that are the most likely to have contributed to contamination in river sediments at the RM 13.5 Study Area are described in Section 3.2.2. Other likely sources of contamination include potential releases during overwater activities and contamination from upstream sources. Figures 5 and 6 present the historical CSMs for the RM

13.5 Study Area, depicting release mechanisms and transport media from approximately 1922-1959 and 1959-1988, respectively. Figure 7 presents the current CSM for the RM 13.5 Study Area, depicting the current release mechanisms and transport media. The potential sources of historical and current contamination, release mechanisms, and transport media are discussed in the following subsections.

4.2.1 Historical Sources, Release Mechanisms, and Transport Media

The following summarizes the primary historical sources that have been identified and the mechanisms that may have transported contaminants to the sediments at the RM 13.5 Study Area (Figures 5 and 6):

- Inman Poulsen property (approximately 1922-1959): Transport of soil via stormwater (erosion) directly to the River by overland flow, as well as possibly direct discharges to the River from spills/releases during over-water activities (i.e., shipping, ship building, fuel loading, and log raft storage).
- Station L Southern Yard (approximately 1959-1988): Transport of soil via stormwater (erosion) directly to the River by overland flow and/or via the Station L stormwater system that discharged to the River (at the Lincoln Street Outfall and unnamed outfall), as well as potentially direct discharges to the River from spills/releases during over-water activities (i.e., fuel loading).
- Bank soils may have eroded into the study area.
- Contamination from upstream sources likely resulted in transport of contaminants to the study area.

4.2.2 Current Sources, Release Mechanisms, and Transport Media

The following summarizes the current primary sources that have been identified and the mechanisms that may transport contaminants to the sediments at the RM 13.5 Study Area (Figure 7):

- Transport of potentially contaminated stormwater and/or solids (e.g., soil or sediment) into City Outfall ABU956 (directly into the study area).
- Chemicals in stormwater from the CSO project area may infiltrate to groundwater, which discharges to the River.
- Direct discharges to the River from potential spills/releases from over-water activities at the City CSO conveyor and dock or Portland Spirit dock.
- Bank soils may erode and be directly transported into the study area.
- Contamination from upstream sources may be transported to the study area.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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

EXHIBIT ICNU/109

REVENUE REQUIREMENT IMPACT OF MC INITIATIVE COSTS,
AND COMPANY RESPONSE TO OPUC STAFF DR 358, ATTACHMENT B

June 11, 2014

Exhibit ICNU/109
2015 Results of Operations
Adjustment 7 - MC Initiative Costs: Revenue Requirement Impact
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Operating Revenues										
Sales to Consumers (Rev. Req.)	1,730,004	(4,741)	1,725,263	1,725,263	49,695	1,774,958	1,725,263	43,956	1,769,219	1,819,226
Sales for Resale	-	-	-	-	-	-	-	-	-	-
Other Operating Revenues	23,521	-	23,521	23,521	-	23,521	23,521	-	23,521	23,521
Total Operating Revenues	1,753,525	(4,741)	1,748,784	1,748,784	49,695	1,798,479	1,748,784	43,956	1,792,739	1,842,746
Operation & Maintenance										
Net Variable Power Cost	593,425	-	593,425	592,212	-	592,212	577,002	-	577,002	575,789
Operations O&M	246,227	-	246,227	247,706	-	247,706	254,700	-	254,700	256,179
Support O&M	233,349	(39)	233,311	233,658	404	234,061	233,745	357	234,102	235,156
Total Operation & Maintenance	1,073,001	(39)	1,072,963	1,073,575	404	1,073,979	1,065,448	357	1,065,805	1,067,124
Depreciation & Amortization	280,008	-	280,008	293,596	-	293,596	303,679	-	303,679	317,267
Other Taxes / Franchise Fee	110,280	(119)	110,162	111,625	1,243	112,868	117,112	1,099	118,212	120,926
Income Taxes	59,738	(1,830)	57,907	48,294	19,186	67,481	23,466	16,970	40,436	50,010
Total Oper. Expenses & Taxes	1,523,027	(1,987)	1,521,040	1,527,091	20,833	1,547,924	1,509,705	18,427	1,528,132	1,555,327
Utility Operating Income	230,497	(2,753)	227,744	221,693	70,529	250,555	239,078	62,383	264,607	287,419
Rate of Return	7.540%		7.450%	6.593%		7.450%	6.733%		7.450%	7.450%
Return on Equity	9.580%		9.400%	7.687%		9.400%	7.965%		9.400%	9.400%

* 2014 Rates per approved UE 262 and UE 266

Exhibit ICNU/109
2015 Results of Operations
Adjustment 7 - MC Initiative Costs: Revenue Requirement Impact
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Rate Base										
Plant in Service	7,293,364	-	7,293,364	7,603,781	-	7,603,781	7,803,401	-	7,803,401	8,113,818
Accumulated Depreciation	(3,805,842)	-	(3,805,842)	(3,812,518)	-	(3,812,518)	(3,817,676)	-	(3,817,676)	(3,824,352)
Accumulated Def. Income Taxes	(579,549)	-	(579,549)	(574,257)	-	(574,257)	(631,267)	-	(631,267)	(625,975)
Accumulated Def. Inv. Tax Credit	-	-	-	(3,835)	-	(3,835)	48,058	-	48,058	44,222
Net Utility Plant	2,907,972	-	2,907,972	3,213,170	-	3,213,170	3,402,515	-	3,402,515	3,707,713
Misc Deferred Debits	29,352	-	29,352	29,352	-	29,352	29,352	-	29,352	29,352
Operating Materials & Fuel	75,103	-	75,103	75,103	-	75,103	75,103	-	75,103	75,103
Misc. Deferred Credits	(11,740)	-	(11,740)	(11,740)	-	(11,740)	(11,740)	-	(11,740)	(11,740)
Working Cash	56,352	(74)	56,278	56,502	771	57,273	55,859	682	56,541	57,547
Total Rate Base	3,057,039	(74)	3,056,966	3,362,388	771	3,363,158	3,551,089	682	3,551,771	3,857,975
Income Tax Calculations										
Book Revenues	1,753,525	(4,741)	1,748,784	1,748,784	49,695	1,798,479	1,748,784	43,956	1,792,739	1,842,746
Book Expenses	1,463,290	(157)	1,463,133	1,478,796	1,647	1,480,443	1,486,239	1,457	1,487,696	1,505,317
Interest Rate Base @ Weighted Cost of Debt	84,069	(2)	84,067	92,466	21	92,487	97,655	19	97,674	106,094
Production Deduction	-	-	-	-	-	-	-	-	-	-
Permanent Sch M Differences	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)
Temporary Sch M Differences	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)
State Taxable Income	253,314	(4,582)	248,732	224,670	48,027	272,697	212,037	42,480	254,518	278,483
State Income Tax	16,278	(349)	15,929	14,097	3,657	17,754	13,135	3,234	16,369	18,194
Federal Taxable Income	237,036	(4,233)	232,803	210,573	44,371	254,944	198,902	39,246	238,148	260,289
Fed Income Tax	82,963	(1,482)	81,481	73,700	15,530	89,230	69,616	13,736	83,352	91,101
Deferred Taxes	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)
Federal Tax Credits	(28,929)	-	(28,929)	(28,929)	-	(28,929)	(48,711)	-	(48,711)	(48,711)
Total Income Tax	59,738	(1,830)	57,907	48,294	19,186	67,481	23,466	16,970	40,436	50,010
Adjusted Revenue Requirement		(4,741)			49,695			43,956		
Base Revenue Req. w/ updated ROR (ICNU/102)		(4,264)			49,695			43,956		
Revenue Requirement Adjustment		**(476)**			**(0)**			**(0)**		
∑ Adjustment col (2), (5), (8):		**(476.457)**								

PGE Exhibit 304
Amortization Detail ($s)
2010 - 2014 Test Year

Item	FERC Account	AWO	Actual 2011	Provided 2012	Actual 2012	Variance	Actual+ Forecast 2013	Forecast 2014	Test Year 2015	*Reference*
Equity Issuance Fees	4&&		1,721,800	1,721,800	1,721,800	-	1,721,800	33,894		Attachment 358-D
Port Westward Major Maint. Accrual	4&&							4,946,816		Attachment 358-D
Remove Boardman Decomm (to Sch. 145)	4&&							1,512,747	1,454,304	Attachment 358-D for 2013, nets to zero in 2014 and 2015
Def Tax Asset Amortization	4&&							237,796		
Software Amort (Intangible)	404.0	4040001	13,178,424	17,305,027	15,696,734	(1,608,293)	18,987,419	19,781,362	26,774,747	Attachment 358-A
Other Intangible Amort (includes Hydro Relicensing)	404.0	4040001	6,097,457	5,836,639	5,850,777	14,138	3,067,447	3,132,790	3,203,075	Attachment 358-C
Boardman Decommissioning- UE215	407.3	3000000185	(431,270)	(462,960)	(462,960)	-	(462,960)	(490,598)	(519,840)	Attachment 358-D for 2013, nets to zero in 2014 and 2015
Colstrip Common FERC Adjustment	407.3	7000000107	322,140	322,140	322,140	-	322,140	322,140	322,140	Attachment 358-D
AMI Project Office Costs	407.3	7000000129		1,382,835	1,360,588	(22,247)	85,479			Attachment 358-D
Gain on Asset Sales, UE115	407.3	7000000317								
Accumulated ARO Boardman	407.3	7000000236	(1,064,421)	(1,025,518)	(1,041,383)	(15,865)	(1,355,455)	(1,022,149)	(934,464)	Attachment 358-D for 2013, nets to zero in 2014 and 2015
Coyote Springs Major Maintenance	407.3	7000000322	2,044,272	2,044,272	2,044,272	-	2,044,272	4,411,753		Attachment 358-D
ISFSI Tax Credits	407.3	7000000323	2,592,331	2,274,749	2,274,749	-				
Accelerated Depreciation- Old Meters	407.3	7000000351								
Intervener CUB Fund Amortization	407.3	7000000356	47,677							
Intervener Match Fund Amortization	407.3	7000000357	46,082							
Intervener Issue Fund Amortization	407.3	7000000358	125,547							
Intervenor CUB Fund 2	407.3	7000000888	152,457	12,574	12,574	-				
Intervenor Match Fund 2	407.3	7000000889	147,359	12,154	12,154	-				
Intervenor Issue Fund 2	407.3	7000000891	407,468	33,112	33,112	-				
Gain on Asset Sales, UE115	407.4	7000000317								
2011 Local 408/MCBIT Deferral	407.4	3000000135		(604,940)	(810,052)	(205,112)	-			
Interest Income PES Note	407.4	7000000319		(266,032)	(264,322)	1,710	(16,606)			Attachment 358-D
Coyote Springs Major Maintenance	407.4	7000000322	(3,737,959)	(3,886,965)	3,432,955	7,319,920				Attachment 358-D
Sunway 3	407.4	7000000727	(45,480)	(34,110)	(45,480)	(11,370)				
ISFSI Tax Credits- Used	407.4	7000000324	(18,096,269)	(110,290)	(110,290)	-				
SB 1149 Residual Balance	407.4	7000000335	(1,436,041)	(90,226)	(90,226)	-				
Capital Projects Deferral (Deferral)/Amortization	407.4	7000010741		(15,622,661)	(15,094,023)	528,638	(16,966,496)			Attachment 358-D
Trojan Decommissioning	407.0	7000000045	3,500,278	3,500,175	3,500,396	221	3,500,000	3,500,000	3,500,000	See PGE Exhibit 300 and Response to DR 358
EIM	4&&								300,000	See PGE Exhibit 800 and Response to DR 358
Gain from Property Sales	411.6									
Independent Evaluator Deferral	407.3	7000000123					297,920			Attachment 358-D
FiT Pilot Program	407.3	7000002001		4,896,926	4,808,006	(88,920)	4,997,432			Attachment 358-D
Coyote Springs GE LTSA Exp	407.4	7000000673					(4,263,914)	(4,404,919)		Attachment 358-D
Residual Account	407.3	7000001030		891,283	867,739	(23,544)				
Total Amortization			5,573,864	18,129,985	24,019,260	5,889,275	11,960,490	31,963,647	34,101,977	
Excl. ISFSI Tax Credits			23,670,133	18,240,275	24,129,551	5,889,275	11,960,490	31,963,647	34,101,977	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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

EXHIBIT ICNU/110

ESTIMATED REVENUE REQUIREMENT IMPACT OF UPDATED DEPRECIATION EXPENSE

June 11, 2014

Exhibit ICNU/110
2015 Results of Operations
Adjustment 8 - Estimated Depreciation Expense: Revenue Requirement Impact
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Operating Revenues										
Sales to Consumers (Rev. Req.)	1,730,004	(16,425)	1,713,579	1,713,579	45,329	1,758,909	1,713,579	40,890	1,754,469	1,811,934
Sales for Resale	-	-	-	-	-	-	-	-	-	-
Other Operating Revenues	23,521	-	23,521	23,521	-	23,521	23,521	-	23,521	23,521
Total Operating Revenues	1,753,525	(16,425)	1,737,100	1,737,100	45,329	1,782,429	1,737,100	40,890	1,777,990	1,835,454
Operation & Maintenance										
Net Variable Power Cost	593,425	-	593,425	592,212	-	592,212	577,002	-	577,002	575,789
Operations O&M	246,227	-	246,227	247,706	-	247,706	254,700	-	254,700	256,179
Support O&M	233,625	(133)	233,492	233,839	368	234,207	233,926	332	234,259	235,073
Total Operation & Maintenance	1,073,277	(133)	1,073,144	1,073,756	368	1,074,125	1,065,629	332	1,065,961	1,067,040
Depreciation & Amortization	268,908	-	268,908	277,796	-	277,796	289,279	-	289,279	309,267
Other Taxes / Franchise Fee	110,280	(411)	109,869	111,333	1,134	112,467	116,820	1,023	117,843	120,744
Income Taxes	64,109	(6,341)	57,767	49,982	17,501	67,483	24,609	15,787	40,396	50,298
Total Oper. Expenses & Taxes	1,516,574	(6,886)	1,509,689	1,512,867	19,003	1,531,870	1,496,337	17,142	1,513,479	1,547,349
Utility Operating Income	236,950	(9,539)	227,411	224,233	64,332	250,559	240,762	58,032	264,511	288,105
Rate of Return	7.762%		7.450%	6.669%		7.450%	6.782%		7.450%	7.450%
Return on Equity	10.024%		9.400%	7.837%		9.400%	8.065%		9.400%	9.400%

* 2014 Rates per approved UE 262 and UE 266

Exhibit ICNU/110
2015 Results of Operations
Adjustment 8 - Estimated Depreciation Expense: Revenue Requirement Impact
Dollars in (000s)

	Base Business			Base Business and PW2			Base Business and Tucannon			Total
	2015 Results at 2014* Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results at 2015 Base Rates	Change for Reasonable Return	2015 Results After Change for Reasonable Return	2015 Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Rate Base										
Plant in Service	7,293,364	-	7,293,364	7,603,781	-	7,603,781	7,803,401	-	7,803,401	8,113,818
Accumulated Depreciation	(3,805,842)	-	(3,805,842)	(3,810,168)	-	(3,810,168)	(3,816,026)	-	(3,816,026)	(3,820,352)
Accumulated Def. Income Taxes	(585,099)	-	(585,099)	(577,457)	-	(577,457)	(635,167)	-	(635,167)	(621,975)
Accumulated Def. Inv. Tax Credit	-	-	-	(3,835)	-	(3,835)	48,058	-	48,058	44,222
Net Utility Plant	2,902,422	-	2,902,422	3,212,320	-	3,212,320	3,400,265	-	3,400,265	3,715,713
Misc Deferred Debits	30,852	-	30,852	30,852	-	30,852	30,852	-	30,852	30,852
Operating Materials & Fuel	75,103	-	75,103	75,103	-	75,103	75,103	-	75,103	75,103
Misc. Deferred Credits	(11,740)	-	(11,740)	(11,740)	-	(11,740)	(11,740)	-	(11,740)	(11,740)
Working Cash	56,113	(255)	55,858	55,976	703	56,679	55,364	634	55,999	57,252
Total Rate Base	3,052,750	(255)	3,052,496	3,362,511	703	3,363,214	3,549,844	634	3,550,479	3,867,180
Income Tax Calculations										
Book Revenues	1,753,525	(16,425)	1,737,100	1,737,100	45,329	1,782,429	1,737,100	40,890	1,777,990	1,835,454
Book Expenses	1,452,466	(544)	1,451,922	1,462,885	1,502	1,464,387	1,471,728	1,355	1,473,083	1,497,051
Interest Rate Base @ Weighted Cost of Debt	83,951	(7)	83,944	92,469	19	92,488	97,621	17	97,638	106,347
Production Deduction	-	-	-	-	-	-	-	-	-	-
Permanent Sch M Differences	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)	-	(20,679)	(20,679)
Temporary Sch M Differences	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)	-	(26,469)	(26,469)
State Taxable Income	264,256	(15,874)	248,383	228,894	43,808	272,702	214,899	39,518	254,416	279,204
State Income Tax	17,111	(1,209)	15,902	14,419	3,335	17,754	13,353	3,009	16,362	18,249
Federal Taxable Income	247,145	(14,665)	232,480	214,475	40,473	254,948	201,546	36,509	238,055	260,955
Fed Income Tax	86,501	(5,133)	81,368	75,066	14,165	89,232	70,541	12,778	83,319	91,334
Deferred Taxes	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)	-	(10,574)	(10,574)
Federal Tax Credits	(28,929)	-	(28,929)	(28,929)	-	(28,929)	(48,711)	-	(48,711)	(48,711)
Total Income Tax	64,109	(6,341)	57,767	49,982	17,501	67,483	24,609	15,787	40,396	50,298
Adjusted Revenue Requirement		(16,425)			45,329			40,890		
Base Revenue Req. w/ updated ROR (ICNU/102)		(4,264)			49,695			43,956		
Revenue Requirement Adjustment		**(12,160)**			**(4,366)**			**(3,065)**		
∑ Adjustment col (2), (5), (8):		**(19,000)**	**Approximate**							

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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 11, 2014

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017. I am employed by the firm of Brubaker & Associates, Inc. ("BAI"), regulatory and economic consultants with corporate headquarters in Chesterfield, Missouri. My qualifications are provided in Exhibit ICNU/201.

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

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

Q. WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A. My testimony will address the Company's overall rate of return including return on equity, embedded debt cost and capital structure.

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

A. Yes. I am sponsoring Exhibits ICNU/201 through ICNU/221.

<u>SUMMARY</u>

Q. PLEASE SUMMARIZE YOUR RATE OF RETURN RECOMMENDATIONS.

A. I recommend the Public Service Commission of Oregon (the "Commission") award PGE a return on common equity of 9.40%.

My recommended return on equity of 9.40% and capital structure support an overall cost of capital of 7.45% as developed on my Exhibit ICNU/202.

I will also respond to PGE witness Dr. Thomas Zepp's proposed return on equity of 10.5%. For the reasons discussed below, Dr. Zepp's recommended return on equity is excessive and should be rejected.

Q. HOW DID YOU ESTIMATE PGE'S CURRENT MARKET COST OF EQUITY?

A. I applied three versions of the Discounted Cash Flow ("DCF") model, as well as a Risk Premium ("RP") study and a Capital Asset Pricing Model ("CAPM"), to a proxy group of publicly traded companies that have investment risk similar to PGE. Based on these assessments, I estimate PGE's current market cost of equity to be 9.40%.

<u>Electric Utility Industry Market Outlook</u>

Q. PLEASE DESCRIBE THIS SECTION OF YOUR TESTIMONY.

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

Based on the assessments described below, I find the credit rating outlook of the industry to be strong and supportive of the industry's financial integrity, and electric utilities' stocks have exhibited strong price performance over the last several years.

Further, the electric utility industry is funding large capital expenditure programs, which is creating significant demands for external capital. Credit rating agencies and market participants have embraced the utilities' need for significant amounts of external capital by meeting the capital market demands of electric utilities at near historical low capital market costs. All of this supports my belief that PGE should have sufficient access to capital to support its capital program, and relatively moderate capital costs are currently available and expected to be available for the next several years.

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

Q. PLEASE DESCRIBE ELECTRIC UTILITIES' CREDIT RATING OUTLOOK.

A. Electric utilities' credit ratings have improved over the recent past and the credit outlook is Stable to Improving. Standard & Poor's ("S&P") recently published a report titled "U.S. Regulated Utilities Look Forward To Stability In 2014." In that report, S&P noted the following:

> **Effect on ratings**
>
> Although the median investor-owned regulated utility corporate credit rating remains at 'BBB+', credit quality actually improved as many companies entered the low 'A' rating category and the already limited number of speculative-grade utilities continued to diminish. Last year, we raised the ratings on 42 utility holding companies and operating subsidiaries.
>
> * * *
>
> **Industry Ratings Outlook**
>
> The prospective rating movement for U.S. regulated utilities, as measured by outlooks and CreditWatch listings, is limited, with 6% of companies having positive outlooks or positive CreditWatch listings and 5% carrying negative outlooks. (It is important to note that outlooks and CreditWatch placements do not predict rating changes. Rather, they highlight the potential for rating changes and their direction.) With the remaining 88% of the industry having stable outlooks, and with only a modest influence on the sector's business risk and financial risk profiles as a result of

economic volatility, we expect few rating changes in the sector in the near-to-intermediate term.[1/]

* * *

Credit Strength Underlies Solid Access To Funding

Liquidity remains adequate for most utilities and investor appetite for utility debt remains healthy, with deals continuing to be oversubscribed at very attractive rates with tenors as far as five years, and in some cases longer. The amount of medium- to long-term debt and hybrid securities issued during 2013 was about $35.5 billion. The relative certainty of financial performance by utilities operating under relatively predictable regulatory frameworks, and effective monopoly position, and long-lived assets continue to make the utility sector attractive to investors. These strengths have served to mute any impact on the industry from turbulence in the global financial markets and the slow pace of the economic recovery.

Similarly, Fitch states:

Rating Outlook

Stable Ratings Outlook: Fitch Ratings expects the ratings and ratings outlook for the overall U.S. Utilities, Power, and Gas (UPG) sector to remain stable in 2014. Fitch expects modest earnings growth from recent rate base additions and continued maturation of capex projects. Broad macroeconomic conditions remain favorable for the sector; Fitch expects modest economic growth, tepid inflation, low natural gas prices, and a favorable interest rate environment.

* * *

Stable Utility and Utility Parent Company Ratings

Within the context of gradual recovery, low inflation, and stable commodity prices, Fitch expects regulated utilities to maintain their solid investment-grade credit profile. Issuer Default Ratings (IDRs) should remain on the cusp of 'BBB+' to 'A–', with more than 90% of debt issuances being rated in the 'A' category. Long-term debt instrument ratings of Fitch's entire universe of regulated utilities carry investment-grade ratings, a testament to the sound credit profile of the industry.[2/]

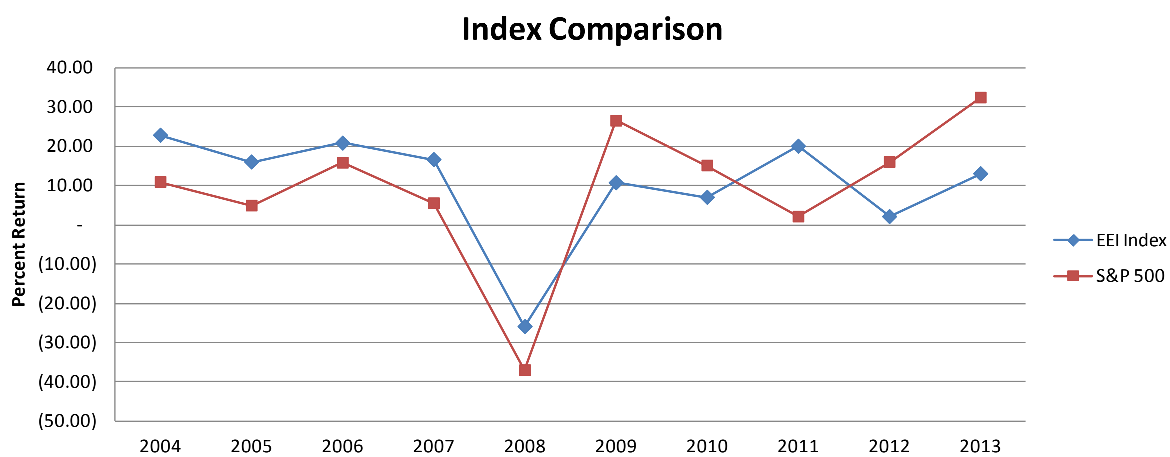
[1/] Standard & Poor's RatingsDirect: "Industry Economic and Ratings Outlook: U.S. Regulated Utilities Look Forward to Stability in 2014," January 22, 2014 at 4 and 7, emphasis added.

[2/] *FitchRatings*: "2014 Outlook: Utilities, Power, and Gas," December 12, 2013 at 1-2, emphasis added.

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

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

FIGURE 1



Source: EEI Q4 2013 Stock Performance Financial Update, at Page 1.

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

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

RATE OF RETURN

PGE Investment Risk

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

A The market's assessment of PGE's investment risk is reasonably described by analysts in credit rating reports. PGE's current "corporate" and "senior secured" bond ratings from S&P and Moody's are "BBB" and "A-," and "A3" and "A1," respectively.[3/] Both rating agencies have a Stable outlook for PGE.

Specifically, S&P states the following:

> **Business Risk: Strong**
>
> Our assessment of PGE's business risk profile is "strong," as defined in our criteria, based on the company's "satisfactory" competitive position, "very low" industry risk derived from the regulated utility industry, and "very low" country risk of the U.S. PGE's competitive position reflects the company's low-risk regulated operations under a generally constructive regulatory environment, a midsize customer base, and competitive rates across customer classes. PGE's reliance on power purchases and its vulnerability to hydroelectric power variability result in the careful management of power resources and collateral needs.
>
> * * *
>
> **Financial Risk: Significant**
>
> Based on the medial volatility financial ratio benchmarks, our assessment of PGE's financial risk profile is "significant." PGE has recurring cash flows as a vertically integrated electric utility. We believe PGE's capital spending and dividend payments will result in a drop in discretionary cash flow during the forecast period, requiring management to be vigilant about cost recovery so the company can maintain its cash flow measures.[4/]

These risks are recognized by the credit rating agencies and are reflected in PGE's current bond rating. The proxy group used to estimate a fair return on equity reflects

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3/ *SNL Financial*, online May 28, 2014.

4/ *Standard & Poor's RatingsDirect Summary:* "Portland General Electric Co.," May 8, 2014 at 3-4.

comparable risk based on PGE's bond ratings and other risk factors. Hence, all these risks are considered in my estimate of a fair return on equity for PGE's level of investment risk.

PGE's Proposed Capital Structure

Q. WHAT IS PGE'S PROPOSED CAPITAL STRUCTURE?

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

TABLE 1

PGE's Proposed Capital Structure
(December 31, 2015)

Description	Weight
Long-Term Debt	50.0%
Common Equity	50.0%
Total Regulatory Capital Structure	100.00%

Source: Direct Testimony of Hager, Valach and Greene, page 4.

Q. DO YOU HAVE ANY ISSUES WITH PGE'S PROPOSED CAPITAL STRUCTURE IN THIS PROCEEDING?

A. No. I will not raise issues with PGE's capital structure in this case.

RETURN ON EQUITY

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

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

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

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

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

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

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

<u>Risk Proxy Group</u>

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

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

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

A. The proxy group is shown in my Exhibit ICNU/203. This proxy group has an average corporate credit rating from S&P of "BBB+," which is one notch above S&P's corporate credit rating for PGE of "BBB." The proxy group's corporate credit rating from Moody's of "Baa1" is one notch below PGE's corporate credit rating from Moody's of "A3." For these reasons, I believe the proxy group bond rating is a reasonable risk proxy and reflective of PGE's investment risk.

In 2013, the proxy group had an average common equity ratio of 46.6% (including short-term debt) from SNL Financial ("SNL") and 49.8% (excluding short-term debt) from *The Value Line Investment Survey* ("*Value Line*"). The proxy group's common equity ratio is comparable to the common equity ratio of 50% that PGE proposes in this case.

I believe that my proxy group reasonably approximates the investment risk of PGE, and can be used to estimate a fair return on equity for PGE.

Discounted Cash Flow Model

Q. PLEASE DESCRIBE THE DCF MODEL.

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

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

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

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

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

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

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

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

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

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

A. I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on May 16, 2014. An average stock price is less susceptible to market price variations and aberrant market price movements than a spot price, which may not be reflective of the stock's long-term value.

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

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

A. I used the most recent quarterly dividend paid by PGE, as reported in *Value Line*.[5/] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above.

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

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

As predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[6/] That is, assuming the market generally makes rational investment decisions, analysts' growth

5/ *The Value Line Investment Survey*, February 21, March 21, and May 2, 2014.

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

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

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, SNL, and Reuters. All such projections were available on May 16, 2014, and all were reported online.

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

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

A. The growth rates I used in my DCF analysis are shown in Exhibit ICNU/204. The average growth rate for my proxy group is 5.71%.

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

A. As shown in Exhibit ICNU/205, the average and median constant growth DCF returns for my proxy group are 9.49% and 9.47%, respectively.

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

A. Yes. The constant growth DCF analysis for my proxy group was based on a long-term sustainable growth rate of 5.71%. This growth rate is higher than my estimate of a maximum long-term sustainable growth rate of 4.7% which I discuss later in this testimony. I believe the constant growth DCF analysis produces slightly overstated return estimates.

Q. WHAT IS YOUR ESTIMATE OF A MAXIMUM LONG-TERM SUSTAINABLE GROWTH RATE?

A. A long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. Hence, a reasonable proxy for the long-term maximum sustainable growth rate for a utility investment is best proxied by the projected long-term Gross Domestic Product ("GDP"). *Blue Chip Economic Indicators* projects that over the next 5 and 10 years, the U.S. nominal GDP will grow in the range of 4.8% to 4.6%. As such, the average growth rate over the next 10 years is around 4.7%, which I believe is a reasonable proxy of long-term sustainable growth.[7/]

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

7/ *Blue Chip Economic Indicators*, March 10, 2014 at 14.

Sustainable Growth DCF

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

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

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

The payout ratios of the proxy group are shown in my Exhibit ICNU/206. These dividend payout ratios and earnings retention ratios then can be used to develop a sustainable long-term earnings retention growth rate. A sustainable long-term earnings retention ratio will help gauge whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time.

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

As shown in Exhibit ICNU/207, page 1, the average sustainable growth rate for the proxy group using this internal growth rate model is 4.96%.

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

A. A DCF estimate based on these sustainable growth rates is developed in Exhibit ICNU/208. As shown there, a sustainable growth DCF analysis produces proxy group average and median DCF results of 8.69% and 8.82%, respectively.

Multi-Stage Growth DCF Model

Q. HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

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

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

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

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

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

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

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

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

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

The Energy Information Administration ("EIA") has observed that utility sales growth tracks, albeit is lower than, the U.S. GDP growth, as shown in Exhibit ICNU/209. Utility sales growth has lagged behind GDP growth for more than a decade. As a result, nominal GDP growth is a very conservative proxy for electric utility sales growth, rate base growth, and earnings growth. Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.

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

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

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).[8/]

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

A. Yes. This is evident by a comparison of the compound annual growth of the U.S. GDP compared to the geometric growth of the U.S. stock market. Ibbotson & Associates

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

measures the historical geometric growth of the U.S. stock market over the period 1926-2013 to be approximately 5.8%. During this same time period, the U.S. nominal compound annual growth of the U.S. GDP was approximately 6.2%.[9/]

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

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

A. I relied on the consensus analysts' projections of long-term GDP growth. *Blue Chip Economic Indicators* publishes consensus economists' GDP growth projections twice a year. These consensus analysts' GDP growth outlooks are the best available measure of the market's assessment of long-term GDP growth. These analyst projections reflect all current outlooks for GDP, as reflected in analyst projections, and are likely the most influential on investors' expectations of future growth outlooks. The consensus economists' published GDP growth rate outlook is 4.8% to 4.6% over the next 10 years.[10/]

Therefore, I propose to use the consensus economists' projected 5- and 10-year average GDP consensus growth rates of 4.8% and 4.6%, respectively, as published by *Blue Chip Economic Indicators*, as an estimate of long-term sustainable growth. *Blue Chip Economic Indicators'* projections provide real GDP growth projections of 2.6% and

9/ *Ibbotson & Associates 2014 Classic Yearbook* inflation rate of 3.0%, and U.S. Bureau of Economic Analysis, April 2014.

10/ *Blue Chip Economic Indicators*, March 10, 2014 at 14.

2.4%, and GDP inflation of 2.1%[11/] over the 5-year and 10-year projection periods, respectively. This consensus GDP growth forecast represents the most likely views of market participants because it is based on published consensus economist projections.

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

A. Yes, and these sources corroborate my consensus analysts' projections. The U.S. EIA in its *Annual Energy Outlook* for 2014 projects real GDP through 2040 to be in the range of 1.9% to 2.8%, with a midpoint or reference case of 2.4%.[12/]

Also, the Congressional Budget Office ("CBO") makes long-term economic projections. The CBO is projecting real GDP growth of 2.8% to 2.1% during the next 5 and 10 years, respectively, with GDP price inflation of 2.0%.[13/] The CBO's real GDP and GDP inflation projections are slightly lower than the consensus economists.

The real GDP and nominal GDP growth projections made by the U.S. EIA and those made by the CBO support the use of the consensus analyst 5-year and 10-year projected GDP growth outlooks as a reasonable estimate of market participants' long-term GDP growth outlooks.

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

A. I relied on the same 13-week stock price and the most recent quarterly dividend payment data discussed above. For stage one growth, I used the consensus analysts' growth rate projections discussed above in my constant growth DCF model. The first stage growth covers the first five years, consistent with the term of the analyst growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The

11/ *Id.*
12/ *DOE/EIA Annual Energy Outlook 2014 With Projections to 2040*, April 2014 at MT-2.
13/ *CBO: The Budget and Economic Outlook: Fiscal Years 2014 to 2024,* February 2014 at 152.

second stage growth transitions the growth rate from the first stage to the third stage using a linear trend. For the third stage, or long-term sustainable growth stage, which starts in year 11, I used a 4.7% long-term sustainable growth rate, which is based on the consensus economists' long-term projected nominal GDP growth rate.

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

A. As shown in Exhibit ICNU/210, the average and median DCF returns on equity for my proxy group are 8.67% and 8.59%, respectively.

Q. PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

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

TABLE 2

Summary of DCF Results

	Proxy Group	
Description	**Average**	**Median**
Constant Growth DCF Model (Analysts' Growth)	9.49%	9.47%
Constant Growth DCF Model (Sustainable Growth)	8.69%	8.82%
Multi-Stage Growth DCF Model	8.67%	8.59%

My DCF studies indicate a return on equity range of 8.60% to 9.50%. I conclude that a reasonable DCF return for PGE in this case is 9.05%.

RISK PREMIUM MODEL

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

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

This risk premium model is based on two estimates of an equity risk premium. First, I estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds. The difference between the required return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year over the period 1986 through March 2014. The common equity required returns were based on regulatory commission-authorized returns for electric utility companies. Authorized returns are typically based on expert witnesses' estimates of the contemporary investor-required return.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period 1986 through March 2014 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit ICNU/211, which shows that the market to book ratio since 1986 for the electric utility industry was consistently above a multiple of 1.0x. Over this period, regulatory authorized returns were sufficient to support market prices that at least exceeded book value. This is an indication that regulatory authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit ICNU/212, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.35%. Of the 29 observations, 23 indicated risk premiums fall in the range of 4.41% to 6.18%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity using this methodology.

As shown in Exhibit ICNU/213, the average indicated equity risk premium over contemporary Moody's utility bond yields was 3.97% over the period 1986 through March 2014. The indicated equity risk premium estimates based on this analysis primarily fall in the range of 3.03% to 5.01% over this time period.

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

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

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

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

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

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

A. The equity risk premium should reflect the relative market perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit ICNU/214. In that exhibit, I show the yield spread between utility bonds and Treasury bonds over the last 35 years. As shown in Exhibit ICNU/214, the average utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.53% and 1.94%, respectively. The utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utilities during 2014 are 0.88% and 1.35%, respectively. The current average "A" and "Baa" rated utility bond yield spreads over Treasury bond yields are now lower than the 35-year average spreads.

A current 13-week average "A" rated utility bond yield of 4.42%, when compared to the current Treasury bond yield of 3.54%, as shown on page 1 of Exhibit ICNU/215, implies a yield spread of around 88 basis points. This current utility bond yield spread is lower than the 35-year average spread for "A" utility bonds of 1.53%. Similarly, the current spread for the "Baa" utility yields of 1.33% is lower than the 35-year average spread of 1.94%.

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

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

A. I added a projected long-term Treasury bond yield to my estimated equity risk premium over Treasury yields. The 13-week average 30-year Treasury bond yield, ending May 16, 2014 was 3.54%, as shown in Exhibit ICNU/215, page 1. *Blue Chip Financial Forecasts* projects the 30-year Treasury bond yield to be 4.40%, and a 10-year Treasury bond yield to be 3.70%.[14/] Using the projected 30-year Treasury bond yield of 4.40%, and a Treasury bond risk premium of 4.41% to 6.18%, as developed above, produces an estimated common equity return in the range of 8.81% (4.40% + 4.41%) to 10.58% (4.40% + 6.18%). Therefore, my risk premium estimates fall in the range of 8.81% to 10.58%.

Next, I added my equity risk premium over utility bond yields to a current 13-week average yield on "Baa" rated utility bonds for the period ending May 16, 2014 of 4.87%. Adding the utility equity risk premium of 3.03% to 5.01%, as developed

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14/ *Blue Chip Financial Forecasts*, May 1, 2014 at 2.

above, to a "Baa" rated bond yield of 4.87%, produces a cost of equity in the range of 7.90% (4.87% + 3.03%) to 9.88% (4.87% + 5.01%).

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

A. My recommendation considers both utility security risk and market interest rate risk. Current interest rate spreads suggest the market is embracing utility investments as relatively low-risk investment alternatives. This is clearly evident from the low utility bond spreads relative to Treasury bonds currently compared to the historical time period studied. (See Exhibit ICNU/214). Also, the market is pricing "Baa" utility bonds to produce lower yields compared to general corporate "Baa" bonds. On average over time, "Baa" utility bond yields are higher than "Baa" corporate bond yields, but not currently. (*Id*.) All of this supports my conclusion that the utility industry is perceived as a low-risk stable investment.

On the other hand, the Federal Reserve has been procuring long-term Treasury and collateralized bonds in an effort to stimulate the U.S. economy. This stimulus has reduced long-term interest rates, but recently the stimulus has been reduced and is expected to be suspended in the near future. The suspension of the Federal Reserve's stimulus in long-term interest rate markets could cause long-term market interest rates to increase. I believe there is additional risk in long-term interest rate markets created by this Federal Reserve stimulus policy.

I recommend giving more weight to the high-end of my risk premium results to reflect the greater current market interest rate risk. I propose to provide 70% weight to the high-end of my risk premium estimates and 30% to the low-end of my risk premium estimates. Providing more weight to the high-end risk premium captures the greater interest rate risk in the current market. This results in a risk premium estimate over Treasury bond yields of 10.05%,[15/] and a risk premium estimate over "Baa" utility bond yields of 9.29%.[16/]

My risk premium analyses produce a return estimate in the range of 9.29% to 10.05%, with a midpoint of approximately 9.70%.

<u>Capital Asset Pricing Model ("CAPM")</u>

Q. PLEASE DESCRIBE THE CAPM.

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

$R_i = R_f + B_i \times (R_m - R_f)$ where:

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

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

[15/] 70% (10.58) + 30% (8.81) = 10.05.
[16/] 70% (9.88) + 30% (7.90) = 9.29.

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

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

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

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

A. As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 4.40%.[17/] The current 30-year Treasury bond yield is 3.54%, as shown in Exhibit ICNU/215, page 1. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 4.40% for my CAPM analysis.

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

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

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[17/] *Blue Chip Financial Forecasts*, May 1, 2014 at 2.

risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

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

Q. WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A. As shown in Exhibit ICNU/216, the proxy group average *Value Line* beta estimate is 0.80.

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

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

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

Morningstar's *Stocks, Bonds, Bills and Inflation 2014 Classic Yearbook* estimates the historical arithmetic average real market return over the period 1926 to 2013 as

8.9%.[18/] A current consensus analysts' inflation projection, as measured by the Consumer Price Index, is 2.2%.[19/] Using these estimates, the expected market return is 11.30%.[20/] The market risk premium then is the difference between the 11.30% expected market return, and my 4.40% risk-free rate estimate, or approximately 6.90%.

The historical estimate of the market risk premium was also estimated by Morningstar in *Stocks, Bonds, Bills and Inflation 2014 Classic Yearbook.* Over the period 1926 through 2013, Morningstar's study estimated that the arithmetic average of the achieved total return on the S&P 500 was 12.1%,[21/] and the total return on long-term Treasury bonds was 5.9%.[22/] The indicated market risk premium is 6.2% (12.1% - 5.9% = 6.2%). The average of my market risk premium estimates is 6.6% (6.9% to 6.2%).

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

A. Morningstar's analysis indicates that a market risk premium falls somewhere in the range of 6.2% to 7.0%. My market risk premium falls in the range of 6.2% to 6.9%. My average market risk premium of 6.6% is within Morningstar's range.

Morningstar estimates a forward-looking market risk premium based on actual achieved data from the historical period of 1926 through 2013. Using this data, Morningstar estimates a market risk premium derived from the total return on large company stocks (S&P 500), less the income return on Treasury bonds. The total return includes capital appreciation, dividend or coupon reinvestment returns, and annual yields received from coupons and/or dividend payments. The income return, in contrast, only

18/ *Morningstar, Inc., Ibbotson SBBI 2014 Classic Yearbook*; Market Results for Stocks, Bonds, Bills, and Inflation 1926-2013 at 92.

19/ *Blue Chip Financial Forecasts*, May 1, 2014 at 2.

20/ $\{ [(1 + 0.089) * (1 + 0.022)] - 1 \} * 100$.

21/ *Morningstar, Inc. Ibbotson SBBI 2014 Classic Yearbook* at 91.

22/ *Id*.

reflects the income return received from dividend payments or coupon yields. Morningstar argues that the income return is the only true risk-free rate associated with Treasury bonds and is the best approximation of a truly risk-free rate.[23/] I disagree with this assessment from Morningstar, because it does not reflect a true investment option available to the marketplace and therefore does not produce a legitimate estimate of the expected premium of investing in the stock market versus that of Treasury bonds. Nevertheless, I will use Morningstar's conclusion to show the reasonableness of my market risk premium estimates.

Morningstar's range is based on several methodologies. First, Morningstar estimates a market risk premium of 7.0% based on the difference between the total market return on common stocks (S&P 500) less the income return on Treasury bond investments. Second, Morningstar found that if the New York Stock Exchange (the "NYSE") was used as the market index rather than the S&P 500, that the market risk premium would be 6.8%, not 7.0%. Third, if only the two deciles of the largest companies included in the NYSE were considered, the market risk premium would be 6.2%.[24/]

Finally, Morningstar found that the 7.0% market risk premium based on the S&P 500 was influenced by an abnormal expansion of price-to-earnings ("P/E") ratios relative to earnings and dividend growth during the period 1980 through 2001. Morningstar believes this abnormal P/E expansion is not sustainable.[25/] Therefore, Morningstar adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be

23/ *Morningstar, Inc., Ibbotson SBBI 2014 Classic Yearbook: Market Results for Stocks, Bonds, Bills, and Inflation 1926-2013* at 153.

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

25/ *Id*. at 156.

more in line with the growth in dividends and earnings. Based on this alternative methodology, Morningstar published a long-horizon supply-side market risk premium of 6.1%.[26/]

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A. As shown in Exhibit ICNU/217, based on Morningstar's market risk premium of 6.2% to 7.0%, a risk-free rate of 4.40%, and a beta of 0.80, my CAPM analysis produces a return of 9.33% to 9.93% with a midpoint of 9.63%.

This CAPM estimate reflects a projected risk-free rate that is approximately 90 basis points higher than the current long-term risk-free rate as proxied by the U.S. Treasury security. The increase in the projected Treasury bond yield largely captures the additional risk in the marketplace related to the uncertainty of long-term interest rates, after the Federal Reserve discontinues its economic stimulus intervention.

<u>Return on Equity Summary</u>

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

A. Based on my analyses, I estimate PGE's current market cost of equity to be 9.40%.

[26/] *Id*. at 157.

TABLE 3

Return on Common Equity Summary

Description	Results
DCF	9.05%
Risk Premium	9.70%
CAPM	9.60%

My recommended return on common equity of 9.40% is the approximate midpoint of my estimated range of 9.05% to 9.70%. The high-end of my estimated range is based on my risk premium study and CAPM study. The low-end is based on my DCF studies. The midpoint of this range reflects current market capital costs, increased interest rate risk in the current market due to Federal Reserve policies and other factors, and represents fair compensation to PGE's investors for the total investment risk of its regulated utility.

Financial Integrity

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

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

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

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

expanded its matrix criteria[27/] by including additional business and financial risk categories. Based on S&P's most recent credit matrix, the business risk profile categories are "Excellent," "Strong," "Satisfactory," "Fair," "Weak," and "Vulnerable." Most electric utilities have a business risk profile of "Excellent" or "Strong." The financial risk profile categories are "Minimal," "Modest," "Intermediate," "Significant," "Aggressive," and "Highly Leveraged." Most of the electric utilities have a financial risk profile of "Aggressive." PGE has a "Strong" business risk profile and a "Significant" financial risk profile.

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

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

S&P publishes ranges for two core financial ratios that it uses as guidance in its credit review for utility companies. The two primary financial ratio benchmarks it relies on in its credit rating process include: (1) Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"); and (2) Funds From Operations ("FFO") to Total Debt.[28/]

[27/] 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.

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

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

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

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

A. The S&P financial metric calculations for PGE at a 9.40% return are reflected in Exhibit ICNU/218.

As shown on this exhibit, page 1, column 1, based on an equity return of 9.40%, PGE will be provided an opportunity to produce a debt to EBITDA ratio of 2.7x. This is within S&P's "Intermediate" guideline range of 2.5x to 3.5x.[29/] This ratio also supports an investment grade credit rating.

Finally, PGE's retail operations FFO to total debt coverage at a 9.40% equity return is 22%, which is within S&P's "Significant" metric guideline range of 13% to 23%. The FFO/total debt ratio will support an investment grade bond rating.

At my recommended return on equity of 9.40% and the Company's proposed capital structure, PGE's financial credit metrics are supportive of its current investment grade utility bond rating.

29/ *Id*. at 35.

RESPONSE TO PGE WITNESS DR. ZEPP

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

A. Dr. Zepp recommended a return on equity in the range of 9.9% to 10.6%, and concluded that an appropriate return for PGE is in the upper half of his range to reflect his assertion that PGE is riskier than his proxy group. (PGE/1200, Zepp/2). PGE is proposing to set rates based on a return on equity of 10.0%. (PGE/1200, Zepp/2).

Dr. Zepp relied on several versions of the DCF model and risk premium studies. He also analyzed the earned and authorized returns on equity to provide support for his recommendation.

Dr. Zepp's study results are summarized in Table 4 below under Column 1.

TABLE 4

Summary of Dr. Zepp's ROE Estimate

Description	**Zepp Results[1]** **(1)**	**Adjusted Zepp Results[2]** **(2)**
DCF Analysis		
Constant Growth Model (Exhibit PGE/1208)	9.6%	9.30%
FERC Two-Step (Exhibit PGE/1209)	9.6%	9.00%
Three-Stage Model (Exhibit PGE/1210)	9.9%	8.40%
Average	9.7%	
Risk Premium Analysis		
California Staff Approach (Exhibit PGE/1212)	10.8%	Reject
Realized Annual Returns (Exhibit PGE/1213)	11.0%	9.46%
Morin Statistical Approach (Exhibit PGE/1214)	10.4%	Reject
Average	10.7%	
ROE Range	10.2% - 10.6%	8.0% - 9.5%
Recommended Range	9.9% - 10.6%	

Sources and Note:
[1]PGE/1200, Zepp/1.
[2]Exhibit ICNU/219.

As shown under Column 1, Dr. Zepp's results suggest a return on equity in the range of 9.9% to 10.6% is unreasonable. However, under Column 2, I show appropriate adjustments to Dr. Zepp's DCF and risk premium studies that show a fair return on equity for PGE is in the range of 8.0% to 9.5%. These adjustments to Dr. Zepp's study support my recommended return on equity for PGE.

Q. PLEASE DESCRIBE THE COMPANY'S DISCOUNTED CASH FLOW ANALYSIS.

A. Dr. Zepp performed three versions of the DCF model. First, he used a constant growth DCF model. This DCF analysis used analysts' growth rate projections from Zacks, Yahoo! Finance, Reuters and *Value Line* as shown on Exhibit PGE/1207.

The second DCF model was based on Federal Energy Regulatory Commission ("FERC") methodology. FERC methodology develops a composite growth rate by applying a two-thirds weight to the analysts' growth rate, and a one-third weight to a GDP growth rate. PGE/1200, Zepp/23-26; Exhibit PGE/1209.

Finally, Dr. Zepp developed a multi-stage DCF model using the analysts' growth projections for the first stage, a second transitional growth stage that lasted 10 years, followed by a long-term sustainable growth stage, starting in year 16. The third stage sustainable growth rate was based on a GDP growth rate. PGE/1200, Zepp/6; Exhibit PGE/1210.

Q. DO YOU HAVE ANY CONCERNS WITH DR. ZEPP'S CONSTANT GROWTH DCF MODEL?

A. Yes. I have two concerns with Dr. Zepp's constant growth DCF analyses. First, Dr. Zepp removed one of his companies from the group average DCF result on his Table 8. There, he removed IDACORP's DCF estimate of 6.8%. Had he not removed this from the sample group, his proxy group average would have been 9.5%, and group median is

9.3%, as shown on page 2 of my Exhibit ICNU/219. Dr. Zepp's rationale for excluding this company is that IDACORP's DCF estimate of 6.8% is less than 100 basis points above his projected "Baa" utility bond yield of 5.95% as shown on his Table 11. Dr. Zepp's proposal is imbalanced and inappropriate.

First, the "Baa" current bond yield is around 5%, which is 180 basis points lower than the IDACORP DCF return estimate. Therefore, his parameter for excluding it because it is not at least 100 basis points above the "Baa" bond yield is highly biased and faulty.

Second, it is inappropriate for Dr. Zepp to exclude low-end DCF estimates on his Table 8 while not also excluding high-end return estimates. For example, the DCF return for PNM Resources, Inc. is 12.7% and the return for UNS Energy is 11.1%. These two return estimates are more than 600 and 500 basis points, respectively, higher than his 5.95% "Baa" utility bond yield. The risk spread on the high-end suggests that these two estimates should be excluded if low-end estimates are excluded.

A balanced and appropriate way to deal with proxy group outlier estimates is to rely on the proxy group median estimate as opposed to the group mean estimate. As shown on my exhibit, based on Dr. Zepp's own analysis, the group median DCF return estimate is 9.3%. I believe this group median estimate captures fairly the central tendency of all the proxy group DCF results. Dr. Zepp's proposal to exclude only low-end outliers is not balanced and inflates the DCF return estimate.

Also, Dr. Zepp's proxy group's three- to five-year analysts' growth rate estimate is higher than a reasonable estimate of a long-term sustainable growth rate. Dr. Zepp's average analysts' growth rate for the proxy group is 5.3%, which is significantly higher than the long-term GDP growth forecast of 4.7%. This indicates that Dr. Zepp's sustainable growth rate is a very high estimate of PGE's current market cost of equity.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH DR. ZEPP'S CONSTANT GROWTH DCF ANALYSIS?

A. Yes. Dr. Zepp adjusts his DCF analysis to modify the dividend yield component to reflect a reinvestment return on quarterly dividends throughout the year. This increases his initial dividend estimates outlined on his Table 6 to 3.92%, from 3.77%. This approximate 15 basis point increase in his return on equity is then increased again by the growth rate estimate and ultimately increases his DCF return estimate by about 20 basis points.

This adjustment to the dividend yield component is not appropriate. The quarterly compounding return element is not a cost to the utility. While I do not dispute that investors will pay a higher price to receive quarterly dividends, as opposed to an annual dividend, my complaint deals with whether or not the quarterly reinvestment dividend return is a cost of the utility. In this proceeding, we are attempting to estimate the utility's cost of capital. The utility's costs include making the dividend payments, and retaining adequate earnings to grow the dividend in line with investor expectations. However, the dividend reinvestment return is income investors receive by reinvesting the dividends. The utility does not pay that dividend reinvestment return. Rather, it is received by investing the dividend in other enterprises of comparable risk and return. Since the dividend reinvestment return is not a cost of the utility, it should not be included in the utility's cost of common equity capital. In addition to my comments concerning Dr. Zepp's DCF model described above, I also believe his DCF return estimate is overstated by about 20 basis points because it includes a dividend reinvestment return as a component of the utility's cost of capital. This is inappropriate, because the utility does not pay the dividend reinvestment return, and it should not be included in its cost of capital estimate.

Q. DO YOU HAVE ANY CONCERNS WITH DR. ZEPP'S PROPOSED FERC AND MULTI-STAGE DCF MODELS METHODOLOGY?

A. Yes. My primary concern with Dr. Zepp's non-constant growth models is his use of a GDP growth rate of 6.0%, which overstates the consensus economists' projected long-term GDP growth forecast. As noted above, consensus economists are projecting a long-term GDP growth rate of only 4.7%. Dr. Zepp's proposed 6.0% GDP forecast is not reasonable and does not reflect market participants' GDP growth outlook.

Q. HOW DID DR. ZEPP DERIVE A GDP GROWTH RATE OF 6.0%?

A. Dr. Zepp developed his GDP estimate of 6.0% by relying on the method utilized by Staff of the Arizona Corporation Commission ("ACC"). PGE/1200 at 24 and 25. ACC's Staff determined in March 2012 that the average historical GDP growth was 6.5%. However, to be conservative, Dr. Zepp assumed a future growth rate of 6.0%.

Q. IS THE 6.0% GDP GROWTH RATE USED BY DR. ZEPP REASONABLY REFLECTIVE OF CONSENSUS MARKET GDP GROWTH OUTLOOKS?

A. No. Dr. Zepp's GDP growth estimate of 6.0% significantly overstates the consensus analysts' GDP growth forecast for the next 10 years of 4.7% as published by the *Blue Chip Financial Forecasts*. Dr. Zepp's GDP estimate reflects the historical GDP growth, which is not necessarily a good benchmark to determine analysts' expectations. Further, as Dr. Zepp correctly observes, one should use the best available growth estimates, which are the consensus analysts' projections. PGE/1200 at 22. Using consensus analysts' growth projections most accurately reflects the current consensus market outlook instead of relying on an estimate provided by a single analyst such as Dr. Zepp, or an analyst on the ACC Staff.

Q. ADJUSTING THE FINDINGS ON DR. ZEPP'S DCF STUDIES, WHAT DOES HIS DCF ANALYSIS SUGGEST IS A FAIR RETURN ON EQUITY FOR PGE?

A. As shown on my Exhibit ICNU/219, reflecting a consensus analysts' projected GDP growth rate, and including all of his constant growth DCF results in his analysis by using a group median estimate, indicates a fair return on equity for PGE in the range of 8.4% up to 9.3%.

Q. PLEASE DESCRIBE DR. ZEPP'S RISK PREMIUM ANALYSIS.

A. The Company developed three versions of the risk premium analysis. The first risk premium analysis is based on a model Dr. Zepp asserts was derived by the Staff of the Division of Ratepayer Advocates of the California Public Utilities Commission (Application 065-02-014 – California RA Risk Premium). This methodology is based on the earned return on equity (accounting return), rather than market required, or expected returns on investments. Using this methodology, Dr. Zepp estimated an equity risk premium in the range of 5.83% to 6.99%.

Second, Dr. Zepp estimated a market risk premium based on the difference between the total earned returns on investment in an electric utility stock index, compared to the income return on long-term Treasury bond yields over the period 1950-2012. This Holding Period Returns methodology produced an equity risk premium of 5.54%. He then increased this to 6.41% by including 50% of the difference in change in yield on historical Treasury bonds and his projected Treasury bonds.

Dr. Zepp performed a second Holding Period risk premium analysis but covered the time period 1950 to 2000. This methodology produced an unadjusted risk premium of 5.70%, and an adjusted risk premium of 6.77%, again representing 50% of the difference in change in Treasury bond yield. This second risk premium study is referred to as his Annual Investment Holding Period risk premium.

Finally, based on a comparison of authorized returns on equity relative to Treasury bond yields of 4.41%, Dr. Zepp estimated an equity risk premium of 6.01%. Dr. Zepp refers to this approach as Morin Statistical Approach.

Using these methodologies and a Treasury bond yield of 4.41%, Dr. Zepp estimated a return on equity for PGE of 10.2% to 11.4%, as shown above in my Table 4.

Q. PLEASE OUTLINE THE ISSUES YOU HAVE WITH DR. ZEPP'S RISK PREMIUM ANALYSIS.

A. I have three major additional issues with Dr. Zepp's risk premium analysis.

First, Dr. Zepp's California RA risk premium analysis is based on historical accounting returns, over the period 1997-2011. This risk premium study is flawed because it does not measure the rate of return required by investors to accept an investment based on its risk and a market-required return to assume the risk.

Second, Dr. Zepp's Annual Holding Period risk premium study is not reasonable because he does not accurately measure the holding period returns on both bonds and equity investments. Consequently, he does not accurately measure the return premium an investor has earned by investing in equity securities rather than Treasury bond securities over the study period.

Specifically, his annual return on utility stock investments reflects a total investment return. A total investment return includes both annual capital gains and losses, and dividend income. In significant contrast, his return on Treasury bonds reflects only the income return on the bonds. Dr. Zepp ignores the capital gains and losses an investor would realize by owning a 30-year Treasury bond.

Ignoring bond capital gains and losses is significant because the interest rate changes which cause the change in the annual yield on the bond, will also cause changes to bond and stock prices. It is simply not possible for an investor to invest in a Treasury bond, without experiencing annual capital gains and losses on the face value of the bond.

Therefore, Dr. Zepp's Annual Holding Period risk premium is flawed and the risk premium is erroneous because it does not properly compare the total annual investment returns on stock investments, with the total annual investment returns on Treasury bond investments.

Q. WHY DO YOU BELIEVE THAT DR. ZEPP'S CALIFORNIA STAFF APPROACH RISK PREMIUM ANALYSIS IS FLAWED?

A. Dr. Zepp's CA Staff Approach risk premium analysis is based on actual historical accounting returns over the period 1997-2011. Accounting returns do not reflect investors' required investment returns. This methodology is not market-based. The market return on equity for regulated utilities is determined by competitive market forces. In contrast, the earned accounting returns used here by Dr. Zepp are book returns which reflect accounting measures. Therefore, using this methodology will not accurately measure the market-required investment returns and is, therefore, flawed and it should be rejected.

Further, a review of his Table 12 shows the illogical conclusions drawn from his accounting return risk premium study. As shown on this table, throughout the time period studied, utility-projected earned returns on common equity are relatively stable. However, yields on Treasury bonds move significantly. What Dr. Zepp's analysis fails to show is the impact on utility stocks through this stable earned return on equity, given the more volatile nature of interest rates over the study period. As such, the indicated equity risk premium is completely devoid of measuring a fair return on equity given the level of risk of the security investment. Therefore, the analysis is flawed, and produces an unreliable result.

Q. DO YOU BELIEVE THAT DR. ZEPP'S REALIZED ANNUAL HOLDING PERIOD RETURNS RISK PREMIUM IS REASONABLE?

A. No. Dr. Zepp's Annual Holding Period return risk premium study does not compare the total investment returns on utility stock investments versus Treasury bond investments. It is inaccurate because he compares the total investment returns on stocks (capital gains and yield) with only the income returns on Treasury bonds. The changes in market factors including interest rates which cause stock prices to increase and decrease from year to year, and also impact the market value of the bond investment. As such, his analysis should be adjusted to compare the actual investment results an investor would experience by investing in either utility stocks or Treasury bonds.

Q. CAN DR. ZEPP'S ANNUAL HOLDING PERIOD RISK PREMIUM STUDY BE MODIFIED TO COMPARE ANNUAL TOTAL INVESTMENT RETURNS OF STOCKS VERSUS TOTAL INVESTMENT RETURNS OF BONDS OVER HIS STUDY PERIOD?

A. Yes. I have modified his second risk premium study, his historical annual achieved and total investment returns to compare the total investment returns on stocks, compared to the total investment returns on bonds. As shown on my Exhibit ICNU/220, over the period 1950-2012, the difference between investing in equities versus Treasury bonds during this time period was 5.06%.

Q. WOULD IT BE APPROPRIATE TO ADJUST THIS EQUITY RISK PREMIUM BY THE DIFFERENCE IN TREASURY BOND RATES CURRENTLY VERSUS THAT IN THE HISTORICAL PERIOD?

A. No. This study reflects long-term Treasury rates ranging from 2% to 7%. This study considers the average annual premium of investing in stocks versus bonds given various interest rate environments and other market factors. Dr. Zepp's proposal to adjust this by 50% of the change in Treasury bond yields is inappropriate and is simply an inaccurate estimate of the actual risk premium earned on utility stock versus Treasury bond investment over the study period.

Q. BASED ON YOUR REVISION TO THE HISTORICAL ANNUAL HOLDING PERIOD RETURN ON UTILITY STOCKS VERSUS TREASURY BONDS, WHAT RETURN ON EQUITY WOULD BE APPROPRIATE FOR PGE?

A. The Annual Holding Period return on Treasury bonds and utility stocks implies a risk premium of 5.06%. Applying this risk premium to Dr. Zepp's projected Treasury bond yield of 4.4% implies a return on equity of 9.46% for PGE.

Q. DO YOU HAVE ANY COMMENTS CONCERNING DR. ZEPP'S PROPOSED MORIN STATISTICAL APPROACH RISK PREMIUM STUDY?

A. Yes. Dr. Zepp's statistical study assumes there is a direct inverse relationship between interest rates and equity risk premiums. This methodology does not capture the likelihood that Commission-authorized returns on equity are often reduced more slowly than declines in the market utility bond yields. As regulatory commissions act conservatively, it is reasonable to expect that they wouldn't reduce the authorized return on equity until there is a clear trend or sustained level of lower capital market costs. I believe that is precisely what has happened in the marketplace over the last 10 to 15 years. Therefore, his simple regression analysis of a comparison of authorized returns on equity to Treasury yields gives a false impression of a strong statistical correlation between decreases in interest rates and increases in equity risk premiums.

Q. WHY IS DR. ZEPP'S USE OF A SIMPLE INVERSE RELATIONSHIP BETWEEN INTEREST RATES AND EQUITY RISK PREMIUMS NOT REASONABLE?

A. Dr. Zepp's belief that there is a simplistic inverse relationship between equity risk premiums and interest rates is not supported by academic research. While academic studies have shown that, in the past, there has been an inverse relationship with these variables, researchers have found that the relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, and not simply changes to interest rates.[30/]

In the 1980s, equity risk premiums were inversely related to interest rates, but that was likely attributable to the interest rate volatility that existed at that time. Interest rate volatility currently is much lower than it was in the 1980s.[31/] As such, when interest rates were more volatile, the relative perception of bond investment risk increased relative to the investment risk of equities. This changing investment risk perception caused changes in equity risk premiums.

In today's marketplace, interest rate variability is not as extreme as it was during the 1980s. Nevertheless, changes in the perceived risk of bond investments relative to equity investments still drive changes in equity premiums. However, a relative investment risk differential cannot be measured simply by observing nominal interest rates. Changes in nominal interest rates are highly influenced by changes in inflation

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30/ "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 and "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.

31/ *Ibbotson SBBI 2009 Valuation Yearbook* (Morningstar, Inc.) at 95-96.

outlooks, which also change equity return expectations. As such, the relevant factor needed to explain changes in equity risk premiums is the relative changes to the risk of equity versus debt securities investments, not simply changes to interest rates.

Importantly, Dr. Zepp's analysis simply ignores investment risk differentials. He bases his adjustment to the equity risk premium exclusively on changes in nominal interest rates. This is a flawed methodology and does not produce accurate or reliable risk premium estimates. His results should be rejected by the Commission.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH DR. ZEPP'S RISK PREMIUM STUDIES?

A. Yes. Dr. Zepp's risk premium studies only consider projected interest rates. Dr. Zepp did not include or provide any risk premium estimates based on current observable interest rates. This is inappropriate because projections of future interest rates are highly volatile, uncertain, and projections rarely turn out to reflect a utility's actual cost of borrowing during the projected period. Also, history suggests that current observable interest rates are just as likely to reflect prevailing interest rates when the utility rates determined in this case are in effect as are projected interest rates.

For example, on my Exhibit ICNU/221, I show the *Blue Chip Financial Forecasts* actual interest rates, and projected interest rates. I also show the actual prevailing interest rates that were realized at the quarter the projection was made. As shown on this exhibit, under Columns 2 and 3, economists almost always project increases to current prevailing interest rates. However, as shown under Columns 5 and 6, those projected interest rates rarely turn out to be accurate, and almost always overstate the interest rates that are realized in the projected quarter.

Because economists generally always expect increases in interest rates, and the projections almost always overstate the level of interest rates that prevail in the projected period, it is not appropriate to consider only projected interest rates in developing a risk premium return on equity estimate. Because Dr. Zepp failed to consider current observable interest rates in developing a risk premium estimate for PGE in this case, he has biased his return on equity upward to reflect highly uncertain and largely unpredictable future interest rate levels. This results in an overstatement of a fair and balanced return on equity estimate for PGE in this case.

Q. DO YOU HAVE ANY COMMENTS IN REGARD TO DR. ZEPP'S CHECK FOR REASONABLENESS OF HIS RECOMMENDED RETURN ON EQUITY?

A. Yes. Dr. Zepp checks the reasonableness of his estimate based on the earned, authorized and forecasted returns for his comparable group and he concludes that excluding the book returns below the cost of investment grade debt plus 100 basis points results in a return on equity in the range of 10.2% to 10.6%. PGE/1200, Zepp/40; Exhibit PGE/1215.

Q. PLEASE COMMENT ON DR. ZEPP'S RETURN CHECK.

A. As discussed above in regards to Dr. Zepp's first risk premium analysis, using the actual book returns does not reflect the investors' required return on equity. The accounting earned returns do not measure the current cost of capital necessary to attract capital in the marketplace. An accounting return is not derived from the market valuation of security prices. Consequently, it does not measure investors' return requirements. This is an important distinction, because if the accounting returns on equity are lower than the market required return on equity, then the utility's ability to attract capital could be impaired. Conversely, if the accounting return on equity exceeds the utility's market cost of capital, then utility rates would be adjusted higher than necessary to fairly compensate investors and maintain their ability to attract capital. Hence, the accounting-based methodology is flawed because it does not estimate a fair risk adjusted return on equity that fairly compensates PGE for making utility plant investments.

Because of the severe deficiencies in this methodology, Dr. Zepp's test for reasonableness should be disregarded.

Q. DID DR. ZEPP CONCLUDE THAT PGE HAS GREATER RISK THAN OTHER ELECTRIC UTILITY COMPANIES?

A. Yes. Dr. Zepp concluded that PGE has greater risk than his sample of electric utility companies because of several factors. First, he concludes PGE has significantly more exposure to the wholesale market, due to reliance on wind and hydro generation. Second, he believes PGE has a weak power cost adjustment mechanism based on S&P reports covering PGE. Third, PGE has greater risk due to an authorized ROE lower than the proxy group over the last five years. Fourth, PGE has debt imputation of related purchased power contracts; and finally, PGE has a beta above the sample average. He also points to witnesses Hager, Valach and Greene for other unique risks faced by PGE.

Q. DO THE OTHER WITNESSES PROVIDE ANY EVIDENCE THAT THE RISKS THEY IDENTIFIED ARE NOT ALREADY CONSIDERED IN THE RISK METRICS OF DR. ZEPP, THAT YOU USE TO COMPARE PGE TO THE PROXY GROUP OF UTILITY COMPANIES?

A. No. All the risks identified by Dr. Zepp and the other utility witnesses are known to the market, reflected in PGE's bond rating, and represent information available to investors to make a total investment risk assessment of PGE. Therefore, they are in the risk metrics used to compare PGE's investment risk to the proxy group. The indicated fair return on equity derived from the proxy group consequently represents fair consideration for PGE's total investment risk. For all these reasons, an external adjustment to the return on equity estimate of the proxy group is not justified.

Q. WHY DO YOU BELIEVE THE RISKS IDENTIFIED BY DR. ZEPP ARE CONSIDERED BY CREDIT RATING AGENCIES AND ANALYSTS IN ASSIGNING PGE'S BOND RATING?

A. In its publication *Key Credit Factors for the Regulated Utilities*, S&P identifies the following business and financial risks that reflect the credit rating determination of corporate entities. These are outlined below:

Business risk:

- Industry risk
- Country risk
- Competitive position

Financial risk:

- Accounting
- Cash flow/leverage

Rating Modifiers:

- Diversification/portfolio effect
- Capital structure
- Liquidity
- Financial policy
- Management and governance
- Comparable ratings

The competitive position outlined above includes utilities' regulatory environment, exposure to commodity risk, capital and financing requirements and company size. The exposure to off-balance sheet debt equivalents such as purchased power agreements and operating leases is discussed in the financial risk review. As shown above, all the risks discussed by Dr. Zepp have already been reflected in the proxy group credit rating. Therefore, selecting a proxy group that has a comparable total investment risk like Dr. Zepp and I have done fully captures all the risks outlined by Dr. Zepp.

Q. WHAT DO YOU RECOMMEND CONCERNING DR. ZEPP'S PROPOSED 20 BASIS POINT RETURN ON PGE'S GREATER RISK EQUITY ADDER?

A. On page 18 of Dr. Zepp's testimony (PGE/1200, Zepp/18), he recommends a 20 basis point upward adjustment to the cost of equity for PGE based on PGE's higher risk compared to the proxy group. This 20 basis point adjustment is without merit, and should be rejected.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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

EXHIBIT ICNU/201

QUALIFICATIONS OF MICHAEL P. GORMAN

June 11, 2014

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

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

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

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

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

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

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

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

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

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

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

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

9898/259975

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision.	)
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EXHIBIT ICNU/202

RATE OF RETURN

June 11, 2014

Portland General Electric

Rate of Return

Line	Description	Weight (1)	Cost (2)	Weighted Cost (3)
1	Long-Term Debt	50.00%	5.50%	2.75%
2	Common Equity	50.00%	**9.40%**	4.70%
3	**Total**	**100.00%**		**7.45%**

Sources:
Gorman Direct at 2.
Direct testimony of Hager, Valach, and Greene, page 4.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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In the Matter of	)
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EXHIBIT ICNU/203

PROXY GROUP

June 11, 2014

Portland General Electric Company

Proxy Group

Line	Company	Credit Ratings[1]		Common Equity Ratios	
		S&P	Moody's	*SNL* [1]	*Value Line* [2]
		(1)	(2)	(3)	(4)
1	ALLETE, Inc.	BBB+	A3	54.7%	55.4%
2	Alliant Energy Corporation	A-	A3	45.6%	47.0%
3	Avista Corporation	BBB	Baa1	44.9%	48.6%
4	Black Hills Corporation	BBB	Baa1	46.9%	48.4%
5	Cleco Corporation	BBB+	Baa2	54.3%	54.5%
6	CMS Energy Corporation	BBB	Baa2	30.1%	32.2%
7	Great Plains Energy Inc.	BBB+	Baa2	47.4%	49.4%
8	Hawaiian Electric Industries, Inc.	BBB-	Baa2	49.9%	55.0%
9	IDACORP, Inc.	BBB	Baa1	52.5%	53.4%
10	MGE Energy, Inc.	AA-	A1	46.7%	60.7%
11	NorthWestern Corporation	BBB	A3	43.7%	46.5%
12	OGE Energy Corp.	A-	A3	51.7%	56.9%
13	Pinnacle West Capital Corporation	A-	Baa1	53.6%	60.0%
14	PNM Resources, Inc.	BBB	Baa3	45.8%	49.7%
15	Portland General Electric Company	BBB	A3	48.7%	48.7%
16	SCANA Corporation	BBB+	Baa3	44.5%	46.5%
17	TECO Energy, Inc.	BBB+	Baa1	43.7%	45.0%
18	UNS Energy Corporation	N/A	Baa2	38.0%	40.6%
19	Westar Energy, Inc.	BBB+	Baa1	45.7%	49.0%
20	Wisconsin Energy Corporation	A-	A2	44.5%	49.0%
21	**Average**	**BBB+**	**Baa1**	**46.6%**	**49.8%**
22	**Portland General Electric Company**	**BBB**	**A3**		**50.0%**[3]

Sources:
[1] SNL Financial, Downloaded on May 16, 2014.
[2] *The Value Line Investment Survey, February 21, March 21, and May 2, 2014.*
[3] PGE Exhibit 1201.

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EXHIBIT ICNU/204

CONSENSUS ANALYSTS' GROWTH RATES

June 11, 2014

Portland General Electric Company

Consensus Analysts' Growth Rates

		Zacks		SNL		Reuters		Average of
Line	Company	Estimated Growth %[1] (1)	Number of Estimates (2)	Estimated Growth %[2] (3)	Number of Estimates (4)	Estimated Growth %[3] (5)	Number of Estimates (6)	Growth Rates (7)
1	ALLETE, Inc.	N/A	N/A	N/A	N/A	NA	0	N/A
2	Alliant Energy Corporation	5.50%	N/A	5.00%	1	5.27%	3	5.26%
3	Avista Corporation	N/A	N/A	N/A	N/A	NA	0	N/A
4	Black Hills Corporation	N/A	N/A	N/A	N/A	7.00%	1	7.00%
5	Cleco Corporation	8.00%	N/A	7.00%	1	7.00%	1	7.33%
6	CMS Energy Corporation	6.10%	N/A	6.10%	3	6.30%	3	6.17%
7	Great Plains Energy Inc.	5.10%	N/A	5.10%	4	5.25%	2	5.15%
8	Hawaiian Electric Industries, Inc.	6.00%	N/A	4.00%	1	3.80%	3	4.60%
9	IDACORP, Inc.	4.00%	N/A	4.00%	1	4.00%	1	4.00%
10	MGE Energy, Inc.	N/A	N/A	N/A	N/A	NA	0	N/A
11	NorthWestern Corporation	7.00%	N/A	7.00%	1	8.00%	2	7.33%
12	OGE Energy Corp.	5.70%	N/A	N/A	N/A	NA	0	5.70%
13	Pinnacle West Capital Corporation	4.10%	N/A	4.10%	3	4.28%	5	4.16%
14	PNM Resources, Inc.	8.50%	N/A	8.50%	4	8.39%	3	8.46%
15	Portland General Electric Company	6.80%	N/A	8.10%	3	10.17%	5	8.36%
16	SCANA Corporation	4.50%	N/A	4.70%	2	4.70%	2	4.63%
17	TECO Energy, Inc.	5.00%	N/A	5.00%	1	4.84%	2	4.95%
18	UNS Energy Corporation	N/A	N/A	N/A	N/A	NA	0	N/A
19	Westar Energy, Inc.	3.70%	N/A	3.30%	3	2.90%	2	3.30%
20	Wisconsin Energy Corporation	4.90%	N/A	5.00%	1	5.16%	4	5.02%
21	**Average**	**5.66%**	**N/A**	**5.49%**	**2**	**5.80%**	**2**	**5.71%**

Sources:
[1] Zacks Elite, http://www.zackselite.com/, downloaded on May 16, 2014.
[2] SNL Interactive, http://www.snl.com/, downloaded on May 16, 2014.
[3] Reuters, http://www.reuters.com/, downloaded on May 16, 2014.

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EXHIBIT ICNU/205

CONSTANT GROWTH DCF MODEL

June 11, 2014

Portland General Electric Company

Constant Growth DCF Model
(Consensus Analysts' Growth Rates)

Line	Company	13-Week AVG Stock Price[1] (1)	Analysts' Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE, Inc.	$51.04	N/A	$1.96	N/A	N/A
2	Alliant Energy Corporation	$56.00	5.26%	$2.04	3.83%	9.09%
3	Avista Corporation	$30.62	N/A	$1.27	N/A	N/A
4	Black Hills Corporation	$57.35	7.00%	$1.56	2.91%	9.91%
5	Cleco Corporation	$50.30	7.33%	$1.45	3.09%	10.43%
6	CMS Energy Corporation	$29.09	6.17%	$1.08	3.94%	10.11%
7	Great Plains Energy Inc.	$26.43	5.15%	$0.92	3.66%	8.81%
8	Hawaiian Electric Industries, Inc.	$24.72	4.60%	$1.24	5.25%	9.85%
9	IDACORP, Inc.	$55.22	4.00%	$1.72	3.24%	7.24%
10	MGE Energy, Inc.	$38.63	N/A	$1.09	N/A	N/A
11	NorthWestern Corporation	$46.79	7.33%	$1.60	3.67%	11.00%
12	OGE Energy Corp.	$36.26	5.70%	$0.90	2.62%	8.32%
13	Pinnacle West Capital Corporation	$55.05	4.16%	$2.27	4.30%	8.46%
14	PNM Resources, Inc.	$26.91	8.46%	$0.74	2.98%	11.45%
15	Portland General Electric Company	$32.32	8.36%	$1.10	3.69%	12.04%
16	SCANA Corporation	$50.91	4.63%	$2.03	4.17%	8.81%
17	TECO Energy, Inc.	$17.20	4.95%	$0.88	5.37%	10.31%
18	UNS Energy Corporation	$60.19	N/A	$1.92	N/A	N/A
19	Westar Energy, Inc.	$34.93	3.30%	$1.40	4.14%	7.44%
20	Wisconsin Energy Corporation	$45.93	5.02%	$1.56	3.57%	8.59%
21	**Average**	**$41.29**	**5.71%**	**$1.44**	**3.78%**	**9.49%**
22	**Median**					**9.47%**

Sources:
[1] SNL Financial, Downloaded on May 20, 2014.
[2] Exhibit ICNU/204.
[3] *The Value Line Investment Survey, February 21, March 21, and May 2, 2014.*

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EXHIBIT ICNU/206

PAYOUT RATIOS

June 11, 2014

Portland General Electric Company

Payout Ratios

Line	Company	Dividends Per Share 2013 (1)	Dividends Per Share Projected (2)	Earnings Per Share 2013 (3)	Earnings Per Share Projected (4)	Payout Ratio 2013 (5)	Payout Ratio Projected (6)
1	ALLETE, Inc.	$1.90	$2.30	$2.63	$3.75	72.24%	61.33%
2	Alliant Energy Corporation	$1.88	$2.40	$3.29	$4.00	57.14%	60.00%
3	Avista Corporation	$1.22	$1.50	$1.85	$2.25	65.95%	66.67%
4	Black Hills Corporation	$1.52	$1.90	$2.61	$3.25	58.24%	58.46%
5	Cleco Corporation	$1.43	$2.00	$2.65	$3.50	53.96%	57.14%
6	CMS Energy Corporation	$1.02	$1.35	$1.66	$2.25	61.45%	60.00%
7	Great Plains Energy Inc.	$0.88	$1.30	$1.62	$2.00	54.32%	65.00%
8	Hawaiian Electric Industries, Inc.	$1.24	$1.30	$1.62	$2.00	76.54%	65.00%
9	IDACORP, Inc.	$1.57	$2.00	$3.64	$3.65	43.13%	54.79%
10	MGE Energy, Inc.	$1.07	$1.30	$2.16	$3.10	49.54%	41.94%
11	NorthWestern Corporation	$1.52	$1.90	$2.46	$3.00	61.79%	63.33%
12	OGE Energy Corp.	$0.85	$1.35	$1.94	$2.50	43.81%	54.00%
13	Pinnacle West Capital Corporation	$2.23	$2.75	$3.66	$4.25	60.93%	64.71%
14	PNM Resources, Inc.	$0.68	$1.15	$1.41	$2.35	48.23%	48.94%
15	Portland General Electric Company	$1.10	$1.30	$1.77	$2.50	62.15%	52.00%
16	SCANA Corporation	$2.03	$2.30	$3.40	$4.25	59.71%	54.12%
17	TECO Energy, Inc.	$0.88	$0.95	$0.92	$1.35	95.65%	70.37%
18	UNS Energy Corporation	$1.74	$2.28	$3.04	$3.80	57.24%	60.00%
19	Westar Energy, Inc.	$1.36	$1.56	$2.27	$2.75	59.91%	56.73%
20	Wisconsin Energy Corporation	$1.45	$2.10	$2.51	$3.25	57.77%	64.62%
21	**Average**	**$1.38**	**$1.75**	**$2.36**	**$2.99**	**59.98%**	**58.96%**

Source:
The Value Line Investment Survey, February 21, March 21, and May 2, 2014.

BEFORE THE PUBLIC UTILITY COMMISSION

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EXHIBIT ICNU/207

SUSTAINABLE GROWTH RATE

June 11, 2014

Portland General Electric Company

Sustainable Growth Rate

Line	Company	Dividends Per Share (1)	Earnings Per Share (2)	Book Value Per Share (3)	Book Value Growth (4)	ROE (5)	Adjustment Factor (6)	Adjusted ROE (7)	Payout Ratio (8)	Retention Rate (9)	Internal Growth Rate (10)	Sustainable Growth Rate (11)
		3 to 5 Year Projections										
1	ALLETE, Inc.	$2.30	$3.75	$39.75	4.15%	9.43%	1.02	9.63%	61.33%	38.67%	3.72%	5.32%
2	Alliant Energy Corporation	$2.40	$4.00	$34.80	3.39%	11.49%	1.02	11.69%	60.00%	40.00%	4.67%	5.32%
3	Avista Corporation	$1.50	$2.25	$25.00	2.96%	9.00%	1.01	9.13%	66.67%	33.33%	3.04%	3.71%
4	Black Hills Corporation	$1.90	$3.25	$35.25	3.70%	9.22%	1.02	9.39%	58.46%	41.54%	3.90%	4.43%
5	Cleco Corporation	$2.00	$3.50	$33.25	4.88%	10.53%	1.02	10.78%	57.14%	42.86%	4.62%	4.62%
6	CMS Energy Corporation	$1.35	$2.25	$17.25	5.85%	13.04%	1.03	13.41%	60.00%	40.00%	5.37%	6.28%
7	Great Plains Energy Inc.	$1.30	$2.00	$25.75	2.66%	7.77%	1.01	7.87%	65.00%	35.00%	2.75%	2.81%
8	Hawaiian Electric Industries, Inc.	$1.30	$2.00	$20.25	3.49%	9.88%	1.02	10.05%	65.00%	35.00%	3.52%	4.35%
9	IDACORP, Inc.	$2.00	$3.65	$44.55	3.87%	8.19%	1.02	8.35%	54.79%	45.21%	3.77%	3.97%
10	MGE Energy, Inc.	$1.30	$3.10	$23.60	5.79%	13.14%	1.03	13.51%	41.94%	58.06%	7.84%	8.73%
11	NorthWestern Corporation	$1.90	$3.00	$32.00	3.77%	9.38%	1.02	9.55%	63.33%	36.67%	3.50%	3.68%
12	OGE Energy Corp.	$1.35	$2.50	$20.75	6.28%	12.05%	1.03	12.42%	54.00%	46.00%	5.71%	6.46%
13	Pinnacle West Capital Corporation	$2.75	$4.25	$45.00	3.40%	9.44%	1.02	9.60%	64.71%	35.29%	3.39%	4.00%
14	PNM Resources, Inc.	$1.15	$2.35	$24.50	3.26%	9.59%	1.02	9.75%	48.94%	51.06%	4.98%	5.00%
15	Portland General Electric Company	$1.30	$2.50	$29.00	4.47%	8.62%	1.02	8.81%	52.00%	48.00%	4.23%	5.34%
16	SCANA Corporation	$2.30	$4.25	$43.50	5.55%	9.77%	1.03	10.03%	54.12%	45.88%	4.60%	6.12%
17	TECO Energy, Inc.	$0.95	$1.35	$11.75	1.79%	11.49%	1.01	11.59%	70.37%	29.63%	3.43%	3.47%
18	UNS Energy Corporation	$2.28	$3.80	$32.70	3.74%	11.62%	1.02	11.83%	60.00%	40.00%	4.73%	5.29%
19	Westar Energy, Inc.	$1.56	$2.75	$29.65	4.92%	9.27%	1.02	9.50%	56.73%	43.27%	4.11%	4.69%
20	Wisconsin Energy Corporation	$2.10	$3.25	$20.75	2.05%	15.66%	1.01	15.82%	64.62%	35.38%	5.60%	5.60%
21	**Average**	**$1.75**	**$2.99**	**$29.45**	**4.00%**	**10.43%**	**1.02**	**10.63%**	**58.96%**	**41.04%**	**4.37%**	**4.96%**

Sources and Notes:
Cols. (1), (2) and (3): *The Value Line Investment Survey, February 21, March 21, and May 2, 2014.*
Col. (4): [Col. (3) / Page 2 Col. (2)] ^ (1/5) - 1.
Col. (5): Col. (2) / Col. (3).
Col. (6): [2 * (1 + Col. (4))] / (2 + Col. (4)).
Col. (7): Col. (6) * Col. (5).
Col. (8): Col. (1) / Col. (2).
Col. (9): 1 - Col. (8).
Col. (10): Col. (9) * Col. (7).
Col. (11): Col. (10) + Page 2 Col. (9).

Portland General Electric Company

Sustainable Growth Rate

Line	Company	13-Week Average Stock Price[1] (1)	2013 Book Value Per Share[2] (2)	Market to Book Ratio (3)	Common Shares Outstanding (in Millions)[2] 2013 (4)	Common Shares Outstanding (in Millions)[2] 3-5 Years (5)	Growth (6)	S Factor[3] (7)	V Factor[4] (8)	S * V (9)
1	ALLETE, Inc.	$51.04	$32.44	1.57	41.40	47.50	2.79%	4.38%	36.44%	1.60%
2	Alliant Energy Corporation	$56.00	$29.45	1.90	110.98	115.00	0.71%	1.36%	47.41%	0.64%
3	Avista Corporation	$30.62	$21.61	1.42	60.08	65.00	1.59%	2.25%	29.43%	0.66%
4	Black Hills Corporation	$57.35	$29.39	1.95	44.50	45.75	0.56%	1.08%	48.76%	0.53%
5	Cleco Corporation	$50.30	$26.20	1.92	60.50	60.50	0.00%	0.00%	47.91%	0.00%
6	CMS Energy Corporation	$29.09	$12.98	2.24	266.10	276.00	0.73%	1.64%	55.38%	0.91%
7	Great Plains Energy Inc.	$26.43	$22.58	1.17	153.87	156.50	0.34%	0.40%	14.57%	0.06%
8	Hawaiian Electric Industries, Inc.	$24.72	$17.06	1.45	101.26	111.00	1.85%	2.69%	30.99%	0.83%
9	IDACORP, Inc.	$55.22	$36.84	1.50	50.23	51.20	0.38%	0.57%	33.28%	0.19%
10	MGE Energy, Inc.	$38.63	$17.81	2.17	34.67	36.00	0.76%	1.64%	53.89%	0.88%
11	NorthWestern Corporation	$46.79	$26.60	1.76	38.75	39.20	0.23%	0.41%	43.15%	0.18%
12	OGE Energy Corp.	$36.26	$15.30	2.37	198.50	204.00	0.55%	1.30%	57.80%	0.75%
13	Pinnacle West Capital Corporation	$55.05	$38.07	1.45	110.18	118.00	1.38%	2.00%	30.84%	0.62%
14	PNM Resources, Inc.	$26.91	$20.87	1.29	79.65	80.00	0.09%	0.11%	22.44%	0.03%
15	Portland General Electric Company	$32.32	$23.30	1.39	78.09	90.00	2.88%	3.99%	27.91%	1.11%
16	SCANA Corporation	$50.91	$33.20	1.53	140.00	161.00	2.83%	4.35%	34.79%	1.51%
17	TECO Energy, Inc.	$17.20	$10.75	1.60	217.30	218.00	0.06%	0.10%	37.51%	0.04%
18	UNS Energy Corporation	$60.19	$27.22	2.21	41.54	42.50	0.46%	1.01%	54.78%	0.55%
19	Westar Energy, Inc.	$34.93	$23.32	1.50	127.46	135.00	1.16%	1.73%	33.24%	0.58%
20	Wisconsin Energy Corporation	$45.93	$18.75	2.45	225.50	217.00	-0.77%	-1.88%	59.17%	-1.11%
21	**Average**	**$41.29**	**$24.19**	**1.74**	**109.03**	**113.46**	**1.02%**	**1.63%**	**39.98%**	**0.61%**

Sources and Notes:

[1] SNL Financial, Downloaded on May 20, 2014.

[2] *The Value Line Investment Survey, February 21, March 21, and May 2, 2014.*

[3] Expected Growth in the Number of Shares, Column (3) * Column (6).

[4] Expected Profit of Stock Investment, [1 - 1 / Column (3)].

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OF OREGON

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EXHIBIT ICNU/208

CONSTANT GROWTH DCF MODEL

June 11, 2014

Portland General Electric Company

Constant Growth DCF Model
(Sustainable Growth Rate)

Line	Company	13-Week AVG Stock Price[1] (1)	Sustainable Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE, Inc.	$51.04	5.32%	$1.96	4.04%	9.36%
2	Alliant Energy Corporation	$56.00	5.32%	$2.04	3.84%	9.15%
3	Avista Corporation	$30.62	3.71%	$1.27	4.30%	8.01%
4	Black Hills Corporation	$57.35	4.43%	$1.56	2.84%	7.27%
5	Cleco Corporation	$50.30	4.62%	$1.45	3.02%	7.63%
6	CMS Energy Corporation	$29.09	6.28%	$1.08	3.95%	10.22%
7	Great Plains Energy Inc.	$26.43	2.81%	$0.92	3.58%	6.39%
8	Hawaiian Electric Industries, Inc.	$24.72	4.35%	$1.24	5.23%	9.58%
9	IDACORP, Inc.	$55.22	3.97%	$1.72	3.24%	7.20%
10	MGE Energy, Inc.	$38.63	8.73%	$1.09	3.06%	11.78%
11	NorthWestern Corporation	$46.79	3.68%	$1.60	3.55%	7.22%
12	OGE Energy Corp.	$36.26	6.46%	$0.90	2.64%	9.10%
13	Pinnacle West Capital Corporation	$55.05	4.00%	$2.27	4.29%	8.29%
14	PNM Resources, Inc.	$26.91	5.00%	$0.74	2.89%	7.89%
15	Portland General Electric Company	$32.32	5.34%	$1.10	3.59%	8.93%
16	SCANA Corporation	$50.91	6.12%	$2.03	4.23%	10.35%
17	TECO Energy, Inc.	$17.20	3.47%	$0.88	5.29%	8.77%
18	UNS Energy Corporation	$60.19	5.29%	$1.92	3.36%	8.65%
19	Westar Energy, Inc.	$34.93	4.69%	$1.40	4.20%	8.88%
20	Wisconsin Energy Corporation	$45.93	5.60%	$1.56	3.59%	9.19%
21	**Average**	**$41.29**	**4.96%**	**$1.44**	**3.74%**	**8.69%**
22	**Median**					**8.82%**

Sources:
[1] SNL Financial, Downloaded on May 20, 2014.
[2] Exhibit ICNU/207, Gorman/1.
[3] *The Value Line Investment Survey, February 21, March 21, and May 2, 2014.*

BEFORE THE PUBLIC UTILITY COMMISSION

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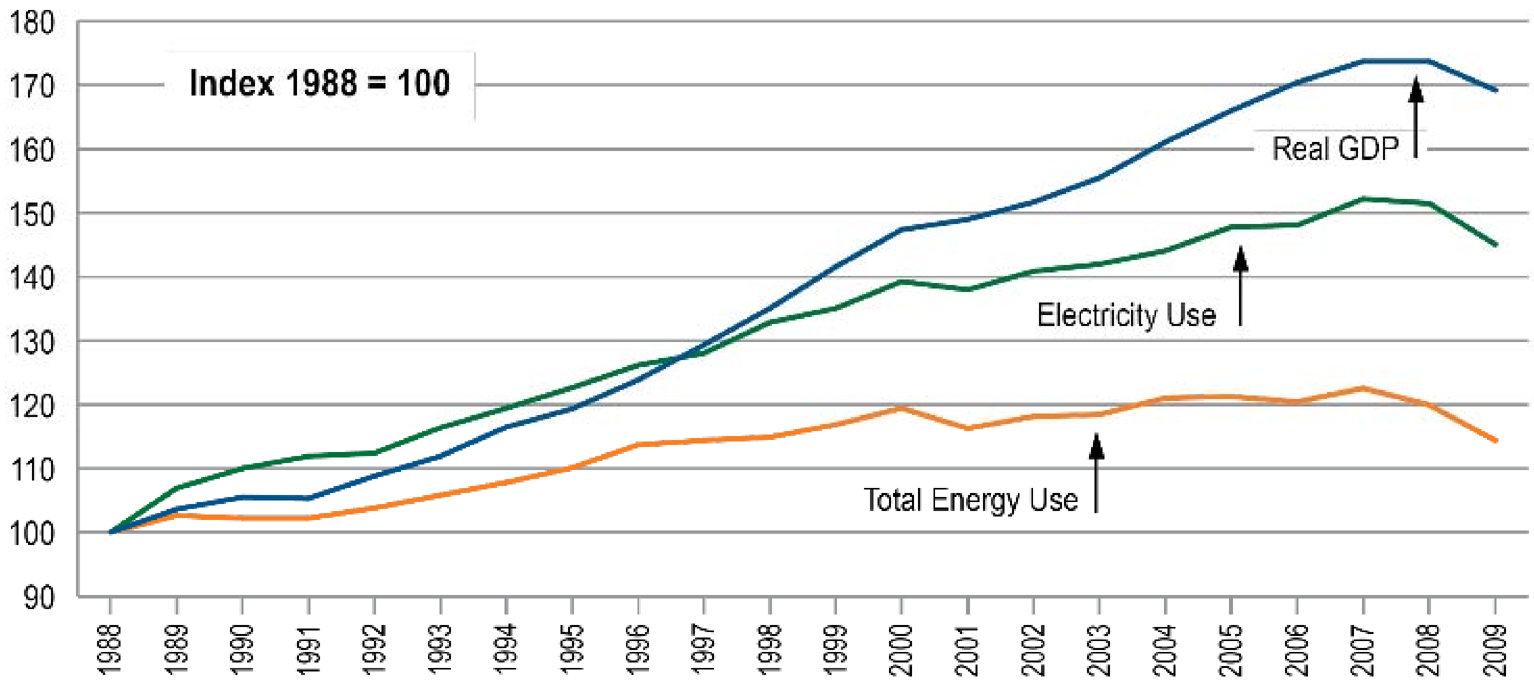
EXHIBIT ICNU/209

ELECTRICITY SALES ARE LINKED TO U.S. ECONOMIC GROWTH

June 11, 2014

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.

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EXHIBIT ICNU/210

MULTI-STAGE GROWTH DCF MODEL

June 11, 2014

Portland General Electric Company

Multi-Stage Growth DCF Model

Line	Company	13-Week AVG Stock Price[1] (1)	Annualized Dividend[2] (2)	First Stage Growth[3] (3)	Second Stage Growth Year 6 (4)	Year 7 (5)	Year 8 (6)	Year 9 (7)	Year 10 (8)	Third Stage Growth[4] (9)	Multi-Stage Growth DCF (10)
1	ALLETE, Inc.	$51.04	$1.96	N/A	N/A	N/A	N/A	N/A	N/A	4.70%	N/A
2	Alliant Energy Corporation	$56.00	$2.04	5.26%	5.16%	5.07%	4.98%	4.89%	4.79%	4.70%	8.65%
3	Avista Corporation	$30.62	$1.27	N/A	N/A	N/A	N/A	N/A	N/A	4.70%	N/A
4	Black Hills Corporation	$57.35	$1.56	7.00%	6.62%	6.23%	5.85%	5.47%	5.08%	4.70%	7.99%
5	Cleco Corporation	$50.30	$1.45	7.33%	6.89%	6.46%	6.02%	5.58%	5.14%	4.70%	8.26%
6	CMS Energy Corporation	$29.09	$1.08	6.17%	5.92%	5.68%	5.43%	5.19%	4.94%	4.70%	8.96%
7	Great Plains Energy Inc.	$26.43	$0.92	5.15%	5.08%	5.00%	4.93%	4.85%	4.78%	4.70%	8.45%
8	Hawaiian Electric Industries, Inc.	$24.72	$1.24	4.60%	4.62%	4.63%	4.65%	4.67%	4.68%	4.70%	9.92%
9	IDACORP, Inc.	$55.22	$1.72	4.00%	4.12%	4.23%	4.35%	4.47%	4.58%	4.70%	7.81%
10	MGE Energy, Inc.	$38.63	$1.09	N/A	N/A	N/A	N/A	N/A	N/A	4.70%	N/A
11	NorthWestern Corporation	$46.79	$1.60	7.33%	6.89%	6.46%	6.02%	5.58%	5.14%	4.70%	8.92%
12	OGE Energy Corp.	$36.26	$0.90	5.70%	5.53%	5.37%	5.20%	5.03%	4.87%	4.70%	7.46%
13	Pinnacle West Capital Corporation	$55.05	$2.27	4.16%	4.25%	4.34%	4.43%	4.52%	4.61%	4.70%	8.87%
14	PNM Resources, Inc.	$26.91	$0.74	8.46%	7.84%	7.21%	6.58%	5.95%	5.33%	4.70%	8.35%
15	Portland General Electric Company	$32.32	$1.10	8.36%	7.75%	7.14%	6.53%	5.92%	5.31%	4.70%	9.17%
16	SCANA Corporation	$50.91	$2.03	4.63%	4.64%	4.66%	4.67%	4.68%	4.69%	4.70%	8.86%
17	TECO Energy, Inc.	$17.20	$0.88	4.95%	4.91%	4.86%	4.82%	4.78%	4.74%	4.70%	10.14%
18	UNS Energy Corporation	$60.19	$1.92	N/A	N/A	N/A	N/A	N/A	N/A	4.70%	N/A
19	Westar Energy, Inc.	$34.93	$1.40	3.30%	3.53%	3.77%	4.00%	4.23%	4.47%	4.70%	8.54%
20	Wisconsin Energy Corporation	$45.93	$1.56	5.02%	4.97%	4.91%	4.86%	4.81%	4.75%	4.70%	8.33%
21	**Average**	**$41.29**	**$1.44**	**5.71%**	**5.54%**	**5.38%**	**5.21%**	**5.04%**	**4.87%**	**4.70%**	**8.67%**
22	**Median**										**8.59%**

Sources:
[1] SNL Financial, Downloaded on May 20, 2014.
[2] *The Value Line Investment Survey, February 21, March 21, and May 2, 2014.*
[3] Exhibit ICNU/204.
[4] *Blue Chip Economic Indicators, March* 10, 2014 at 14.

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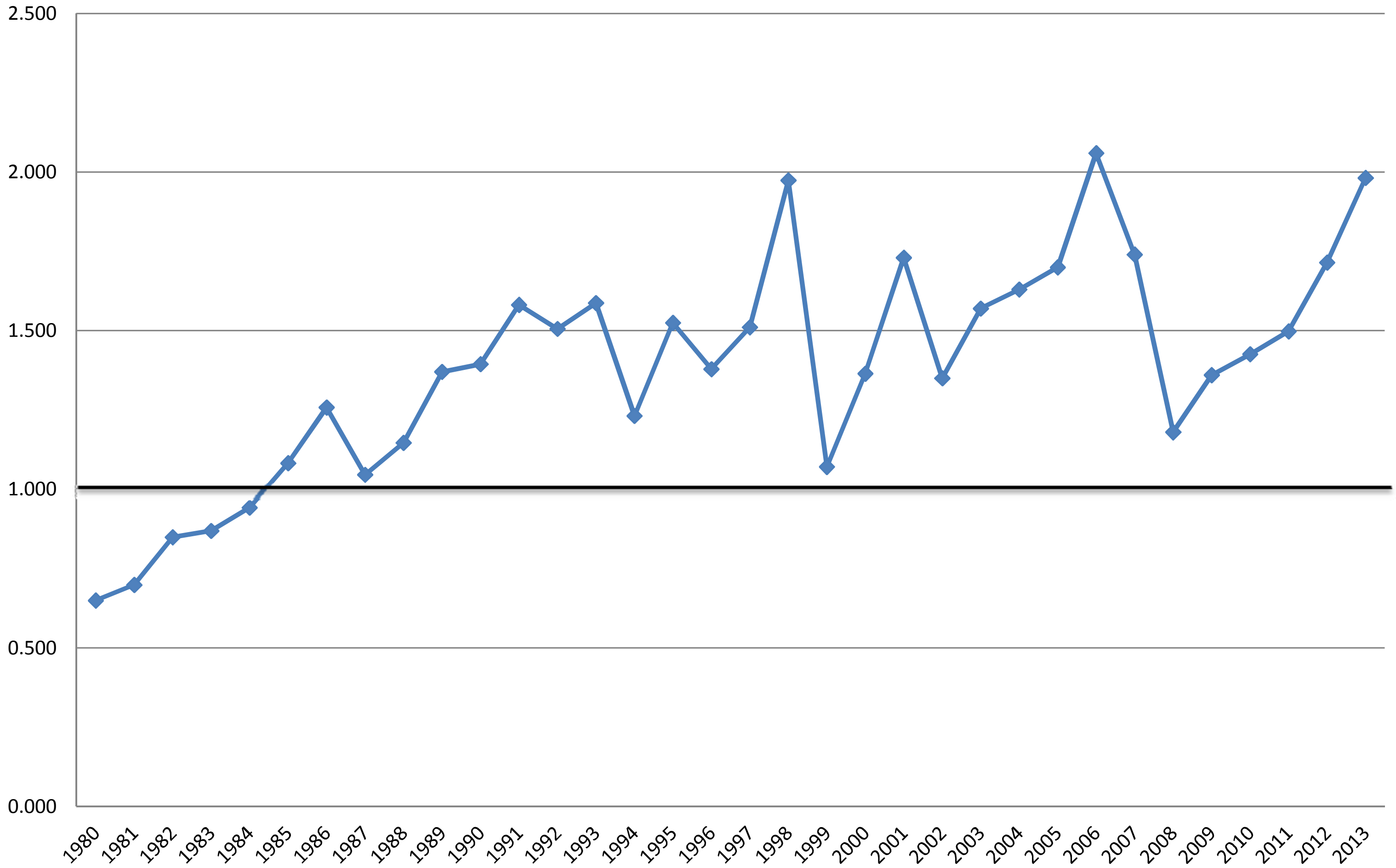
EXHIBIT ICNU/211

COMMON STOCK MARKET/BOOK RATIO

June 11, 2014

Portland General Electric Company

Common Stock Market/Book Ratio



Source:
AUS Utility Reports, various dates.

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EXHIBIT ICNU/212

EQUITY RISK PREMIUM – TREASURY BOND

June 11, 2014

Portland General Electric Company

Equity Risk Premium - Treasury Bond

Line	Year	Authorized Electric Returns[1] (1)	Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)
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%
6	1991	12.55%	8.14%	4.41%
7	1992	12.09%	7.67%	4.42%
8	1993	11.41%	6.60%	4.81%
9	1994	11.34%	7.37%	3.97%
10	1995	11.55%	6.88%	4.67%
11	1996	11.39%	6.70%	4.69%
12	1997	11.40%	6.61%	4.79%
13	1998	11.66%	5.58%	6.08%
14	1999	10.77%	5.87%	4.90%
15	2000	11.43%	5.94%	5.49%
16	2001	11.09%	5.49%	5.60%
17	2002	11.16%	5.43%	5.73%
18	2003	10.97%	4.96%	6.01%
19	2004	10.75%	5.05%	5.70%
20	2005	10.54%	4.65%	5.89%
21	2006	10.36%	4.99%	5.37%
22	2007	10.36%	4.83%	5.53%
23	2008	10.46%	4.28%	6.18%
24	2009	10.48%	4.07%	6.41%
25	2010	10.24%	4.25%	5.99%
26	2011	10.07%	3.91%	6.16%
27	2012	10.01%	2.92%	7.09%
28	2013	9.79%	3.45%	6.34%
29	2014 [3]	9.57%	3.68%	5.89%
30	**Average**	**11.27%**	**5.92%**	**5.35%**

Sources:

[1] Regulatory Research Associates, Inc., *Regulatory Focus,* Jan. 1985 - Dec. 1996, and April 9, 2014, excluding the VA cases, which are subject to an adjustment for certain generation assets up to 200 basis points.

[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 2014.

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EXHIBIT ICNU/213

EQUITY RISK PREMIUM – UTILITY BOND

June 11, 2014

Portland General Electric Company

Equity Risk Premium - Utility Bond

Line	Year	Authorized Electric Returns[1] (1)	Average "A" Rated Utility Bond Yield[2] (2)	Indicated Risk Premium (3)
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%
6	1991	12.55%	9.36%	3.19%
7	1992	12.09%	8.69%	3.40%
8	1993	11.41%	7.59%	3.82%
9	1994	11.34%	8.31%	3.03%
10	1995	11.55%	7.89%	3.66%
11	1996	11.39%	7.75%	3.64%
12	1997	11.40%	7.60%	3.80%
13	1998	11.66%	7.04%	4.62%
14	1999	10.77%	7.62%	3.15%
15	2000	11.43%	8.24%	3.19%
16	2001	11.09%	7.76%	3.33%
17	2002	11.16%	7.37%	3.79%
18	2003	10.97%	6.58%	4.39%
19	2004	10.75%	6.16%	4.59%
20	2005	10.54%	5.65%	4.89%
21	2006	10.36%	6.07%	4.29%
22	2007	10.36%	6.07%	4.29%
23	2008	10.46%	6.53%	3.93%
24	2009	10.48%	6.04%	4.44%
25	2010	10.24%	5.46%	4.78%
26	2011	10.07%	5.04%	5.03%
27	2012	10.01%	4.13%	5.88%
28	2013	9.79%	4.48%	5.31%
29	2014 [3]	9.57%	4.56%	5.01%
30	**Average**	**11.27%**	**7.30%**	**3.97%**

Sources:
[1] Regulatory Research Associates, Inc., *Regulatory Focus,* Jan. 85 - Dec. 06, and April 9, 2014, excluding the VA cases, which are subject to an adjustment for certain generation assets up to 200 basis points.
[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 2010-2013 were obtained from http://credittrends.moodys.com/.
[3] The data includes the period Jan - Mar 2014.

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EXHIBIT ICNU/214

BOND YIELD SPREADS

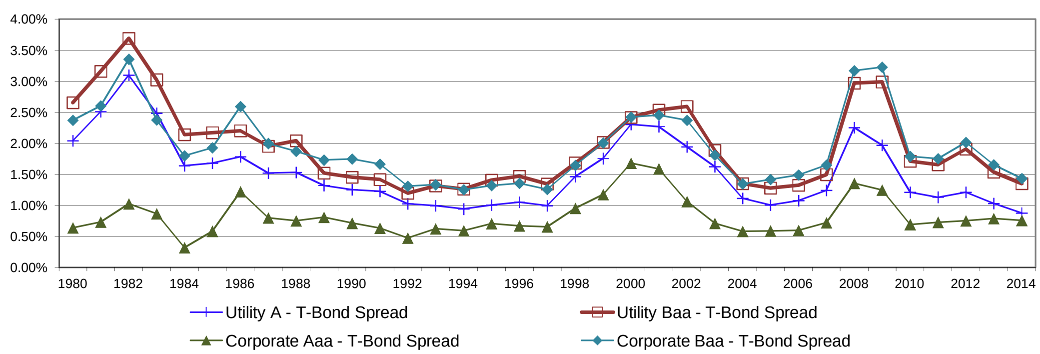
June 11, 2014

Portland General Electric Company

Bond Yield Spreads

			Public Utility Bond				Corporate Bond				Utility to Corporate	
Line	Year	T-Bond Yield[1]	A[2]	Baa[2]	A-T-Bond Spread	Baa-T-Bond Spread	Aaa[1]	Baa[1]	Aaa-T-Bond Spread	Baa-T-Bond Spread	Baa Spread	A-Aaa Spread
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(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]	3.68%	4.56%	5.03%	0.88%	1.35%	4.44%	5.12%	0.76%	1.43%	-0.08%	0.12%
35	**Average**	**6.96%**	**8.49%**	**8.90%**	**1.53%**	**1.94%**	**7.78%**	**8.89%**	**0.82%**	**1.93%**	**0.02%**	**0.71%**

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 2010-2013 were obtained from http://credittrends.moodys.com/.
[3] The data includes the period Jan - Mar 2014.

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EXHIBIT ICNU/215

TREASURY AND UTILITY BOND YIELDS

June 11, 2014

Portland General Electric Company

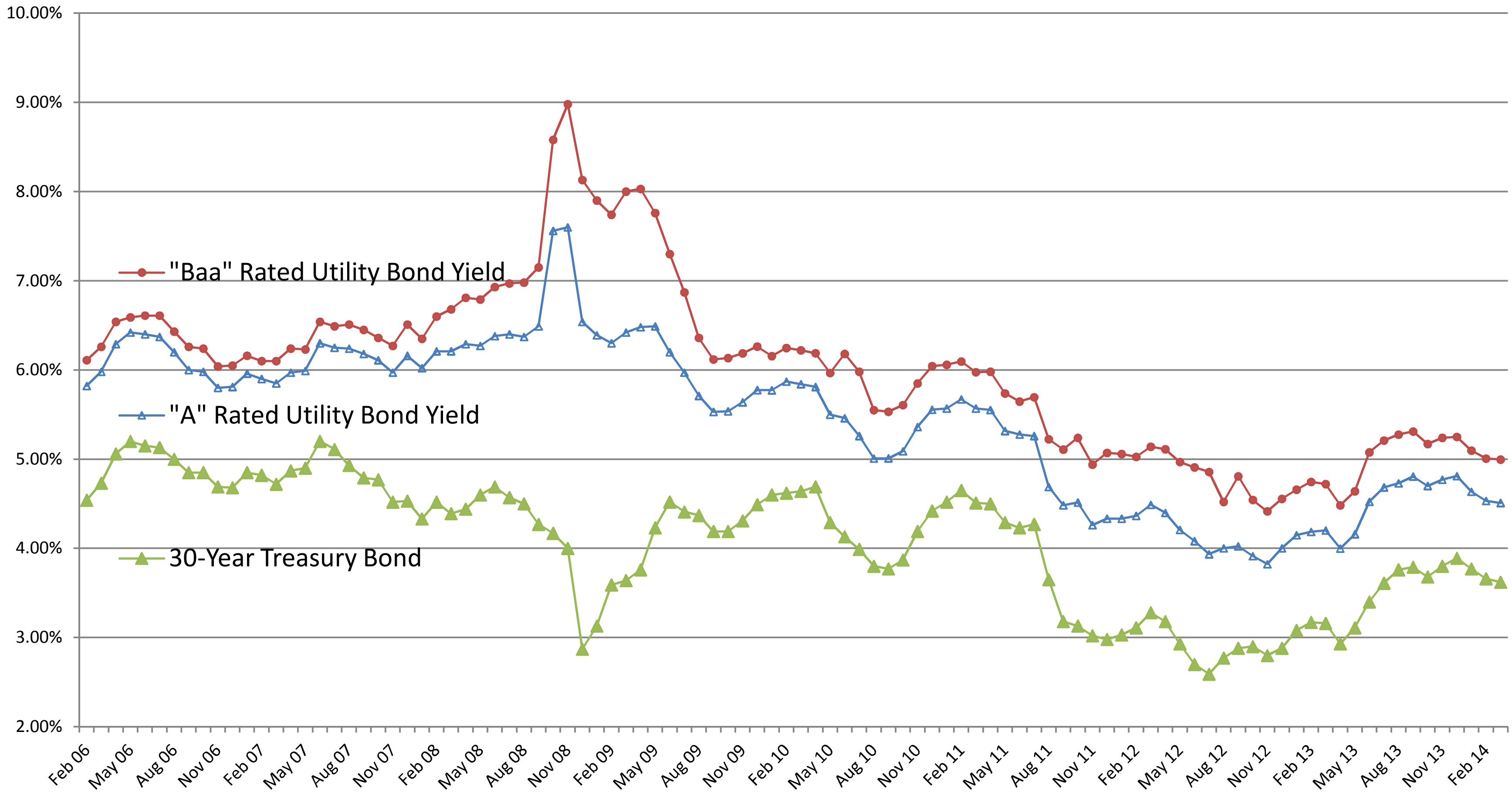
Treasury and Utility Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	05/16/14	3.34%	4.21%	4.64%
2	05/09/14	3.47%	4.33%	4.76%
3	05/02/14	3.37%	4.24%	4.67%
4	04/25/14	3.45%	4.32%	4.75%
5	04/17/14	3.52%	4.40%	4.83%
6	04/11/14	3.48%	4.37%	4.81%
7	04/04/14	3.59%	4.48%	4.94%
8	03/28/14	3.55%	4.45%	4.92%
9	03/21/14	3.61%	4.52%	5.01%
10	03/14/14	3.59%	4.48%	4.97%
11	03/07/14	3.72%	4.58%	5.07%
12	02/28/14	3.59%	4.46%	4.93%
13	02/21/14	3.69%	4.56%	5.03%
14	**Average**	**3.54%**	**4.42%**	**4.87%**
15	**Spread To Treasury**		**0.88%**	**1.33%**

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

Portland General Electric Company

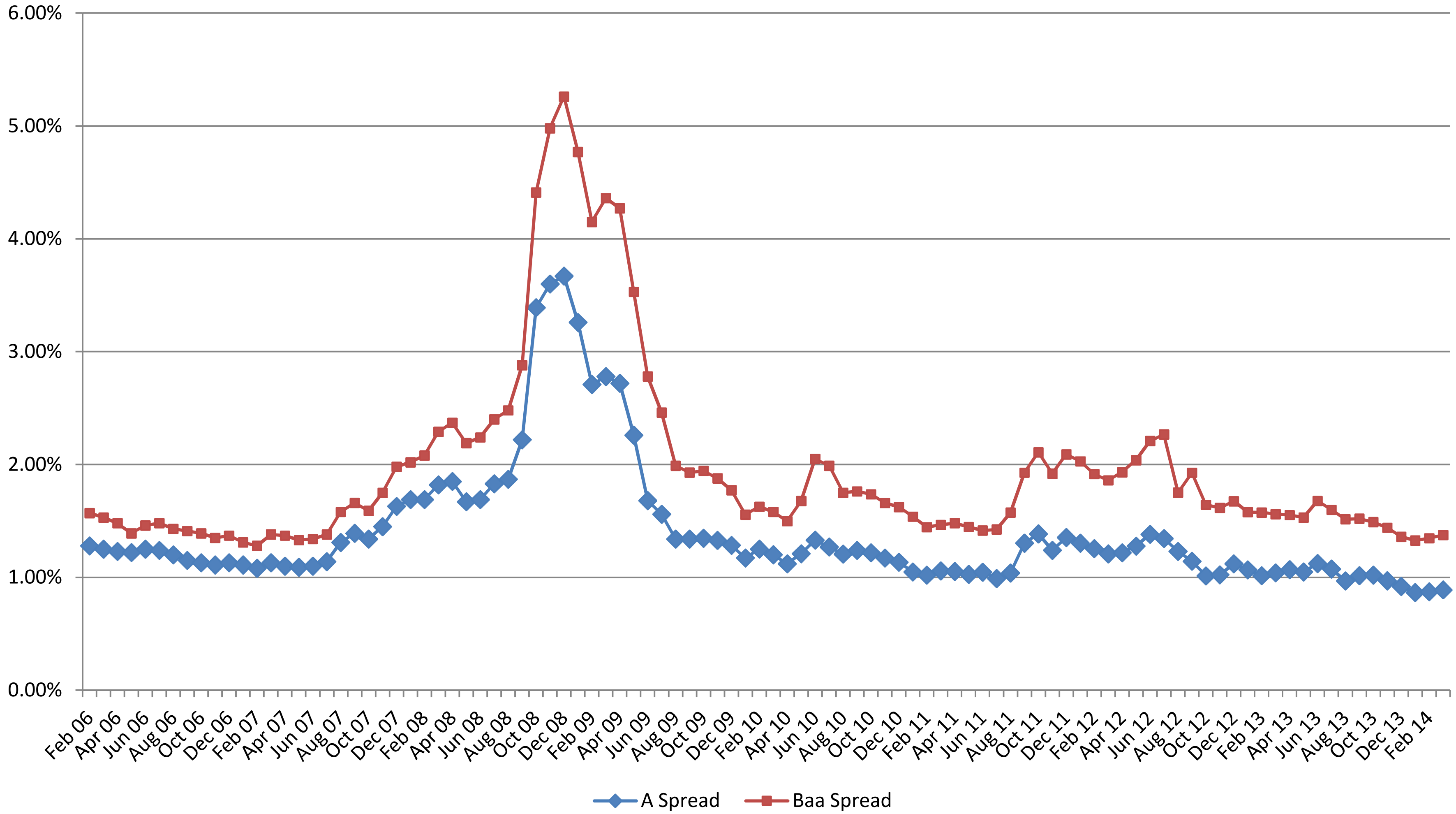
Trends in Bond Yields



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

Portland General Electric Company

Yield Spread Between Utility Bonds and 30-Year Treasury Bonds



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

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EXHIBIT ICNU/216

VALUE LINE BETA

June 11, 2014

Portland General Electric Company

Value Line Beta

Line	Company	Beta
1	ALLETE, Inc.	0.80
2	Alliant Energy Corporation	0.80
3	Avista Corporation	0.80
4	Black Hills Corporation	0.90
5	Cleco Corporation	0.70
6	CMS Energy Corporation	0.70
7	Great Plains Energy Inc.	0.90
8	Hawaiian Electric Industries, Inc.	0.85
9	IDACORP, Inc.	0.80
10	MGE Energy, Inc.	0.70
11	NorthWestern Corporation	0.70
12	OGE Energy Corp.	0.85
13	Pinnacle West Capital Corporation	0.75
14	PNM Resources, Inc.	0.95
15	Portland General Electric Company	0.80
16	SCANA Corporation	0.75
17	TECO Energy, Inc.	0.95
18	UNS Energy Corporation	0.70
19	Westar Energy, Inc.	0.80
20	Wisconsin Energy Corporation	0.70
21	**Average**	**0.80**

Source:
The Value Line Investment Survey,
February 21, March 21, and May 2, 2014.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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

EXHIBIT ICNU/217

CAPM RETURN

June 11, 2014

Portland General Electric Company

CAPM Return

Line	Description	High Market Risk Premium (1)	Low Market Risk Premium (2)
1	Risk-Free Rate[1]	4.40%	4.40%
2	Risk Premium[2]	6.96%	6.20%
3	Beta[3]	0.80	0.80
4	**CAPM**	**9.93%**	**9.33%**
5	**Average**	**9.63%**	

Sources:
[1] *Blue Chip Financial Forecasts*; May 1, 2014, at 2.
[2] Morningstar, Inc. *Ibbotson SBBI 2014 Classic Yearbook* at 91 and 152.
[3] Exhibit ICNU/216.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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EXHIBIT ICNU/218

STANDARD & POOR'S CREDIT METRICS

June 11, 2014

Portland General Electric

Standard & Poor's Credit Metrics

Dollars in Thousands

Line	Description	Retail Cost of Service Amount (1)	S&P Benchmark (Medial Volatility)[1/2] Intermediate (2)	Significant (3)	Aggressive (4)	Reference (4)
1	Rate Base	$ 3,859,789				Exhibit 301, Page 2.
2	Weighted Common Return	4.70%				Page 2, Line 2, Col. 3.
3	Pre-Tax Rate of Return	10.58%				Page 2, Line 3, Col. 4.
4	Income to Common	$ 181,410				Line 1 x Line 2.
5	EBIT	$ 408,257				Line 1 x Line 3.
6	Depreciation & Amortization	$ 317,267				Exhibit 301, Page 1.
7	Imputed Amortization	$ 14,551				S&P Ratings Direct, May 13, 2014.
8	Deferred Income Taxes & ITC	$ (59,285)				Exhibit 301, Page 2.
9	Funds from Operations (FFO)	$ 453,943				Sum of Line 4 and Lines 6 through 8.
10	Imputed Interest Expense	$ 25,568				S&P Ratings Direct, May 13, 2014.
11	EBITDA	$ 765,643				Sum of Lines 5 through 7 and Line 10.
12	Adjusted Total Debt Ratio	53.4%				Page 3, Line 3, 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	22%	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," May 8, 2014.

Note:
Based on the May 2014 S&P report, Portland General has an "Strong" business profile and a "Significant" financial profile,

Portland General Electric

Standard & Poor's Credit Metrics
(Pre-Tax Rate of Return)

Line	Description	Weight (1)	Cost (2)	Weighted Cost (3)	Pre-Tax Weighted Cost (4)
1	Long-Term Debt	50.00%	5.50%	2.75%	2.75%
2	Common Equity	50.00%	**9.40%**	4.70%	7.83%
3	**Total**	**100.00%**		**7.45%**	**10.58%**
4	Tax Conversion Factor*				1.6653

Sources:
Exhibit ICNU/202
*Exhibit 301, Page 3.

Portland General Electric

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

Line	Description	Amount (1)	Weight (2)
1	Long-Term Debt	$ 2,343,818	47.95%
2	Off Balance Sheet Debt*	$ 268,150	5.49%
3	Total Debt	$ 2,611,968	53.44%
4	Common Equity	$ 2,275,659	46.56%
5	**Total**	**$ 4,887,627**	**100.00%**

Sources:
Direct testimony of Hager, Valach, and Greene, page 4.
*S&P Ratings Direct, May 13, 2014.

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EXHIBIT ICNU/219

SUMMARY OF THE REVISIONS TO DR. ZEPP'S DCF MODEL

June 11, 2014

Portland General Electric Company

Summary of the Revisions to Dr. Zepp's DCF Model

Line	Description	Zepp Estimate[a/] (1)	Adjusted Median Estimates[b/] (2)
1	Constant Growth DCF Model	9.6%	9.3%
2	FERC Multi-period DCF Method	9.6%	9.2%
3	Multi-Stage DCF Growth Analysis	9.9%	8.4%
4	Average	9.7%	9.0%

Sources:
[a/] PGE/1200, Zepp/1.
[b/] Exhibit ICNU/219, pages 2-4.

Portland General Electric

Revised Zepp Constant Growth DCF Cost of Equity Estimates

		3-Month Average D_1/P_0 [a/]	Average of Forecasts of Growth [a/]	Equity Cost Estimates [a/]
1	ALLETE	4.32%	6.50%	10.8%
2	Alliant Energy	4.05%	5.58%	9.6%
3	Avista	4.92%	4.50%	9.4%
4	Black Hills Corporation	3.37%	7.75%	11.1%
5	CLECO Corporation	3.48%	5.87%	9.4%
6	CMS Energy	4.15%	5.79%	9.9%
7	Great Plains Energy	4.38%	5.84%	10.2%
8	Hawaiian Electric	5.19%	3.18%	8.4%
9	IDACORP	3.75%	3.00%	6.8%
10	MGE Energy, Inc.	3.30%	4.75%	8.1%
11	Northwestern Corp	3.85%	5.42%	9.3%
12	OGE Energy	2.48%	5.17%	7.6%
13	Pinnacle West	4.47%	4.80%	9.3%
14	PNM Resources, Inc.	3.30%	9.44%	12.7%
15	Portland General Electric	4.16%	4.78%	8.9%
16	SCANA	4.72%	4.54%	9.3%
17	TECO	5.57%	3.34%	8.9%
18	UNS Energy	4.12%	7.00%	11.1%
19	Westar	4.72%	4.11%	8.8%
20	Wisconsin Energy	4.06%	5.39%	9.5%
21	Average			9.5%
22	Median			9.3%

Sources:
a/ PGE Exhibit 1208.

Portland General Electric

Revised Zepp FERC Two-Step Multiperiod DCF Method

			Low Estimate		High Estimate	
		D_1/P_0	Low Growth	Low Equity Cost Estimate	High Growth	High Equity Cost Estimate
1	ALLETE	4.32%	5.57%	9.89%	6.24%	10.56%
2	Alliant Energy	4.05%	4.77%	8.82%	5.57%	9.62%
3	Avista	4.92%	4.23%	9.16%	4.90%	9.83%
4	Black Hills Corporation	3.37%	4.23%	7.60%	9.26%	12.63%
5	CLECO Corporation	3.48%	3.38%	6.86%	6.91%	10.39%
6	CMS Energy	4.15%	5.24%	9.39%	5.64%	9.79%
7	Great Plains Energy	4.38%	2.65%	7.03%	6.24%	10.62%
8	Hawaiian Electric	5.19%	3.09%	8.28%	4.06%	9.26%
9	IDACORP	3.75%	2.89%	6.64%	4.23%	7.98%
10	MGE Energy, Inc.	3.30%	4.23%	7.53%	5.24%	8.54%
11	Northwestern Corp	3.85%	4.57%	8.42%	6.24%	10.09%
12	OGE Energy	2.48%	4.90%	7.38%	5.57%	8.05%
13	Pinnacle West	4.47%	4.57%	9.04%	4.90%	9.38%
14	PNM Resources, Inc.	3.30%	5.86%	9.16%	9.59%	12.89%
15	Portland General Electric	4.16%	3.90%	8.06%	5.87%	10.04%
16	SCANA	4.72%	4.50%	9.22%	4.72%	9.44%
17	TECO	5.57%	3.37%	8.95%	4.90%	10.48%
18	UNS Energy	4.12%	5.91%	10.03%	6.91%	11.03%
19	Westar	4.72%	2.22%	6.94%	5.57%	10.29%
20	Wisconsin Energy	4.06%	5.04%	9.11%	5.24%	9.30%
21	Average			8.4%		10.0%
22	Median			8.6%		9.9%

Sources and Notes:
a/ Exhibit PGE 1209.
Uses a long-term GDP growth rate of 4.7%

Portland General Electric

Revised Zepp Three Stage DCF Analysis

		Internal Rate of Return		First Year Dividend D_1[a]	Stage 1[a]		Stage 2 and 3[b]				
		Return	P_{2013}	D_{2014}	D_{2015}	D_{2019}	D_{2020}	D_{2021}	D_{2028}	$(P+D)_{2029}$	P_{2029}[b]
1	ALLETE	8.9%	-$48.75	$2.10	$2.23	$2.87	$3.06	$3.24	$4.69	$94.23	$89.31
2	Alliant Energy	8.1%	-$50.93	$2.06	$2.17	$2.70	$2.85	$3.00	$4.24	$93.50	$89.06
3	Avista	8.8%	-$26.91	$1.32	$1.38	$1.65	$1.72	$1.80	$2.47	$49.97	$47.38
4	Black Hills Corporation	7.9%	-$50.73	$1.70	$1.83	$2.47	$2.65	$2.84	$4.25	$95.53	$91.08
5	CLECO Corporation	7.4%	-$45.74	$1.59	$1.68	$2.11	$2.24	$2.36	$3.36	$81.22	$77.70
6	CMS Energy	8.3%	-$27.02	$1.12	$1.18	$1.48	$1.57	$1.65	$2.35	$50.32	$47.86
7	Great Plains Energy	8.7%	-$23.17	$1.01	$1.07	$1.34	$1.42	$1.50	$2.13	$43.84	$41.61
8	Hawaiian Electric	8.6%	-$25.64	$1.33	$1.37	$1.55	$1.60	$1.66	$2.20	$45.88	$43.59
9	IDACORP	6.7%	-$49.23	$1.84	$1.89	$2.13	$2.20	$2.27	$2.99	$80.06	$76.93
10	MGE Energy, Inc.	6.7%	-$53.95	$1.77	$1.86	$2.24	$2.34	$2.45	$3.39	$90.20	$86.65
11	Northwestern Corp	7.7%	-$43.43	$1.66	$1.75	$2.16	$2.28	$2.40	$3.37	$78.01	$74.48
12	OGE Energy	5.4%	-$37.00	$0.91	$0.96	$1.17	$1.23	$1.30	$1.81	$56.75	$54.86
13	Pinnacle West	8.4%	-$55.37	$2.47	$2.59	$3.12	$3.27	$3.43	$4.74	$101.40	$96.44
14	PNM Resources, Inc.	8.5%	-$22.82	$0.75	$0.82	$1.18	$1.28	$1.39	$2.17	$45.48	$43.21
15	Portland General Electric	8.0%	-$28.75	$1.19	$1.25	$1.51	$1.58	$1.66	$2.29	$51.61	$49.22
16	SCANA	8.6%	-$46.67	$2.20	$2.30	$2.74	$2.87	$3.00	$4.12	$85.87	$81.55
17	TECO	9.1%	-$16.95	$0.94	$0.97	$1.11	$1.15	$1.19	$1.58	$31.04	$29.39
18	UNS Energy	8.8%	-$47.08	$1.93	$2.07	$2.71	$2.89	$3.08	$4.52	$91.48	$86.75
19	Westar	8.4%	-$31.18	$1.47	$1.53	$1.80	$1.87	$1.95	$2.65	$56.45	$53.68
20	Wisconsin Energy	8.1%	-$41.26	$1.67	$1.76	$2.18	$2.29	$2.41	$3.39	$75.28	$71.73
21	Average	8.0%									
22	Median	8.4%									

Notes and Sources:
a/ PGE Exhibit 1210.
b/ Growth based on gradual transition from initial forecasts of EPS growth to expected long-term average GDP growth of 4.7%.

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EXHIBIT ICNU/220

REVISION OF DR. ZEPP'S TABLE 13
RISK PREMIUM ANALYSIS

June 11, 2014

Portland General Electric

Revision of Dr. Zepp's Table 13
Risk Premium Analysis Based on Holding Period Returns for
Moody's Electric Utilities Sample as Updated, 1950 to 2012

	Long-term Treasury Bond Rate [a/]	30-Yr Maturity Bond Value	Capital Gain/Loss	Interest	Bond Total Return	Year-end Price Index	Annual Average Dividend	Index Gain/Loss	Dividend Yield	Total Return	Risk Premium
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1950	2.24%	$ 1,000.00				$ 30.81					
1951	2.69%	$ 907.76	$ (92.24)	$ 22.40	-6.98%	$ 33.85	$ 1.88	9.87%	6.10%	15.97%	22.95%
1952	2.79%	$ 979.77	$ (20.23)	$ 26.90	0.67%	$ 37.85	$ 1.91	11.82%	5.64%	17.46%	16.79%
1953	2.74%	$ 1,010.18	$ 10.18	$ 27.90	3.81%	$ 39.61	$ 2.01	4.65%	5.31%	9.96%	6.15%
1954	2.72%	$ 1,004.08	$ 4.08	$ 27.40	3.15%	$ 47.56	$ 2.13	20.07%	5.38%	25.45%	22.30%
1955	2.95%	$ 954.42	$ (45.58)	$ 27.20	-1.84%	$ 49.35	$ 2.21	3.76%	4.65%	8.41%	10.25%
1956	3.45%	$ 907.01	$ (92.99)	$ 29.50	-6.35%	$ 48.96	$ 2.32	-0.79%	4.70%	3.91%	10.26%
1957	3.23%	$ 1,042.06	$ 42.06	$ 34.50	7.66%	$ 50.30	$ 2.43	2.74%	4.96%	7.70%	0.04%
1958	3.82%	$ 895.18	$ (104.82)	$ 32.30	-7.25%	$ 66.37	$ 2.50	31.95%	4.97%	36.92%	44.17%
1959	4.47%	$ 893.19	$ (106.81)	$ 38.20	-6.86%	$ 65.77	$ 2.61	-0.90%	3.93%	3.03%	9.89%
1960	3.80%	$ 1,119.32	$ 119.32	$ 44.70	16.40%	$ 76.82	$ 2.68	16.80%	4.07%	20.88%	4.47%
1961	4.15%	$ 940.26	$ (59.74)	$ 38.00	-2.17%	$ 99.32	$ 2.81	29.29%	3.66%	32.95%	35.12%
1962	3.95%	$ 1,034.97	$ 34.97	$ 41.50	7.65%	$ 96.49	$ 2.97	-2.85%	2.99%	0.14%	-7.51%
1963	4.17%	$ 962.54	$ (37.46)	$ 39.50	0.20%	$ 102.31	$ 3.21	6.03%	3.33%	9.36%	9.15%
1964	4.23%	$ 989.86	$ (10.14)	$ 41.70	3.16%	$ 115.54	$ 3.43	12.93%	3.35%	16.28%	13.13%
1965	4.50%	$ 955.79	$ (44.21)	$ 42.30	-0.19%	$ 114.86	$ 3.86	-0.59%	3.34%	2.75%	2.94%
1966	4.55%	$ 991.86	$ (8.14)	$ 45.00	3.69%	$ 105.99	$ 4.11	-7.72%	3.58%	-4.14%	-7.83%
1967	5.56%	$ 853.40	$ (146.60)	$ 45.50	-10.11%	$ 98.19	$ 4.34	-7.36%	4.09%	-3.26%	6.85%
1968	5.98%	$ 941.76	$ (58.24)	$ 55.60	-0.26%	$ 104.04	$ 4.50	5.96%	4.58%	10.54%	10.81%
1969	6.87%	$ 887.53	$ (112.47)	$ 59.80	-5.27%	$ 84.62	$ 4.61	-18.67%	4.43%	-14.23%	-8.97%
1970	6.48%	$ 1,051.30	$ 51.30	$ 68.70	12.00%	$ 88.59	$ 4.70	4.69%	5.55%	10.25%	-1.75%
1971	5.97%	$ 1,070.80	$ 70.80	$ 64.80	13.56%	$ 85.56	$ 4.77	-3.42%	5.38%	1.96%	-11.60%
1972	5.99%	$ 997.23	$ (2.77)	$ 59.70	5.69%	$ 83.61	$ 4.87	-2.28%	5.69%	3.41%	-2.28%
1973	7.26%	$ 845.66	$ (154.34)	$ 59.90	-9.44%	$ 60.87	$ 5.01	-27.20%	5.99%	-21.21%	-11.76%
1974	7.60%	$ 960.04	$ (39.96)	$ 72.60	3.26%	$ 41.17	$ 4.83	-32.36%	7.93%	-24.43%	-27.69%
1975	8.05%	$ 949.34	$ (50.66)	$ 76.00	2.53%	$ 55.66	$ 4.97	35.20%	12.07%	47.27%	44.73%
1976	7.21%	$ 1,102.59	$ 102.59	$ 80.50	18.31%	$ 66.29	$ 5.18	19.10%	9.31%	28.40%	10.10%
1977	8.03%	$ 907.51	$ (92.49)	$ 72.10	-2.04%	$ 68.19	$ 5.54	2.87%	8.36%	11.22%	13.26%
1978	8.98%	$ 901.79	$ (98.21)	$ 80.30	-1.79%	$ 59.75	$ 5.81	-12.38%	8.52%	-3.86%	-2.07%
1979	10.12%	$ 893.18	$ (106.82)	$ 89.80	-1.70%	$ 56.41	$ 6.22	-5.59%	10.41%	4.82%	6.52%
1980	11.99%	$ 848.78	$ (151.22)	$ 101.20	-5.00%	$ 54.42	$ 6.58	-3.53%	11.66%	8.14%	13.14%
1981	13.34%	$ 900.90	$ (99.10)	$ 119.90	2.08%	$ 57.20	$ 6.99	5.11%	12.84%	17.95%	15.87%
1982	10.95%	$ 1,209.35	$ 209.35	$ 133.40	34.28%	$ 70.26	$ 7.43	22.83%	12.99%	35.82%	1.55%
1983	11.97%	$ 917.39	$ (82.61)	$ 109.50	2.69%	$ 72.03	$ 7.87	2.52%	11.20%	13.72%	11.03%
1984	11.70%	$ 1,022.32	$ 22.32	$ 119.70	14.20%	$ 80.16	$ 8.26	11.29%	11.47%	22.75%	8.55%
1985	9.56%	$ 1,210.26	$ 210.26	$ 117.00	32.73%	$ 94.98	$ 8.61	18.49%	10.74%	29.23%	-3.50%
1986	7.89%	$ 1,190.89	$ 190.89	$ 95.60	28.65%	$ 113.66	$ 8.89	19.67%	9.36%	29.03%	0.38%
1987	9.20%	$ 867.19	$ (132.81)	$ 78.90	-5.39%	$ 94.24	$ 9.12	-17.09%	8.02%	-9.06%	-3.67%
1988	9.18%	$ 1,002.03	$ 2.03	$ 92.00	9.40%	$ 100.94	$ 8.87	7.11%	9.41%	16.52%	7.12%
1989	8.16%	$ 1,113.65	$ 113.65	$ 91.80	20.55%	$ 122.52	$ 8.82	21.38%	8.74%	30.12%	9.57%
1990	8.44%	$ 969.60	$ (30.40)	$ 81.60	5.12%	$ 117.77	$ 8.79	-3.88%	7.17%	3.30%	-1.82%
1991	7.30%	$ 1,137.99	$ 137.99	$ 84.40	22.24%	$ 144.02	$ 8.95	22.29%	7.60%	29.89%	7.65%
1992	7.26%	$ 1,004.86	$ 4.86	$ 73.00	7.79%	$ 141.06	$ 9.05	-2.06%	6.28%	4.23%	-3.56%
1993	6.54%	$ 1,094.12	$ 94.12	$ 72.60	16.67%	$ 146.70	$ 8.99	4.00%	6.37%	10.37%	-6.30%
1994	7.99%	$ 835.82	$ (164.18)	$ 65.40	-9.88%	$ 115.50	$ 8.96	-21.27%	6.11%	-15.16%	-5.28%
1995	6.03%	$ 1,270.35	$ 270.35	$ 79.90	35.03%	$ 142.90	$ 9.02	23.72%	7.81%	31.53%	-3.49%
1996	6.73%	$ 910.27	$ (89.73)	$ 60.30	-2.94%	$ 136.00	$ 9.06	-4.83%	6.34%	1.51%	4.45%
1997	6.02%	$ 1,098.04	$ 98.04	$ 67.30	16.53%	$ 155.73	$ 9.06	14.51%	6.66%	21.17%	4.64%
1998	5.42%	$ 1,088.45	$ 88.45	$ 60.20	14.86%	$ 181.84	$ 7.83	16.77%	5.03%	21.79%	6.93%
1999	6.82%	$ 822.17	$ (177.83)	$ 54.20	-12.36%	$ 137.30	$ 8.10	-24.49%	4.45%	-20.04%	-7.68%
2000	5.58%	$ 1,179.59	$ 179.59	$ 68.20	24.78%	$ 227.09	$ 8.27	65.40%	6.02%	71.42%	46.64%
2001	5.75%	$ 975.83	$ (24.17)	$ 55.80	3.16%	$ 227.95	$ 8.65	0.38%	3.81%	4.19%	1.03%
2002	4.84%	$ 1,143.23	$ 143.23	$ 57.50	20.07%	$ 219.63	$ 8.84	-3.65%	3.88%	0.22%	-19.85%
2003	5.11%	$ 958.79	$ (41.21)	$ 48.40	0.72%	$ 247.54	$ 8.99	12.71%	4.09%	16.80%	16.08%
2004	4.84%	$ 1,042.50	$ 42.50	$ 51.10	9.36%	$ 289.86	$ 9.23	17.09%	3.73%	20.82%	11.46%
2005	4.61%	$ 1,037.18	$ 37.18	$ 48.40	8.56%	$ 302.10	$ 9.47	4.22%	3.27%	7.49%	-1.07%
2006	4.91%	$ 953.16	$ (46.84)	$ 46.10	-0.07%	$ 343.43	$ 9.73	13.68%	3.22%	16.91%	16.98%
2007	4.50%	$ 1,067.14	$ 67.14	$ 49.10	11.62%	$ 319.74	$ 10.00	-6.90%	2.91%	-3.99%	-15.61%
2008	3.03%	$ 1,288.33	$ 288.33	$ 45.00	33.33%	$ 258.56	$ 10.40	-19.13%	3.25%	-15.88%	-49.22%
2009	4.58%	$ 748.56	$ (251.44)	$ 30.30	-22.11%	$ 297.39	$ 11.21	15.02%	4.34%	19.35%	41.47%
2010	4.14%	$ 1,075.19	$ 75.19	$ 45.80	12.10%	$ 350.40	$ 11.90	17.82%	4.00%	21.83%	9.73%
2011	2.48%	$ 1,349.81	$ 349.81	$ 41.40	39.12%	$ 379.14	$ 12.32	8.20%	3.51%	11.72%	-27.40%
2012	2.41%	$ 1,014.89	$ 14.89	$ 24.80	3.97%	$ 416.77	$ 12.32	9.92%	3.25%	13.17%	9.20%
Period Average					6.63%					11.69%	5.06%

Notes and Sources:

a/ Monthly rates for December of the indicated year. Morningstar, 2013 SBBI Valuation Yearbook, pages 198-199.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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

EXHIBIT ICNU/221

ACCURACY OF INTEREST RATE FORECASTS

June 11, 2014

Portland General Electric Company

Accuracy of Interest Rate Forecasts
(Long-Term Treasury Bond Yields - Projected Vs. Actual)

		Forecast Increase to Current				Forecast Exceeds Actual		
Line	Date	Prior Quarter Actual (1)	Projected (2)	Difference[1] (3)	Projected Quarter (4)	Projected (5)	Actual (6)	Difference[2] (7)
1	Dec-00	5.8%	5.8%	0.0%	1Q, 02	5.8%	5.6%	0.2%
2	Mar-01	5.7%	5.6%	-0.1%	2Q, 02	5.6%	5.8%	-0.2%
3	Jun-01	5.4%	5.8%	0.4%	3Q, 02	5.8%	5.2%	0.6%
4	Sep-01	5.7%	5.9%	0.2%	4Q, 02	5.9%	5.1%	0.8%
5	Dec-01	5.5%	5.7%	0.2%	1Q, 03	5.7%	5.0%	0.7%
6	Mar-02	5.3%	5.9%	0.6%	2Q, 03	5.9%	4.7%	1.2%
7	Jun-02	5.6%	6.2%	0.6%	3Q, 03	6.2%	5.2%	1.0%
8	Sep-02	5.8%	5.9%	0.1%	4Q, 03	5.9%	5.2%	0.7%
9	Dec-02	5.2%	5.7%	0.5%	1Q, 04	5.7%	4.9%	0.8%
10	Mar-03	5.1%	5.7%	0.6%	2Q, 04	5.7%	5.4%	0.3%
11	Jun-03	5.0%	5.4%	0.4%	3Q, 04	5.4%	5.1%	0.3%
12	Sep-03	4.7%	5.8%	1.1%	4Q, 04	5.8%	4.9%	0.9%
13	Dec-03	5.2%	5.9%	0.7%	1Q, 05	5.9%	4.8%	1.1%
14	Mar-04	5.2%	5.9%	0.7%	2Q, 05	5.9%	4.6%	1.4%
15	Jun-04	4.9%	6.2%	1.3%	3Q, 05	6.2%	4.5%	1.7%
16	Sep-04	5.4%	6.0%	0.6%	4Q, 05	6.0%	4.8%	1.2%
17	Dec-04	5.1%	5.8%	0.7%	1Q, 06	5.8%	4.6%	1.2%
18	Mar-05	4.9%	5.6%	0.7%	2Q, 06	5.6%	5.1%	0.5%
19	Jun-05	4.8%	5.5%	0.7%	3Q, 06	5.5%	5.0%	0.5%
20	Sep-05	4.6%	5.2%	0.7%	4Q, 06	5.2%	4.7%	0.5%
21	Dec-05	4.5%	5.3%	0.8%	1Q, 07	5.3%	4.8%	0.5%
22	Mar-06	4.8%	5.1%	0.3%	2Q, 07	5.1%	5.0%	0.1%
23	Jun-06	4.6%	5.3%	0.7%	3Q, 07	5.3%	4.9%	0.4%
24	Sep-06	5.1%	5.2%	0.1%	4Q, 07	5.2%	4.6%	0.6%
25	Dec-06	5.0%	5.0%	0.0%	1Q, 08	5.0%	4.4%	0.6%
26	Mar-07	4.7%	5.1%	0.4%	2Q, 08	5.1%	4.6%	0.5%
27	Jun-07	4.8%	5.1%	0.3%	3Q, 08	5.1%	4.5%	0.7%
28	Sep-07	5.0%	5.2%	0.2%	4Q, 08	5.2%	3.7%	1.5%
29	Dec-07	4.9%	4.8%	-0.1%	1Q, 09	4.8%	3.5%	1.4%
30	Mar-08	4.6%	4.8%	0.2%	2Q, 09	4.8%	4.0%	0.8%
31	Jun-08	4.4%	4.9%	0.5%	3Q, 09	4.9%	4.3%	0.6%
32	Sep-08	4.6%	5.1%	0.5%	4Q, 09	5.1%	4.3%	0.8%
33	Dec-08	4.5%	4.6%	0.2%	1Q, 10	4.6%	4.6%	0.0%
34	Mar-09	3.7%	4.1%	0.4%	2Q, 10	4.1%	4.4%	-0.3%
35	Jun-09	3.5%	4.6%	1.2%	3Q, 10	4.6%	3.9%	0.8%
36	Sep-09	4.0%	5.0%	1.0%	4Q, 10	5.0%	4.2%	0.8%
37	Dec-09	4.3%	5.0%	0.7%	1Q, 11	5.0%	4.6%	0.4%
38	Mar-10	4.3%	5.2%	0.9%	2Q, 11	5.2%	4.3%	0.9%
39	Jun-10	4.6%	5.2%	0.6%	3Q, 11	5.2%	3.7%	1.5%
40	Sep-10	4.4%	4.7%	0.3%	4Q, 11	4.7%	3.0%	1.7%
41	Dec-10	3.9%	4.6%	0.8%	1Q, 12	4.6%	3.1%	1.5%
42	Mar-11	4.2%	5.1%	0.9%	2Q, 12	5.1%	2.9%	2.2%
43	Jun-11	4.6%	5.2%	0.6%	3Q, 12	5.2%	2.8%	2.5%
44	Sep-11	4.3%	4.2%	-0.1%	4Q, 12	4.2%	2.9%	1.3%
45	Dec-11	3.7%	3.8%	0.1%	1Q, 13	3.8%	3.1%	0.7%
46	Mar-12	3.0%	3.8%	0.8%	2Q, 13	3.8%	3.2%	0.7%
47	Jun-12	3.1%	3.7%	0.6%	3Q, 13	3.7%	3.7%	0.0%
48	Sep-12	2.9%	3.4%	0.5%	4Q, 13	3.4%	3.8%	-0.4%
49	Oct-12	2.8%	3.4%	0.7%	1Q, 14			
50	Nov-12	2.8%	3.4%	0.7%	1Q, 14			
51	Dec-12	2.8%	3.4%	0.7%	1Q, 14			
52	Jan-13	2.9%	3.4%	0.5%	2Q, 14			
53	Feb-13	2.9%	3.5%	0.6%	2Q, 14			
54	Mar-13	2.9%	3.6%	0.7%	2Q, 14			
55	Apr-13	3.1%	3.7%	0.6%	3Q, 14			
56	May-13	3.1%	3.7%	0.6%	3Q, 14			
57	Jun-13	3.1%	3.7%	0.6%	3Q, 14			
58	Jul-13	3.1%	4.0%	0.9%	4Q, 14			
59	Aug-13	3.2%	4.1%	1.0%	4Q, 14			
60	Sep-13	3.2%	4.2%	1.1%	4Q, 14			
61	Oct-13	3.7%	4.2%	0.5%	1Q, 15			
62	Nov-13	3.7%	4.2%	0.5%	1Q, 15			
63	Dec-13	3.7%	4.2%	0.5%	1Q, 15			
64	Jan-14	3.8%	4.4%	0.6%	2Q 15			
65	Feb-14	3.8%	4.4%	0.6%	2Q 15			
66	Mar-14	3.8%	4.4%	0.6%	2Q 15			
67	Apr-14	3.7%	4.5%	0.8%	3Q 15			
68	May-14	3.7%	4.4%	0.7%	3Q 15			

Source and Notes:
Blue Chip Financial Forecasts , Various Dates.
[1] Col. 2 - Col. 1.
[2] Col. 5 - Col. 6.