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May 3, 2012

VIA ELECTRONIC FILING
& FIRST CLASS MAIL

Oregon Public Utility Commission
Attn: Filing Center
550 Capitol Street N.E., #215
P.O. Box 2148
Salem, Oregon 97308-2148

Re: **Docket No. UG-221** - In the Matter of Northwest Natural Gas Company – Application for a General Rate Revision

Dear Filing Center:

Enclosed please find an original and five (5) copies of the redacted public version of the **Direct Intervenor Testimony of Hugh Larkin, Jr.**, on behalf of the Northwest Industrial Gas Users and Citizens Utility Board. Also enclosed is an original and five (5) copies of the confidential portions of this testimony as required by Order 12-058.

Please note that the redacted version was submitted via electronic mail to the PUC Filing Center on this date, with confidential copies served on the parties who have signed the Protective Order in this docket.

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

Very truly yours,

Tommy A. Brooks

TAB:sk
Enclosures
cc: UG 221 Service List

CERTIFICATE OF SERVICE

I CERTIFY that I have on this day served the foregoing document upon all parties of record in this proceeding via electronic mail and/or by mailing a copy properly addressed with first class postage prepaid.

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Dated in Portland, Oregon, this 3RD day of May 2012.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DIRECT INTERVENOR TESTIMONY OF HUGH LARKIN, JR.

ON BEHALF OF THE NORTHWEST INDUSTRIAL GAS USERS

AND

THE CITIZENS' UTILITY BOARD

REDACTED PUBLIC VERSION

May 3, 2012

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Hugh Larkin, Jr. I am a Certified Public Accountant licensed in the States of Michigan and Florida and the senior partner of the firm of Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe the firm Larkin & Associates, PLLC.

A. Larkin & Associates, PLLC, is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorney general, etc.). Larkin & Associates, PLLC, has extensive experience in the utility regulatory field as expert witnesses in more than 800 regulatory proceedings including numerous gas, electric, water and sewer, and telephone utilities.

Q. Have you prepared an exhibit which describes your qualifications and experience?

A. Yes. I have attached Exhibit NWIGU-CUB 101 which is a summary of my regulatory qualifications and experience.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you appearing?

A. Larkin & Associates, PLLC, was retained by the Northwest Industrial Gas Users ("NWIGU") and the Citizens' Utility Board ("CUB") to review the rate case filing submitted by Northwest Natural Gas Company ("NW Natural" or "Company").

Q. What is the purpose of your testimony?

A: I will be addressing various rate base and operating income and expense issues as well as the company's requested recovery of environmental remediation costs.

III. SUMMARY OF ADJUSTMENTS

Q. Have you prepared a summary of your proposed adjustments?

A. Yes. Below is a schedule detailing my adjustments to various rate base and operating revenues and expenses.

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10/31/13 Test Year
($000 thousands)
*****Confidential Amounts in Bold*****

	NW Natural	NWIGU/ CUB	Adjustment
Rate Base			
Plant In Service			$ (53,642)
Accumulated Depreciation			$ 754
Pension	$ 21,930	$ -	$ (21,930)
Materials & Supplies	$ 7,422	[redacted]	[redacted]
Contributions in Aid of Construction	$ (1,994)	$ (2,063)	$ (69)
Customer Deposits	$ -	$ (5,101)	$ (5,101)
Injuries & Damages Reserve	$ -	[redacted]	[redacted]
Subtotal Rate Base Adjustments			[redacted]
Revenues			
Miscellaneous Revenues	$ 4,325	$4,533	$ 207
Amortization of State Tax Change	$ (896)	$ -	$ 896
Subtotal Revenue Adjustments			$ 1,103
O&M Expenses			
Depreciation Expense			$ (1,508)
Injuries & Damages Expense	[redacted]	[redacted]	[redacted]
Rate Case Expense	$ 235	$ 141	$ (94)
AGA Dues	$ 370	$ 222	$ (148)
Uncollectibles	$ 2,110	$ 1,662	$ (448)
Customer Deposit Interest			$ 5
Directors & Officers Insurance	$ 544	$ 272	$ (272)
Advertising- Category A	$ 1,412	$ 833	$ (579)
Advertising- Category B	$ 583	$ 335	$ (247)
Base Payroll	$ 52,190	$ 49,465	$ (2,725)
O&M Payroll			$ (4,357)
Payroll Tax			$ (643)
Pension Amortization	$ 4,569	$ -	$ (4,569)
Medical Benefits	$ 32,616	$ 31,479	$ (1,137)
Subtotal O&M Adjustments			[redacted]

IV. RATE BASE

A. PLANT IN SERVICE/ACCUMULATED DEPRECIATION

Q. What amount has the Company included in the test year rate base for plant in service?

A. The Company's requested test year plant in service is $2.227 billion on an Oregon jurisdictional basis, compared to the base year plant in service balance of $2.038 billion, an increase of $188.8 million.

Q. Please describe the Company's methodology for calculating plant in service in the test year.

A. The Company used the December 2010 book balance as its starting point. It forecasted 2011, 2012, and 2013 capital expenditures. For 2011 and 2012, annual increases were added to the book balance, and for 2013, ten months of the annual increase were added. To derive the test year plant in service amount, the company prorated the 2012 and 2013 increases to correspond with the test period.

Q. Has the Company identified any major capital expenditures it plans to implement during the test year?

A. The Company identified test year capital expenditures in a workpaper titled "Large Projects Timeline-DRAFT." Major capital expenditures proposed by the company relate to the following three projects: 1) Corvallis Loop Project, 2) Willamette Valley Feeder Project, and 3) the purchase of a new facility in Sherwood, Oregon.

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Q. What criteria did you rely on in determining whether the Company's proposed capital expenditures should be included in rate base?

A. To be included in rate base in the test year, basic criteria must be met. First, the investment must be in service in the test year. If the investment will be in service during the test year, the investment cost must be known and measureable and the benefit of the investment must be reflected in the test year as well (i.e., reduced O&M costs, increased efficiency).

Q. Does the Commission also rely on similar standards regarding the inclusion of utility property in rate base?

A. ORS 757.355 provides guidance as to what is includable in rate base and states:

> 757.355 Costs of property not presently providing utility service excluded from rate base; exception. (1) Except as provided in subsection (2) of this section, a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer.
> (2) The Public Utility Commission may allow rates for a water utility that include the costs of a specific capital improvement if the water utility is required to use the additional revenues solely for the purpose of completing the capital improvement.

Furthermore, the Commission's Order No. 08-487 states that, "Rate base has a narrow meaning. It generally includes amounts that a utility prudently invests in capital assets that service its customers."

Q. Do you have any concerns with the Company’s proposed increases to plant in service during the test year?

A. Yes. The Company's workpaper titled "Large Projects Timeline-Draft," summarizes various projects it is proposing to implement during the test year. The majority of these projects do not meet the criteria I described above to be included in the test year. Below I will briefly discuss each project and whether it meets the criteria I have identified above to be included in rate base, based on the information provided by the Company.

<u>2012 Projects</u>

1. Westside Transmission Re-Rate (TIMP)

The Large Projects Timeline identified the in-service date of this project as October 31, 2012 and a forecasted cost of $2,000,000. The Company's response to OPUC-DR 158 indicates the in-service date for this project was changed from October 31, 2012 to "under review." The Company again changed its estimated in-service date for this project to "Re-scheduled to 2013" in response to NWIGU-CUB DR 95.

OPUC-DR 165 requested copies of requests for proposals, bids, bid evaluations, winning bids, construction budgets, construction schedules, and any changes to the budgets or schedules. The Company's response stated that there are no bids for this project and all work will be done by NW Natural crews and referred to OPUC-DR 165 Attachment 4. Attachment 4 is an untitled two-line table showing estimated costs by month, totaling $2 million, for the period January 2012 through December 2013. The table states that the bulk of the rerate work will be completed in 2013.

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The Company's estimate of $2,000,000 should be removed from the test year, as it is not clear whether the project will be in service during the test year and the costs were not demonstrated to be known and measureable.

2. Corvallis Reinforcement

The Large Projects Timeline identified the in-service date for this project as October 31, 2012 and the estimated cost to be $9,300,000. The response to OPUC-DR 165, Attachment 8 indicates the total estimated project cost is $13,451,105 with COH (Construction Overhead). The response to NWIGU-CUB DR 95 has updated the in-service date to July 1, 2013 and states the project is 0% complete.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

The Company's response to OPUC-DR 216 stated it did not conduct a financial analysis of the investment for this project. The decision to invest in this project was based on system reliability and reinforcement. The Company later updated this response and provided a copy of a schedule illustrating the [BEGIN CONFIDENTIAL] [redacted]

[redacted]

[redacted] [END CONFIDENTIAL]

The Company's response to OPUC-DR-267 states:

> The estimated capital cost of the Corvallis Loop Project is $12.8 million. Approximately $3.5 million of expense occurred in 2011. The remaining $9.3 is forecast to be spent in 2012 as stated in the Capital Projects Timeline.

An Excel schedule titled "200363 Corvallis Reinforcement" listed amounts charged to various accounts totaling $4,073,726.

[BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL]

/ / /

The Company has not fully justified the $9,300,000 identified in the filing as known and measureable. The Company's estimate for this project should be removed from the test year, less the $96,000 for the purchase order for land owner services with WHPacific.

3. Perrydale to Monmouth

The Large Projects Timeline identified the in-service date for this project as October 31, 2012 and the estimated cost to be $13,500,000. The response to OPUC-DR 165 Attachment 9 provided a memo dated August 24, 2011 regarding the "Proposal for Project Initiation 200581" and states the possible start date for this project is September 1, 2012 and the estimated construction duration is 10 months. The Company provided the following updated response to OPUC-DR 165 with regard to the August 24, 2011 memo:

> The memorandum stated that the possible start date of the project was September 1, 2012 and that the project would take 10 months to complete. The start date listed in the project initiation memorandum, which was drafted by an engineering summer intern, was in error. When the project memo was created, the final proposed schedule for the project was yet not known and was developed later by the Capital Projects Project Manager utilizing inputs from all other projects planned for the year and resource availability.
>
> The correct start date for construction of the project is May, 2012 and the expected completion date is October, 2012.

The updated response also attached an RFP for the project dated March 5, 2012 with bids due April 20, 2012.

An Excel schedule titled "200581 Perrydale to Monmouth" listed amounts charged to various accounts totaling $478,065.

The response to NWIGU-CUB DR 95 dated April 24, 2012 states the project is 0% complete.

The Company's response to OPUC-DR-216 stated it did not conduct a financial analysis of the investment for this project. The decision to invest was based on the system reliability, replacement of legacy bare steel and system reinforcement. The memo dated August 24, 2011 identifies the "rough estimated cost" for this project as $13,300,000. The response to OPUC-DR-165 states that all work will be performed by NW Natural crews.

The Company has not fully justified the $13,500,000 estimated project cost as known and measureable. The Company's estimate for this project should be removed from the test year.

4. Monmouth Reinforcement

The Large Projects Timeline identified the in-service date for this project as May 15, 2011 and the estimated cost to be $5,600,000. A memo dated August 12, 2011, provided in response to OPUC-DR 165 Attachment 12, states the possible start date for this project is November 1, 2011 for Phase 1 and March 1, 2012 for Phase 2. The Company's response to OPUC-DR 216 states the anticipated in-service date is August 31, 2012.

The Company's response to OPUC-DR 216 stated it did not conduct a financial analysis of the investment for this project. The decision to invest was based on the system reliability, replacement of legacy bare steel and system reinforcement. The memo dated August 12, 2011 identifies the "rough estimated cost" as $7,500,000. The Company's response to OPUC-DR 175 identifies the project cost as $8,100,000. The Company's response to OPUC-DR 165 states that only a portion of the project was sent to bid and other portions of the project will be performed by NW company crews. That response provided a copy of the RFP issued by the Company on December 16, 2011 for Phase 1 of the Monmouth project. The Company received [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] An email provided in response to NWIGU-CUB DR 95, Attachment G-2, dated January 31, 2012, notified Brotherton Corporation as the contractor selected. Attachment 14 to OPUC-DR 165 provided a copy of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

An Excel schedule titled "200580 Monmouth" listed amounts charged to various accounts totaling $3,322,509. The response to NWIGU-CUB DR 95 states the project is 15% complete.

The Company has not fully justified the $5,600,000 identified in the filing as known and measureable. The Company's estimate should be removed from the test year, less the amount of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

5. Portland System Optimization (Phase 1)

The Large Projects Timeline identified the in-service date for this project as October 31, 2012 and the estimated cost to be $1,250,000.

The Company's response to OPUC-DR 165 states that the work will be performed by NW crews and refers to OPUC-DR 165 Attachment 20 which is an untitled table showing amounts by month totaling $3.5 million for the period January 2012 through December 2013. Four pages with the description "Portland System Opt" listed amounts charged to various accounts totaling $98,905.

The Company has not fully justified the $1,250,000 estimated project cost as known and measureable. The Company's estimate for this project should be removed from the test year.

6. Nertec Replacement

According to the Project Charter, the Nertec system is a data collection system used to bill the largest industrial and commercial customers. The objective of this project is to replace 650 Nertec devices with vendor supported product that interface with the current MV90-xi system. The Company's Capital Project Timeline estimates the Nertec replacement project to cost $1,875,000 and to be in service on October 31, 2012.

The Company's response to OPUC-DR-158 provided a copy of the Project Charter created on October 3, 2011. It was signed by various management personnel in October

2011, but the line titled "Approved by Executive Committee" was not signed. The Project Charter identifies the project cost as $2,600,000 and the estimated end date as the 4th quarter of 2012. The Project Charter identifies the following potential high risk/impact areas:

- Implementing new technology
- NW Natural resource availability
- Completing project by required 10/31/2012 date

[BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL]

The Company has not fully justified the $1,875,000 estimated project cost as known and measureable. The Company's estimate for this project should be removed from the test year.

7. Unified Communications Phase 1 (PBX Switch)

The Company's Large Project Timeline estimates the Unified Communications Project to cost $1,875,000 and to be in service on October 31, 2012.

The Company's response to OPUC-DR 158 provided a copy of the Project Charter created in November 2011. It was signed by various management personnel in November 2011. The Project Charter identifies the project cost as $3,500,000.

The Company issued a Request for Proposal for the Unified Communications Project on September 1, 2011, which was provided in an attachment in response to OPUC-DR 168. The RFP identifies this project as a "major initiative to implement a Unified Communications IP based telephony environment planned for deployment over the next 18 months." The Company received four bids in response to the RFP. Copies of the bids were not provided with this data request. However, a Vendor Decision Report dated January 24, 2012, identified the costs of the four bids and stated the Unified Communications Project Team recommends [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL]

The Company has not fully justified the $1,875,000 estimated project cost as known and measureable. The Company's estimate for this project should be removed from the test year.

8. Tualatin bio-swale

The Large Projects Timeline identified the in-service date for this project as October 31, 2012 and the estimated cost to be $600,000. Workpapers identify this project as a "tentative project." The response to OPUC-DR 165 states the project is "on hold." The Company did not provide any documentation supporting this project.

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The Company's estimate of $600,000 should be removed from the test year, as it is not clear whether the project will be in service during the test year and the Company has not supported the $600,000 as being known and measureable.

9. Tualatin replacement, training facility and land

The Large Projects Timeline identified the in-service date for this project as October 31, 2012 and the estimated cost to be $17,750, 000. The Company's response to NWIGU-CUB DR 95 indicates that Phase 1 of this project will be in service on October 15, 202 [sic] and Phase II will be in service in the 4th quarter of 2013. The Project Charter[1] provided in response to OPUC-DR 158 also identifies the in-service date as the fourth quarter of 2013.

In its filing, the Company stated it was in the process of purchasing property in Sherwood, Oregon, to construct a multi-purpose facility. The Company stated it identified two functional business needs: 1) an integrated training facility and 2) a business continuity center. The Company considered options to retrofit two of its existing facilities, South Center and Tualatin. However, due diligence analysis conducted for the South Center facility revealed that the property was in a 10-year flood zone as opposed to a 100–year zone, as previously thought. The South Center property was eliminated as an option. The Company stated its consultant estimated $10.5 million would be required to renovate the Tualatin facility. The Project Charter stated:

> A study of the site determined that the remodeling cost was high enough to support a decision to move the Tualatin Regional Operations to a new property. The former

[1] The Project Charter appears to be documents created by the Company that contain information about the project.

> BMC lumber manufacturing site was identified, and based on initial studies appears to meet NW Natural's business requirements.

The Project Charter states that this is a preliminary charter for planning purposes only. It was signed by management and the executive committee in December of 2011. The document identifies the following estimated costs for the project: pre-approval planning, $602,000; capital, $21,090,967; and O&M, $850,000. The document describes the objectives as:

> The goal of this project is to evaluate and optionally purchase the BMC property, complete the design and schedule the construction. The actual construction may be prioritized by function and phased in over time. The final schedule will be developed during the planning phase.

A purchase agreement was executed for the Sherwood property on December 16, 2011, a copy of which was provided as an attachment to OPUC-DR 266.

The Company received bids for the architectural design and the due diligence for this property. The Company's response to NWIGU-CUB DR 48 states that the due diligence regarding the Sherwood property was completed on March 16, 2012. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

The Project Charter also identifies the following potential high risk/impact areas of the project:

- Permitting uncertainties
- Scope creep during design phase by stakeholders

- Moving the regional operations employees and equipment from Tualatin to the new site has the potential to disrupt work flow. It is recommended that a separate project be formed following construction to move the employees and equipment.

The Company's response to NWIGU-CUB DR 95, Attachment H-2, titled "Total Project Cost Analysis," identifies actual costs associated with this project as of April 17, 2012 as $9,059,883.

The Company's response to OPUC-DR-266 states:

> The Company assumes that it will be allowed to include in rate base the full change for the purchase of the facility and the cost of improvements. This amount is estimated to be about $19.5 million. We expect that a portion of this will be returned to ratepayers once the two facilities are sold, assuming they are sold for a gain over the current book value.

It does not appear that this project will be in-service during the test year, therefore the Company's estimate $17.750 should be removed from the test year.

10. Sunset Sheds

The Large Projects Timeline identified the in-service date for this project as October 31, 2012 and the estimated cost to be $670,000. The Company's response to NWIGU-CUB DR 95 states that this project was cancelled. The Company's response to OPUC-DR 158 stated these are routine replacements/additions and did not attach any documentation supporting the cost. Since these projects will not be in service during the test year, coupled with the lack of supporting documentation, the Company's estimate of $670,000 for this project should be removed from the test year.

11. Generators

The Large Projects Timeline identified the in-service date for this project as October 31, 2012 and the estimated cost to be $600,000. The company's response to NWIGU-CUB DR-95 states that this project is 30% complete. The company's response to OPUC-DR 165 stated these are routine replacements/additions and did not provide attach documentation supporting the cost. Due to the lack of information supporting this project, the Company's estimate of $600,000 for this project should be removed from the test year.

12. Parkrose Retrofit

The Large Projects Timeline identified the in-service date for this project as October 31, 2012 and the estimated cost to be $1,400,000. The Company's response to NWIGU-CUB DR 95 states the project is 0% complete.

The Company's response to OPUC-DR 158 provided a copy of the Project Charter created on September 19, 2011, which was signed by various management personnel in September 2011. The Project Charter identifies the project cost as $2,209,840 ($2,154,273 for capital and $55,567 for O&M) for remodeling this facility, and $100,000 for pre-approval planning work. The project charter identifies the following potential high risk/impact areas:

- If the facility is determined to be located in a FEMA floodplain, the total amount of building improvements may trigger additional permitting and construction requirements that are not included in the present scope or budget.

- The construction of the bio-swale may be difficult due to limited yard space available. The direction of the bio-swale outlet could have a large impact on the total cost.
- There may not be adequate yard space to support simultaneous construction and operations. It may be necessary to relocate employees during construction.

[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] The Company's estimate for this project should be reduced by [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] and removed from the test year.

13. Salem Retrofit

The Large Projects Timeline identified the in-service date for this project as October 31, 2012 and the estimated cost to be $1,400,000. The Company's response to NWIGU-CUB DR 95 states the in-service date is December 2012 and the project is 0% complete. The Company's response to OPUC-DR 158 provided a copy of the Project Charter created on September 19, 2011, which was signed by various management personnel in September 2011. The Project Charter identifies the project costs as $210,000 for pre-approval planning work, $5,588,246 for capital and $220,638 for O&M. The project description is to remodel this facility. The project charter identifies the following potential high risk/impact areas:

- Building may require significant seismic upgrades (not included in estimate)
- Building may require significant ADA upgrades (not included in estimate)
- With the large number of employees at the site, it may not be feasible to utilize modular trailers

[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

The Company's response to OPUC-DR-165 stated the bid process has not yet started and did not provide any other supporting documents.

The Company has not fully justified the $1,400,000 estimated project cost as known and measureable. The Company's estimate should be reduced by [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] and removed from the test year.

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<u>2013 Projects</u>

14. Portland System Optimization (Phase 2)

The Large Projects Timeline identified the in-service date for this project as April 30, 2013 and the estimated cost to be $1,250,000. The Company's response to OPUC-DR 158 Attachment 2 states the start and finish dates of Phase 2 are March 5, 2012 and October 31, 2013, respectively. The Company's response to NWIGU-CUB DR 95 states the project is 0% complete and the in-service date is "2013." The Company has not demonstrated that this project will be in service during the test period, and the entire $1.250 million should be removed from the test year.

15. Unified Communications Phase 2 (PBX Switch)

The Large Projects Timeline identified the in-service date for this project as October 31, 2013 and the estimated cost to be $1,000,000. Based on the arguments for Phase 1 of this project, I recommend the removing the forecasted amount of $1 million for Phase 2 from the test year as well.

16. Coos Bay Retrofit

The Large Projects Timeline identified the projected in-service date for this project as June 30, 2013 and an estimated cost of $1,250,000. The in-service date was later updated to September 30, 2013 in response to OPUC-DR 158 and again to December 2013 in response to NWIGU-CUB DR 95. OPUC-DR 165 requested copies of requests for proposals, bids, bid evaluations, winning bids, construction budgets, construction schedules, and any changes to the budgets or schedules. The Company's response stated this project is still in the planning phase and stated "none" in reference to the requested documents. As the in-service date is now projected to be outside the test year, and documentation supporting this project is lacking, the estimated $1.250 million for this project should be removed from the test year.

17. Astoria Retrofit

The Large Projects Timeline identified the projected in-service date for this project as March 31, 2012. It was later updated to June 30, 2013 in response to OPUC-DR-158, and again to December 2013 in response to NWIGU-CUB DR 95. OPUC-DR 165 requested copies of requests for proposals, bids, bid evaluations, winning bids, construction budgets, construction schedules, and any changes to the budgets or schedules. The Company's response stated this project is still in the planning phase and stated "none" in reference to the requested documents. As, the in-service date is now projected to be outside the test year and the documentation supporting this project is lacking, the estimated $800,000 for this project should be removed from the test year.

18. Generators (5)

The Large Projects Timeline identified the projected in-service date for this project as June 30, 2013. It was later updated to May 31, 2013 in response to OPUC-DR 158, and again to December 2013 in response to NWIGU-CUB DR 95. OPUC-DR 165 requested copies of requests for proposals, bids, bid evaluations, winning bids, construction budgets, construction schedules, and any changes to the budgets or schedules. The Company's response stated this project is still in the planning phase and the stated "none" in reference to the requested documents. As the in-service date is now projected to be outside the test year and there is a lack of documents supporting this project, the estimated $600,000 for this project should be removed from the test year.

Q. Are you recommending an adjustment to plant in service?

A. I am proposing to remove the above capital projects that the Company has stated it will implement during the test period that have not been adequately justified. Since the Company has not provided adequate documentation supporting the project costs as known and measureable, and analysis that that the benefits outweigh the costs for these projects, ratepayers should not be expected to fund this "wish list" provided by the Company. My total recommended adjustments reduce plant in service by approximately $60.110 million on a system basis and $53.642 million on an Oregon basis.

Q. Have you made an adjustment to the accumulated depreciation reserve to correspond with your plant adjustment?

A. Yes. I recommend increasing the accumulated depreciation reserve by approximately $754,000 to correspond with my plant adjustment. I derived this amount by taking half of my depreciation expense adjustment, which is discussed in section G of my testimony. Though not precise, it is a reasonable estimate of my plant adjustment's impact on the reserve balance.

B. <u>MATERIALS AND SUPPLIES</u>

Q. What amount of materials and supplies has the company included in the test year rate base?

A. The Company has included $8.251 million on a system basis and $7.422 million on an Oregon basis for materials and supplies in the test year rate base, an increase of $484,000 over the base year level. This amount was calculated by using a three-year average for the period June 2008 through May 2011 of actual Materials and Supplies inventory, excluding demonstration appliances.

Q. What amount are you recommending to include in the test year rate base for materials and supplies?

A. Though the materials and supplies balance fluctuates, since 2008, levels have declined and remained fairly consistent in 2010 and 2011. I have calculated an average of monthly materials and supplies balance of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] on a System basis and [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] on an Oregon jurisdictional basis based on the 13 months ended December 31, 2011. This reduces the Company's test year amount of materials and supplies by [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

C. <u>CONTRIBUTIONS IN AID OF CONSTRUCTION ("CIAC")</u>

Q. What amount of CIAC has the company deducted from the test year rate base?

A. The Company has decreased rate base by $2.151 million on a system basis and $1.994 million on an Oregon basis, for contributions in aid of construction. The Company projected no change from the base year to the test year level of CIAC. The Company calculated the test year CIAC by using the 12 months ended September 30, 2011 average of actual monthly balances.

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Q. What amount are you recommending to deduct from the test year rate base for CIAC?

A. The Company provided actual balances through February 2012 for this account, which show that the balance has increased slightly since September 30, 2011. I have calculated the average contributions in aid of construction balances to reflect the 13 months ended December 31, 2011. This increases the Company's test year amount of CIAC by $68,821, which reduces rate base.

D. <u>CUSTOMER DEPOSITS</u>

Q: What are customer deposits?

A: Customer deposits are monies paid by customers prior to receiving utility service as security for future payment of monthly bills. These deposits are returned to customers after a certain time period, or whenever the customer terminates service with the Company.

Q: Did the Company deduct the average balance of customer deposits held in the test year from rate base?

A: No.

Q. Why is an adjustment necessary?

A. The Company has an obligation to return these deposits to customers with interest; however, during the time that the deposits are held by the Company, these ratepayer-supplied funds are available for use by the Company.

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Q. Have you reduced the Company's rate base for the average balance of customer deposits held by the Company in the test year?

A. Yes. I have reduced the Company's rate base by the 13-month average balance of customer deposits held by the Company for the year ended December 31, 2011 by $5,100,518 on an Oregon jurisdictional basis.

Q. Are the customer deposits cost-free capital to the Company?

A. No. The Company is required to pay customers interest for the period of time that the deposits are held by the Company.

Q. Have you reflected an adjustment to include this interest expense in the Company's operating expense in the test year?

A. Yes. The Company stated in its response to NWIGU-CUB DR 90 that the Oregon rate for interest on customer deposits is .1%. Multiplying the test year average balance by this rate will yield the test year interest expense for customer deposits. I am also increasing O&M expense in the test year by $5,101 for interest expense on the customer deposits to be paid by the Company during the test year.

E. INJURIES AND DAMAGES RESERVE

Q. What is the injuries and damages reserve?

A. The utility has collected amounts in rates to build up a reserve for future injuries and damages costs. In the event of an injury, an amount is charged to expense on the income statement and a corresponding amount is credited to an injuries and damages reserve account.

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Q. Has the Company deducted the injuries and damages reserve balance from rate base?

A. No.

Q. Why should the injuries and damages reserve balance be deducted from rate base?

A. The expense is reflected in the utility's cost of service collected from ratepayers and the reserve is reflected as a liability on the Company's balance sheet to be applied to future injuries and damages claims. To properly match the rate base with the expense, the injuries and damages reserve liability should be deducted from rate base.

Q: What amount should be deducted from rate base related to the injuries and damages reserve?

A: I recommend reducing rate base by the average balance of injuries and damages reserve held by the Company for the 13 months ended December 31, 2011, which is [BEGIN CONFIDENTIAL][redacted] [END CONFIDENTIAL]

V. OPERATING INCOME

F. <u>MISCELLANEOUS REVENUES</u>

1. Amortization of State Tax Change-Deferred Taxes

Q. Please describe the Company's proposed adjustment "Amortization of State Tax Change- Def Taxes."

A. In 2009, the State of Oregon increased its state tax rate from 6.6% to 7.9%. As a result of the tax change, the Company recorded a regulatory asset of $5,834,389. In 2010, the state tax rate decreased from 7.9% to 7.6%. The incremental change as a result of this was $1,354,558. The net of these two items is $4,479,831, which the Company is proposing to amortize over five years and has reflected as a decrease of $895,966 to miscellaneous revenues in the test year.

Q. Why has the Company reflected this amount as a reduction to miscellaneous income?

A. Data request OPUC-DR 305 asked the Company why it reflected this adjustment as an offset to miscellaneous revenues. The Company's response stated:

> Typically, an amortization of a revenue-related deferred account would appear in the rate adjustments area of our income statement, and would offset the billing effect coming through in revenues. In addition, typical amortizations would be considered during the PGA each year. This issue was set for consideration in a general rate case. In a general rate case, the rate adjustment section is not typically shown, so the amortization is needed as a reduction to miscellaneous revenue to generate the revenue requirement needed to ensure the amortization of the account.

Q. Is this an appropriate adjustment?

A. No. First, this is an example of single issue ratemaking, where the Company has singled out an item and is requesting special cost recovery for this item. The Company could have petitioned the Commission to issue an Accounting Order regarding the treatment of this issue when it occurred. It is not appropriate to now set aside this one single issue for future recovery. The Company should not be permitted to single out and charge ratepayers for this effect of the state tax change, which may have occurred during a period when the Company was otherwise earning a reasonable return.

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This is also an example of retroactive ratemaking. All Cost of Service components, i.e., revenues, expenses, and cost of capital, change over time. However, the "matching principle" dictates that all of the cost of service components should be considered and evaluated in relation to the specific test year. That is why a test year is chosen and utilized, so that a proper relationship is established between revenues, expenses, and the cost of capital. The Company is requesting that current ratepayers fund the cost for an event which occurred in a prior period outside the test year. The adjustment that the Company made on its books was to adjust deferred taxes for 2007 and 2008 as a result of these state tax rate changes. This is clearly retroactive ratemaking, which is a violation of ratemaking principles, and should be disallowed.

Q. What adjustment are you recommending?

A. I recommend disallowing the Company's proposed $895,966 reduction to miscellaneous revenues.

2. Miscellaneous Revenues

Q: Are you recommending another adjustment to miscellaneous revenues?

A. Yes. The Company has presented a schedule illustrating its historical miscellaneous revenues normalized for the years 12-months ended 2009, 2010 and 2011 on Exhibit NWN/304. The Company calculated test year revenues for the various components using either a one or three year average, but did not offer any compelling reason why the different averages were used for the different components of miscellaneous revenue. I have calculated a three year average of these items based on the 12 months ended

December 31, 2009, 2010 and 2011. My adjustment increases miscellaneous revenues by $207,452.

G. DEPRECIATION EXPENSE

Q. Please explain your adjustment to depreciation expense.

A. I recommend decreasing depreciation expense to correspond with my recommended reduction to plant in service. To come up with an approximate depreciation rate, I divided the base year plant in service by the base year depreciation expense. This yielded an average depreciation rate of 2.81%. I multiplied this percentage by my recommended reduction to plant in service. Though not a precise calculation, it is a reasonable estimate of the reduction in depreciation expense corresponding with my reduction to plant in service. My recommended adjustment reduces test year depreciation expense by approximately $1.508 million.

H. INJURIES & DAMAGES EXPENSE

Q. What amount has the Company included in the test year for injuries and damages expense?

A. According to the response to NWIGU-CUB DR 27, the Company has included [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] on an Oregon jurisdictional basis in the test year for injuries and damages expense. This amount is based on the average annual payments from 2008 - 2010.

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Q. Do you agree with this amount?

A. No. According to that response, the year 2009 contained an *extraordinary* claim of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] which should not have been considered in the average.

Q. What adjustment are you recommending?

A. I am recommending the removal of the extraordinary claim in 2009 and the use of the GDP for 2008-2011 to adjust the Company's expenses for the last four years to 2011 dollars (the most recent GDP available.) I then recommend the average of the amounts from those four years to arrive at a test year expense of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] on a system basis and [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] on an Oregon basis.[2] Using this four year average results in a reduction of the Company's expense by [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

I. <u>RATE CASE EXPENSE</u>

Q. What amount of rate case expense has the Company included in the test year?

A. The company has projected $704,000 of rate case expense for this proceeding. The Company proposes to amortize this over three years and has included $234,667 of rate case expense in the test year.

Q. Do you agree with the Company's proposal?

A. Not entirely. It has been eight years since the Company's last rate case. The Company has been earning a reasonable return and its financial risk is reduced by the various cost

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[2] 2006 was not readily available by the company for use in the submission of this testimony.

recovery mechanisms it has in place. It is uncertain when the Company may have another full rate case. I recommend amortizing this expense over five years, which brings the annual amortization to $140,800. This reduces the Company's test year rate case expense by $93,867.

J. AMERICAN GAS ASSOCIATION ("AGA") DUES

Q. What amount has the Company included in the test year for AGA dues?

A. According to the Company's response to NWIGU-CUB DR 40, the Company has included $370,284 in the test year for AGA dues on an Oregon jurisdictional basis.

Q. Please describe the AGA.

A. The AGA is an organization that advocates for the interests of its natural gas company members and provides information and services regarding gas distribution.

Q. Is the total amount of this expense necessary for the provision of gas service?

A. No. The National Association of Regulatory Utility Commissioners ("NARUC") sponsors Audit Reports of the Expenditures of the AGA. The audit report categorizes the AGA's expenditures funded by membership dues. A 2001 memo to the Chairs and Accountants of State Regulatory Commissions included with the NARUC-sponsored audit report of 1999 AGA expenditures stated "these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy, or promotional activities which may not be to their benefit." The table below shows a breakdown of the categories of expenditures funded by AGA member dues from a more recent NARUC audit.

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Table 1: NARUC Recommendation for AGA Dues

NARUC Operating Expense Category	March 2005 NARUC Audit Report for Year Ended 12/31/02: % of Dues	March 2005 NARUC Audit Report for Year Ended 12/31/02: Recommended Disallowance	AGA 2008 Budget: 2008 % Allocation	AGA 2008 Budget: Recommended Disallowance
Public Affairs	24.13%	-24.13%	24.44%	-24.44%
Advertising			1.18%	-1.18%
Communications	15.53%			
Corporate Affairs and International	10.54%	-10.54%	9.14%	-9.14%
General Counsel & Corp Secretary	5.20%	-2.60%	4.17%	-2.09%
Regulatory Affairs	15.51%			
Policy Planning & Regulatory Affairs			15.78%	
Marketing Department	2.37%	-2.37%		
Operating & Engineering Services	15.85%		21.71%	
Policy & Analysis	12.94%			
Industry Finance & Admin. Programs	4.75%		3.36%	
General & Administrative			20.22%	
Total Expenses	106.82%	-39.64%	100.00%	-36.85%

As can be seen in the table above, approximately 40% of AGA dues fund expenses related to public and corporate affairs, general counsel, and marketing and are recommended to be disallowed. For comparative purposes, a copy of AGA's 2008 budget is shown, which contains a comparable percent of dues related to public corporation affairs, general counsel, and marketing.

Q: Did the Company exclude any portion of lobbying related AGA dues from the test year?

A: No. The Company's response to NWIGU-CUB DR-6 states that in 2010 the AGA spent approximately 5.4% of its membership dues on lobbying and advocacy efforts; however, it believes this expense benefits ratepayers.

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Q: Have other state utility commissions disallowed a similar percent of AGA dues in rate cases?

A: Yes. The Arizona Corporation Commission disallowed 40% of AGA dues in UNS Gas Inc.'s rate case Docket No. G-04204A-06-0463. The Florida Public Service Commission disallowed 40% of AGA dues in City Gas' rate case Dockets 030569-GU and 940276-GU and 45.10% in Chesapeake Utilities Corporation's rate case Docket No. 000108-GU.

Q: What adjustment are you recommending?

A: Based on the 2008 AGA dues budget, I am recommending that the Commission remove the approximate 40% of AGA dues that relate to public and corporate affairs, general counsel, and marketing, which are not necessary for the provision of gas service, from the test year. This reduces the Company's test year expense by $148,114 on an Oregon basis.

K. <u>UNCOLLECTIBLES</u>

Q. Please describe the Company's adjustment for uncollectible expense.

A. The Company has projected uncollectible expense of $2.110 million in the test year compared to the base year amount of $1.617 million. This is an increase of approximately 31% over 2011 levels. The Company's test year amount is based on a three-year historical average of write-offs as a percent of total revenues times the total test year revenue.

Q: Has the Company provided adequate justification for this increase to uncollectibles expense?

A: In my opinion, no. The Company calculated a three year average of write-offs using the years 2009 through 2011. 2009 contained a much higher level of write-offs due to the weakened economy and should not be factored into the calculation of uncollectible expense. I have calculated uncollectible expense based on the last two calendar years of write-offs, 2011 and 2010, as this is the best estimate of what uncollectibles would be during the test year. Although the use of a two-year average is typically not preferred, it is a better measurement than the three year average of write-offs which contains a much higher amount of write-offs due to the recession.

Q: What adjustment are you recommending?

A: Using this two-year average yields a test year amount of $1.662 million. I am recommending that uncollectible expense be reduced by $448,000 on Oregon jurisdictional basis.

L. <u>DIRECTORS & OFFICERS INSURANCE</u>

Q. Does the Company's filing include costs for Directors and Officers liability insurance ("D&O")?

A. Yes, it does. The Company has included $603,571 of D&O expense for the total system, with a 90.12% allocation to Oregon of $543,938.

Q. What is the purpose of this coverage?

A. D&O provides financial protection for the Company's directors and officers in the event that they are sued for actions taken while performing their professional duties. These lawsuits are typically brought against Company management by the Company's own shareholders. Therefore, in essence, this insurance protects shareholders from the decisions they made when they hired the Company's Board of Directors, and the Board of Directors in turn hired the officers of the Company.

Q Are you recommending an adjustment for the D&O expense?

A. Yes. In ratemaking, the burden should follow the benefit, and the ratepayers are not the primary beneficiaries of this insurance. As such, they should not be responsible for all of the costs. Companies will sometimes argue that this is a justifiable business expense, but the question is not whether the expense is justified, but to what extent it benefits the ratepayers.

Q. Who are the beneficiaries of D&O?

A. In my opinion, shareholders, directors, and officers receive most of the benefits from D&O. In the event of a claim, the beneficiaries of this insurance are the shareholders, who are most likely to be the ones making claims and receiving payouts, and the directors and officers that receive the personal protection from the claim.

Q. Do ratepayers receive any benefit from this insurance?

A. The ratepayers may receive a small benefit from the D&O. The ratepayers are beneficiaries to the extent that this insurance aids in attracting and retaining qualified directors. Although there is a possible minor benefit to the ratepayer, it can be clearly seen that the ratepayer is at best a secondary or incidental beneficiary of the insurance and not the primary beneficiary. Because of this fact, it would be inappropriate to assign 100% of the costs to ratepayers.

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Q. In response to NWIGU-CUB DR 101, the Company states that it would be impossible to hire knowledgeable and experienced board members and officers without this insurance. Does your recommendation jeopardize the Company's ability to hire qualified directors and officers?

A. No, it does not. I am not recommending that the Company no longer offer D&O. I am simply stating that the costs for this insurance should not be fully borne by the Company's customers.

Q. Who should be responsible for this expense?

A. As the shareholders receive most of the benefit, it would be inappropriate for the ratepayers to bear all of the costs. This expense should be shared by both parties 50/50. Thus, I am recommending that 50% of the D&O insurance expense be removed from rates.

Q. Has the Commission determined a 50/50 split between ratepayers and shareholders to be an appropriate allocation of D&O expense?

A. It has. In Order No. 09-020, the Commission stated on page 22:

> We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost.

Q. Have other jurisdictions concluded that D&O expense should be shared between the Company's shareholders and ratepayers?

A. Yes. In Connecticut, sharing of these costs has been determined to be appropriate on multiple occasions. In Docket No. 07-07-01, the Department limited D&O recovery from ratepayers to 30%. The Department limited ratepayer responsibility for this expense to 25% in Docket 05-06-04. In New York, Consolidated Edison was limited to recovering 50% of D&O costs from ratepayers in Case 08-E-05539. In the discussion, the New York commission stated:

> We find no particularly good way to distinguish and quantify the benefits of D&O insurance to ratepayers from the benefits to shareholders, especially taking into account the advantage that shareholders have in control over directors and officers. We believe the fairest and most reasonable way to apportion the cost of D&O insurance therefore is to share it equally between ratepayers and shareholders.

The New York commission calls attention to an important point in that discussion. As these cases typically involve a lawsuit between shareholders and officers, ratepayers have very little influence or involvement.

Q. What is your recommended adjustment to D&O expense?

A. I recommend that the expense be shared by both the ratepayers and the shareholders. In my opinion, a 50/50 split is an appropriate allocation of this expense. I am therefore recommending the removal of 50% of the $603,571 in D&O costs, resulting in an adjustment of $301,786 on a total system basis and $271,969 on an Oregon basis.

M. <u>ADVERTISING</u>

Q. Does the Company's filing include advertising expenses?

A. Yes, it does. The Company has included $1,575,000 for Category A advertising expenses and $650,000 for Category B advertising expenses.

Q. Please explain these two categories.

A. Oregon Administrative Rule 860-026-0022 describes Category A expenses as:

> Energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses.

The rule defines Category B expenses as "Legally mandated advertising expenses."

Q. Do you propose any adjustments for advertising expenses?

A. Yes, I recommend adjustments for both Categories A and B. First, I will explain my adjustment to the Category A expense.

OAR-860-026-0022 (3)(a) states:

> Advertising expenses in Category "A" are presumed to be just and reasonable in a rate proceeding to the extent that expenses are twelve and one-half hundredths of 1 percent (0.125 percent) or less of the gross retail operating revenues determined in that proceeding.

Q. Is the Company's request under this threshold?

A. No, it is not. The Company's request is 0.212% of operating revenues. This puts the Company's Category A expenses at 69% over the amount "presumed to be just and reasonable."

Q. Doesn't OAR-860-026-0022 also state that these presumptions are rebuttable?

A. It does. However, the rule further states that the Company will have the burden of proof of showing that the expenditures are just and reasonable.

Q. What justification did the Company offer to rebut this assumption?

A. In her direct testimony at page 4, Kimberly Heiting makes three arguments for going over the reasonableness threshold. First, the formula provides LDCs with an unfairly low allocation-per-customer compared to an electric utility. Second, the Company's service territory is very large and diverse. Third, media costs have increased.

Q. Did the Company provide sufficient proof that these expenditures are just and reasonable?

A. In my opinion, the Company has not provided sufficient proof to increase advertising expenses to 69% over the recommended amount. While a larger and more diverse service territory and increased media costs will affect advertising expenses, it must be considered that OAR-860-026-0022 provided a range of expenses, with .125% at the very upper limit to be presumed just and reasonable. I do not believe that the Company has demonstrated that those three factors have justified increasing its expenses beyond that range. Furthermore, the Company has not demonstrated that the advertising benefits ratepayers.

Q. What adjustment are you recommending?

A. For my recommended adjustment to Category A advertising expenses, I multiplied the Test Year Operating Revenue of $742,978,000 by 0.125% to arrive at $928,723 on a total system basis and $832,693 on an Oregon basis. This is an adjustment of $646,278 on a total system basis and $579,452 on an Oregon basis. This is the highest possible amount under OAR-860-026-0022 that would be "presumed to be just and reasonable." I would note that the revenue amount used in determining this expense is the Company's proposed revenue. This means that the amount I am recommending will still be higher than 0.125% of total revenue, assuming that some downward adjustment in the revenue requirement occurs. I would also note that the allocation to Oregon is an estimate based on NWN/Exhibit 312.

Q. Please explain why you are recommending an adjustment to the Category B advertising expenses.

A. The Company's filing includes projections for a 15.8% increase in 2012 and a 36.8% increase in the test year. The test year projection appears to be quite large when considering the fact that the Company's Category B advertising expenses actually averaged a 0.2% decrease from 2007 to 2011. The Chart below shows the increase or decrease in expenses for each year from 2007 through the test year.

Category B Advertising Expense							
Year	2007	2008	2009	2010	2011	2012	Test Year
Expense	325,213	353,507	349,764	344,850	410,058	475,000	650,000
% Change	(26.13)	8.70	(1.06)	(1.40)	18.91	15.84	36.84

Q. What adjustment are you recommending?

A. For Category B expenses, I recommend an adjustment of $275, 914 on total system basis and $247,384 on an Oregon basis. I used the GDP to adjust the Company's expenses for the years 2007-2011 to 2011 dollars (the most recent GDP available.) I then averaged the amounts from those five years to arrive at a test year expense of $374,086 on total system basis and $335,406 on an Oregon basis. I would note that the allocation to Oregon is an estimate based on NWN/Exhibit 312.

N. PAYROLL

Q. What adjustments to payroll are you recommending?

A. I am recommending an adjustment to the level of full time equivalents ("FTEs") and an adjustment to the overall level of payroll expense.

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Q. Please explain your first adjustment.

A. My first adjustment is a reduction to the number of FTEs. The Company has included a number of unfilled positions in the test year. Ratepayers should only be expected to be responsible for expenses that are known and measurable and these unfulfilled positions do not meet that standard.

Q. Please explain how the Company determined the number of FTEs in the test year.

A. Mr. Sohl states on page 4 of his testimony that the Company expects to add 58 FTEs between the end of the base period and the beginning of the test year. Mr. Sohl started with a base period forecast of 1,072 FTEs and added 58 FTEs to reach a test year amount of 1,130 FTEs.

Q. What are your concerns with his results?

A. My first concern is that the Company's calculations did not begin with the correct number of FTEs. The Company projected 1,072 FTEs for the base period, but actually only had 1,040 as of December 31, 2011, according to the response to NWIGU-CUB DR 75. Therefore, the calculation to add 58 FTEs should begin with 1,040, not 1,072, and the actual increase requested should be considered 90 FTEs, not 58 FTEs.

Q. Why shouldn't the 32 FTEs that were projected but not hired by December 31, 2011 be included if the Company still plans to hire them?

A. The Company might plan on hiring those 32 FTEs, (1,072 projected minus 1,040 actual FTEs) but this is not the amount that it started with, nor is it an amount that is known and measurable. Even if the Company does hire some of those FTEs, the timing of the hiring is not known and by the time some employees are hired, others may have left the

Company. The bottom line is that ratepayers should not be expected to pay for 32 employees that do not exist and may never exist.

Q. Do you recommend any further reductions in FTEs?

A. I do. Of the 58 FTEs that Mr. Sohl discussed hiring between the base year and the beginning of the test year, I recommend removing 27 FTEs.

Q. Please explain how you arrived at that figure.

A. As of March 31, 2012, the employee count was 1,058, according to the response to NWIGU-CUB DR 75. This leaves 40 of the planned 58 FTEs unhired. Thirteen of the remaining 40 FTEs are related to service window appointments. Staff will be addressing those thirteen FTE's in their testimony. Subtracting those 13 from 40 results in 27 FTEs that remain unhired from the original 58 that I recommend removing.

Q. What is your reason for removing the remaining 27 FTEs?

A. I recommend their removal for the same reason that I recommended removing the 32 FTEs that were projected but not hired before the end of the base year. These are projected positions that may never be filled. Ratepayers should not be responsible for the costs of hires that may not take place.

Q. Is it possible that some of the remaining 27 positions could be hired before the test period when rates are to go into effect?

A. Yes, it is possible that the employees will be hired, but it is also possible that the employees will not be hired. Even if the Company hires some employees, it is possible that others will leave and there could actually be fewer than 1,058 FTEs in the test period. When making the determination as to whether the 58 requested positions will be filled, it is important to remember that the Company projected that base period FTEs would be 1,072 and the actual count was only 1,040. In my opinion, the number of additional FTEs projected by the Company is overly optimistic.

Q. What is your recommended adjustment?

A. I recommend the removal of 59 FTEs, the 32 not hired in the base period and the 27 requested but unfilled FTEs for the Test Year. After allocating to O&M, the recommended removal of the 59 FTEs results in a recommended reduction of $3,044,670 on a total system basis and $2,724,980 on an Oregon basis.

Q. Please explain your second recommended adjustment to payroll expense.

A. My second adjustment to payroll expense is in regard to total payroll expense. According to the response to NWIGU-CUB DR 99, the test year payroll expense exceeds any of the four years of expense 2008-2011 and 2012 projected, and exceeds the 3-year actual average O&M expense factor of 63.7% for the years 2008-2010. Based on the information provided, the expense factor fluctuates from year to year. This fluctuation is to be expected because it is based on the level of capital projects undertaken from year to year. In its filing, the Company has included an increase in capital expenditures in the test year. The increase in capital expenditures should increase the level of payroll capitalized, thereby reducing the percentage of payroll expensed. Therefore, the increase in the O&M expense factor to 69.3% is considered to be inappropriate.

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Q. Why would an increase in capital expenditures reduce the percentage of payroll expensed?

A. Labor is allocated primarily to either capital projects or O&M. Because total payroll is comprised of these two categories, as the percentage of one goes up the percentage of the other must go down. Due to the increase in capital projects, the percentage of labor that is capitalized will rise, resulting in the decline of the percentage expensed.

Q. What is your recommended adjustment?

A. To arrive at a more appropriate test year amount, I recommend the use of the ratio of expense to total payroll for 2008-2010 to adjust the test year payroll. I then recommend taking the 63.7% average of those three years and multiplying that expense factor by my adjusted payroll of $86,452,889 thus arriving at an expense of $55,070,490 on a total system basis and $49,288,089 on an Oregon basis. This is a recommended adjustment of $4,868,616 on a total system basis and $4,357,411 on an Oregon basis.

O. <u>PAYROLL TAX</u>

Q. Are you recommending an adjustment to payroll tax?

A. Yes. I am recommending a reduction to payroll taxes of $718,421 on a total system basis and $642,987 on an Oregon basis. This adjustment is the flow though impact of my payroll adjustment. I recommend reducing the payroll taxes by the effective payroll tax rate multiplied by my dollar adjustment for payroll.

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P. MEDICAL BENEFITS/WORKERS COMPENSATION

Q. Do you recommend any adjustments to Medical Benefits and Workers Compensation expense?

A. Yes, I do. The Company's response to Standard Data Request No. 96 provides a breakout of test year labor expense expressed as percentages. The response indicates that .96% and .82% of labor expense are allocated to "Merchandise" and "Other," respectively. I recommend the removal of both of these categories of expense from Medical Benefits and Workers Compensation.

Q. What is your reason for removing them?

A. These categories represent unregulated segments of the Company's business and the Company has allocated the labor expense accordingly. If the same allocations are not made to Medical Benefits and Workers Compensation, ratepayers would be funding benefits for the non-regulated segments of the Company's business.

Q. What is your recommendation?

A. I recommend removing both categories of unregulated expense. Together, the allocation of 0.96% to "Merchandise" and 0.82% to "Other" total 1.78% of labor expense. Multiplying total health benefits costs of 16,955,734 by this percentage results in a reduction of $301,812 on a total system basis and $270,122 on an Oregon basis. Multiplying Workers Compensation by this percentage results in a recommended reduction of $25,435 on a total system basis and $22,764 on an Oregon basis. I would note that the allocation to Oregon is an estimate based on NWN/Exhibit 312.

Q. Do you recommend any other adjustments to Medical Benefits and Workers Compensation expense?

A. Yes**.** Because I adjusted the number of FTEs, it is necessary to reflect the effects of that change to both of these categories. The recommended reduction to FTEs was 5.22% so I now recommend reducing Medical Benefits and Workers Compensation by the same amount. The results in a recommended adjustment to Workers Compensation of $73,262 on a total system basis and $65,570 on an Oregon basis. This also results in a recommended adjustment to Total Health Benefits costs was $869,335 on a total system basis and $778,055 on an Oregon basis. I would note that the allocation to Oregon is an estimate based on NWN/Exhibit 312.

Q. <u>PENSION</u>

Q. Do you recommend an adjustment to Pension expense?

A. Yes, I do.

Q. Please explain what the Company is requesting in regards to pension expense.

A. In his Direct Testimony, Mr. Feltz states that the Company is proposing to add unrecovered pension plan contributions from investors to ratebase. Mr. Feltz states that the Company has been required to pay cash contributions totaling $57 million between 2009 and 2011 to its pension plans to meet requirements of the Pension Protection Act (PPA) passed in 2006. The Company proposes to recover this money by adding these contributions to ratebase as described on pages 27-28 of Mr. Feltz's testimony:

> The Company proposes to add the average unrecovered investor contribution amount during the Test Year, estimated at $21,929,876 net of deferred taxes, or $36,549,793 pre-tax, to rate base...The Company proposes to amortize the pre-tax

> amount over eight years...The revenue requirement impact of this proposal is estimated to be $4,568,724, or $36,549,793 divided by eight years.

Q. In your opinion, is this proposal equitable to ratepayers?

A. I believe that this proposal is neither beneficial nor equitable to ratepayers. These cash contributions were necessitated in large part by the country's current economic recession. Mr. Feltz acknowledges as much at page 23 of his direct testimony where he states:

> In 2008 and 2009, the equity and bond markets collapsed, which led to a significant decline in the value of the Plans' assets. The recession that followed also caused a significant reduction in interest rates to historic lows, which dramatically increased Plan liabilities.

The effect of the recession was to lower the value of the pension plan assets to the extent that FAS 87 and PPA regulations required further contributions from the Company. Ratepayers do not receive refunds when pension plan assets are increasing in value so reciprocally ratepayers should not be responsible when the assets' values temporarily decline. As the market recovers, the value of the assets will rise and the additional contributions will no longer be necessary. This is a temporary issue that should be corrected over time without adjustments to ratemaking procedures.

Q. Are there any other reasons why the Company's request is inappropriate?

A. Yes. The Company, according to Mr. Feltz at page 24 of his direct testimony, made contributions between 2009 and 2011. To now include past contributions in future rates would constitute retroactive ratemaking. Retroactive ratemaking is not an appropriate or acceptable practice in utility regulation. Even if the Commission authorized the deferral of these contributions, it is my position that it is not appropriate for ratepayers to fund these past contributions.

Q. What is your recommended adjustment?

A. I recommend removing the unrecovered investor contribution of $21,929,876 from ratebase and removing the entire $4,568,724 from amortizable expenses on an Oregon basis.

VI. ENVIRONMENTAL REMEDIATION

Q. What does NW Natural propose regarding environmental costs associated with manufactured gas plants and the recovery of such costs?

A. My understanding is that NW Natural is proposing that all costs that the Company determines to be related to the environmental remediation of former manufactured gas plants which the Company or its predecessors operated, should be deferred and collected from ratepayers.

The Company's proposal, as I understand it, would defer costs that the Company would determine are related to the environmental remediation of these properties in a deferred account. The Company would earn a full rate of return on these deferrals during the period that they remained in the deferred account.

The Company then proposes that the Commission authorize a recovery mechanism, which would take the balance in the deferred account at a specific date and remove one-fifth of it for recovery through the mechanism proposed by the Company. During the 12-

month period that the recovery amount is being amortized through rates, the Company would collect a Modified Blended Treasury Rate (“MBTR”) on the balance being recovered through the mechanism. As I understand it, this is the rate authorized by the Commission as financing costs on amounts being amortized. The Company would still continue to earn a full rate of return on the balance reflected in the deferred remediation cost account during the period that amounts are being amortized and collected from ratepayers.

Q. Does the Company’s proposal seem equitable to you?

A. No, it does not. Both the United States Environmental Protection Agency ("EPA") and the Oregon Department of Environmental Quality ("DEQ") have held the owners of the land responsible for the environmental remediation. This would be true whether the Company was a regulated company such as NW Natural or an unregulated company subject to competitive pricing. It is clear that the responsibility for remediation flows to those who had responsibility for whatever pollutants were deposited on the land during its use by its owner. In a competitive environment, owners of property who are required to make remediation investments cannot recover those costs automatically from their customers. Owners of the land that was used in a manner which caused environmental damage are held responsible by the EPA and DEQ. This is so because these owners are the ones who profited from the use of the land and were the only ones who could have affected the level of environmental damage incurred.

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Ratepayers never owned or operated the facilities which resulted in the environmental damage. They had no knowledge or input into the operation of these facilities. They were merely consumers of services without any control or knowledge of the possible effects on the environment of the operations taking place on these sites.

NW Natural is now requesting that current ratepayers be held responsible for costs associated with providing manufactured gas to a group of unknown and unrelated ratepayers. The manufactured gas sites were contaminated decades ago and the cost of remediating these sites is unrelated to the current service provided to ratepayers. These costs are not necessary to providing current service, but instead are costs incurred related to the Company's ownership of these pieces of property.

Q. In your opinion, does the Company's return on equity reflect a component related to risk?

A. Yes. When the Company receives a return on equity from its investments, that return reflects a risk factor. There are risks associated with the operation of any business, both competitive and regulated. The equity return reflects a risk factor associated with the operation of a business. This risk factor is related to unknown factors such as the assessment by the environmental agencies of remediation costs against the owners of the land which was contaminated. Even though a regulated entity has substantially less risk than a competitive company, the return it receives still reflects a component related to risk, otherwise it would receive a return on its investment somewhat closer to government bonds. In the case of contaminated property, only the Company's management, who were employed by the stockholders, could have affected the outcome of the initial contamination of this property. The owners and operators of these facilities should have been, or could have been, aware that by-products were either being dumped or stored on site and only they could have affected the amount and type of contamination done to these properties. It seems apparent that the Company's management accepted the risk from the operation of manufactured gas plants that was reflected in the rate of return that they received.

Q. Are you recommending that the Company bear the full cost of the remediation of the contaminated property?

A. No, I am not. However, I do feel that it is not appropriate for ratepayers to bear the full cost of the remediation and have the Company earn a full rate of return on those costs until they are reflected in the Company's proposed recovery mechanism.

Q. Are these costs subject to insurance recovery?

A. Ms. Hart's testimony states the following:

> Based on the language of its policies, controlling Oregon law and the underlying facts, NW Natural believes that each of its historical policies provide coverage for the costs related to the environmental damage that NW Natural is investigating and remediating.

Therefore, the cost subject to earning a return at this time are not known at this time. Any proceeds could reduce the cost significantly.

Q. What is your recommendation with respect to the cost in question?

A. I would recommend that the Commission allocate 50 percent of the total environmental remediation costs to stockholders. In addition, the Company should only earn a debt rate of return on the balance reflected in the Deferred Environmental Cost Account. Once the

Commission has issued an order stating what amount NW Natural would recover as a reimbursement for environmental remediation costs, that amount would be a guaranteed recovery amount. There would be no risk associated with the recovery of this amount by the Company, and therefore no equity investment would be necessary. The Commission's Order would guarantee the return of the environmental remediation costs and therefore only a debt return should be recovered by the Company, because no risk would be involved in the recovery of the authorized amount.

Q. Does that conclude your testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

EXHIBIT NWIGU-CUB/101

QUALIFICATION STATEMENT OF HUGH LARKIN, JR.

May 3, 2012

QUALIFICATIONS OF HUGH LARKIN, JR.

Q. WHAT IS YOUR OCCUPATION?

A. I am a certified public accountant and a partner in the firm of Larkin & Associates, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I graduated from Michigan State University in 1960. During 1961 and 1962, I fulfilled my military obligations as an officer in the United States Army.

In 1963 I was employed by the certified public accounting firm of Peat, Marwick, Mitchell & Co., as a junior accountant. I became a certified public accountant in 1966.

In 1968 I was promoted to the supervisory level at Peat, Marwick, Mitchell & Co. As such, my duties included the direction and review of audits of various types of business organizations, including manufacturing, service, sales and regulated companies.

Through my education and auditing experience of manufacturing operations, I obtained an extensive background of theoretical and practical cost accounting.

I have audited companies having job cost systems and those having process cost systems, utilizing both historical and standard costs.

I have a working knowledge of cost control, budgets and reports, the accumulation of overheads and the application of same to products on the various recognized methods.

Additionally, I designed and installed a job cost system for an automotive parts manufacturer.

I gained experience in the audit of regulated companies as the supervisor in charge of all railroad audits for the Detroit office of Peat, Marwick, including audits of the Detroit, Toledo and Ironton Railroad, the Ann Arbor Railroad, and portions of the Penn Central Railroad Company. In 1967, I was the supervisory senior accountant in charge of the audit of the Michigan State Highway Department, for which Peat, Marwick was employed by the State Auditor General and the Attorney General.

In October of 1969, I left Peat, Marwick to become a partner in the public accounting firm of Tischler & Lipson of Detroit. In April of 1970, I left the latter firm to form the certified public accounting firm of Larkin, Chapski & Company. In September 1982 I re-organized the firm into Larkin & Associates, a certified public accounting firm. The firm of Larkin & Associates performs a wide variety of auditing and accounting services, but concentrates in the area of utility regulation and ratemaking. I am a member of the Michigan Association of Certified Public Accountants and the American Institute of Certified Public Accountants. I testified before the Michigan Public Service Commission and in other states in the following cases:

U-3749	Consumers Power Company - Electric Michigan Public Service Commission
U-391	Detroit Edison Company Michigan Public Service Commission
U-4331	Consumers Power Company - Gas Michigan Public Service Commission
U-4332	Consumers Power Company - Electric Michigan Public Service Commission
U-4293	Michigan Bell Telephone Company Michigan Public Service Commission
U-4498	Michigan Consolidated Gas sale to Consumers Power Company Michigan Public Service Commission
U-4576	Consumers Power Company - Electric Michigan Public Service Commission
U-4575	Michigan Bell Telephone Company Michigan Public Service Commission
U-4331R	Consumers Power Company - Gas - Rehearing Michigan Public Service Commission
6813	Chesapeake and Potomac Telephone Company of Maryland, Public Service Commission, State of Maryland

Formal Case No. 2090	New England Telephone and Telegraph Co. State of Maine Public Utilities Commission
Dockets 574, 575, 576	Sierra Pacific Power Company, Public Service Commission, State of Nevada
U-5131	Michigan Power Company Michigan Public Service Commission
U-5125	Michigan Bell Telephone Company Michigan Public Service Commission
R-4840 & U-4621	Consumers Power Company Michigan Public Service Commission
U-4835	Hickory Telephone Company Michigan Public Service Commission
36626	Sierra Pacific Power Company v. Public Service Commission, et al, First Judicial District Court of the State of Nevada
American Arbitration Association	City of Wyoming v. General Electric Cable TV
760842-TP	Southern Bell Telephone and Telegraph Company, Florida Public Service Commission
U-5331	Consumers Power Company Michigan Public Service Commission
U-5125R	Michigan Bell Telephone Company Michigan Public Service Commission
770491-TP	Winter Park Telephone Company, Florida Public Service Commission
77-554-EL-AIR	Ohio Edison Co., Public Utility Commission of Ohio
78-284-EL-AEM	Dayton Power and Light Co., Public Utility Commission of Ohio
0R78-1	Trans Alaska Pipeline, Federal Energy Regulatory Commission (FERC)

78-622-EL-FAC	Ohio Edison Co., Public Utility Commission of Ohio
U-5732	Consumers Power Company - Gas, Michigan Public Service Commission
77-1249-EL-AIR, et al	Ohio Edison Co., Public Utility Commission of Ohio
78-677-EL-AIR	Cleveland Electric Illuminating Co., Public Utility Commission of Ohio
U-5979	Consumers Power Company, Michigan Public Service Commission
790084-TP	General Telephone Company of Florida, Florida Public Service Commission
79-11-EL-AIR	Cincinnati Gas and Electric Co., Public Utilities Commission of Ohio
790316-WS	Jacksonville Suburban Utilities Corp., Florida Public Service Commission
790317-WS	Southern Utility Company, Florida Public Service Commission
U-1345	Arizona Public Service Company, Arizona Corporation Commission
79-537-EL-AIR	Cleveland Electric Illuminating Co., Public Utilities Commission of Ohio
800011-EU	Tampa Electric Company, Florida Public Service Commission
800001-EU	Gulf Power Company, Florida Public Service Commission
U-5979-R	Consumers Power Company, Michigan Public Service Commission
800119-EU	Florida Power Corporation, Florida Public Service Commission

810035-TP	Southern Bell Telephone and Telegraph Company, Florida Public Service Commission
800367-WS	General Development Utilities, Inc., Port Malabar, Florida Public Service Commission
TR-81-208**	Southwestern Bell Telephone Company, Missouri Public Service Commission
810095-TP	General Telephone Company of Florida, Florida Public Service Commission
U-6794	Michigan Consolidated Gas Company, 16 refunds Michigan Public Service Commission
U-6798	Cogeneration and Small Power Production -PURPA, Michigan Public Service Commission
0136-EU	Gulf Power Company, Florida Public Service Commission
E-002/GR-81-342	Northern State Power Company Minnesota Public Utilities Commission
820001-EU	General Investigation of Fuel Cost Recovery Clauses, Florida Public Service Commission
810210-TP	Florida Telephone Corporation, Florida Public Service Commission
810211-TP	United Telephone Co. of Florida, Florida Public Service Commission
810251-TP	Quincy Telephone Company, Florida Public Service Commission
810252-TP	Orange City Telephone Company, Florida Public Service Commission
8400	East Kentucky Power Cooperative, Inc., Kentucky Public Service Commission

U-6949	Detroit Edison Company - Partial and Immediate Rate Increase Michigan Public Service Commission
18328	Alabama Gas Corporation, Alabama Public Service Commission
U-6949	Detroit Edison Company - Final Rate Recommendation Michigan Public Service Commission
820007-EU	Tampa Electric Company, Florida Public Service Commission
820097-EU	Florida Power & Light Company, Florida Public Service Commission
820150-EU	Gulf Power Company, Florida Public Service Commission
18416	Alabama Power Company, Public Service Commission of Alabama
820100-EU	Florida Power Corporation, Florida Public Service Commission
U-7236	Detroit Edison-Burlington Northern Refund Michigan Public Service Commission
U-6633-R	Detroit Edison - MRCS Program, Michigan Public Service Commission
U-6797-R	Consumers Power Company - MRCS Program, Michigan Public Service Commission
82-267-EFC	Dayton Power & Light Company, Public Utility Commission of Ohio
U-5510-R	Consumers Power Company - Energy Conservation Finance Program, Michigan Public Service Commission
82-240-E	South Carolina Electric & Gas Company, South Carolina Public Service Commission

8624 8625	Kentucky Utilities, Kentucky Public Service Commission
8648	East Kentucky Power Cooperative, Inc., Kentucky Public Service Commission
U-7065	The Detroit Edison Company (Fermi II) Michigan Public Service Commission
U-7350	Generic Working Capital Requirements, Michigan Public Service Commission
820294-TP	Southern Bell Telephone Company, Florida Public Service Commission
Order RH-1-83	Westcoast Gas Transmission Company, Ltd., Canadian National Energy Board
8738	Columbia Gas of Kentucky, Inc., Kentucky Public Service Commission
82-168-EL-EFC	Cleveland Electric Illuminating Company, Public Utility Commission of Ohio
6714	Michigan Consolidated Gas Company Phase II, Michigan Public Service Commission
82-165-EL-EFC	Toledo Edison Company, Public Utility Commission of Ohio
830012-EU	Tampa Electric Company, Florida Public Service Commission
ER-83-206**	Arkansas Power & Light Company, Missouri Public Service Commission
U-4758	The Detroit Edison Company (Refunds), Michigan Public Service Commission
8836	Kentucky American Water Company, Kentucky Public Service Commission
8839	Western Kentucky Gas Company, Kentucky Public Service Commission

83-07-15	Connecticut Light & Power Company, Department of Utility Control State of Connecticut
81-0485-WS	Palm Coast Utility Corporation, Florida Public Service Commission
U-7650	Consumers Power Company - (Partial and Immediate), Michigan Public Service Commission
83-662**	Continental Telephone Company, Nevada Public Service Commission
U-7650	Consumers Power Company – Final Michigan Public Service Commission
U-6488-R	Detroit Edison Co. (FAC & PIPAC Reconciliation), Michigan Public Service Commission
Docket No. 15684	Louisiana Power & Light Company, Public Service Commission of the State of Louisiana
U-7650	Consumers Power Company (Reopened Reopened Hearings) Michigan Public Service Commission
38-1039**	CP National Telephone Corporation Nevada Public Service Commission
83-1226	Sierra Pacific Power Company (Re application to form holding company) Nevada Public Service Commission
U-7395 & U-7397	Campaign Ballot Proposals Michigan Public Service Commission
820013-WS	Seacoast Utilities Florida Public Service Commission
U-7660	Detroit Edison Company Michigan Public Service Commission
U-7802	Michigan Gas Utilities Company Michigan Public Service Commission

830465-EI	Florida Power & Light Company Florida Public Service Commission
U-7777	Michigan Consolidated Gas Company Michigan Public Service Commission
U-7779	Consumers Power Company Michigan Public Service Commission
U-7480-R	Michigan Consolidated Gas Company Michigan Public Service Commission
U-7488-R	Consumers Power Company – Gas Michigan Public Service Commission
U-7484-R	Michigan Gas Utilities Company Michigan Public Service Commission
U-7550-R	Detroit Edison Company Michigan Public Service Commission
U-7477-R	Indiana & Michigan Electric Company Michigan Public Service Commission
U-7512-R	Consumers Power Company – Electric Michigan Public Service Commission
18978	Continental Telephone Company of the South - Alabama, Alabama Public Service Commission
9003	Columbia Gas of Kentucky, Inc. Kentucky Public Service Commission
R-842583	Duquesne Light Company Pennsylvania Public Utility Commission
9006*	Big Rivers Electric Corporation Kentucky Public Service Commission *Company withdrew filing
U-7830	Consumers Power Company - Electric (Partial and Immediate) Michigan Public Service Commission

7675	Consumers Power Company - Customer Refunds Michigan Public Service Commission
5779	Houston Lighting & Power Company Texas Public Utility Commission
U-7830	Consumers Power Company - Electric – "Financial Stabilization" Michigan Public Service Commission
U-4620	Mississippi Power & Light Company (Interim) Mississippi Public Service Commission
U-16091	Louisiana Power & Light Company Louisiana Public Service Commission
9163	Big Rivers Electric Corporation Kentucky Public Service Commission
U-7830	Consumers Power Company - Electric - (Final) Michigan Public Service Commission
U-4620	Mississippi Power & Light Company - (Final) Mississippi Public Service Commission
76-18788AA & 76-18788AA	Detroit Edison (Refund - Appeal of U-4807) Ingham County Circuit Court Michigan Public Service Commission
U-6633-R	Detroit Edison (MRCS Program Reconciliation) Michigan Public Service Commission
19297	Continental Telephone Company of the South - Alabama, Alabama Public Service Commission
9283	Kentucky American Water Company Kentucky Public Service Commission
850050-EI	Tampa Electric Company Florida Public Service Commission
R-850021	Duquesne Light Company Pennsylvania Public Service Commission

TR-85-179**	United Telephone Company of Missouri Missouri Public Service Commission
6350	El Paso Electric Company The Public Utility Board of the City of El Paso
6350	El Paso Electric Company Public Utility Commission of Texas
85-53476AA & 85-534855AA	Detroit Edison-refund-Appeal of U-4758 Ingham County Circuit Court Michigan Public Service Commission
U-8091/ U-8239	Consumers Power Company-Gas Michigan Public Service Commission
9230	Leslie County Telephone Company, Inc. Kentucky Public Service Commission
85-212	Central Maine Power Company Maine Public Service Commission
850782-EI & 850783-EI	Florida Power & Light Company Florida Public Service Commission
ER-85646001 & ER-85647001	New England Power Company Federal Energy Regulatory Commission
Civil Action * No. 2:85-0652	Allegheny & Western Energy Corporation, Plaintiff, - against – The Columbia Gas System, Inc. Defendant
Docket No. 850031-WS	Orange Osceola Utilities, Inc. Before the Florida Public Service Commission
Docket No. 840419-SU	Florida Cities Water Company South Ft. Myers Sewer Operations Before the Florida Public Service Commission
R-860378	Duquesne Light Company Pennsylvania Public Service Commission
R-850267	Pennsylvania Power Company Pennsylvania Public Service Commission

R-860378	Duquesne Light Company - Surrebuttal Testimony - OCA Statement No. 2D Pennsylvania Public Service Commission
Docket No. 850151	Marco Island Utility Company Before the Florida Public Service Commission
Docket No. 7195 (Interim)	Gulf States Utilities Company Public Utility Commission of Texas
R-850267 Reopened	Pennsylvania Power Company Pennsylvania Public Service Commission
Docket No. 87-01-03	Connecticut Natural Gas Corporation Connecticut Department of Public Utility Control
Docket No. 5740	Hawaiian Electric Company Hawaii Public Utilities Commission
1345-85-367	Arizona Public Service Company Arizona Corporation Commission
Docket 011	Tax Reform Act of 1986 - California No. 86-11-019 California Public Utilities Commission
Case No. 29484	Long Island Lighting Company New York Department of Public Service
Docket No. 7460	El Paso Electric Company Public Utility Commission of Texas
Docket No. 870092-WS*	Citrus Springs Utilities Before the Florida Public Service Commission
Case No. 9892	Dickerson Lumber EP Company - Complainant vs. Farmers Rural Electric Cooperative and East Kentucky Power Cooperative – Defendants Before the Kentucky Public Service Commission
Docket No. 3673-U	Georgia Power Company Before the Georgia Public Service Commission
Docket No. U-8747	Anchorage Water and Wastewater Utility Report on Management Audit

Docket No. 861564-WS	Century Utilities Before the Florida Public Service Commission
Docket No. FA86-19-001	Systems Energy Resources, Inc. Federal Energy Regulatory Commission
Docket No. 870347-TI	AT&T Communications of the Southern States, Inc. Florida Public Service Commission
Docket No. 870980-WS	St. Augustine Shores Utilities Inc. Florida Public Service Commission
Docket No. 870654-WS*	North Naples Utilities, Inc. Florida Public Service Commission
Docket No. 870853	Pennsylvania Gas & Water Company Pennsylvania Public Utility Commission
Civil Action* No. 87-0446-R	Reynolds Metals Company, Plaintiff, v. The Columbia Gas System, Inc., Commonwealth Gas Services, Inc., Commonwealth Gas Pipeline Corporation, Columbia Gas Transmission Corporation, Columbia Gulf Transmission Company, Defendants - In the United States District Court for the Eastern District of Virginia - Richmond Division
Docket No. E-2, Sub 537	Carolina Power & Light Company North Carolina Utilities Commission
Case No. U-7830	Consumers Power Company - Step 2 Reopened Michigan Public Service Commission
Docket No. 880069-TL	Southern Bell Telephone & Telegraph Florida Public Service Commission
Case No. U-7830	Consumers Power Company - Step 3B Michigan Public Service Commission
Docket No. 880355-EI	Florida Power & Light Company Florida Public Service Commission
Docket No. 880360-EI	Gulf Power Company Florida Public Service Commission

Docket No. FA86-19-002	System Energy Resources, Inc. Federal Energy Regulatory Commission
Docket Nos. 83-0537-Remand & 84-0555-Remand	Commonwealth Edison Company Illinois Commerce Commission
Docket Nos. 83-0537 Remand & 84-0555 Remand	Commonwealth Edison Company Surrebuttal Illinois Commerce Commission
Docket No. 880537-SU	Key Haven Utility Corporation Florida Public Service Commission
Docket No. 881167-EI***	Gulf Power Company Florida Public Service Commission
Docket No. 881503-WS	Poinciana Utilities, Inc. Florida Public Service Commission
Cause No. U-89-2688-T	Puget Sound Power & Light Company Washington Utilities & Transportation Committee
Docket No. 89-68	Central Maine Power Company Maine Public Utilities Commission
Docket No. 861190-PU	Proposal to Amend Rule 25-14.003, F.A.C. Florida Public Service Commission
Docket No. 89-08-11	The United Illuminating Company State of Connecticut, Department of Public Utility Control
Docket No. R-891364	The Philadelphia Electric Company Pennsylvania Public Utility Commission
Formal Case No. 889	Potomac Electric Power Company Public Service Company of the District of Columbia
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (In the Supreme Court County of Onondaga, State of New York)

Case No. 87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf + Western, Inc. et al, defendants (In the Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
Case No. 89-640-G-42T*	Mountaineer Gas Company West Virginia Public Service Commission
Docket No. 890319-EI	Florida Power & Light Company Florida Public Service Commission
Docket No. EM-89110888	Jersey Central Power & Light Company Board of Public Utilities Commissioners
Docket No. 891345-EI	Gulf Power Company Florida Public Service Commission
BPU Docket No. ER 8911 0912J	Jersey Central Power & Light Company Board of Public Utilities Commissioners
Docket No. 6531	Hawaiian Electric Company Hawaii Public Utilities Commissioners
Docket No. 890509-WU	Florida Cities Water Company, Golden Gate Division Florida Public Service Commission
Docket No. 880069-TL	Southern Bell Telephone Company Florida Public Service Commission
Docket Nos. F-3848, F-3849, and F-3850	Northwestern Bell Telephone Company South Dakota Public Utilities Commission
Docket Nos. ER89-* 678-000 & EL90-16-000	System Energy Resources, Inc. Federal Energy Regulatory Commission
Docket No. 5428	Green Mountain Power Corporation Vermont Department of Public Service
Docket No. 90-10	Artesian Water Company, Inc. Delaware Public Service Commission
Case No. 90-243-E-42T*	Wheeling Power Company West Virginia Public Service Commission

Docket No. 900329-WS	Southern States Utilities, Inc. Florida Public Service Commission
Docket Nos. ER89-* 678-000 & EL90-16-000	System Energy Resources, Inc. (Surrebuttal) Federal Energy Regulatory Commission
Application No. 90-12-018	Southern California Edison Company California Public Utilities Commission
Docket No. 90-0127	Central Illinois Lighting Company Illinois Commerce Commission
Docket Nos. 90-0080- 91-0095	Generic Coal Tar Proceedings Illinois Commerce Commission
Docket No. FA-89-28-000	System Energy Resources, Inc. Federal Energy Regulatory Commission
Docket No. U-1551-90-322	Southwest Gas Corporation Before the Arizona Corporation Commission
Docket No. R-911966	Pennsylvania Gas & Water Company The Pennsylvania Public Utility Commission
Docket No. 176-717-U	United Cities Gas Company Kansas Corporation Commission
Docket No. 860001-EI-G	Florida Power Corporation Florida Public Service Commission
Docket No. 6720-TI-102	Wisconsin Bell, Inc. Wisconsin Citizens' Utility Board
(No Docket No.)	Southern Union Gas Company Before the Public Utility Regulation Board of the City of El Paso
Docket No. 6998	Hawaiian Electric Company, Inc. Before the Public Utilities Commission of the State of Hawaii
Docket No. TC91-040A	In the Matter of the Investigation into the Adoption of a Uniform Access Methodology Before the Public Utilities Commission of the State of South Dakota

Docket Nos. 911030-WS & 911067-WS	General Development Utilities, Inc. Before the Florida Public Service Commission
Docket No. 910890-EI	Florida Power Corporation Before the Florida Public Service Commission
Docket No. 910890-EI	Florida Power Corporation, Supplemental Before the Florida Public Service Commission
Case No. 3L-74159	Idaho Power Company, an Idaho corporation In the District Court of the Fourth Judicial District of the State of Idaho, In and For the County of Ada - Magistrate Division
Cause No. 39353*	Indiana Gas Company Before the Indiana Utility Regulatory Commission
Docket No. 90-0169 (Remand)	Commonwealth Edison Company Before the Illinois Commerce Commission
Docket No. 92-06-05	The United Illuminating Company State of Connecticut, Department of Public Utility Control
Cause No. 39498	PSI Energy, Inc. Before the State of Indiana - Indiana Utility Regulatory Commission
Cause No. 39498	PSI Energy, Inc. - Surrebuttal testimony Before the State of Indiana - Indiana Utility Regulatory Commission
Docket No. 7287	Public Utilities Commission - Instituting a Proceeding to Examine the Gross-up of CIAC Before the Public Utilities Commission of the State of Hawaii
Docket No. 92-227-TC	US West Communications, Inc. Before the State Corporation Commission of the State of New Mexico
Docket No. 92-47	Diamond State Telephone Company Before the Public Service Commission of the State of Delaware

Docket Nos. 920733-WS & 920734-WS	General Development Utilities, Inc. Before the Florida Public Service Commission
Docket No. 92-11-11	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket Nos.EC92-21-000 & ER92-806-000	Entergy Corporation Before the Federal Energy Regulatory Commission
Docket No. 930405-EI	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. UE-92-1262	Puget Sound Power & Light Company Before the Washington Utilities & Transportation Commission
Docket No. 93-02-04	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 93-02-04	Connecticut Natural Gas Corporation, Supplemental State of Connecticut, Department of Public Utility Control
Docket No. 93-057-01	Mountain Fuel Supply Company Before the Utah Public Service Commission
Cause No. 39353 (Phase II)	Indiana Gas Company Before the Indiana Utility Regulatory Commission
PU-314-92-1060	US West Communications, Inc. Before the North Dakota Public Service Commission
Cause No. 39713	Indianapolis Water Company Before the Indiana Utility Regulatory Commission
93-UA-0301*	Mississippi Power & Light Company Before the Mississippi Public Service Commission
Docket No. 93-08-06	SNET America, Inc. State of Connecticut, Department of Public Utility Control

Docket No. 93-057-01	Mountain Fuel Supply Company - Rehearing on Unbilled Revenues - Before the Utah Public Service Commission
Case No. 78-T119-0013-94	Guam Power Authority vs. U.S. Navy Public Works Center, Guam - Assisting the Department of Defense in the investigation of a billing dispute. Before the American Arbitration Association
Application No. 93-12-025 - Phase I	Southern California Edison Company Before the California Public Utilities Commission
Case No. 94-0027-E-42T	Potomac Edison Company Before the Public Service Commission of West Virginia
Case No. 94-0035-E-42T	Monongahela Power Company Before the Public Service Commission of West Virginia
Docket No. 930204-WS**	Jacksonville Suburban Utilities Corporation Before the Florida Public Service Commission
Docket No. 5258-U	Southern Bell Telephone and Telegraph Company Before the Georgia Public Service Commission
Case No. 95-0011-G-42T*	Mountaineer Gas Company Before the West Virginia Public Service Commission
Case No. 95-0003-G-42T*	Hope Gas, Inc. Before the West Virginia Public Service Commission
Docket No. 95-02-07	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 95-057-02*	Mountain Fuel Supply Before the Utah Public Service Commission
Docket No. 95-03-01	Southern New England Telephone Company State of Connecticut, Department of Public Utility Control

BRC Docket No. EX93060255 OAL Docket PUC96734-94	Generic Proceeding Regarding Recovery of Capacity Costs Associated with Electric Utility Power Purchases from Cogenerators and Small Power Producers Before the New Jersey Board of Public Utilities
Docket No. U-1933-95-317	Tucson Electric Power Before the Arizona Corporation Commission
Docket No. 950495-WS	Southern States Utilities Before the Florida Public Service Commission
Docket No. 960409-EI	Prudence Review to Determine Regulatory Treatment of Tampa Electric Company's Polk Unit 1 Before the Florida Public Service Commission
Docket No. 960451-WS	United Water Florida Before the Florida Public Service Commission
Docket No. 94-10-05	Southern New England Telephone Company State of Connecticut Department of Public Utility Control
Docket No. 96-UA-389	Generic Docket to Consider Competition in the Provision of Retail Electric Service Before the Public Service Commission of the State of Mississippi
Docket No. 970171-EU	Determination of appropriate cost allocation and regulatory treatment of total revenues associated with wholesale sales to Florida Municipal Power Agency and City of Lakeland by Tampa Electric Company Before the Florida Public Service Commission
Case No. PUE960296 *	Virginia Electric and Power Company Before the Commonwealth of Virginia State Corporation Commission
Docket No. 97-035-01	PacifiCorp, dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. G-03493A-98-0705*	Black Mountain Gas Division of Northern States Power Company, Page Operations Before the Arizona Corporation Commission

Docket No. 98-10-07	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. 98-10-07	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket NO. 99-02-05	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 99-03-36	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 99-03-35	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. 99-03-04	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. 99-08-02	Yankee Energy System, Inc. State of Connecticut Department of Public Utility Control
Docket No. 99-08-09	CTG Resources, Inc. State of Connecticut Department of Public Utility Control
Docket No. 99-07-20	Connecticut Energy Corporation / Energy East State of Connecticut Department of Public Utility Control
Docket No. 99-09-03 Phase II	Connecticut Natural Gas State of Connecticut Department of Public Utility Control
Docket No. 99-09-03 Phase III	Connecticut Natural Gas State of Connecticut Department of Public Utility Control
Docket No. 99-04-18	Southern Connecticut Gas Company

Phase II	State of Connecticut Department of Public Utility Control
Docket No. 99-057-20*	Questar Gas Company Public Service Commission of Utah
Docket No. 99-035-10	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. T-1051B-99-105	U.S. West Communications, Inc. Arizona Corporation Commission
Docket No. 01-035-10*	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. 991437-WU	Wedgefield Utilities, Inc. Before the Florida Public Service Commission
Docket No. 991643-SU	Seven Springs Before the Florida Public Service Commission
Docket No. 98P55045	General Telephone and Electronics of California California Public Utilities Commission
Docket No. 00-01-11	Consolidated Edison, Inc. and Northeast Utilities Merger State of Connecticut Before the Department of Public Utility Control
Docket No. 00-12-01	Connecticut Light & Power Company State of Connecticut Before the Department of Public Utility Control
Docket No. 000737-WS	Aloha Utilities/Seven Springs Utilities Before the Florida Public Service Commission
Consolidated Docket Nos. EL00-66-000 ER00-2854-000 EL95-33-000	Entergy Services, Inc. Before the Federal Energy Regulatory Commission
Docket No. 950379-EI	Tampa Electric Company Before the Florida Public Service Commission
Docket No. 010503-WU	Aloha Utilities, Inc. – Seven Springs Water Division Before the Florida Public Service Commission

Docket No. 01-07-06*	The Towns of Durham and Middlefield State of Connecticut Before the Department of Public Utility Control
Docket No. 99-09-12-RE-02	Connecticut Light & Power/Millstone State of Connecticut Before the Department of Public Utility Control
Civil Action No. C2-99-1181	The United States et al v. Ohio Edison et al U.S. District Court, S.D. Ohio
Docket No. 001148-ET****	Florida Power & Light Company Before the Florida Public Service Commission
Civil Action No. 99-833-Per *	The United States et al v. Illinois Power Company U.S. District Court, S.D. Illinois
Civil Action No. IP99-1692-C-M/s *	The United States et al v. Southern Indiana Gas and Electric Company U.S. District Court, S.D. Indiana
Docket No. 02-057-02*	Questar Gas Company Public Service Commission of Utah
Docket No. EL01-88-000	Entergy Services, Inc. et. al. Mississippi Public Service Commission
Docket No. 9355-U	Georgia Power Company Before the Georgia Public Service Commission
Case No. 1016	Washington Gas Light Company Before the Public Service Commission of the District of Columbia
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Docket No. 030438-EI *	Florida Public Utilities Company Before the Florida Public Service Commission
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Application No. 02-12-028	San Diego Gas & Electric Company Before the California Public Utilities Commission
Civil Action No. 1:00 CV1262	The United States et al v. Duke Energy Company
Docket No. 050045-EI *	Florida Power & Light Corporation Before the Florida Public Service Commission
Docket No. 050078-EI *	Progress Energy Florida, Inc. Before the Florida Public Service Commission
Civil Action No. 1P99-1693 C-M/S	The United States et al. v. Cinergy Corporation, ET AL.
Civil Action No. 04-34-KSF	The United States et al. v. East Kentucky Power Cooperative, Inc. ET AL.
Case No. 05-0304-G-42T *	Hope Gas, Inc. d/b/a Dominion Hope Consumer Advocate Division of the Public Service Commission of West Virginia
Case No. 05-E-1222	New York State Electric & Gas Corporation Before the New York Public Service Commission
Case Nos. 05-E-0934 05-G-0935	Central Hudson Gas & Electric Corporation Before the New York Public Service Commission
Case No. 05-G-1494	Orange and Rockland Utilities, Inc. Before the New York Public Service Commission
Docket No. 060038-EI	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 060154-EI*	Gulf Power Company Before the Florida Public Service Commission
Docket No. 060300-TL	GTC, Inc. d/b/a GT Com Before the Florida Public Service Commission
Case Nos. 06-G-1185 06-G-1186	KeySpan Gas East Corporation Before the New York Public Service Commission
Docket No. U-29203	Gulf States, Inc. and Entergy Louisiana, Inc.

(Phase II)	Before the Louisiana Public Service Commission
Formal Case No. 1053	Potomac Electric Power Company Before the Public Service Commission of the District of Columbia
Application No. 06-12-009	San Diego Gas & Electric Company Before the California Public Utilities Commission
Formal Case No. 1054*	Washington Gas Light Company Before the Public Service Commission of the District of Columbia
Civil Action No. 2:05cv0885	Commonwealth of Pennsylvania et al vs Allegheny Energy Inc. et al
Docket No. P06-004	Lake Charles Pilots', Inc. Before the Louisiana Pilotage Fee Commission
Docket Nos. 070304-EI & 070300-EI	Florida Public Utilities Company Before the Florida Public Service Commission
Docket No. ER07-956-001	Entergy Service, Inc. Before the Federal Energy Regulatory Commission
Docket No. 080001-EI	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 080317-EI	Tampa Electric Company Before the Florida Public Service Commission
Civil Action No. 5:07-CV-75	The United States et al. v. Kentucky Utilities Company
Formal Case No. 1053 Phase II	Potomac Electric Power Company Before the Public Service Commission of the District of Columbia
Case No. GUD No. 9869	Atmos Energy Corporation City of Dallas Before the Texas Railroad Commission
Case No. GUD No. 9902	CenterPoint Energy Resources Corp. City of Houston and the Houston Coalition of Cities Before the Texas Railroad Commission

Docket Nos. UE-090134 & UG-090135	Avista Corporation Before the Washington Utilities & Transportation Commission
Docket No. 10-02-13	Aquarion Water Company of Connecticut State of Connecticut Before the Department of Public Utility Control
Docket No. 09-12-11	Connecticut Water Company State of Connecticut Before the Department of Public Utility Control
Docket UG-201*	Avista Corporation Before the Oregon Public Utilities Commission
Civil Action Case No.***** 10-CV-13101	The United States et al. v. Detroit Edison Company
Docket No. P07-001	Crescent River Port Pilots Before the Louisiana Pilotage Fee Commission
Civil Action Case No. 09-100-Ret-CN	The United States et al. v. Louisiana Generating Company
Civil Action Case No. 2:01-cv-00152-VEH	The United States et al. v. Alabama Power Company
Civil Action Case No. CV-08-1136-HA	The United States et al. v. Portland General Electric Company

*Case Settled
**Issues Stipulated
***Testimony Withdrawn
****Case Settled, Testimony Not Filed
*****Case Dismissed