Oregon

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July 24, 2009

Via Electronic Filing and U.S. Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: **Docket No. UE 210 – In the Matter of PACIFICORP, dba PACIFIC POWER Request for a General Rate Revision.**

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff's Opening Testimony.

/s/ Kay Barnes
Kay Barnes
Regulatory Operations Division
Filing on Behalf of Public Utility Commission Staff
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c: UE 210 Service List (parties)

PUBLIC UTILITY COMMISSION
OF OREGON

UE 210

STAFF OPENING TESTIMONY OF

Deborah Garcia
Dustin Ball
Michael Dougherty
Ed Durrenberger
Lisa Gorsuch
Ming Peng
Paul Rossow
Steve Storm
Jorge Ordonez
Robert Clark
George R. Compton
Matt Muldoon
Kelcey Brown

In the Matter of
PACIFICORP, dba PACIFIC POWER
Request for a General Rate Revision.

REDACTED VERSION
July 24, 2009

CASE: UE 210
WITNESS: Deborah Garcia

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

July 24, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Deborah Garcia. I am a Senior Revenue Requirements Analyst in the Electric & Natural Gas Revenue Requirements section of the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is three-fold. First, I am the revenue requirements summary witness for the Public Utility Commission of Oregon Staff (Staff) in this proceeding. Accordingly, I am generally familiar with the Staff sponsored adjustments to PacifiCorp's filing in this docket. Second, I am proposing adjustments to the test-year rate base. Third, I propose adjustments to the property taxes associated with all Staff rate base adjustments.

Q. PLEASE PROVIDE A LIST OF STAFF WITNESSES, EXHIBIT NUMBERS, AND THE SUBJECTS EACH ADDRESSES.

A. Staff witnesses who are providing opening testimony in this docket are as follows:

Witness	Exhibit	Subject(s)
Garcia	100	Revenue Requirement, TAM NPC-related Revenue Adjustment, Misc. Rate Base, & Property Taxes

Witness	Exhibit	Subject(s)
Ball	200	Misc. A&G Expense, Misc. Transmission & O&M Expense, & Property Tax Factor
Dougherty	300	Distribution Expense & Sale of Renewable Energy Credits
Durrenberger	400	Threemile Knoll Substation, Misc. Transmission Rate Base, & Misc. Wind Resource Rate Base
Gorsuch	500	Employee Bonus & Incentive Plans
Peng	600	Depreciation & Amortization related to Expense and Rate Base
Rossow	700	Uncollectible Expense & Revenue Sensitive Factor
Storm	800	Capital Structure, Rate of Return, Return on Equity
Ordonez	900	Cost of Long Term Debt & Cost of Preferred Stock
Clark	1000	Allocation Factors
Compton	1100	Rate Spread & Rate Design
Muldoon	1200	Long Run Incremental Cost Data Models
Brown	1300	Wind Resource Acquisition, TAM Methodology Changes

Q. HAVE YOU PREPARED EXHIBITS FOR THIS DOCKET?

A. Yes. I have prepared Exhibit Staff/Garcia/102, consisting of 8 pages. This exhibit contains tables summarizing the Staff proposal for PacifiCorp's Oregon-allocated revenue requirements in this docket. I have also prepared Exhibit Staff/103 consisting of 5 pages, which provide support for the adjustment to rate base that I am sponsoring.

Q. IS THERE A DIFFERENCE BETWEEN THE REVENUE REQUIREMENT REQUESTED BY PACIFICORP AND THE AMOUNT STAFF PROPOSES?

A. Yes. To summarize, PacifiCorp requested an increase to revenue requirement (not related to power costs) of approximately $92.0 million, while Staff proposes an increase of approximately $9.6 million -- a difference of approximately $82.4 million. The details related to Staff's proposed adjustments are described in the following testimony.

Q. PLEASE DESCRIBE THE INFORMATION IN EXHIBIT STAFF/GARCIA/102.

A. This Exhibit summarizes the Staff-proposed adjustments and resulting revenue requirement on an Oregon-allocated basis for PacifiCorp in UE 210 as follows: On Pages 1 and 2 is a narrative summary that begins with the PacifiCorp's original revenue requirement request, followed by a short description of each of Staff's proposed adjustments and the associated adjustment to revenue requirement. The summary includes issues that Staff addresses in testimony but for which there are no associated revenue requirement adjustments.

Page 3 is a summary that illustrates the effects of Staff's proposed adjustments to revenues, expenses, rate base, and cost of capital. Specifically, Column (1) is the PacifiCorp's test period results of operations as filed in this case; Column (2) is the aggregate of Staff's proposed adjustments; Column (3) is the sum of Columns (1) and (2); Column (4) represents the revenue requirement change required to meet Staff's proposed cost of capital; and, Column (5) is the test period results of operations as adjusted by Staff's proposals.

Page 4 shows the income tax calculations related to the results of operations summary on Page 3.

Page 5 shows the effects on revenues, expenses, and rate base for each Staff-proposed adjustment with the associated tax calculations shown on Page 6. Page 7 is a list of the revenue sensitive factors used to calculate revenue requirement, as modified by Staff's proposed adjustment to uncollectible expense.

On Page 8 there are two Cost of Capital summaries, the first proposed by PacifiCorp in its filing and the second proposed by Staff.

Q. IS STAFF PROPOSING AN ADJUSTMENT THAT WILL IMPACT THE STAFF-PROPOSED REVENUE REQUIREMENT THAT IS NOT CURRENTLY INCLUDED IN EXHIBIT 102?

A. Yes. Staff Witness Clark proposes to change the methodology and final percentages associated with some of the factors PacifiCorp uses to allocate its system-wide costs to Oregon. Subsequent to the Commission decision in this case, PacifiCorp will implement and Staff will verify the impact of those changes to the account balances and Commission-ordered adjustments.

Q. WHY ARE THE STAFF-PROPOSED CHANGES TO ALLOCATION FACTORS NOT INCORPORATED INTO THE CURRENT EXHIBIT?

A. The final dollar adjustment resulting from a change to even a single allocation factor methodology may impact hundreds of accounts and depends in part on the level of expense that the Commission approves. In an effort to generally quantify what the results will be, Staff Witness Clark has submitted a data request to PacifiCorp asking it to provide the total dollars by allocation factor included in its filing, further broken out into revenue, expense, and rate base. Staff will include those results in its rebuttal testimony.

Q. WHY DOES THE REVENUE REQUIREMENT MODEL SHOW A COMPANY-PROPOSED REVENUE REQUIREMENT OF APPROXIMATELY $112.6 MILLION RATHER THAN $92.0 MILLION, AS STATED EARLIER IN YOUR TESTIMONY?

A. The difference of approximately $20.6 million represents the revenue increase requested by PacifiCorp in Docket No. UE 207, PacifiCorp's annual power cost adjustment commonly known as the TAM, in which PacifiCorp updates its power costs for the upcoming year.

Q. PLEASE EXPLAIN WHY THE TAM REVENUE REQUEST IS INCLUDED IN THE GENERAL RATE CASE RATHER THAN CONFINED TO THE TAM DOCKET.

A. The TAM revenue request is included as a placeholder[1] only for the purpose of calculating the associated revenue sensitive expense[2] for inclusion into base rates. The result narrows the difference between the expense customers will pay for in rates, and PacifiCorp's obligations. Staff Adjustment S-1[3] removes the TAM revenue request of $20.6 million from the rate case, leaving the associated revenue requirement intact.

[1] The actual dollar amount will be modified to reflect the final outcome of UE 207.
[2] Revenue sensitive factors are generally included in all revenue requirement calculations and include a utility's ongoing obligation for expenses such as income taxes, other taxes including franchise fees, and uncollectible expense
[3] See Staff exhibit/Garcia 102/Page 1. Again, the dollar amount will be reconciled to the outcome of UE 207.

MISCELLANEOUS RATE BASE ADJUSTMENT (S-8)

Q. DO YOU PROPOSE TO ADJUST PACIFICORP'S PROFORMA ADJUSTMENT[4] TO RATE BASE?

A. Yes. I recommend that PacifiCorp's proposed increase to rate base on an Oregon-allocated basis be reduced by approximately $116.6 million or 15.4 percent, from $758.7 million to $642.1 million.[5]

Q. DOES YOUR ADJUSTMENT INCLUDE ANY RATE BASE ADDITIONS THAT OTHER STAFF WITNESSES PROPOSE TO ADJUST?

A. No.

Q. PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT.

A. A review of the line items identified in PacifiCorp's proposed increase to rate base revealed that it should be reduced by approximately $116.6 million. The adjustment is based on three categories of line items that should be removed or reduced. The first category is related to items that are scheduled to go into service subsequent to rates taking effect, totaling approximately $36.4 million. The second is items that do not belong in rate base, totaling approximately $400,000. The third is items that are labeled by PacifiCorp as having "monthly" or "variable" in-service dates, totaling approximately $79.8 million.

Q PLEASE DESCRIBE THE PROPOSED ADJUSTMENT FOR EACH CATEGORY.

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[4] PPL/700/Dalley/pgs 31-32; PPL/702/pgs 8.618-8.6.29
[5] See Staff Exhibit/Garcia 103, p. 1 for a summary of the adjustment.

A. The first category is the proposed additions that are scheduled to be completed some time in 2010, but not until after rates go into effect, currently scheduled for February 2, 2010.

Q. DOES PACIFICORP PROPOSE TO INCLUDE THE FULL COST FOR THESE ITEMS INTO RATE BASE?

A. No. PacifiCorp proposes to add to rate base, on an annual basis, a portion of the dollars equal to the number of months in 2010 that the item would be in-service. (Total dollars divided by 12, times the number of months.) For example, if the item were scheduled to go into service on November 1, 2010, the Company would add the equivalent of 2 months of the total cost to rate base, with the balance carrying forward until the next general rate case.

Q. WHY IS THIS PROBLEMATIC IF THE COMPANY HAS CHOSEN A TEST YEAR ENDING DECEMBER 31, 2010?

A. Generally, a future test year is based on actual results of a historic period, increased by known and measurable changes. Regarding rate base specifically, Oregon Revised Statute 757.355 prohibits the addition to "… customer rates any costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer." The proposed rate base additions included in this category are related to new plant, and for repairs or upgrades to existing plant that is currently providing service to customers. In either case there is no guarantee that the projected costs associated with any of the projects is entirely accurate, that any of them will be completed by the forecasted date, or even whether they will be completed. In other words, the expenditures are not known and measurable. Staff does not believe the PacifiCorp is intentionally misrepresenting the proposed additions, rather it is a simple reality that no entity can foresee unexpected changes in costs, delays, or whether there would be a logical reason to scrap a proposed project. It is not in the best interest of customers to include a “guesstimate” of rate base into ongoing rates, particularly considering the directive provided by the statute. I recommend an adjustment to remove 100 percent, or approximately $36.4 million, from this category of rate base additions.

Q. HAS THE COMMISSION EVER MADE EXCEPTIONS FOR THIS POLICY?

A. Yes. As I will discuss in more detail in my testimony below, one common exception has been made related to an electric utility’s ongoing need to increase distribution plant as its customer base grows. Some examples of these costs are for the poles, wires, meters, and other plant necessary to distribute electricity to customers. These costs are ongoing in nature and can be reasonably assumed to be made on a regular basis. Historically, the Commission has allowed a reasonable percentage increase in distribution plant rate base for a future test year, relative to the expected growth in a utility’s customer base. The other point to this accommodation is that, aside from installing new distribution plant, the utility has ongoing obligations related to safety and reliability to repair, replace, or reinforce this plant. In its case, PacifiCorp has labeled the in-service date of this type of Distribution Plant as “various.”

Q. PLEASE EXPLAIN YOUR ADJUSTMENT OF "ITEMS THAT DO NOT BELONG IN RATE BASE."

A. The Workpapers related to PacifiCorp's requested increase to rate base consist of more than 3,000 line items. It appears that 2 items were added to the data base in error. One is the cost associated with Construction Work in Progress which is not eligible for inclusion into rate base. The other is related to a treadmill for employees' use, which is not a rate base item. I recommend an adjustment to remove 100 percent, or approximately $400,000 for this category.

Q. PLEASE EXPLAIN THE RESULTS OF YOUR REVIEW FOR ITEMS WHERE THE IN-SERVICE DATES ARE "VARIOUS" OR "MONTHLY."

A. A review of the items in the Distribution category confirms that they are necessary for the direct provision of service to customers, such as wires, poles, meters, etc. However, for the period of June 2008 to December 31, 2010, PacifiCorp's proposed addition of $130.3 million to Distribution-related rate base results in a net increase of approximately $110.0 million, [6] from 1.58 million to 1.69 million, an increase of approximately 6.51 percent, while forecasted customer growth is approximately 1.83 percent for the same period. Stated another way, PacifiCorp's addition to Distribution rate base is more than three times the expected customer growth. Distribution rate base line items with an in-service date of "various" consist of approximately $101.4 million of the requested $130.3 million increase.

[6] See PPL/702/pg. 2.26/line 1693. The net increase is derived from the proposed additions to rate base, less plant retirements.

The balance of the increase for items in rate base categories other than Distribution that have a designated in-service date of “various” or monthly” could reasonably be assumed to be necessary for PacifiCorp to operate, but the level of the cost and even whether the cost will be incurred, as stated in PacifiCorp’s case, is somewhat uncertain.

Q. DID YOU REQUEST ADDITIONAL INFORMATION FROM PACIFICORP?

A. Yes. I sent Staff Data Request No. 307[7] asking PacifiCorp to provide the in-service dates for the items. PacifiCorp responded that the term “various” is used as the in-service date when capital investment for a project is projected to be placed into service in more than one month. For many of the items in this category not categorized as Distribution Plant, it appears that the line items refer to a single project.

Q. DO YOU BELIEVE THIS EXPLANATION IS SUFFICIENT TO ALLOW ALL SUCH COSTS TO BE INCLUDED IN RATE BASE?

A. No. Again, the costs are forecast, rather than known and measurable changes. With the exception of costs associated with Distribution Plant, it is not appropriate to adjust rates when the rate base expenditures are not know and measurable. As mentioned above, the statute requires that items in rate base are used in the provision of service before their inclusion into rate base.

In response to Staff’s follow up questions, PacifiCorp sent Data Response No. 307-1st Supplemental[8] to further explain its use of “various” as the in-service date as follows: “…subsequent to the in-service date, remaining capital

[7] See Staff Exhibit/Garcia/102/p. 3.
[8] Ibid., pp. 4-5

outlays are anticipated to cover costs related to the completion of each project." This further reinforces the idea that PacifiCorp should have some ability to forecast the in-service date if it is able to forecast the months in which subsequent capital outlays to finalize the projects will be made.

In its response, PacifiCorp also included the in-service dates for a subset of projects that have been completed but where the in-service date was not in PacifiCorp's accounting system (SAP) when the data was pulled for the rate case, further lending credibility to the idea that the items listed as "various" do not have finalized in-service dates.

Q. DOES YOUR PROPOSED ADJUSTMENT TO RATE BASE TAKE INTO CONSIDERATION THE UPDATED IN-SERVICE DATES?

A. Yes. I did not adjust any line item for which PacifiCorp provided updated information.

Q. WHAT IS YOUR RECOMMENDED ADJUSTMENT FOR THE RATE BASE LINE ITEMS WHERE THE DESIGNATED IN-SERVICE DATES ARE "MONTHLY" OR "VARIOUS."

A. The Commission has three options for rate base in this category: the first is to entirely disallow the cost until the in-service date is certain with the item closed to books; the second is to allow the cost assuming that the project will close to books by the date rates go into effect or be providing service to customers in a timely manner; and, the third is to allow some portion of the cost assuming it is necessary for the provision of service to customers. I recommend the third option and my adjustment removes 50 percent of the cost as a reasonable middle ground between the two extremes. This option is also supported by my finding that PacifiCorp has proposed a level of Distribution Plant that is more than three times higher than projected customer growth. I recommend a reduction of approximately $79.8 million.

Q. PLEASE EXPLAIN WHY YOU HAVE NOT ADJUSTED THE DEPRECIATION AND AMORTIZATION ASSOCIATED WITH THE PROPOSED ADJUSTMENT TO RATE BASE.

A. Staff Witness Peng has incorporated the depreciation and amortization associated with Staff Witness Adjustments S-3, S-8, S10, and S-11 into Adjustment S-7 that she is sponsoring. These amounts will need to be revised for any changes to the Staff-recommended adjustments to rate base that may occur in this proceeding.

Property Tax Adjustment (S-3, S-8, S-10 & S-11)

Q. PLEASE EXPLAIN THE ADJUSTMENT TO PROPERTY TAXES THAT YOU RECOMMEND.

A. Property Tax that is included in rates is calculated by applying the appropriate property tax factor to the dollars of rate base allowed in rates. These adjustments to Property Tax align Staff's proposed reductions to rate base in Adjustments S-3, S-8, S-10, and S-11[9] with the property taxes PacifiCorp will pay. The Property Tax adjustments will need to be revised if, during this proceeding, changes are made to Staff's recommended rate base adjustments,

[9] See Staff Exhibit 102/pg 5 for the amount of property tax adjustment that is associated with each of the Staff adjustments.

or if there is a change to the methodology used by Staff Witness Ball[10] to determine the appropriate property tax factor.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[10] See Staff 200/Ball/Issue 11

CASE: UE 210
WITNESS: Deborah Garcia

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

July 24, 2009

WITNESS QUALIFICATIONS STATEMENT

NAME: DEBORAH A. GARCIA

EMPLOYER: PUBLIC UTILITY COMMISSION OF OREGON

TITLE: SENIOR REVENUE REQUIREMENT ANALYST

ADDRESS: 550 CAPITOL ST NE SUITE 215, SALEM, OREGON 97301-2551

EDUCATION:

- Western Utility Rate School, San Diego, California. (2002)

- The Center For Public Utilities at New Mexico University and the National Association of Regulatory Commissioners' Annual Regulatory Studies Program. (2000)

- National Association of Regulatory Utility Commissioners' Annual Regulatory Studies Program at Michigan State University. (2000)

- Certificate in Mediation Training (1994)

- College-level coursework in financial accounting, business law, business management, and economics.

WORK EXPERIENCE:

- Sr Revenue Requirement Analyst --Public Utility Commission of Oregon Lead accounting witness for revenue requirement in various proceedings. (2007 - present)

- Utility Analyst -- Public Utility Commission of Oregon Focus on utility policies, natural gas purchased gas adjustment issues, utility territory allocation issues, consumer issues, tariff review, promotional concessions, rate case review & witness, and rulemakings. (2002 - 2007)

- Research Analyst -- Public Utility Commission of Oregon Focus on SB 1149 implementation, rulemaking, various utility and electric service supplier policies, including certification of electric service suppliers, tariff review, rate case review & witness. (2000 -2002)

- Compliance Specialist -- Public Utility Commission of Oregon--Handled consumer complaints, liaison between the public, regulated utilities and various Commission staff, reviewed proposed tariffs, administrative rules, and policies with an emphasis on potential impact to consumers. Identified trends, services, and policies where no statute, rule or precedent applied and recommended appropriate action. (1992 - 2000)

CASE: UE 210
WITNESS: Deborah Garcia

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 102

Exhibits in Support Of Opening Testimony

July 24, 2009

PACIFICORP UE 210
Staff's Adjustments to Oregon Allocated Results
Year Ending December 31, 2010
($000)

Item	Staff	Issue	Revenue Requirement Effect
		Revenue Requirement on the Company's Filed Results This Revenue Requirement on the Company's Filed Results includes the 2010 Net Power Cost-related requested increase of $20,572 million made in UE 207. This amount is removed by Staff Adjustment S-1 below.	**$112,629**
S-0	SS/JO	**Cost of Capital** This adjustment reflects Staff proposed modifications to the Company's capital structure, cost of debt, and return on equity.	**($42,585)**
S-1	DG	**TAM Net Power Cost-Related Revenue Adjustment** The purpose of this adjustment is to remove the requested 2010 NPC-related revenue increase while retaining the associated revenue requirement that would apply if the requested revenue increase is granted.	**($20,572)**
S-2	PR	**Uncollectible Expense** This adjustment modifies the Company base case uncollectible expense to account for Staff's adjustment of the uncollectible rate from 0.531% to 0.43%	**($989)**
S-2.0	PR	**Adjustment to Revenue Sensitive Uncollectible Rate** This adjustment modifies the Company revenue requirement to account for Staff's adjustment of the uncollectible rate from 0.531% to 0.43%	**($118)**
S-3	ED	**Transmission Rate Base Adjustment** This adjustment adjusts transmission rate base.	**($1,247)**
S-4	DB	**A&G Miscellaneous Adjustments** This adjustment is based on a series of adjustments in Accounts 901 through 935.	**($11,912)**

PACIFICORP UE 210
Staff's Adjustments to Oregon Allocated Results
Year Ending December 31, 2010
($000)

S-5	MD	**Distribution O&M** This adjustment removes non-labor related expense, net of the applicable Company O&M adjustment in Tab 4.20.	($1,195)
S-6	DB	**Transmission O&M/ Property Taxes** This adjustment is based on a series of adjustments in Accounts 580 through 598 and Taxes Oher Than Income.	($2,665)
S-7	MP	**Depreciation & Amortization** This adjustment consists of adjustments to Depreciation & Amortization expense and accumulated reserves.	($3,163)
S-8	DG	**Miscellaneous Rate Base** This adjustment reduces the proforma rate base additions (2010 ROO, Tab 8.6) based on the inservice date or whether the expense is properly included in rate base.	($13,725)
S-9	LG	**Bonus & Incentives** This adjustment removes 100% of officer bonuses and 50% of the Annual Incentive Plan bonuses that apply to all other employees.	($3,808)
S-10	ED	**Threemile Knoll Substation** This adjustment reduces costs attributed to this substation that Staff believes are unjustifyably high.	($792)
S-11	ED	**Wind Plant Miscellaneous Rate Base** This adjustment removes remove Capital Surcharge and Contingency Expenses from the Pro Forma Additions for Wind Plant Capital Costs (adjustment 8.6)	($238)
		Total Adjustments	**($103,009)**
		Staff Adjusted Revenue Requirement (Non-NPC)	**$9,620**

DB Dustin Ball - 503/373-7946
RC Robert Clark - 503/378-5942
GC George Compton - 503/378-6123
MD Mike Dougherty - 503/378-3623
ED Ed Durrenberger - 503/373-1536
DG Deborah Garcia - 503/378-6688

LG Lisa Gorsuch - 503/378-3778
JO Jorge Ordonez 503/378-4629
MP Ming Peng - 503/373-1123
PR Paul Rossow - 503/378-6917
SS Steven Storm - 503/378-5264

PACIFICORP UE 210
Results of Operations
Year Ending December 31, 2010
($000)

	SUMMARY SHEET	2010 Oregon Results Per Company Filing (1)	Staff Adjustments (2)	2010 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	**Operating Revenues**					
2	General Business Revenues	$949,341	$20,572	$969,913	$9,620	$979,533
3	Special Sales	201,717	0	201,717	0	201,717
4	Other Revenues	42,876	0	42,876	0	42,876
5	**Total Operating Revenues**	$1,193,934	$20,572	$1,214,506	$9,620	$1,224,126
6	**Operating Expenses**					
7	Steam Production	$251,950	$0	$251,950	$0	$251,950
8	Hydro Production	9,912	0	9,912	0	9,912
9	Other Power Supply	275,008	0	275,008	0	275,008
10	Transmission	51,260	(252)	51,008	0	51,008
11	Distribution	70,711	(1,163)	69,548	0	69,548
12	Customer Accounts (Uncollectibles)	31,711	(963)	30,748	130	30,878
13	Customer Service & Info	3,695	0	3,695	0	3,695
14	Sales	0	0	0	0	0
15	Administrative and General	57,052	(14,920)	42,132	0	42,132
16	**Total Operation & Maintenance**	$751,299	($17,298)	$734,001	$130	$734,131
17	Depreciation	148,046	(2,777)	145,269	0	145,269
18	Amortization	16,476	(617)	15,859	0	15,859
19	Taxes Other than Income	51,965	(3,449)	48,516	698	49,214
20	Income Taxes	43,231	18,447	61,678	3,337	65,015
21	Miscellaneous Revenue & Expense	(2,077)	0	(2,077)	0	(2,077)
22	**Total Operating Expenses**	$1,008,940	($5,694)	$1,003,246	$4,165	$1,007,411
23	**Net Operating Revenues**	$184,994	$26,266	$211,260	$5,481	$216,741
24	**Average Rate Base**					
25	Electric Plant in Service	$5,550,442	($139,393)	$5,411,049	$0	$5,411,049
26	Less: Accumulated Depreciation & Amortization	(2,182,523)	2,982	(2,179,541)	0	(2,179,541)
27	Accumulated Deferred Income Taxes	(548,748)	0	(548,748)	0	(548,748)
28	Accumulated Deferred Inv. Tax Credit	(4,172)	0	(4,172)	0	(4,172)
29	**Net Utility Plant**	$2,814,999	($136,411)	$2,678,588	$0	$2,678,588
30	Plant Held for Future Use	0	0	0	0	0
31	Acquisition Adjustments	18,568	0	18,568	0	18,568
32	Working Capital	12,867	0	12,867	0	12,867
33	Fuel Stock	41,007	0	41,007	0	41,007
34	Materials & Supplies	49,318	0	49,318	0	49,318
35	Customer Advances for Construction	(3,499)	0	(3,499)	0	(3,499)
36	Weatherization Loans	(1)	0	(1)	0	(1)
37	Prepayments	12,200	0	12,200	0	12,200
38	Misc. Deferred Debits	32,823	0	32,823	0	32,823
39	Misc. Rate Base Additions/(Deductions)	(19,976)	0	(19,976)	0	(19,976)
40	**Total Average Rate Base**	$2,958,307	($136,411)	$2,821,896	$0	$2,821,896
41	**Rate of Return**	6.25%		7.49%		7.68%
42	**Implied Return on Equity**	6.52%		8.93%		9.40%

PACIFICORP UE 210
Results of Operations
Year Ending December 31, 2010
($000)

	Income Tax Calculations	2010 Oregon Per Company Filing (1)	Staff Adjustments (2)	2010 Oregon Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Book Revenues	$1,193,934	$20,572	$1,214,506	$9,620	$1,224,126
2	Book Expenses Other than Depreciation	817,663	($21,364)	796,299	828	797,127
3	State Tax Depreciation	148,046	($2,777)	145,269	0	145,269
4	Interest	84,395	($3,892)	80,503	0	80,503
5 Less:	Schedule M Differences(Deductions less Additions)	38,802	$0	38,802	0	38,802
6	State Taxable Income	$105,028	$48,604	$153,633	$8,792	$162,425
7	Add OR Depletion Adjustment	$0	$0	$0	$0	$0
8	Total State Taxable Income	$105,028	$48,604	$153,633	$8,792	$162,425
9	State Income Tax @ 4.540%	$4,470	$2,207	$6,677	$399	$7,076
10	State Tax Credits	$0	$0	0	0	0
11	Net State Income Tax	$4,470	$2,207	$6,677	$399	$7,076
12	Additional Tax Depreciation	0	0	0	0	0
13 Plus:	Other Schedule M Differences	0	0	0	0	0
14	Federal Taxable Income	$99,154	46,397	$145,551	$8,393	$153,944
15	Federal Tax @ 35%	20,969	16,240	37,209	2,938	40,147
16	Federal Tax Credits		0	0	0	0
17	Current Federal Tax	$20,969	$16,240	$37,209	$2,938	$40,147
18	ITC Adjustment		-			
19	Deferral	0	0	0	0	0
20	Restoration	0	0	0	0	0
21	Total ITC Adjustment	$0	$0	$0	$0	$0
22	Provision for Deferred Taxes	$17,792	$0	$17,792	$0	$17,792
23	Total Income Tax	$43,231	$18,447	$61,678	$3,337	$65,015

PACIFICORP UE 210
Staff Adjustments to Oregon Results
Year Ending December 31, 2010
($000)

	Staff Adjustments	NPC (TAM) Related Revenue (S-1)	Uncollectible Expense (S-2)	Transmission Rate Base (S-3)	A&G O&M/Cap. Adjs (S-4)	Distribution O&M Expense (S-5)	Transmission O&M Expense (S-6)	Dep&Amort O&M/Cap Adjs (S-7)	8.6 Proforma Rate Base (S-8)	Bonus & Incentives Adj (S-9)	Threemile Knoll Substation (S-10)	Wind Plant Misc. Rate Base (S-11)	Total Adjustments (Base Rates)
1	**Operating Revenues**												
2	General Business Revenues	$20,572	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,572
3	Special Sales	0	0	0	0	0	0	0	0	0	0	0	$0
4	Other Revenues	0	0	0	0	0	0	0	0	0	0	0	$0
5	**Total Operating Revenues**	$20,572	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,572
6	**Operating Expenses**												
7	Steam Production	0	0	0	0	0	0	0	0	0	0	0	$0
8	Hydro Production	0	0	0	0	0	0	0	0	0	0	0	$0
9	Other Power Supply	0	0	0	0	0	0	0	0	0	0	0	$0
10	Transmission	0	0	0	0	0	(252)	0	0	0	0	0	($252)
11	Distribution	0	0	0	0	(1,163)	0	0	0	0	0	0	($1,163)
12	Customer Accounting	0	(963)	0	0	0	0	0	0	0	0	0	($963)
13	Customer Service & Info	0	0	0	0	0	0	0	0	0	0	0	$0
14	Sales	0	0	0	0	0	0	0	0	0	0	0	$0
15	Administrative and General	0	0	0	(11,368)	0	0	0	0	(3,552)	0	0	($14,920)
16	**Total Operation & Maintenance**	$0	($963)	$0	($11,368)	($1,163)	($252)	$0	$0	($3,552)	$0	$0	($17,298)
17	Depreciation	0	0	0	0	0	0	(2,777)	0	0	0	0	($2,777)
18	Amortization	0	0	0	0	0	0	(617)	0	0	0	0	($617)
19	Taxes Other than Income	0	0	(86)	0	0	(2,340)	0	(951)	0	(55)	(16)	($3,449)
20	Income Taxes	7,807	366	148	4,337	442	984	1,256	1,623	1,363	93	28	$18,447
21	Miscellaneous Revenue and Expense	0	0	0	0	0	0	0	0	0	0	0	$0
22	**Total Operating Expenses**	$7,807	($597)	$62	($7,031)	($721)	($1,608)	($2,138)	$672	($2,189)	$38	$12	($5,694)
23	**Net Operating Revenues**	$12,765	$597	($62)	$7,031	$721	$1,608	$2,138	($672)	$2,189	($38)	($12)	$26,266
24	**Average Rate Base**												
25	Electric Plant in Service	$0	$0	($10,600)	($2,050)	$0	$0	$0	($116,586)	($1,419)	($6,719)	($2,019)	($139,393)
26	Accumulated Depreciation & Amortization	0	0	0	0	0	0	2,982	0	0	0	0	$2,982
27	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0	$0
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0	0	$0
29	**Net Utility Plant**	$0	$0	($10,600)	($2,050)	$0	$0	$2,982	($116,586)	($1,419)	($6,719)	($2,019)	($136,411)
30	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	0	$0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0	0	$0
32	Working Capital (manually supressed)	0	0	0	0	0	0	0	0	0	0	0	$0
33	Fuel Stock	0	0	0	0	0	0	0	0	0	0	0	$0
34	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	0	$0
35	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0	0	$0
36	Weatherization Loans	0	0	0	0	0	0	0	0	0	0	0	$0
37	Prepayments	0	0	0	0	0	0	0	0	0	0	0	$0
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0	0	$0
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	0	0	0	0	0	$0
40	**Total Average Rate Base**	$0	$0	($10,600)	($2,050)	$0	$0	$2,982	($116,586)	($1,419)	($6,719)	($2,019)	($136,411)
41	**Revenue Requirement Effect**	($20,572)	($989)	($1,247)	($11,912)	($1,195)	($2,665)	($3,163)	($13,725)	($3,808)	($792)	($238)	($60,306)

PACIFICORP UE 210
Staff Adjustments to Oregon Results
Year Ending December 31, 2010
($000)

	Income Tax Calculations	NPC (TAM) Related Revenue (S-1)	Uncollectible Expense (S-2)	Transmission Rate Base (S-3)	A&G O&M/Cap. Adjs (S-4)	Distribution O&M Expense (S-5)	Transmission O&M Expense (S-6)	Dep&Amort O&M/Cap Adjs (S-7)	8.6 Proforma Rate Base (S-8)	Bonus & Incentives Adj (S-9)	Threemile Knoll Substation (S-10)	Wind Plant Misc. Rate Base (S-11)	Total Adjustments (Base Rates)
1	Book Revenues	$20,572	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,572
2	Book Expenses Other than Depreciation	0	(963)	(86)	(11,368)	(1,163)	(2,592)	(617)	(951)	(3,552)	(55)	(16)	($21,364)
3	State Tax Depreciation	0	0	0	0	0	0	(2,777)	0	0	0	0	($2,777)
4	Interest	0	0	(302)	(58)	0	0	85	(3,326)	(40)	(192)	(58)	($3,892)
5	Schedule M Differences	0	0	0	0	0	0	0	0	0	0	0	$0
6	State Taxable Income	$20,572	$963	$389	$11,426	$1,163	$2,592	$3,309	$4,277	$3,592	$246	$74	$48,604
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0	0	0	0	$0
8	Total State Taxable Income	$20,572	$963	$389	$11,426	$1,163	$2,592	$3,309	$4,277	$3,592	$246	$74	$48,604
9	State Income Tax	$934	$44	$18	$519	$53	$118	$150	$194	$163	$11	$3	$2,207
10	State Tax Credits	0	0	0	0	0	0	0	0	0	0	0	$0
11	Net State Income Tax	$934	$44	$18	$519	$53	$118	$150	$194	$163	$11	$3	$2,207
12	Additional Tax Depreciation	0	0	0	0	0	0	0	0	0	0	0	$0
13	Other Schedule M Differences	0	0	0	0	0	0	0	0	0	0	0	$0
14	Federal Taxable Income	$19,638	$919	$371	$10,907	$1,110	$2,474	$3,159	$4,083	$3,429	$235	$71	$46,397
15	Federal Tax @ 35%	6,873	322	130	3,818	389	866	1,106	1,429	1,200	82	25	$16,240
16	Federal Tax Credits	0	0	0	0	0	0	0	0	0	0	0	$0
17	Current Federal Tax	$6,873	$322	$130	$3,818	$389	$866	$1,106	$1,429	$1,200	$82	$25	$16,240
18	ITC Adjustment												$0
19	Deferral	0	0	0	0	0	0	0	0	0	0	0	$0
20	Restoration	0	0	0	0	0	0	0	0	0	0	0	$0
21	Total ITC Adjustment	0	0	0	0	0	0	0	0	0	0	0	$0
													$0
22	Provision for Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	$0
													$0
23	Total Income Tax	$7,807	$366	$148	$4,337	$442	$984	$1,256	$1,623	$1,363	$93	$28	$18,447

REVENUE REQUIREMENTS EFFECTS OF ADJUSTMENTS	(S-1)	(S-2)	(S-3)	(S-4)	(S-5)	(S-6)	(S-7)	(S-8)	(S-9)	(S-10)	(S-11)	Adjustments (Base Rates)
Revenues and Expenses	($20,572)	($989)	$102	($11,651)	($1,195)	($2,665)	($3,543)	$1,114	($3,627)	$63	$19	($42,944)
Rate Base	0	0	(1349)	(261)	0	0	380	(14839)	(181)	(855)	(257)	($17,362)
Total	($20,572)	($989)	($1,247)	($11,912)	($1,195)	($2,665)	($3,163)	($13,725)	($3,808)	($792)	($238)	($60,306)

PACIFICORP UE 210
Revenue Sensitive Costs
Year Ending December 31, 2010
($000)

REVENUE SENSITIVE COSTS	
Revenues (Operating Income)	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00430
Taxes Other - Franchise	0.02250
- Other	0.00000
- Resource supplier	0.00063
State Taxable Income	0.97257
State Income Tax	0.04415
Federal Taxable Income	0.92842
Federal Income Tax @ 35%	0.32495
ITC	0.00000
Current FIT	0.32495
Other	0.00000
Total Excise Taxes	0.36910
Total Revenue Sensitive Costs	0.39653
Utility Operating Income (NOI)	0.60347
Net-to-Gross Factor	**1.65708**

Input:	
STATERATE (Income Tax Rate)	4.540%
WORKINGCAP	1.410%

PACIFICORP UE 210
Cost of Capital
Year Ending December 31, 2010
($000)

COST OF CAPITAL - As Filed by PacifiCorp	PERCENT CAPITAL	COST	WEIGHTED COST
Long Term Debt	48.50%	5.980%	2.900%
Preferred Stock	0.30%	5.410%	0.016%
Common Equity	51.20%	11.000%	5.632%
Total	100.00%		8.549%

COST OF CAPITAL - Staff Proposal	PERCENT CAPITAL	COST	WEIGHTED COST
Long Term Debt	48.50%	5.882%	2.853%
Preferred Stock	0.30%	5.048%	0.015%
Common Equity	51.20%	9.400%	4.81%
Total	100.00%		7.68%

CASE: UE 210
WITNESS: Deborah Garcia

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

July 24, 2009

UE 210
Summary Staff Adjustment to PacifiCorp's 8.6 Proforma Plant Additions

		Per UE 210 Filing 13 Month Plant Additions		Not in-service by date rates take effect (100% disallowance)		Not allowed in rate base (100% disallowance)		Unknown in-service date (50% disallowance)		Staff Adjustment by FERC Acct	
Type	FERC Account	OR Allocated	Staff Proposed	Company wide 13 month average	OR Allocated 13 month Average	Company wide 13 month average	OR Allocated 13 month Average	Company wide 13 month average	OR Allocated 13 month Average	Company wide 13 month average	OR Allocated 13 month Average
Steam Plant	312	110,488,088	91,452,600	(68,250,131)	(18,299,864)	(1,468,653)	(394,728)	(1,268,359)	(340,895)	(70,987,143)	(19,035,488)
Hydro Plant	332	27,115,693	25,657,345	(5,426,032)	(1,458,348)	0	0	0	0	(5,426,032)	(1,458,348)
Other Plant	343	94,982,268	94,582,419	(1,438,606)	(362,369)	0	0	(139,450)	(37,480)	(1,578,056)	(399,849)
Other Wind**	343	223,271,577	223,271,577	0	0	0	0	0	0	0	0
Transmission	355	97,384,761	80,748,082	(35,673,913)	(9,588,036)	0	0	(26,225,670)	(7,048,643)	(61,899,583)	(16,636,679)
Distribution	364	130,279,659	78,172,368	(1,413,427)	(1,413,427)	0	0	(50,693,864)	(50,693,864)	(52,107,291)	(52,107,291)
General Plant	397	38,724,456	24,358,834	(1,554,847)	(428,290)	(4,325)	(1,222)	(27,146,594)	(13,936,110)	(28,705,767)	(14,365,622)
Intangible Plant	302	16,267,163	11,133,882	(2,024,875)	(572,160)	0	0	(17,753,316)	(4,561,121)	(19,778,191)	(5,133,281)
	303	12,428,435	8,077,878	(15,725,033)	(4,251,484)	0	0	(350,621)	(99,073)	(16,075,654)	(4,350,557)
Mining	399	7,760,465	4,661,845	0	0	0	0	(12,393,540)	(3,098,620)	(12,393,540)	(3,098,620)
Sub Total by Adjustment Category		**758,702,565**	**642,116,829**	**(131,506,863)**	**(36,373,978)**	**(1,472,979)**	**(395,950)**	**(135,971,414)**	**(79,815,807)**	**(268,951,256)**	**(116,585,735)**

Total Adjustment	**(268,951,256)**	**(116,585,735)**

** Per Data response # 310 - Co will adjust $2M related to liquidated damages in Rebuttal Test.

UE-210/PacifiCorp
June 12, 2009
OPUC Data Request 310

OPUC Data Request 310

Regarding Staff Data Request 309. Does the proposed adjustment of $4,767,389 for the Goodnoe Hills wind resource include an offset for the liquidated damages the Company reported during the UE 200 process that it expected to receive for this plant? If not, why not?

Response to OPUC Data Request 310

No. The adjustment of $4.8m actually included a true-up of $2,818,000 for a reversal of liquidated damages that the Company had previously withheld during the base period and felt would reasonably be returned to the contractor. This $2,818,000 was only a portion of the total amount of liquidated damages that were included in the base year, $4,128,000 which had either been withheld from contractor payments or paid by the contractor. The assumption during the test period was that the total project included $1.3m of offsets for liquidated damages as that was the amount the liquidated damages were anticipated to be at the time the case was prepared.

Goodnoe Hills Capital included in the case:
Amount in the base year (year ending June 2008): $188m
Forecast amount included in the case: $4.8m
Total Goodnoe Hill's capital in the case: $192.8

Liquidated Damages:
Amount in the base year: ($4.1m)
True up included in the forecast: $2.8m
Amount of liquidated damages included in the test year: ($1.3m)

The final amount of liquidated damages for Goodnoe Hills that was agreed to in the Executed Settlement Agreement was $3.3m.

An adjustment reducing capital by approximately $2.0 million on a total company basis is necessary to appropriately reflect the final amount of liquidated damages included in the test year, The Company will make this update in its rebuttal position.

UE-210/PacifiCorp
June 15, 2009
OPUC Data Request 307

OPUC Data Request 307

Regarding Dalley/Results of Operations 2010/ Adjustment 8.6, Proforma Plant Additions: For those line items listed on pages 8.6.7-8.6.17 ($1 million and more, and under $1 million) that have the word "various" inserted in the Inservice Date column, please explain when these plant additions will be completed or in service. Provide documentation supporting the projected dates.

Response to OPUC Data Request 307

Please refer to the Company's response to OPUC 173; specifically Attachment OPUC 173 – 2 for a list of the capital projects along with the forecasted amounts to be placed into service for each project by month. The term "various" is used as the in-service date when capital investment for a project is projected to be placed into service in more than one month.

OPUC Data Request 307

Regarding Dalley/Results of Operations 2010/ Adjustment 8.6, Proforma Plant Additions: For those line items listed on pages 8.6.7-8.6.17 ($1 million and more, and under $1 million) that have the word "various" inserted in the Inservice Date column, please explain when these plant additions will be completed or in service. Provide documentation supporting the projected dates.

1st Supplemental Response to OPUC Data Request 307

Please see Attachment OPUC 307 1st Supplemental for a list of projects that had "various" as the in-service date in the filing but only had amounts being placed into service in the filing in a single month. The in-service date was listed as "various" as the date was not included in SAP at the time the data was extracted to determine rate base for this case. These projects had a forecast amount to be placed into service during a single month in the Company's filing.

The in-service date for a project represents the substantial completion of an asset that is considered used and useful for its intended purpose. For many projects, subsequent to the in-service date, remaining capital outlays are anticipated to cover costs related to the completion of each project. The following are a few examples of situations in which a project may have amounts placed into service in multiple months:

- Milestone contract payments based in performance or other quantitative factors or testing
- Tuning, performance, or completion work even after in-service (for example: An overhaul on a turbine or generator may occur and the equipment is capable of generation and is placed in-service. The equipment may be generating electricity, but efficiency, testing, performance reviews, and integration of other components can occur for several months following the in-service date.)
- For a wind project these costs may include items such as turbine acceptance on the wind turbine generator contract as well as milestone completion for the balance of the plant contract.

A few specific examples from this filing are the following:

- Hydro Compliance GIS/ ph2 (Intangible Project): This project has amounts being placed into service from Nov.08-Dec.09. The reason amounts are forecast to be placed into service during multiple months is that a majority of the work to meet compliance monitoring is estimated to be completed and functioning as intended. However, subsequent to that date, additional work will be completed to add additional sites, equipment, and functionality to the system.
- Huntington U2 Cooling Tower Fill Replacement (Steam Project): This project has amounts being placed into service in various periods. This type

of project will typically have work yet to be completed, such as minor structural work, siding replacement, and other punch list items that occur after the cooling tower is functional.

- Mine Mainline or Section Extension (Mining Project): This project has amount being placed into service in various months because this project accumulates the cost of advancing the underground coal mine future into the coal seam. As the coal mine advances, the underground roads, belting, water, electrical, and communications infrastructure are extended to support the ongoing mining operations. The advanced section is supporting current mining operations and is therefore in-service.

Please refer to non-confidential attachment OPUC 307 1st Supplemental on the enclosed CD.

CASE: UE 210
WITNESS: Dustin Ball

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

July 24, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dustin Ball. I am employed by the Public Utility Commission of Oregon as Senior Financial Analyst, Corporate Analysis and Water Regulation Section, in the Economic Research and Financial Analysis Division of the Utility Program. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/201

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to recommend adjustments to PacifiCorp's medical expenses, insurance expenses, workers compensation expenses, pension and postretirement expenses, stock/401(k)/ESOP expenses, pension administration expenses, regulatory asset amortization, other non-labor Administrative and General expenses (A&G), enhanced reliability standards expenses, other non-labor Operations and Maintenance (O&M) expenses, and property tax expenses. In addition, I will address the deferred Change-In-Control (CIC) severance cost amortization, the Grid West amortization, and the proposed flow-through treatment of AFDC Equity.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/202 (13 pages of supporting calculations), and Exhibit Staff/203 (45 pages of PacifiCorp data request responses/attachments and documentation in support of footnotes).

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

ISSUE 1, MEDICAL BENEFIT EXPENSE ADJUSTMENT

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. This adjustment is shown in Exhibit Staff/202, Ball/3 and focuses on PacifiCorp's medical benefit expense. Staff proposes the following adjustment:

Medical Expense	($1,005,047)

In UE 210, PacifiCorp submitted a forecasted total cost of $57,435,478. Staff recommends a total cost of $53,878,672. As shown in Exhibit Staff/202, Ball/3, the difference of $3,556,806 is allocated at the SO allocation factor to arrive at the Oregon Allocated reduction of $1,005,047, which is split between Capital and O&M.

Q. PLEASE EXPLAIN YOUR MEDICAL BENEFIT EXPENSE ADJUSTMENT.

A. Staff examined PacifiCorp's medical benefit costs for both union and non-union personnel. Staff estimated PacifiCorp's medical expense for each labor group, using the total (employee and employer share) 2009 budgeted medical expense[1] as the starting point. The 2009 budget amounts were then escalated to 2010 using a 6.5 percent escalation factor[2]. Staff then applied PacifiCorp's forecasted 2010 employer/employee sharing of medical expenses to the forecasted 2010 expense for each individual labor group[3] and arrived at a forecasted 2010 medical expense of $53,878,672.

ISSUE 2, INSURANCE EXPENSE ADJUSTMENT

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

[1] As shown in Attachment OPUC 203 and Attachment OPUC 204 to Staff DR Nos. 203 and 204, which is a projection of 2009 Health Care costs prepared by Hewitt Associates. Included in Exhibit Staff/203.
[2] Staff's escalation factor of 6.5 percent is based on a Hewitt Associates projection which estimates an average increase to health care costs for 2009 of 6.4 percent. Included in Exhibit Staff/203.
[3] As reported in PacifiCorp's responses to Staff DR Nos. 86 and 341. Included in Exhibit Staff/203.

A. This adjustment is shown in Exhibit Staff/202, Ball/4 and focuses on PacifiCorp's non-captive property and liability insurance, uninsured property and liability losses, and low claims bonuses. Staff proposes the following Adjustments:

Non-Captive Insurance Adjustment	($281,139)
Uninsured Losses Adjustment	($3,617,299)
Low Claims Bonus Adjustment	($122,918)

In UE 210, on a system basis, PacifiCorp submitted non-captive property and liability insurance costs of $14,759,936, uninsured property and liability losses totaling $22,251,425, and does not include (as an offset to insurance costs) any low claims bonuses for 2010. Staff recommends non-captive property and liability insurance costs of $13,765,000, uninsured property and liability losses totaling $9,450,000, and a low claims bonus in the amount of $435,000 (as an offset to insurance costs). As shown on Staff/202, Ball/4, the differences of $994,936, $12,801,425, and $435,000 are allocated at the SO allocation factor to arrive at the Oregon Allocated reductions of $281,139, $3,617,299, and $122,918.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO NON-CAPTIVE INSURANCE.

A. Staff reduced the non-captive property and liability insurance expense to PacifiCorp's forecasted calendar year 2010 expense, as reported in response to OPUC Data Request No. 91.[4] Included in UE 210 is the expense that

[4] Included in Exhibit Staff/203.

PacifiCorp incurred during the period of July 2007 through June 2008, escalated for inflation to 2010. Staff's proposed adjustment simply reduces the amount included in the UE 210 to PacifiCorp's forecasted 2010 expense.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO UNINSURED LOSSES.

A. Staff reduced the uninsured property and liability losses to PacifiCorp's forecasted calendar year 2010 expense, as reported in response to OPUC Data Request No. 91.[5] Included in UE 210 are the losses that PacifiCorp incurred during the period of July 2007 through June 2008, escalated for inflation to 2010. Staff's proposed adjustment simply reduces the uninsured loss amount included in UE 210 to PacifiCorp's forecasted uninsured losses for 2010.

Q. IN THE PREVIOUS DISCUSSION YOU NOTE THAT PACIFICORP, IN RESPONSES TO DATA REQUESTS, PROVIDED YOU A DIFFERENT FORECAST FOR CERTAIN EXPENSES THAN WHAT IS INCLUDED IN ITS DIRECT CASE (UE 210). IS PACIFICORP'S DATA REQUEST FORECAST MERELY AN UPDATE TO WHAT IS PROVIDED IN TESTIMONY?

A. Perhaps; however, the bases for the two PacifiCorp estimates are different. For UE 210, PacifiCorp took its actual levels for 2008 and escalated those values to 2010. In the responses to the Staff data requests, PacifiCorp provided their forecasted expense for 2010.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO LOW CLAIM BONUSES.

[5] Included in Exhibit Staff/203.

A. Following each of the two most recent policy years, PacifiCorp received low claims bonuses of approximately $870,000. Because ratepayers bear the burden of paying the insurance premiums, ratepayers should be entitled to the low claim bonuses associated the insurance policies they fund. It is not certain whether or not PacifiCorp will receive low claim bonuses during 2010. However, based on historical data, Staff proposes to include 50 percent of one year's low claim bonus as an offset to insurance expense.

ISSUE 3, WORKERS COMPENSATION INSURANCE ADJUSTMENT

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. This adjustment is shown in Exhibit Staff 202, Ball/5 and focuses on PacifiCorp's workers compensation expense. Staff recommends the following adjustment:

Workers Compensation	($512,931)

In UE 210, PacifiCorp set its workers compensation expense at $3,586,894 for 2010. Staff recommends setting the 2010 workers compensation expenses at $1,771,660. As shown on Exhibit Staff/202, Ball/5, the difference of $1,815,234 is allocated at the SO allocation factor to arrive at the Oregon Allocated reduction of $512,931, which is split between Capital and O&M.

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. According to PacifiCorp[6], the amount included in UE 210 ($3,586,894) was calculated by escalating the budgeted 2008 amount by 5 percent annually to arrive at the projected expense for 2010. While Staff uses the same 5 percent

[6] As reported in response to Staff Data Request Nos. 93 and 193. Included in Exhibit Staff/203

annual escalation as PacifiCorp, Staff's starting point is the actual 2008 workers compensation expense as opposed to a budgeted 2008 amount. With this one change to PacifiCorp's method, Staff's forecast results in a $1,815,234 reduction to the forecasted 2010 Workers Compensation expense as shown in Exhibit Staff/202, Ball/5.

ISSUE 4, PENSION FAS 87, FAS 106, AND FAS 112 ADJUSTMENTS

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. These adjustments are shown in Exhibit Staff/202, Ball/6 and focus on PacifiCorp's FAS 87 pension expense, FAS 106 post retirement benefit costs, and FAS 112 post employment benefit costs. Staff proposes the following adjustments:

FAS 87 Pension Expense	($2,304,897)
FAS 106 Post Retirement Benefits	($370,681)
FAS 112 Post Employment Benefits	($316,596)

In UE 210 PacifiCorp submitted a FAS 87 pension expense of $33,128,792, FAS 106 post retirement benefits of $18,440,173, and FAS 112 post employment benefits of 6,502,600. Staff recommends a FAS 87 pension expense of $24,971,886, FAS 106 post retirement benefits of $17,128,355, and FAS 112 post employment benefits of $5,382,185. As shown on Staff/202, Ball/6, the differences of $8,156,906, $1,311,819, and $1,120,415 are allocated at the SO allocation factor to arrive at the Oregon Allocated reductions of $2,304,897, $370,681, and $316,596.

Q. PLEASE EXPLAIN THE ADJUSTMENT MADE TO FAS 87 PENSION EXPENSE AND FAS 106 POST RETIREMENT BENEFITS.

A. In UE 210 PacifiCorp calculates its pension expense and post retirement benefits using a 6.30 percent discount rate and a 7.75 percent estimated long term rate of return. Staff proposes using a discount rate of 6.90 percent and an estimated long term rate of return of 8.25 percent. Staff's proposed increase the discount rate and estimated long term rate of return are supported by Attachment OPUC 198-1 and Confidential Attachment OPUC 198-2[7] provided by PacifiCorp in response to Staff Data Request No. 198.

Attachment OPUC 198-1, which is dated February 4, 2009, specifically indicates that *"PacifiCorp proposes a discount rate of 6.90% for its defined benefit pension and post retirement welfare benefits based on the Hewitt Top Quartile for each plan at December 31, 2008."*

Attachment OPUC 198-1 indicates that PacifiCorp is assuming a 7.75 percent long term rate of return and that this is *"within the range of rates being used by Hewitt's utility clients and the EEI Standards Committee members."* However, upon reviewing of the range of rates being used by Hewitt's utility clients and EEI Standards Committee members, shown in Attachment 198-2, Staff found that PacifiCorp's estimate was at the far low end of the range. Staff's adjustment moves PacifiCorp's estimated long term rate of return closer to the middle of the ranges identified.

[7] Included in Exhibit Staff/203

Q. PLEASE EXPLAIN THE ADJUSTMENT MADE TO FAS 112 POST EMPLOYMENT BENEFITS.

A. It appears that PacifiCorp calculated its FAS 112 post employment benefits by escalating budgeted amounts to 2010. Specifically, PacifiCorp's response to Staff Data Request No. 312 indicates that the "Plan for CY 2008" amount was escalated by 2.56 percent to arrive at a 2009 forecast, and the 2009 forecast was escalated by 3.08 percent to arrive at a 2010 forecast. PacifiCorp then removed joint owner costs to arrive at the UE 210 expense of $6,502,600.

Staff disagrees with PacifiCorp's forecast. Rather than escalating budgeted amounts, Staff proposes to escalate the actual calendar year 2008 expense of $5,073,226 (which is net of joint owner costs) by 3 percent annually to arrive at a forecasted 2010 expense of $5,382,185.

The main difference between the PacifiCorp and Staff methods for estimating the 2010 expense, as with many of the adjustments above, is that Staff starts with the <u>actual</u> 2008 expense and PacifiCorp starts with the <u>budgeted</u> 2008 expense.

<u>ISSUE 5, STOCK/401(K)/ESOP EXPENSE ADJUSTMENT</u>

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. This adjustment is shown in Exhibit Staff/202, Ball/7 and focuses on PacifiCorp's Stock/401(k)/ESOP expense. Staff proposes the following adjustment:

Stock/401(k)/ESOP Expense	($2,610,865)

In UE 210, PacifiCorp increase its Stock/401(k)/ESOP expense from the base period amount of $20,576,528 to $41,454,956 for 2010. Staff recommends a 2010 expense of $32,215,247. As shown on Staff/202, Ball/7, the difference of $9,239,709 is allocated at the SO allocation factor to arrive at the Oregon Allocated reduction of $2,610,865, which is split between Capital and O&M.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO STOCK/401(K)/ESOP EXPENSE.

A. PacifiCorp calculated their forecasted 2010 expense by applying an annual escalation factor of 4.7 percent to the 2008 budgeted expense and then applying estimated increases for pension plan conversions that have taken place. A large portion of PacifiCorp's projected increase is attributable to the conversions of various labor groups from the traditional pension plan to an enhanced 401(k) benefit. It appears that these conversions (for PacifiCorp's non-union, Local 695 and Local 125 employees) began during 2007 and were completed as of January 2009.

Staff disagrees with PacifiCorp's forecast. Actual information is available for the first quarter of 2009[8], a period of time when all of the above mentioned conversions were in effect. Rather than using a budgeted 2008 amount as a starting point and then forecasting the effects of conversions, Staff used the actual expense from the first quarter of 2009 as its starting point for estimating the 2010 expense. Staff annualized the first quarter 2009 Stock/401(k)/ESOP

[8] See PacifiCorp's response to Staff Data Request No. 207. Included in Staff/302.

expense to a calendar year 2009 amount and then applied a 2.5 percent escalation factor[9].

Q. DOES THIS METHOD ACCOUNT FOR INCREASES IN STOCK/401(K)/ESOP EXPENSE DUE TO PLAN CONVERSIONS?

A. Yes. Because the various conversions were implemented on or before January 1, 2009, the actual expenses for the first quarter of 2009 represent a period after these conversions were implemented. Therefore, an adjustment for plan conversions is not necessary.

Q. ARE THERE ANY OTHER ADJUSTMENTS THAT STAFF MADE TO PACIFICORP'S STOCK/401(K)/ESOP EXPENSE?

A. Yes. It was brought to Staff's attention, through data requests, that as part of the conversions, employees who met certain criteria are to receive additional 401(k) credits, which vary in amount (as a percentage of pay) as well as for the period of time that they will be received. In many cases these additional 401(k) credits are phased out, in a stair step fashion, over the period of time within which they are received. It appears that the first reduction to the additional 401(k) credits, which is estimated by Hewitt Associates at approximately $700,000[10], takes place during 2010. As shown on Staff/202, Ball/7, Staff takes this reduction into consideration when forecasting the 2010 expense.

<u>ISSUE 6, PENSION ADMINISTRATION EXPENSE ADJUSTMENT</u>

[9] The source of Staff 2.5 percent escalation factor is Page 4.2.5 of Exhibit PPL/702.
[10] See PacifiCorp's response to Staff Data Request No. 206, specifically Attachment OPUC 206 1st Supplemental.

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. This adjustment is shown in Exhibit Staff/202, Ball/8 and focuses on PacifiCorp's pension administration expense. Staff proposes the following adjustment:

Pension Administration Expense	($59,820)

In UE 210 PacifiCorp submitted a pension administration expense of $878,457 for 2010. Staff recommends an expense of $666,759 for 2010. As shown on Staff/202, Ball/8, the difference of $211,698 is allocated at the SO allocation factor to arrive at the Oregon Allocated reduction of $59,820, which is split between Capital and O&M.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PENSION ADMINISTRATION EXPENSE.

A. In UE 210 PacifiCorp increased its pension administration expense from the base period amount of $622,557 to $878,457 for 2010. The actual pension administration expense for calendar years 2007 and 2008 was $926,312 and $339,567 respectively. In response to Data Request No. 208, PacifiCorp explains that the substantial change in expense over these two years is related to timing of union negotiations (during which costs were higher). Due to the varying nature of this expense, Staff proposes to set the 2010 pension administration expense at $666,759, which is the level included in the base period (adjusted for inflation). A simple average of the calendar year 2007 and 2008 actual expenses results in an average expense over the past two years of $632,440, which is in line with Staff's recommendation.

ISSUE 7, REGULATORY ASSET AMORTIZATION ADJUSTMENT

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. This adjustment is shown in Exhibit Staff/202, Ball/9 and focuses on PacifiCorp's regulatory asset amortization. Staff proposes the following adjustments:

Regulatory Asset Amortization	($6,137,657)
Remaining Separate Schedule Amortization	$1,945,214

Q. PLEASE EXPLAIN YOUR REGULATORY ASSET AMORTIZATION ADJUSTMENT.

A. PacifiCorp's base period includes monthly amortizations of the "98 Early Retirement OR" and "Transition Plan OR" regulatory assets. Based on the information available[11], it appears that the amortization of the "98 Early Retirement OR" regulatory asset (of approximately $306,412 per month) ended during December 2007, and was fully recovered by PacifiCorp. It also appears that the "Transition Plan OR" regulatory asset (monthly amortization of approximately $324,358) will have a remaining balance of approximately $1,945,214 as of February 2010, when rates go into effect.

Staff proposes to remove both regulatory assets from the base period and to allow PacifiCorp to recover the remaining $1,945,214 balance on the "Transition Plan OR" regulatory asset (approximately 6 months of amortization) through a separate temporary schedule to ensure that the amortization terminates once fully recovered by PacifiCorp.

[11] The source data is the Transaction Ledger "Attach OPUC 197-1" as well as PacifiCorp's 2007 and 2008 FERC Form 1.

ISSUE 8, NON-LABOR A&G EXPENSE ADJUSTMENT

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. This adjustment is shown in Exhibit Staff/202, Ball/10 and focuses on PacifiCorp's non-labor A&G expense in FERC accounts 901-935. Staff proposes the following adjustment:

Non-Labor A&G Expense	($112,365)

Q. PLEASE EXPLAIN YOUR NON-LABOR EXPENSE ADJUSTMENT.

A. This adjustment removes 50 percent of Meals & Entertainment expense, 50 percent of On-Site Meals & Refreshments expense, 100 percent of Challenge Grant expense, and 100 percent of AUC expense. The adjustments to Meals & Entertainment, On-Site Meals & Refreshments, and AUC expenses are the same in nature as the adjustments proposed by Staff Michael Dougherty and are described in detail in Staff/300, Dougherty/3-6.

Regarding the 100 percent disallowance of Challenge Grant expense, it appears these expenses are related civic activities, which the Commission has not allowed regulated utilities to recovery from ratepayers. Civic activities are discretionary, not required to provide safe and adequate service to customers, and Commission policy does not require ratepayers to support causes in which they to not believe[12].

ISSUE 9, RELIABILITY STANDARDS ADJUSTMENT

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

[12] See OPUC Order 87-406 at 40-41, Order 91-186 at 16, and Order 09-020 at 20-21.

A. This adjustment is shown in Exhibit Staff/202, Ball/11 and focuses on PacifiCorp's reliability standards. Staff proposes the following adjustment::

Reliability Standards	($388,244)

In UE 210, PacifiCorp proposes to increase funding for enhanced reliability standards by $1,403,297 ($388,244 Oregon Allocated) for 2010. Staff recommends that PacifiCorp's requested increase be denied.

Q. PLEASE EXPLAIN YOUR ENHANCED RELIABILITY STANDARDS ADJUSTMENT.

A. In Staff's view, PacifiCorp has not met its burden of proof to demonstrate why additional funding is necessary. It does appear that PacifiCorp will incur costs associated with enhanced reliability standards during 2010, which were not incurred during the base period. However, Staff believes that the current level of funding (adjusted for inflation) should be adequate, as significant costs incurred during the base period do not appear to be recurring in nature.

During 2007 and 2008 a significant number of reliability standards became mandatory and enforceable (June 2007 and January 2008). Additionally, PacifiCorp's base period (July 2007 through June 2008), includes a significant amount of costs directly related to these standards, which appear nonrecurring in nature, and are labeled as "planning."[13] It does not appear that PacifiCorp's request for additional funding takes into consideration costs included in the base period which will not be incurred during 2010.

ISSUE 10, NON-LABOR O&M EXPENSE ADJUSTMENT

[13] See Attachment OPUC 241 (included in Staff/203)

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. This adjustment, focusing on PacifiCorp's non-labor O&M expense in FERC accounts 560-574, is very similar to the non-labor A&G expense adjustment and is shown in Exhibit Staff/202, Ball/12. Staff proposes the following adjustment:

Non-Labor O&M Expense	($407,716)

Q. PLEASE EXPLAIN YOUR NON-LABOR EXPENSE ADJUSTMENT.

A. This adjustment removes 50 percent of Meals & Entertainment expense, 50 percent of On-Site Meals & Refreshments expense, 100 percent of AUC expense, and amortizes non-recurring legal fees associated with FERC Proceeding ER07-882 over a ten year period. The adjustments to Meals & Entertainment, On-Site Meals & Refreshments, and AUC expenses are the same in nature as the adjustments proposed by Staff Michael Dougherty and are described in detail in Staff/300, Dougherty/3-6.

Regarding the amortization of the non-recurring legal fees associated with FERC Proceeding ER07-882, Staff proposes a ten-year amortization of the expense. The expense was associated with the FERC Proceeding that resulted in new lease agreement for the Malin-Indian Springs contract, which has a ten year term. Staff's proposal is to amortize the expense over the term of the lease. The effect of this adjustment is an Oregon allocated reduction of $158,837.

ISSUE 11, PROPERTY TAX EXPENSE ADJUSTMENT

Q. PLEASE SUMMARIZE THIS ADJUSTMENT.

A. This adjustment is shown in Exhibit Staff/202, Ball/13 and focuses on PacifiCorp's property tax expense. Staff proposes the following adjustment:

Property Tax Expense	($2,340,011)

In UE 210, PacifiCorp submitted a property tax expense for 2010 of $95,786,000. Staff recommends an expense for 2010 of $87,504,828. As shown on Staff/202, Ball/13, the difference of $8,281,172 is allocated at the GPS allocation factor to arrive at the Oregon Allocated reduction of $2,340,011.

Q. PLEASE EXPLAIN YOUR PROPERTY TAX EXPENSE ADJUSTMENT.

A. PacifiCorp forecasted the 2010 property tax expense using a method which estimates, jurisdiction specific, 2010 assessed property values, tax rates, and amount of property tax capitalized or charged to fuel expense.

Staff disagrees with PacifiCorp's forecast. A comparison of 2007 and 2008 PacifiCorp forecasts to actual property tax expense shows that the forecast in each of these years was significantly greater than the actual property tax expense. Specifically, as stated in response to Data Request No. 282, for 2007 and 2008 PacifiCorp forecasted its property tax expense at $85.3 million and $82.7 million respectively. Actual property tax expense for 2007 and 2008, as shown in the results of operations report reports were $69.1 million and $77.5 million.

Staff proposes to set the 2010 property tax expense as a function of rate base, which is the main driver of the regulatory property tax expense. This method was previously approved by the Commission in Order No. 09-020, pages 23-24.

Q. PLEASE DESCRIBE THE CALCULATION OF THE 2010 PROPERTY TAX EXPENSE.

A. Staff began with the 2007 and 2008 actual property tax expenses as reported in PacifiCorp's results of operations reports. Because the Leaning Juniper wind project is exempt from property taxation under a three-year enterprise zone (for tax periods 07-08, 08-09, and 09-10), Staff increased the 2007 and 2008 actual property tax expense to represent an estimate of what would have been paid had the property been fully taxed. Staff then compared the property tax expense to rate base for 2007 and 2008, as shown in PacifiCorp's results of operations reports. Staff's calculation resulted in a two year average ratio of 0.8157 percent, which represents the average property tax expense as a percent of rate base for the past two years (2007 and 2008).

Staff then applied the factor of 0.8157 percent to PacifiCorp's estimated 2010 rate base of $10,801,328,048. This resulted in a forecasted property tax of $88,104,828, which was also adjusted to reflect the enterprise zone (09-10 tax exemption) for Leaning Juniper. It is important to note that, because the calculation uses a rate base figure that has not been agreed upon by all parties, this property tax adjustment will need to be revised for any changes to rate base through this proceeding. Staff witness Deborah Garcia describes the property tax adjustment related to individual Staff adjustments.

ISSUE 12, CIC, GRID WEST, AND AFDC EQUITY FLOW-THROUGH

Q. PLEASE EXPLAIN PACIFICORP'S PROPOSED TREATMENT OF CIC SEVERANCE COST AMORTIZATION, THE GRID WEST AMORTIZATION, AND THE FLOW-THROUGH TREATMENT OF AFDC EQUITY.

A. In UE 210, PacifiCorp includes the amortization of CIC severance costs, the write-off of the amount receivable from Grid West, and proposes to treat AFDC Equity as a flow-through item.

Q. DO YOU AGREE PACIFICORP'S TREATMENT OF THE CIC SEVERANCE COST AMORTIZATION?

A. Staff agrees with the adjustment made by PacifiCorp as, in accordance with OPUC Order No. 07-211, CIC severance costs are to be amortized to expense through March 2012. However, Staff proposes that the amortization of Deferred CIC costs be set up on a separate temporary schedule which will terminate March 2012, as shown below.

Reduce Cost-of-Service Amortization	($2,125,245)
Separate Schedule Amortization	$2,125,245

Q. DO YOU AGREE PACIFICORP'S TREATMENT OF THE GRID WEST AMORTIZATION?

A. Staff agrees with the adjustment made by PacifiCorp as it is in accordance with OPUC Order No. 06-483. However, Staff proposes that the amortization of Grid West be set up on a separate temporary schedule which will terminate December 2013, as shown below.

Reduce Cost-of-Service Amortization	($344,703)
Separate Schedule Amortization	$344,703

Q. DO YOU AGREE PACIFICORP'S PROPOSED FLOW-THROUGH TREATMENT OF AFDC EQUITY?

A. Staff supports the flow-through treatment of deferred taxes associated with AFDC. Staff's support is based on the understanding that this treatment is not intended to have any adverse effects on ratepayers through SB 408 filings. In upcoming SB 408 filings, PacifiCorp should be required to specifically identify the effects of AFDC equity and demonstrate that ratepayers are not affected by the flow-through treatment.

ISSUE 13, PACIFICORP'S O&M TO TARGET ADJUSTMENT

Q. DOES STAFF RECOGNIZE PACIFICORP'S O&M TO TARGET ADJUSTMENT MADE ON PAGE 4.20 OF EXHIBIT PPL/702?

A. Yes. As shown on Exhibit Staff/202, Ball/1-2, Staff reduced its total adjustments proposed to A&G accounts as well as Transmission O&M accounts by PacifiCorp's adjustments. Staff's Oregon allocated A&G adjustments totaling $15.507 million were reduced by $2.089 million to arrive at a net adjustment of $13.418 million, and Transmission O&M adjustments totaling $0.796 million were reduced by $0.544 million to arrive at a net adjustment of $0.252 million.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 210
WITNESS: Dustin Ball

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

July 24, 2009

WITNESS QUALIFICATION STATEMENT

NAME:	DUSTIN BALL
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	SENIOR FINANCIAL ANALYSIT, ECONOMIC RESEARCH & FINANCIAL ANALYSIS DIVISION
ADDRESS:	550 CAPITOL STREET NE SUITE 215, SALEM, OREGON 97301-2115.
EDUCATION:	Bachelor of Science, Business focusing in Accounting, Western Oregon University (2003)
EXPERIENCE:	Employed with the Oregon Public Utility Commission since August 2007. I am a Senior Financial Analyst for the Economic Research & Financial Analysis Division. Employed by the Oregon Real Estate Agency as a Financial Investigator in the Regulations Division from January 2006 to August 2007. Employed by the Oregon Department of Revenue as an Income Tax Auditor, in the Personal Tax and Compliance Section from January 2004 to January 2006. Licensed Tax Consultant in the State of Oregon.

CASE: UE 210
WITNESS: Dustin Ball

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

July 24, 2009

PacifiCorp
UE 210
Test Year December 31, 2010
000's of Dollars

Staff/202
Ball/1

Adjustment is based on a series of adjustments in Accounts 901 through 935. The accompanying pages explain these adjustments in detail.

Description/ Account No.	Company Filing	Staff	O&M Adj	Capital Adj	Total Adj
A&G Accounts					
Medical Benefits	$ 16,230	$ 15,224	$ (718)	$ (287)	$ (1,005)
Insurance Expense/Uninsurred Losses	$ 10,458	$ 6,560	$ (3,898)	$ -	$ (3,898)
Low Claim Bonus	$ -	$ (123)	$ (123)	$ -	$ (123)
Workers Compensation Insurance	$ 1,014	$ 501	$ (366)	$ (146)	$ (513)
Pensions	$ 16,409	$ 13,417	$ (2,138)	$ (854)	$ (2,992)
Stock/401(k)/ESOP	$ 11,714	$ 9,103	$ (1,865)	$ (745)	$ (2,611)
Pension Administration	$ 248	$ 188	$ (43)	$ (17)	$ (60)
Regulatory Asset Amortization	$ 6,138	$ 1,945	$ (4,192)	$ -	$ (4,192)
Various A&G Account Summary Adjustments	$ 112	$ -	$ (112)	$ -	$ (112)
Total A&G Adjustments			$ (13,457)	$ (2,050)	**$ (15,507)**
PPL 4.20 A&G Adjustment			$ 2,089		$ 2,089
Incremental Staff A&G Adjustment			**$ (11,368)**	**$ (2,050)**	**$ (13,418)**

Staff Initiator:
Dustin Ball

PacifiCorp
UE 210
Twelve Months Ended Dec 31, 2010
000's of Dollars

Adjustment is based on a series of adjustments in Accounts 580 through 598 and Taxes Other Than Income. The accompanying pages explain these adjustments in detail.

(Please round your answers to the nearest $1,000)

Description/ Account No.	Company Filing	Staff	Adjustment
Transmission O&M Accounts			
Enhanced Reliability Standards	$ 388	$ -	$ (388)
Various O&M Account Summary Adjustments	$ 408	$ -	$ (408)
Total Transmission O&M Adjustments			**$ (796)**
PPL 4.20 Transmission O&M Adjustment			$ 544
Incremental Staff Transmission O&M Adjustment			**$ (252)**
Taxes			
Property Taxes	$ 27,066	$ 24,726	$ (2,340)
Total Tax Adjustments			**$ (2,340)**

Staff Initiator:
Dustin Ball

UE 210 PPL - Medical - A&G

	Non-Union	UWUA 127 & 197	IBEW 695	Western Utilities 57 & 125
Hewitt 2009 Budget (DR 203 & 204)	$ 20,260,332	$ 8,271,048	$ 6,382,968	$ 28,364,286
Escalated to 2010	1.065	1.065	1.065	1.065
Forecasted 2010	$ 21,577,254	$ 8,808,666	$ 6,797,861	$ 30,207,965
PacifiCorp Share (From DR 86)	80%	80%	83%	85%
PacifiCorp 2010 Total	$ 17,261,803	$ 7,046,933	$ 5,642,225	$ 25,676,770

	Staff 2010	PPL UE 210	Adjustment	SO Allocation	Oregon Allocated
Forecasted 2010 Expense	$ 55,627,730	$ 59,300,000			
Joint Owner Portion	$ (1,749,058)	$ (1,864,522)			
Net 2010 Expense	$ 53,878,672	$ 57,435,478	$ 3,556,806	28.257%	$ 1,005,047
		Capital = 28.55%	$ 1,015,468	28.257%	$ 286,941
		O&M = 71.45%	$ 2,541,338	28.257%	$ 718,106
		Total	**$ 3,556,806**		**$ 1,005,047**

* Staff's forecasted 2010 medical benefits expense is calculated by escalating the 2009 total (employer & employee) medical expense to 2010 using an escalation factor of 6.5%, and then applying the 2010 employee/employer sharing to arrive at PacifiCorp's share of the 2010 medical benefit expense.

* The source of Staff's "Hewitt 2009 Budget" figures is the 2009 budget provided in Attachment OPUC 203 & Attachment OPUC 204.

* IBEW 695 Employer/Employee sharing is based on DR No. 86 and 341. 65 percent of employees earning above and 35 percent of employees earning below $65,000. ((.65*.8125)+(.35*.8625)=83%)

* According to Hewitt (As of a report dated September 22, 2008) *"Hewitt is projecting a 6.4 percent average increase for employers in 2009".* *http://www.hewittassociates.com/Intl/NA/en-US/AboutHewitt/Newsroom/PressReleaseDetail.aspx?cid=5604*

UE 210 PPL - Insurance/Uninsured Losses/Low Claim Bonuses - A&G

	Staff	UE 210	Adjustment	SO Allocation	Oregon Allocated
Non-Captive Insurance					
Property Insurance non-captive	$ 10,736,000	$ 11,493,254			
Liability Insurance non-captive	$ 3,029,000	$ 3,266,682			
	$ 13,765,000	$ 14,759,936	**$ 994,936**	28.257%	**$ 281,139**
Uninsured Losses					
Uninsured property losses	$ 6,318,000	$ 18,304,302			
Uninsured liability losses	$ 3,132,000	$ 3,947,122			
	$ 9,450,000	$ 22,251,425	**$ 12,801,425**	28.257%	**$ 3,617,299**

* Staff has adjusted PacifiCorp's non-captive insurance and uninsured losses to the Company's 2010 forecast. See Attachment OPUC 91.

* The "Staff" column above reflects PacifiCorp's forecasted Calendar Year 2010 expenses, as reported on Attachment OPUC 91.

* The source of the UE 210 amounts above is the actual expense from the base period, as shown in Attachment OPUC 91, escalated to 2010 at the A&G Operation rate of 7.1%, as shown on Page 4.8.8 of exhibit PPL/702.

Low Claims Bonuses DR No. 96			SO Allocation	Oregon Allocated
Policy Year 10-1-06 to 10-1-07	Received March 2008	$ 869,677		
Policy Year 10-1-07 to 10-1-08	Received December 2008	$ 869,962		
Adjustment		**$ 435,000**	28.257%	**$ 122,918**

* Staff proposes to apply 50 percent of one year's low claims bonus as an offset to insurance expense.

UE 210 PPL - Workers Compensation - A&G

	Staff	SO Allocation	Oregon Allocated
CY 2008 Actual (DR No. 82)	$ 1,606,948		
Escalation to 2009(DR No. 193)	1.05		
Forecasted 2009	$ 1,687,295		
Escalation to 2010 (DR No. 93)	1.05		
Staff Forecasted 2010 Workers Compensation	**$ 1,771,660**		
Staff (net of joint owner portion, from above)	$ 1,771,660		
PPL UE 210 (from DR No 93)	$ 3,586,894		
Adjustment	**$ 1,815,234**	28.257%	**$ 512,931**
Capital = 28.55%	$ 518,249	28.257%	$ 146,442
O&M = 71.45%	$ 1,296,985	28.257%	$ 366,489
Total	**$ 1,815,234**		**$ 512,931**

* Staff forecasted the 2010 workers compensation expense by escalating the actual calendar year 2008 expense using an annual escalation of 5%. This is the same method applied by PacifiCorp with the exception that PacifiCorp escalated budgeted 2008 amounts, where as Staff escalated actual 2008 amounts. (see responses to DR's 93, 193, and 195)

UE 210 PPL - Pensions - A&G

	Staff	(See DR 80) UE 210	% Change	(See DR 81 & 314) Effect on Expense[5]
FAS 87				
Discount Rate	6.90%[2]	6.30%	0.60%	$ (4,320,000)
Rate of Return	8.25%[1]	7.75%	0.50%	$ (4,600,000)
FAS 106				
Discount Rate	6.90%[2]	6.45%	0.45%	$ -
Rate of Return	8.25%[1]	7.75%	0.50%	$ (1,800,000)

FAS 87[3]

Net Periodic Cost	$29,300,000
Discount Rate Adjustment	$(4,320,000)
Rate of Return Adjustment	$(4,600,000)
Adjusted Net Periodic Cost	$20,380,000
Amortize Curtailment/Measurement	$(2,674,600)
Forecasted Local 57 Pensions	$ 8,100,000
Adjusted FAS 87 Pension Cost	$25,805,400
Less Joint Owner Portion	96.77%
Staff's Net FAS 87 Cost	**$24,971,886**

FAS 106[4]

Net Periodic Cost	$24,000,000
Discount Rate Adjustment	$ -
Rate of Return Adjustment	$ (1,800,000)
Adjusted Net Periodic Cost.	$22,200,000
Less Mines (estimated @ 20.5%)	79.50%
Adjusted Utility Net Periodic Cost	$17,649,000
Less Joint Owner Portion	97.05%
Staff's Net FAS 106 Cost	**$17,128,355**

FAS 112

2008 CY Actual (DR 82)	$ 5,073,226
Escalation to 2009	1.03
Estimated 2009 Exp	$ 5,225,423
Escalation to 2010	1.03
Staff's Net FAS 112 Cost	**$ 5,382,185**

	FAS 87	FAS 106	FAS 112
Staff's Forecast (from above)	$24,971,886	$ 17,128,355	$ 5,382,185
PPL UE 210 Cost (page 4.2.7)	$33,128,792	$ 18,440,173	$ 6,502,600
Total Adjustment	**$ 8,156,906**	**$ 1,311,819**	**$ 1,120,415**
SO Allocation	28.257%	28.257%	28.257%
OR Allocated	**$ 2,304,897**	**$ 370,681**	**$ 316,596**
Capital = 28.55%	$ 658,048	$ 105,829	$ 90,388
O&M = 71.45%	$ 1,646,849	$ 264,851	$ 226,208
Total OR Adjustment	**$ 2,304,897**	**$ 370,681**	**$ 316,596**

1-Staff proposes to set the long-term estimated rate of return at 8.25 percent, an increase of 50 basis points over the Company's estimate for FAS 87 and FAS 106. Staff's proposed increase is supported by Confidential Attachment OPUC 198-1 and Confidential Attachment OPUC 198-2.

2-Staff proposes to increase the FAS 87 and FAS 106 discount rate to 6.90 percent. Staff's proposed increase is supported by Confidential Attachment OPUC 198-1 and Confidential Attachment OPUC 198-2.

3-For FAS 87 the amortization amount for curtailment/measurement and forecasted Local 57 are as shown on Attachment OPUC 301, and the joint owner portion is the same ratio as shown on Page 4.2.7 of exhibit PPL/702

4-For FAS 106 the mines portion (20.5%) is derived from Attachment OPUC 206 and the joint owner portion is the same ratio as shown on Page 4.2.7 of exhibit PPL/702.

5-The effect on expense was calculated by figuring Staff's proposal as compared to a 25 basis point change and then multiplying the result by the dollar amount associated with an increase of 25 basis points, as reported in response to DR No. 81. FAS 87 discount rate (60 basis points / 25 basis points = 2.4 * $1,800,000 = $4,320,000). FAS 87 rate of return (50 basis points / 25 basis points = 2 * $2,300,000 = $4,600,000). FAS 106 rate of return (50 basis points / 25 basis points = 2 * $900,000 = $1,800,000)

UE 210 PPL - Pension Administration Costs - A&G

Actual Base Period Pension Administration Expense (DR No. 82)	$	622,557
A&G escalation factor (Page 4.8.8 of exhibit PPL/702)		1.071
Staff's Forecasted 2010 Pension Administration Expense	$	666,759
Staff's Forecasted 2010 Pension Admin Expense	$	666,759
PPL Forecasted 2010 Pension Admin Expense (Page 4.2.7 of exhibit PPL/702)	$	878,457
Adjustment	**$**	**211,698**

			SO Allocation		Oregon Allocated
Capital = 28.55%	$	60,440	28.257%	$	17,079
O&M = 71.45%	$	151,259	28.257%	$	42,741
Total	**$**	**211,698**		**$**	**59,820**

* Staff proposes to set the 2010 pension administration expense by escalating the actual pension administration expense from the base period, escalated to 2010 at the A&G Operation rate of 7.1%, as shown on Page 4.8.8 of exhibit PPL/702.

* During CY 2007 and CY 2008, PacifiCorp's pension administration expense was $926,312 and $338,567 respectively. A simple average of the two years expense results in an average of $632,440, which is in line with Staff's forecast.

UE 210 PPL - Stock/401(k)/ESOP - A&G

2009 Actual Q1 (see DR No. 207)	$	8,028,109
Annualize		4
2009 Expense	$	32,112,436
Wage escalation to 2010		1.025
2010 Expense	$	32,915,247
Less: transition credits are reduced in 2010	$	(700,000)
Staff's Forecasted 2010 Expense	$	32,215,247
Staff (net of joint owner portion, from above)	$	32,215,247
PPL UE 210 (Page 4.2.7 of exhibit PPL/702)	$	41,454,956
Difference	**$**	**9,239,709**
Voluntary PPL adjustment (see DR No. 206)	**$**	**6,916,258**
Additional Staff Adjustment	**$**	**2,323,451**

	Voluntary PPL Adjustment	Additional Staff Adjustment	Total Adjustments	SO Allocation	Oregon Allocated
Capital = 28.55%	$ 1,974,592	$ 663,345	$ 2,637,937	28.257%	$ 745,402
O&M = 71.45%	$ 4,941,666	$ 1,660,106	$ 6,601,772	28.257%	$ 1,865,463
Total	**$ 6,916,258**	**$ 2,323,451**	**$ 9,239,709**		**$ 2,610,865**

* Staff proposes to set the Stock/401(k)/ESOP based on annualizing the first quarter 2009 expense, and escalating the annualized 2009 expense to 2010 at a wage escalation factor of 2.5%. See Page 4.2.5 of exhibit PPL/702 regarding the wage escalation factor of 2.5%.

* The ($700,000) applied by staff represents the decrease, forecasted by Hewitt Associates, which is attributable to transition credits being reduced during 2010, as compared to 2009. See Attachment OPUC 206 1st Supplemental.

UE 210 PPL - Regulatory Asset Amortization - A&G

98 Early Retirement OR		
Amortization included in the Base Period	$	1,838,472
Escalation to 2010		1.071
Amortization included in UE 210	$	1,969,004
Staff Adjustment (100% OR)	**$**	**1,969,004**

* Staff removed the amortization of the "98 Early Retirement" regulatory asset from the base period. The amortization of this regulatory asset ended December 2007, and has been fully recovered by the Company. The annual amortization of the regulatory asset was $3,676,946, or $306,412.16 per month. Staff removed $1,838,472 ($306,412.16 X 6 months) which represents the amortization from July through December 2007. The source data for Staff's adjustment is the Transaction ledger "Attach OPUC 197-1" as well as PacifiCorp's 2007 and 2008 FERC Form 1.

Transition Plan OR		
Amortization included in the Base Period	$	3,892,300
Escalation to 2010		1.071
Amortization included in UE 210	$	4,168,653
Staff Adjustment to A&G (100% OR)	**$**	**4,168,653**
Balance of Transition Plan Reg Asset as of 1-1-09	$	6,161,872
Amortization during 2009 (12 months @ approximately $324,358)	$	(3,892,300)
Amortization During January 2010 (1 month @ approximately $324,358)	$	(324,358)
Remaining Transition Plan Reg Asset when rates are effective	$	1,945,214
Remaining Amortization to be Recovered on a Separate Schedule (100% OR)	**$**	**1,945,214**
Staff's Net Adjustment to Transition Plan OR Reg Asset	**$**	**2,223,439**

* Staff removed the amortization of the "Transition Plan" regulatory asset from the base period. As of January 1, 2009 the regulatory asset had a unamortized balance of $6,161,872, and is currently being amortized at the rate of $3,892,300 annually, $324,358.33 per month. At this rate of amortization, the remaining unamortized balance at February 2010 (when rates will be effective) will be approximately $1,945,214. The source data for Staff's adjustment is the Transaction ledger "Attach OPUC 197-1" as well as PacifiCorp's 2007 and 2008 FERC Form 1.

* Staff proposes that the remaining unamortized balance of $1,945,214, at February 2010 be recovered through a separate schedule and that the amortization terminate once fully recovered by the Company.

UE 210 PPL - Summary of Various A&G Adjustments- A&G

	AUC Expense	Challenge Grant	Meals & Entertainment	On-Site Meals...
Jul-07	$ 1,652	$ 1,017	$ 3,475	$ 1,861
Aug-07	$ 552	$ 3,391	$ 4,678	$ 946
Sep-07	$ -	$ 28	$ 3,963	$ 1,071
Oct-07	$ 941	$ 2,779	$ 5,101	$ 2,810
Nov-07	$ 919	$ 16,247	$ 6,932	$ 2,432
Dec-07	$ 51	$ 17,407	$ 3,517	$ 3,121
Jan-08	$ 1,257	$ -	$ 6,062	$ 2,459
Feb-08	$ (35)	$ 4,888	$ 4,323	$ 1,442
Mar-08	$ -	$ 3,532	$ 5,486	$ 3,003
Apr-08	$ 3,305	$ 3,179	$ 3,911	$ 714
May-08	$ -	$ 390	$ 6,331	$ 1,833
Jun-08	$ 758	$ 1,554	$ 4,669	$ 2,068
Total	$ 9,400	$ 54,412	$ 58,448	$ 23,760
Disallowance	100%	100%	50%	50%
Staff Adjustment	$ 9,400	$ 54,412	$ 29,224	$ 11,880

Total Adjustments	$ 104,916
Escalation to 2010	1.071
Total Staff Adjustment	**$ 112,365**

* Staff proposes to disallow 100% of the AUC and Challenge Grant Expense included in the base period along with 50% of Meals & Entertainment and On-Site Meals & Refreshments Expense included in the base period. The source of Staff's adjustment is Attachment OPUC 197-1.

* The amounts shown above are Oregon Allocated amounts, therefore no additional allocation is necessary.

UE 210 PPL - Enhanced Reliability Standards - O&M

PPL Proposed Increase (Page 4.17.1 of exhibit PPL/702)	$	1,403,297		**Oregon Allocated**
Staff's Proposed Increase for Enhanced Reliability Standards	$	-	$	388,236
Adjustment	**$**	**1,403,297**		

* Staff proposes to disallow PPL's proposed increase shown on page 4.17 of exhibit PPL/702

UE 210 PPL - Summary of Various O&M Adjustments- O&M

	AUC Expense	Meals & Entertainment	On-Site Meals
July - September 2007	$ 16,534	$ 966	$ 608
October - December 2007	$ 98,739	$ 923	$ 292
January - March 2008	$ 121,904	$ 169	$ 482
April - June 2008	$ 8,346	$ 2,719	$ 552
Total	$ 245,523	$ 4,777	$ 1,934
Disallowance	100%	50%	50%
Staff Adjustment	$ 245,523	$ 2,389	$ 967

Remove Legal/Consulting Fees Related to FERC ER07-882[1]	$ 656,642
Ten Year Amortization	90.00%
Adjustment	$ 590,978
SG Allocation	26.877%
Oregon Allocated Adjustment	$ 158,837

Various Staff Adjustments (from above)	$ 248,879
Additional Legal/Consulting Fees Adjustment (from above)	$ 158,837
Total Staff Adjustment	**$ 407,716**

* Staff proposes to disallow 100% of the AUC and 50% of Meals & Entertainment and On-Site Meals & Refreshments Expense included in the base period. The source of Staff's adjustment is Attachment OPUC 197-2.

* The amounts shown above are Oregon Allocated amounts, therefore no additional allocation is necessary.

[1] Staff proposes to amortize, over a ten year period, non-reoccurring legal and consulting fees and services related to FERC Proceeding ER07-882 from FERC Acct 566. Staff chose a ten year amortization as the new lease agreement for which these fees are associated has a ten year term. See FERC Order Issued, December 20, 2007, in Docket No ER07-882-00.

UE 210 PPL - Property Taxes

	2007 Actual	2008 Actual	Average
Rate Base	$ 8,535,930,889	$ 9,662,388,567	
Property Tax Excluding Leaning Juniper	$ 69,102,000	$ 77,529,000	
Leaning Juniper Adjustment	$ 600,000	$ 1,200,000	
Property Tax With Leaning Juniper	$ 69,702,000	$ 78,729,000	
% of Rate Base	0.8166%	0.8148%	0.8157%

Estimated 2010 Rate Base	$ 10,801,328,048
Average 07 & 08 Property Tax of Rate Base	0.8157%
2010 Property Tax Expense	$ 88,104,828
Less: Leaning Juniper exemption for half of 2010	$ (600,000)
Staff's Forecasted Property Tax Expense for 2010	$ 87,504,828

		GPS Allocation	Oregon Allocated
2010 Property Tax Expense per Staff	$ 87,504,828		
2010 Property Tax Expense per PPL	$ 95,786,000		
Adjustment	**$ 8,281,172**	28.257%	$ 2,340,011

* Staff proposes to set property taxes as a function of rate base. This method provides for the derivation of a reasonable level of 2010 property tax expense which is aligned with 2007 and 2008 actuals. This is similar to the method applied in UE 197 and adopted by Commission Order No. 09-020, Pages 23-24.

* Leaning Juniper wind project located in Gilliam County, Oregon is under a three-year enterprise zone in which it is exempt from taxation. This exemption covers the 2007-2008, 2008-2009, and 2009-2010 tax years. Beginning with the 2010-2011 tax period the Leaning Juniper wind project will become fully taxable. Annual property taxes for Leaning Juniper are estimated at $1,200,000 annually.

CASE: UE 210
WITNESS: Dustin Ball

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

July 24, 2009

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 203

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 09-120. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 210 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

OPUC Data Request 203

As a follow up to DR No. 88, please provide work papers, along with any and all supporting documentation, which supports the $6,883,385 increase to medical expenses from the base period amount of $48,040,147 to the 2009 estimate amount of $54,923,532. In the work papers, please be sure to demonstrate the effects of employer/employee sharing.

Response to OPUC Data Request 203

	Actual July 2007 - June 2008*	2009 Estimate
Nonunion		16,600,320
UWUA 127 & 197		7,278,012
IBEW 659		5,602,668
Total Flex Plan Groups	27,259,677	29,481,000
Western Utilities Health Plan	20,780,470	25,442,532
	48,040,147	54,923,532
Joint Owner Portion	-	(1,726,916)
	48,040,147	53,196,616

* Actuals are booked net of the joint owner portion

For support, please refer to Attachment OPUC 203.

The effects of changes in employer/employee sharing between the base year (12 months ended June 2008) and 2009 have not been calculated *in total*. Notwithstanding, the impacts of changes in employer/employee sharing in 2009 on a major segment of the Company's medical costs are known. Western Utilities Health Plan costs for 2009 have been calculated with and without changes in sharing. The difference is approximately 1% of total 2009 costs; i.e., 2009 costs for this segment are 1% lower than otherwise. This calculation represents a subset of the total impact achieved in this regard. The total impact of all sharing changes between the base year and 2009 is expected to substantially exceed this when all employee groups are taken into account and when the full time period between base year and 2009 is taken into account.

Please refer to non-confidential Attachment OPUC 203 on the enclosed CD.

825 NE Multnomah, Suite 1800
Portland, OR 97232

Employee Benefits

2009 Budget

MEDICAL GROUP	L 57	PARTICIPANTS	RATE*	PREMIUM COST
Code 1	225	225	$381.48	$85,833.00
Codes 2 & 18	678	678	$791.28	$536,487.84
Codes 3 & 4	940	940	$1,182.14	$1,111,211.60
TOTAL	1,843	1,843		$1,733,532.44

	L 125	PARTICIPANTS	RATE*	PREMIUM COST
Code 1	88	88	$370.88	$32,637.44
Codes 2 & 18	146	146	$769.30	$112,317.80
Codes 3 & 4	207	207	$1,149.30	$237,905.10
TOTAL	441	441		$382,860.34
		2,284		

PEPM	$927
PEPY	$11,119
Annual Cost	$25,396,713

LIFE GRO	LIVES	57 Volume	125 Volume	VOLUME	RATE	PREMIUM COST
Employee	2043	$221,047,000	$51,941,000	$272,988,000	$0.26	$70,976.88
TOTAL Pr	2043			272,988,000		$70,976.88

Company portion of life:

Monthly	$35,488.44
Co. Annual Cost	$425,861.28

Estimated rates per Segal Company
Headcounts - actuals at 9/1/08
Estimated medical trend: 13.9%
Wages increased by 2.5%

Staff/203
Ball/2

IBEW/Western Utilities Health and Welfare Trust Fund
2009 CONTRIBUTION SUMMARY

	Current - 2008								
	Basic Plan			Premium Plan - 90% / 10% Split			Premium Plus Plan		
	Total Rate	ER Contribution	EE Contribution	Total Rate	ER Contribution	EE Contribution	Total Rate	ER Contribution	EE Contribution
Single	$334.85	$334.85	$0.00	$372.05	$334.85	$37.20	$399.97	$334.85	$65.12
2-Party	$694.56	$694.56	$0.00	$771.74	$694.56	$77.18	$829.64	$694.56	$135.08
Family	$1,037.64	$1,037.64	$0.00	$1,152.92	$1,037.64	$115.28	$1,239.43	$1,037.64	$201.79

	2009 - 90% / 10% Split								
	Basic Plan			Premium Plan			Premium Plus Plan		
	Total Rate	ER Contribution	EE Contribution	Total Rate	ER Contribution	EE Contribution	Total Rate	ER Contribution	EE Contribution
Single	$381.48	$381.48	$0.00	$423.86	$381.48	$42.38	$455.66	$381.48	$74.18
2-Party	$791.28	$791.28	$0.00	$879.20	$791.28	$87.92	$945.18	$791.28	$153.90
Family	$1,182.14	$1,182.14	$0.00	$1,313.48	$1,182.14	$131.34	$1,412.02	$1,182.14	$229.88
2009 Increase	+13.9%								

	2009 - 87.5% / 12.5% Split								
	Basic Plan			Premium Plan			Premium Plus Plan		
	Total Rate	ER Contribution	EE Contribution	Total Rate	ER Contribution	EE Contribution	Total Rate	ER Contribution	EE Contribution
Single	$381.48	$381.48	$0.00	$423.86	$370.88	$52.98	$455.66	$370.88	$84.78
2-Party	$791.28	$791.28	$0.00	$879.20	$769.30	$109.90	$945.18	$769.30	$175.88
Family	$1,182.14	$1,182.14	$0.00	$1,313.48	$1,149.30	$164.18	$1,412.02	$1,149.30	$262.72
2009 Increase	+13.9%								

OPUC Data Request 204

As a follow up to DR No. 90, please provide complete copies of the Hewitt Associates reports/studies/etc. from which the "2008 Budget Summary – Active Employees – Annual Cost" and "Flex Plan – All Companies" documents were part of. Also, please provide a copy of PacifiCorp's 2009 Budget Summary – Active Employees – Annual Cost from Hewitt Associates.

Response to OPUC Data Request 204

Please refer to Attachment OPUC 204 for the Hewitt reports containing the "2008 Budget Summary – Active Employees – Annual Cost," "Flex Plan – All Companies Associates, " and "PacifiCorp's 2009 Budget Summary – Active Employees – Annual Cost" documents.

Please refer to non-confidential Attachment OPUC 204 on the enclosed CD.

Staff/203
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PacifiCorp

Flex Plan - All Companies
August 1, 2008

	Enrollment	Claims/ Premiums	Expenses	Total Cost	Contributions	Net Cost	Net Cost per Enrollee
Nonunion							
Medical	2,405	$19,029,838	$1,230,494	$20,260,332	$3,647,196	$16,613,136	$6,908
Dental	2,405	2,377,714	7,790	2,385,504	944,208	1,441,296	599
Vision	2,405	331,056	0	331,056	165,528	165,528	69
Total		$21,738,608	$1,238,284	$22,976,892	$4,756,932	$18,219,960	$7,576
Mines							
Medical	536	$6,204,218	$285,430	$6,489,648	$603,780	$5,885,868	$10,981
Dental	536	542,526	22,062	564,588	225,240	339,348	633
Vision	536	$81,504	0	81,504	40,752	40,752	76
Total		$6,828,248	$307,492	$7,135,740	$869,772	$6,265,968	$11,690
UWUA 127 & 197							
Medical	651	$7,869,803	$401,245	$8,271,048	$993,036	$7,278,012	$11,180
Dental	651	705,873	2,235	708,108	283,152	424,956	653
Vision	651	101,856	0	101,856	50,928	50,928	78
Total		$8,677,532	$403,480	$9,081,012	$1,327,116	$7,753,896	$11,911
IBEW 659							
Medical	496	$6,117,285	$265,683	$6,382,968	$780,300	$5,602,668	$11,296
Dental	496	574,880	1,696	576,576	230,448	346,128	698
Vision	496	$77,088	0	77,088	$38,544	38,544	78
Total		$6,769,253	$267,379	$7,036,632	$1,049,292	$5,987,340	$12,071
Electric Operations							
Medical	3,552	$33,006,522	$1,897,422	$34,903,944	$5,422,836	$29,481,108	$8,300
Dental	3,552	3,658,467	11,721	3,670,188	1,457,808	2,212,380	623
Vision	3,552	$510,000	0	510,000	$255,000	255,000	72
Total		$37,174,989	$1,909,143	$39,084,132	$7,135,644	$31,948,488	$8,995
All Active Groups							
Medical	4,088	$39,221,144	$2,182,852	$41,403,996	$6,024,312	$35,379,684	$8,655
Dental	4,088	4,200,993	33,783	4,234,776	1,683,048	2,551,728	624
Vision	4,088	591,504	0	591,504	295,752	295,752	72
Total Active		$44,013,641	$2,216,635	$46,230,276	$8,003,112	$38,227,164	$9,351

Staff/203
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Hewitt Data Reveals Little Change in U.S. Health Care Cost Increases for 2009

Media Contacts:
Maurissa Kanter, Hewitt Associates, (847) 883-1000
MacKenzie Lucas, Hewitt Associates, (847) 883-1000

September 22, 2008

Moderating Increases Attributed to More Aggressive Plan Management, Deeper Emphasis on Employee Health

LINCOLNSHIRE, Ill. – After enjoying a steady decline in health care cost trends over the past eight years, U.S. companies have seen average rate increases settle in around 6 percent to 7 percent, according to Hewitt Associates, a global human resources consulting and outsourcing company. In 2008, average health care costs increased 6.0 percent, up from 5.3 percent in 2007. Hewitt is projecting a 6.4 percent average increase for employers in 2009.

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According to Hewitt, the average health cost per person for major companies will increase from $8,331 in 2008 to $8,863 in 2009. The amount employees are being asked to contribute toward this cost will be $1,946, representing approximately 22 percent of the overall health care premium and up from $1,806 in 2008. Average employee out-of-pocket costs, such as copayments, coinsurance and deductibles, are also expected to increase from $1,707 in 2008 to $1,880 in 2009. Overall, employees' total health care costs—including employee contribution and out-of-pocket costs—are projected to be $3,826 in 2009, up 8.9 percent from $3,513 in 2008.

"Employers continue to diligently manage health care costs through a combination of approaches, including continued cost shifting, tougher negotiations with health plans, and expanded health and wellness programs with incentives to encourage behavior change, which is why we're seeing rate increases level out a bit," said Jim Winkler, North American practice leader of Hewitt's Health Management Consulting business. "The challenge now will be sustaining or even lowering those rate increases in an environment where the legislative, economic and political landscape is rapidly changing, and where companies are under more pressure than ever to balance their needs with the needs of employees and their families. Over the next few years, they will need to take a more rigorous and aggressive approach to getting employees healthy—which means implementing a combination of programs that drive actual behavior change, eliminate barriers to health and encourage people to take more responsibility for their personal health. These are the steps that will ultimately make an impact in lowering overall benefit costs and putting more money in the wallets of employees."

2008 Cost Increases by Major Metropolitan Area

While Hewitt's data shows relatively flat overall cost increases in 2008, a few major U.S. markets experienced rate increases significantly higher than the average: Cincinnati, OH (11.1 percent), Columbus, OH (9.9 percent), Orlando, FL (9.2 percent) and Minneapolis, MN (9.1 percent). Conversely, Austin, TX (1.0 percent), Houston, TX (2.6 percent) and Chicago, IL (3.7 percent) experienced lower-than-average rate increases in 2008.

2008 Cost Increases by Plan Type

In 2008, Hewitt saw average cost increases of 10.1 percent for traditional indemnity plans, 8.0 percent for health maintenance organizations (HMOs), 3.9 percent for point-of-service (POS) plans and 4.8 percent for preferred provider organizations (PPOs).

For 2009, Hewitt forecasts that companies will receive cost increases of 6.5 percent for traditional indemnity plans, 8.0 percent for HMOs, 5.5 percent for POS plans, and 5.5 percent for PPOs. That means from 2008 to 2009, the average cost per person for major companies will increase from $9,296 to $9,900 for traditional indemnity plans; $8,442 to $9,117 for HMOs; $8,986 to $9,480 for POS plans; and $8,048 to $8,491 for PPOs.

"Over the past few years, HMO rates have averaged almost two times higher than the rate increases of PPO or POS plans, mainly due to the fact that local and regional fully insured HMO plan

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2008-2009 Health Care Cost Increase Charts

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offerings have higher administrative costs and are subject to state-mandated benefit requirements that drive up premium costs," said Bob Tate, chief health care actuary at Hewitt. "We expect to see this trend continue, particularly because premiums translate directly into profit and loss for fully insured HMOs, and higher rate increases for these plans ensure higher profit margins."

Employer Response to Rate Increases

To keep rate increases in the 6 percent to 7 percent range, employers continue to take proactive steps to mitigate costs and implement initiatives focused on improving employee health and productivity. These steps include:

Increasing attention on plan dependents. While cost-shifting in its traditional sense has tapered, an increasing number of companies are beginning to look at cost shifting a portion of their dependent subsidy dollars to employees, either through increased payroll contributions for dependent health care coverage or by applying surcharges to encourage dependent spouses to take coverage under their own employer's plans.

In addition, employers are becoming increasingly interested in conducting dependent audits, which are designed to assess and remove plan costs for dependents who don't qualify for coverage based on the employer's eligibility requirements. More than 40 percent of Hewitt's clients have conducted a dependent audit in the past five years, and another 10 percent planned to conduct one in 2008.

Eliminating "cost-inefficient" plans. As fully insured HMO rates increase in excess of overall medical cost increases, an increasing number of companies are consolidating plan participants under self-insured arrangements with fewer health plans. This enables them to streamline administration, offer more consistent designs across their markets and reduce costs—all of which help them avoid additional cost shifting to employees, either in the form of reduced benefits or higher payroll increases.

Aggressively managing health plans. As in past years, employers continue to negotiate aggressively with their health plans to try to reduce initial premium increases, and they are coming to the negotiations table with clear expectations and requests.

In addition to negotiating costs, an increasing number of employers are holding health plans accountable for delivering on specific measures in their health and productivity programs, including participation levels, clinical outcomes, reductions in claim costs and member satisfaction levels. Hewitt research shows that almost 60 percent of companies planned to ask their vendors for quarterly reports on their contribution to their health and productivity strategy within the next five years.

Continuing emphasis on employee health and productivity. Companies are continuing to invest significant resources in programs aimed at improving health and productivity of employees and their families. Flu shots, smoking cessation, physical fitness and weight management programs, as well as health risk questionnaires and online tools, are currently the most

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popular programs offered by employers. On-site health services, biometric screening and health/clinical advocacy programs—while still emerging trends—are also gaining increased attention, as companies look for more effective ways to motivate consistent and long-term employee behavior change.

To encourage participation in these programs, Hewitt's research shows just under two-thirds (63 percent) of companies provide or plan to provide employees with financial incentives, most likely in the form of credits or lower premiums. While most companies work on the "honor system," expecting employees to participate in a program once they enroll, a smaller minority are beginning to require completion of a program as a prerequisite for obtaining the incentive.

On the opposite end, almost 17 percent of companies in 2008 charged or planned to charge higher contributions for employees engaging in certain health behaviors, such as smoking. Another 40 percent said they were considering this option for a future date. In addition, 5 percent of companies in 2008 planned to require employees to take health assessments and/or participate in health improvement programs in order to receive health benefits, and more than half of companies said they are considering doing so at a future date.

"Over the past two years, we've seen health and productivity programs become fairly well established in large organizations, and now we're seeing increased efforts on the part of the employer—through both carrot and stick approaches—to ensure employees are actually getting value from the programs that are offered," said Winkler. "The next step will be for companies to determine whether these programs are providing a return on investment. Most currently measure the effectiveness of their programs by looking at changes in overall costs from year to year, or by the levels of employee participation in these programs. While these measures provide some short-term insight, companies that measure performance in actual outcomes will be in the best position to determine whether their programs have made an impact on truly improving employee health and productivity."

Digging deeper into chronic health conditions. According to Hewitt research, more than half (51 percent) of employees or their dependents have a chronic health condition that requires ongoing care. Most companies (93 percent) have already identified the chronic health conditions that are most pressing for their employee populations and plan to target these conditions over the next three to five years, with particular emphasis on tackling diabetes. Half (50 percent) currently offer employees enhanced medical and/or prescription drug benefits for at least one or more chronic condition, and almost a quarter (23 percent) provide incentives for at-risk individuals who participate in condition management programs and comply with recommended therapies.

Companies also continue to show an interest in value-based design (VBD) programs, which reduce or remove financial barriers for health care services proven to be effective to treat certain conditions, while potentially increasing cost-sharing for those services that have not been proven to be as effective.

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Hewitt's research shows that while just a small percentage of companies use value-based design programs today (12 percent), more than half (52 percent) said they were considering them in the next three to five years. Of those that currently offer value-based plan designs, 16 percent planned to expand the program beyond prescription drugs to include preventive care services or medical care services for certain chronic illnesses in 2009, and another two-thirds planned to do so in the next three to five years.

About Hewitt's Data

Hewitt's health care cost data is derived from the Hewitt Health Value Initiative, a cost and performance analysis database of more than 1,800 health plans throughout the U.S., including 400 major employers and more than 13 million health plan participants.

About Hewitt Associates

For more than 65 years, Hewitt Associates (NYSE: HEW) has provided clients with best-in-class human resources consulting and outsourcing services. Hewitt consults with more than 3,000 large and mid-size companies around the globe to develop and implement HR business strategies covering retirement, financial and health management; compensation and total rewards; and performance, talent and change management. As a market leader in benefits administration, Hewitt delivers health care and retirement programs to millions of participants and retirees, on behalf of more than 300 organizations worldwide. In addition, more than 30 clients rely on Hewitt to provide a broader range of human resources business process outsourcing services to nearly a million client employees. Located in 33 countries, Hewitt employs approximately 23,000 associates. For more information, please visit www.hewitt.com.

BACK
Newsroom

OPUC Data Request 86

Please provide the current employer/employee contribution to each (non-represented, and each union group) of the medical (health, dental, and vision) plans (i.e. 90/10, 85/15, 80/20, etc.). Is the Company anticipating any change to these percentages for 2009 or 2010? Please explain.

Response to OPUC Data Request 86

2008:

- Non-union overall 80% / 20%
- Local 57 90% / 10%
- Local 125 90% / 10%
- Local 197 87.5% / 12.5%
- Local 127 87.5% / 12.5%
- Local 659 those employees making less than $65,000 88.75% / 11.25%; those making over $65,000 83.75% / 16.25%

2009

- Non-union overall 80% / 20%
- Local 57 90% / 10%
- Local 125 87.5% / 12.5%
- Local 197 87.5% / 12.5%
- Local 127 87.5% / 12.5%
- Local 659 those employees making less than $65,000 82.5% / 17.5%; those making over $65,000 87.5% / 12.5%

2010

- Non-union overall 80% / 20%
- Local 57 85% / 15%
- Local 125 85% / 15%
- Local 197 87.5% / 12.5%; in negotiations target is 80% / 20%
- Local 127 87.5% / 12.5%; in negotiations target is 80% / 20%
- Local 659 those employees making less than $65,000 86.25% / 13.75%; those making over $65,000 81.25% / 18.75%

The changes shown from 2008 forward are tied to the union employees and are based on their Collective Bargaining Agreements as negotiated.

OPUC Data Request 341

What portion of PacifiCorp's IBEW 695 employees are currently earning in excess of $65,000 annually? What portion of IBEW 695 employees does PacifiCorp expect will be earning in excess of $65,000 annually during 2010, considering forecasted wage/salary increases?

Response to OPUC Data Request 341

As of July 1, 2009, 64% of the IBEW Local 659 population earns above $65,000. When considering the agreed upon 2010 wage adjustment of 2.5%, the percentage changes to 65%.

OPUC Data Request 91

In the following table format, please provide the following information for insurance premiums/self-insurance costs.

Cost	July 2006 – June 2007	July 2007 – June 2008	Forecasted Calendar Yr 2010
Property Insurance Premiums			
Property – Uninsured Loss			
Liability Insurance Premiums			
Liability – Uninsured Losses			
Terrorism – Premiums			
Terrorism – Uninsured losses			
Workers Compensation Premiums			
Workers Compensation – Uninsured Losses			
Other Risk Management Expenses (FERC accounts 924 and 925)			

Response to OPUC Data Request 91

Please refer to Attachment OPUC 91.

Please refer to non-confidential Attachment OPUC 91 on the enclosed CD.

Cost		July 2006 - June 2007	July 2007 - June 2008	Forecasted Calendar Yr 2010
Property Insurance Premiums - Account 924	Non captive	11,568,365	10,731,330	10,736,000
	Captive	5,687,557	5,572,797	5,760,000
Property - Uninsursed Loss - Account 924		6,000,001	17,090,852	6,318,000
Liability Insurance Premiums - Account 925	Non captive	3,273,111	3,050,123	3,029,000
	Captive	1,623,426	1,588,680	1,640,000
Liability - Uninsured Losses - Account 925		7,661,608	3,685,455	3,132,000
Terrorism - Premiums**				
Terrorism - Uninured Losses**				
Workers Compensation Premiums		3,119,803	2,149,642	3,586,891
Workers Compensation - Uninsured Losses*				
Other Risk Management Expenses (FERC accounts 924 and 925)***				

* Workers Compensation Uninsured Losses are not tracked separately.
** The Company has not made separate terrorism payments since 2005.
*** All expenses for FERC accounts 924 and 925 are included in the property and liability insurance expenses in the first six boxes above.

OPUC Data Request 93

Please provide and explanation and supporting documentation for the forecasted $1,437,249 increase to workers compensation, as shown in Exhibit 702 on page 4.2.7.

Response to OPUC Data Request 93

Please refer to the table below:

Large deductible (UT, ID, OR)	1,763,056
California Insured	19,049
Wyoming	1,701,709
Excess Policy (WA)	23,773
PERCO	10,349
Estimate of 2009	3,517,936
Escalation to 2010	1.05
2010 Estimate	3,693,833
Round for Plan	3,700,000
Joint Owner Portion	(113,109)
	3,586,891
Actual 7/2007 - 6/2008	2,149,642
Increase	1,437,249

OPUC Data Request 193

As a follow up to DR No. 93, please provide work papers, along with any and all supporting documentation, which supports the $1,368,294 increase to workers compensation, from the base period amount of $2,149,642, to the 2009 estimate amount of $3,517,936.

Response to OPUC Data Request 193

The original projected figure for 2009 was derived by taking the budgeted 2008 amount and increasing it by 5%.

2009 Projection	
Large deductible (UT, ID, OR)	1,763,056
California Insured	19,049
Wyoming	1,701,709
Excess Policy (WA)	23,773
PERCO	10,349
Estimate of 2009	3,517,936

OPUC Data Request 198

As a follow up to DR No. 80, please provide the actuarial reports which support the 2009 and 2010 discount rate and expected rate of return shown for FAS 87, FAS 106, and FAS 112.

Response to OPUC Data Request 198

The original 2009 and 2010 information was based on projections the Company developed during 2008. The projections initially assumed that the discount rate and the expected rate of return on plan assets used for 2008 would not change for 2009 and 2010. Subsequently, the Company finalized assumptions for the actual discount rate and expected rate of return for 2009 as detailed in Attachment OPUC 198 -1 and Confidential Attachment OPUC 198 -2. Confidential information is provided pursuant to the terms and conditions of the protective agreement in this proceeding. As shown in the Company's response to OPUC Data Request 80, the information for 2009 does reflect the actual discount rate and expected rate of return on plan assets. The 2010 information continues to reflect the assumptions the Company developed during 2008.

Please refer to non-confidential Attachment OPUC 198 –1 on the enclosed CD.

Please refer to Confidential Attachment OPUC 198 -2 on the enclosed CD.

PacifiCorp
December 2008 Assumptions
For Pension and Post Retirement Plans

Discount Rate Assumption

PacifiCorp has determined that the discount rate for the December 31, 2008 measurement will be 6.90%, for the pension plan and for the post retirement welfare benefit plans. These discount rates were determined to be appropriate as they are within a range of reasonable rates based on the following:

In recent years, PacifiCorp's discount rates have been based on the Hewitt Yield Curve, now referred to as the Hewitt Top Quartile, tailored to the benefit payment streams of PacifiCorp's plans. Beginning with the December 31, 2008 measurement, Hewitt Associates provided a new index, the Hewitt Above Median. Both are based upon the Hewitt Bond Universe. Recent discount rate information is as follows:

	December 31, 2008	**September 30, 2007 (1)**	**September 30, 2006 (1)**
Pension plan:			
Hewitt Top Quartile	6.93%	6.30%	5.86% (5.85% chosen)
Hewitt Above Median	6.32%	N/A	N/A
Hewitt Bond Universe	5.28%	5.91%	N/A
Post retirement welfare plan:			
Hewitt Top Quartile	6.87%	6.48% (6.45% chosen)	6.00%
Hewitt Above Median	6.25%	N/A	N/A
Hewitt Bond Universe	5.39%	6.08%	N/A
Merrill Lynch 10+ Index	5.92%	6.24%	5.86%

(1) Prior to December 31, 2008, PacifiCorp measured its plan assets and benefit obligations three months prior to its fiscal year end.

For the December 31, 2008 measurement, the duration of benefit payments for PacifiCorp's pension and post retirement welfare plans was 8.4 years and 11.7 years, respectively.

Copied For: Jennifer Kahl
Mahendra Shah
Erich Wilson
Bruce Williams

Hewitt Yield Curves

Hewitt Associates employs Ryan Labs, Inc. to assist with the development of their yield curves. Hewitt Associate's methodology produces a single discount rate for disclosure and related purposes. This rate is generally intended to represent a single discount rate that Hewitt Associates believes is consistent with SFAS Nos. 87 and 106. Hewitt Associates is therefore, typically unable to support the use of a discount rate for accounting purposes that is higher than that obtained by using this method.

The Hewitt Bond Universe is the population of corporate bonds utilized for Hewitt Associate's yield curve calculations and includes only non-callable corporate bonds rated AA or higher with a minimum par value outstanding of $150 million. The bonds are allocated into maturity groups of 1 to 2.99 years; 3 to 6.99 years; 7 to 14.99 years; 15 to 24.99 years; and 25 years and thereafter. Those bonds with yields in excess of two standard deviations from the average yield within each maturity grouping are also excluded. At December 31, 2008, there were 515 bonds in the Hewitt Bond Universe, 58% of which were issued by financial institutions.

The Hewitt Top Quartile includes only the top 25% highest yielding bonds within each maturity group of the Hewitt Bond Universe, while the Hewitt Above Median includes only the top 50% highest yielding bonds within each maturity group.

Deloitte & Touche LLP has previously considered PacifiCorp's use of the Hewitt Top Quartile acceptable and has not indicated any change to that view this year. Deloitte & Touche LLP has cautioned that they do not expect their clients to further raise the results of the analysis such as by rounding up to the nearest quarter percent.

Based on past practice, PacifiCorp proposes a discount rate of 6.90% for its defined benefit pension and post retirement welfare benefit plans based on the Hewitt Top Quartile for each plan at December 31, 2008. This rate is within the range of discount rates being used by Hewitt's utility clients and the EEI Standards Committee members.

PacifiCorp has been advised by its audit manager that Deloitte and Touche's specialists are familiar with the Hewitt Top Quartile and find it acceptable as support for selecting a discount rate.

Based on these considerations, PacifiCorp believes that the discount rate of 6 .90% for the pension and post retirement welfare benefit plans as of the December 31, 2008 measurement date is reasonable and appropriate.

Return on Plan Assets Assumption

PacifiCorp will use a long-term rate of return on plan assets assumption of 7.75% for the December 31, 2008 measurement. The expected return on plan assets was determined using the allocation of plan asset by type (57% equities, 35% bonds and 8% private equities), a nominal return by asset type and a long-term inflation assumption of 2.3%. The nominal return rates used by asset type (including expected performance in excess of the passive benchmark indices from active management) net of investment manager fees are 8.92% for equities, 5.62% for bonds and 11.8% for private equities. These nominal market return projections reflect the consensus from the capital market experts at Strategic Investment Solutions the investment consultant.

Based on the above, PacifiCorp believes an expected return on plan assets of 7.75% net of all fees (investment management, trustee, actuary, auditing, investment consultant, and PBGC premiums) is justified. The projected fees for trustee, actuary, auditing, investment consultant and PBGC premiums are as follows:

Trustee Fees	$ 360,000
Actuary Fees	$ 850,000
Audit Related fees	$ 60,000
Investment Consultant	$ 192,000
PBGC Premium	$ 700,000
Total other than Investment Management Fees	$2,162,000

Total Fees Excluding Investment Management Fees as % of Assets = 25 basis points

This long-term rate of return is within the range of rates being used by Hewitt's utility clients and the EEI Standards Committee members.

Signatures of Approval:

Erich Wilson, Director of Human Resources — Date: 2/4/09

Bruce Williams, VP & Treasurer — Date: 2/4/09

Jennifer N. Kahl, External Reporting Director — Date: 2/4/09

Attachments:

- Hewitt support materials
- Pension Investment Return Projection worksheet
- SIS market return projections

Pages 21 through 26 confidential.

You must have signed the protective order in this docket in order to view this page.

OPUC Data Request 81

For FAS 87, FAS 106, and FAS 112, please provide the estimated effect on 2010 Net periodic postretirement cost (income) if the discount rate is changed 25 basis points in both directions and expected rate of return is changed 25 basis points in both directions.

Response to OPUC Data Request 81

An estimate of the sensitivity for the 2010 Net periodic postretirement benefit cost can be approximated by looking at the 2009 sensitivity, after eliminating factors that would impact the 2009 sensitivity but not the 2010 sensitivity. Based on a discount rate of 6.90%, the following is the sensitivity for FAS 87 and FAS 106. FAS 112 sensitivity is not available.

(in $ millions)	Dis - 25 bps	Dis + 25 bps	EROA – 25 bps	EROA + 25 bps
FAS 87 (PRP only)	$ 1.9	$(1.8)	$2.3	$(2.3)
FAS 106	$ 0.0	$ 0.0	$0.9	$(0.9)

UE-210/PacifiCorp
May 20, 2009
OPUC Data Request 207

OPUC Data Request 207

Please provide a monthly breakout of Stock/401(k)/ESOP costs from July 2007 through March 2009. Also, please provide a detailed explanation on how the January – March 2009 amounts are trending compared to the projected increase for the test period.

Response to OPUC Data Request 207

Actual 401(k) Expense

Jan-07	1,516,550
Feb-07	1,459,632
Mar-07	1,642,051
Apr-07	1,471,399
May-07	1,628,931
Jun-07	1,392,581
Jul-07	1,516,282
Aug-07	1,528,136
Sep-07	1,430,673
Oct-07	1,574,597
Nov-07	1,562,182
Dec-07	1,483,782
Jan-08	2,123,132
Feb-08	1,874,486
Mar-08	1,816,785
Apr-08	1,970,625
May-08	1,894,595
Jun-08	1,801,251
Jul-08	2,030,729
Aug-08	1,793,849

Sep-08	1,936,594
Oct-08	2,339,143
Nov-08	1,909,227
Dec-08	2,261,211
Jan-09	2,788,971
Feb-09	2,519,414
Mar-09	2,719,724

In the response to OPUC Data Request 206, the Company stated that the 401(k) cost included in the case should be reduced by approximately $7 million on a Total Company basis. With this reduction, Total Company 401(k) expenses included in the test period will be approximately $34.5 million.

All 401(k) enhancements were in place by January 1, 2009. Projecting the future from actual expense from January – March 2009:

January 2009 - March 2009	8,028,109
Annualize	x 4
Projection of CY 2009	32,112,435
Pay increases for 2010	1.03%
	33,075,808
401(k) based on December incentive payments and other seasonal factors	1,459,890
	34,535,698

OPUC Data Request 207

Please provide a monthly breakout of Stock/401(k)/ESOP costs from July 2007 through March 2009. Also, please provide a detailed explanation on how the January – March 2009 amounts are trending compared to the projected increase for the test period.

1st Supplemental Response to OPUC Data Request 207

The following information is a supplement to the Company's original response to OPUC Data Request 207, dated May 20, 2009.

The Company's response to OPUC 207 originally included the following table:

January 2009 - March 2009	8,028,109
Annualize	x 4
Projection of CY 2009	32,112,435
Pay increases for 2010	1.03%
	33,075,808
401(k) based on December incentive payments and other seasonal factors	1,459,890
	34,535,698

This response restates the table to reflect the fact that 401(k) expense on Annual Incentive Payments is not charged to Account 501250, the 401(k) expense account, but instead is charged to Account 500410, annual incentive expense. The table is restated below:

January 2009 - March 2009	8,028,109
Annualize	x 4
Projection of CY 2009	32,112,435
Estimated Pay increases for 2010	1.03%
CY 2009 Projection with Pay increases	33,075,808
Revised 2010 401(k) Forecast	34,535,698
Difference	1,459,890

OPUC Data Request 206

As a follow up to DR No. 89, please provide work papers showing the calculations of the "659 conversions to Enhanced 401(k)" amount of $7,127,068 as well as the "Nonunion conversion to Enhanced 401(k)" amount of $12,900,000. Along with the work papers, please provide a written explanation of the calculations/assumptions and copies of any supporting documentation.

Response to OPUC Data Request 206

Upon further investigation of the Enhanced 401(k) included in the 2010 plan, it was discovered that the entire cost of the conversion to the Enhanced 401(k) is included in the $12,900,000, and the $7,127,068 should not have been included in addition. Removing the $7,127,068 will result in a reduction of the 401(k) cost included in the case by that amount. The result is a reduction to the Oregon revenue requirement by approximately $1.4 million as detailed in the table below. The Company's rebuttal position will reflect this change.

Total 401(k) cost to remove	7,127,068
Joint Owner Reduction	97.1%
Total Company Cost Reduction	6,919,258
O&M portion	71.45%
Total Company Expense Reduction	4,943,823
Approximate Oregon Portion - SO	28.26%
Oregon expense reduction	1,396,954

Please see Attachment OPUC 206 for the source of the additional $12.9 million cost due to 401(k) Enhancements. The breakdown of this amount between groups is:

Nonunion - $8.3 million
Local 659 - $3.1 million
Local 125 - $1.5 million

Please refer to non-confidential Attachment OPUC 206 on the enclosed CD.

OPUC Data Request 206

As a follow up to DR No. 89, please provide work papers showing the calculations of the "659 conversions to Enhanced 401(k)" amount of $7,127,068 as well as the "Nonunion conversion to Enhanced 401(k)" amount of $12,900,000. Along with the work papers, please provide a written explanation of the calculations/assumptions and copies of any supporting documentation.

1st Supplemental Response to OPUC Data Request 206

The following information is a supplement to the Company's original response to OPUC Data Request 206, dated May 20, 2009.

The $12.9 million is comprised of additional K Plus contributions in lieu of PRP accruals for Nonunion ($8.3 million), Local 659 ($3.1 million), and Local 125 ($1.5 million).

Estimates were based on January 1, 2008 census data. Each group was projected on an expected basis to 2010 using termination, mortality, and retirement assumptions as used in the 2008 10 Year Plan. Pay was projected assuming 3.5% growth in 2008 and 3.25% thereafter. New hires after January 1, 2008 for Local 659 and Nonunion were added each year to maintain the same number of employees in those groups.

Attachment OPUC 206 1st Supplemental provides further detailed analysis. Within the nonunion group, the projected payroll can be segregated into five subgroups, generally based on age and hire date, each of which is eligible for a defined additional K Plus contribution. The attachment shows the expected contribution for each of these subgroups based on that subgroup's projected payroll multiplied by the Additional K Plus contribution for that subgroup. The sum of these expected contributions equals to the $8.3 million nonunion projected additional K Plus contributions. A similar analysis is provided for Local 659 and Local 125.

The remainder of this note describes the additional K Plus provisions for these groups that are the basis for the analysis above.

Nonunion
Nonunion employees hired on or after January 1, 2008 are not eligible for PRP benefits. Instead, they will receive an additional K Plus contribution of 4%. In addition, nonunion employees hired before January 1, 2008 were given the choice on January 1, 2009 to freeze their PRP accruals and instead receive additional K Plus contributions. The additional K Plus contributions are the same percentage of pay that they would have received as pay credits in their cash balance benefit had

they elected to stay in PRP. Approximately 40% of the nonunion employees elected the additional K Plus contributions. Pay credits are as follows:

Hired before July 1, 2006 and less than age 40 on May 31, 2007: 6.5% of pay plus 4% of pay over the Social Security Wage Base*

Hired before July 1, 2006 and at least age 40 on May 31, 2007: 6.5% of pay plus transition credits of 4% from January 1, 2009 to May 31, 2010, 2.5% from June 1, 2010 to May 31, 2011, and 1.5% from June 1, 2011 to May 31, 2012.

Hired after June 30, 2006 but before January 1, 2008: 5.0%

*Employees must have a base pay of at least $85,000 on July 1, 2008 to get the 4% over the Social Security Wage Base.

Both new hires after January 1, 2008 and the 40% of employees electing the additional K Plus contributions are included in the $8.3 M.

Local 659
The PRP benefits were frozen on December 31, 2007 for Local 659 employees. In place of the accruals under PRP, employees will receive additional K Plus contributions as a percentage of pay, outlined below. These additional K Plus contributions are included in the $3.1 million.

Additional K Plus Contributions by Group:
Hired on or after 1/1/2008: 4.5%
Hired before 1/1/2008 (age determined on 1/1/2008)
Less than age 30: 4.5%
Ages 30-34: 5.5%
Ages 35 and over: 6.0%, plus transition credits.
Transition credits: If under age 40 are 4% for 2 years. If age 40 and over, transition credits are 6.5% for 2 years, 5.5% for year 3, and 4.5% for year 4.

Local 125
The PRP benefits were frozen on September 30, 2008 for anyone who was hired before 1/1/2006 and less than age 53 on October 1, 2008. In place of the accruals under PRP, employees will receive additional K Plus contributions as a percentage of pay, outlined below. These additional K Plus contributions are included in the $1.5 million.

Additional K Plus Contributions by Group:
Less than age 30: 4.5%
Ages 30-34: 5.5%
Ages 35 and over: 6.0%, plus transition credits.

Transition credits: If under age 40 are 3% for 2 years. If age 40 and over, transition credits are 6.5% for 2 years, 5.5% for year 3, and 4.5% for year 4.

Note that employees hired after January 1, 2006 are not eligible for PRP. Employees who were at least age 53 on October 1, 2008 will continue receiving PRP accruals.

Please refer to non-confidential Attachment OPUC 206 1st Supplemental on the enclosed CD.

PacifiCorp

Details for Additional K Plus Contributions shown in the 2008 10 Year Plan

Based on the 1/1/2008 Valuation Results
($ in millions)

Summary - Total Electric Operations Additional K Plus Contributions

	Projected from 1/1/2008	
	2009	**2010**
Nonunion	$ 8.6	$ 8.3
Local 125	1.5	1.5
Local 659	3.5	3.1
Total	$ 13.6	$ 12.9

PacifiCorp

Details for Additional K Plus Contributions shown in the 2008 10 Year Plan

Based on the 1/1/2008 Valuation Results
($ in millions)

Nonunion Employees who elected K Plus or were hired after 12/31/2007[1]

	Projected from 1/1/2008	
	2009	**2010**
Additional Kplus Contribution Percentage		
Hired < 7/1/2006 and at least age 40 at 5/31/2007	10.50%	9.63%
Hired < 7/1/2006 and less than age 40 at 5/31/2007	6.50%	6.50%
Hired between 6/30/2006 and 1/1/2008	5.00%	5.00%
Hired after 12/31/2007	4.00%	4.00%
Payroll above the Social Security Wage Base[2]	4.00%	4.00%
Projected Payroll		
Hired < 7/1/2006 and at least age 40 at 5/31/2007	$ 56.6	$ 55.0
Hired < 7/1/2006 and less than age 40 at 5/31/2007	18.6	17.9
Hired between 6/30/2006 and 1/1/2008	7.8	7.2
Hired after 12/31/2007	17.6	29.2
Total Payroll	$ 100.6	$ 109.3
Payroll above the Social Security Wage Base[2]	$ 9.1	$ 9.1
Projected Additional Kplus Contribution		
Hired < 7/1/2006 and at least age 40 at 5/31/2007	$ 5.9	$ 5.3
Hired < 7/1/2006 and less than age 40 at 5/31/2007	1.2	1.1
Hired between 6/30/2006 and 1/1/2008	0.4	0.4
Hired after 12/31/2007	0.7	1.1
Payroll above the Social Security Wage Base[2]	0.4	0.4
Total	$ 8.6	$ 8.3

[1] Excludes payroll for nonunion employees who elected PRP.
[2] Must be an employee hired before 7/1/2006 with a with base salary of at least $85,000 on 7/1/2008.

PacifiCorp

Details for Additional K Plus Contributions shown in the 2008 10 Year Plan

Based on the 1/1/2008 Valuation Results
($ in millions)

Local 125 Nongrandfathered[1]

	Projected from 1/1/2008	
	2009	**2010**
Additional Kplus Contribution Percentage		
Less than age 30	4.50%	4.50%
Ages 30-34	7.00%	6.63%
Ages 35-39	9.00%	8.25%
Ages 40-52	12.50%	12.25%
Ages 53+	0.00%	0.00%
Projected Payroll		
Less than age 30	$ 0.6	$ 0.5
Ages 30-34	2.1	2.0
Ages 35-39	2.0	1.9
Ages 40-52	9.3	9.3
Ages 53+	11.0	9.9
Total Payroll	$ 25.0	$ 23.6
Projected Additional Kplus Contribution		
Less than age 30	$ 0.0	$ 0.0
Ages 30-34	0.1	0.1
Ages 35-39	0.2	0.2
Ages 40-52	1.2	1.2
Ages 53+	0.0	0.0
Total	$ 1.5	$ 1.5

[1]Hired before 1/1/2006 and less than age 53 on 10/1/2008. Age buckets are determined as of 10/1/2008.

PacifiCorp

Details for Additional K Plus Contributions shown in the 2008 10 Year Plan

Based on the 1/1/2008 Valuation Results
($ in millions)

L659 Employees[1]

	Projected from 1/1/2008	
	2009	**2010**
Additional Kplus Contribution Percentage		
Hired on or after 1/1/2008	4.50%	4.50%
Hired before 1/1/2008 and less than age 30	4.50%	4.50%
Hired before 1/1/2008 and age 30-34	5.50%	5.50%
Hired before 1/1/2008 and age 35-39	10.00%	6.00%
Hired before 1/1/2008 and age 40+	12.50%	11.50%
Projected Payroll		
Hired after 1/1/2008	$ 2.0	$ 4.0
Hired before 1/1/2008 and less than age 30	0.9	0.9
Hired before 1/1/2008 and age 30-34	2.5	2.4
Hired before 1/1/2008 and age 35-39	3.8	3.7
Hired before 1/1/2008 and age 40+	22.9	22.0
	$ 32.1	$ 33.0
Projected Additional Kplus Contribution		
Hired after 1/1/2008	$ 0.1	$ 0.2
Hired before 1/1/2008 and less than age 30	0.0	0.0
Hired before 1/1/2008 and age 30-34	0.1	0.1
Hired before 1/1/2008 and age 35-39	0.4	0.2
Hired before 1/1/2008 and age 40+	2.9	2.6
Total	$ 3.5	$ 3.1

[1] Age buckets are determined as of 1/1/2008.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/03/2008	End of 2007/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Staff/203
Ball/39

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	California DSM Regulatory Asset	(221,524)	215,472	908	242,935	-248,987
2	Idaho DSM Regulatory Asset	5,255,937	2,131,643	908	3,135,822	4,251,758
3	Utah DSM Regulatory Asset	692,991	25,599,944	431,908	26,693,091	-400,156
4	Washington DSM Regulatory Asset	(1,791,744)	5,388,987	431,908	4,692,918	-1,095,675
5	Wyoming DSM Regulatory Asset (10)	329,053	26,226	908	72,652	282,627
6	DSM Regulatory Assets- Accruals	2,763,541	921,915			3,685,456
7	Calif. Alternative Rate For Energy (CARE)	1,389,730	1,677,761	142	1,325,266	1,742,225
8	Transition Plan - OR (10)	13,946,471		930.2	3,892,299	10,054,172
9	FAS 109 Deferred Income Taxes Electric	464,097,262		282	5,551,771	458,545,491
10	SB 1149 Implementation Costs OR Retail Access (5)	11,558,265	1,811,584	407.3	8,876,169	4,493,680
11	Energy Trust of Oregon SB1149	1,111		143	1,111	
12	Retail Access Project Inc. (Various)	1,156,535	251,523		1,408,058	
13	IDAI Costs No. CA Direct Access (5)	638,451		407.3	333,105	305,346
14	Sch 781 Direct Access Shopping Incentive	899,258	553,926	407.3	932,713	520,471
15	98 Early Retirement OR (4)	3,676,946		930.2	3,676,946	
16	Glenrock Mine Excluding Reclamation UT (9)	3,731,222		930.2	1,302,399	2,428,823
17	Deferred Excess Net Power Costs - OR UE116	137,716	12,091			149,807
18	Deferred Excess Net Power Costs - WY (1)	2,554,006	123,534	555	1,796,921	880,619
19	Deferred Excess Net Power Costs - CA		758,296			758,296
20	Deferred Excess Net Power Costs - WY 2007		29,108,115			29,108,115
21	OR SB 408 Recovery (1)	2,305,390	108,668		2,201,005	213,053
22	Environmental Costs (10)	6,045,016	2,141,798	925	1,131,270	7,055,544
23	Environmental Costs - WA (10)	(353,215)	58,507	925	158,983	-453,691
24	Reg Asset - Environmental Costs	8,080,491	1,230,366	253	7,748,899	1,561,958
25	Cholla Plant Transaction Costs (26)	11,878,997		557	1,122,425	10,756,572
26	Cholla Plant Transaction Costs - OR (26)	(569,522)	53,813			-515,709
27	Cholla Plant Transaction Costs - WA (26)	(1,026,649)	97,006			-929,643
28	Cholla Plant Transaction Costs - ID (26)	(348,968)	32,973			-315,995
29	Washington Colstrip #3 (22)	735,011		456	52,188	682,823
30	FAS 133 Derivative Net Regulatory Asset	229,837,168	26,186,602			256,023,770
31	FAS 87/88 Pension UT (7)	3,159,014		930.2	3,159,014	
32	Asset Retirement Obligations Regulatory Difference	54,860,930	20,236,504	230	22,244,031	52,853,403
33	FAS 158 Pension/Other Post Ret./SERP	565,929,191	12,384,148		352,060,406	226,252,933
34	RTO Grid West N/R Reg Asset	1,131,721				1,131,721
35	Contra Reg Asset - RTO Grid West	(1,131,721)				-1,131,721
36	RTO Grid West N/R - OR	810,234	68,645			878,879
37	RTO Grid West N/R - WY	414,098				414,098
38	RTO Grid West N/R - ID (5)	135,811		904	27,162	108,649
39	Deferred UT Independent Evaluator Fee		300,511			300,511
40	Deferred Intervenor Funding Grants (1)	861,532	286,929	928.2	555,488	592,973
41	2006 Transition Plan - WA (3)		1,982,160	920	358,438	1,623,722
42	BPA Washington Balancing Account		1,942,285			1,942,285
43	BPA Oregon Balancing Account		292,678			292,678
44	TOTAL	1,395,660,386	140,832,888		454,753,485	1,081,739,789

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	03/31/2009	End of 2008/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Staff/203
Ball/40

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	California DSM Regulatory Asset	(248,987)	326,217	908	1,078,585	-1,001,35
2	Idaho DSM Regulatory Asset	4,251,758	4,814,838	908	5,374,862	3,691,73
3	Utah DSM Regulatory Asset	(400,156)	34,682,831	431,908	26,660,514	7,622,16
4	Washington DSM Regulatory Asset	(1,095,675)	6,061,769	431,908	5,030,709	-64,61
5	Wyoming DSM Regulatory Asset (10)	282,627	89,699	908	62,260	310,06
6	DSM Regulatory Assets- Accruals	3,685,456	1,779,440			5,464,89
7	Calif. Alternative Rate For Energy (CARE)	1,742,225	897,949			2,640,174
8	Transition Plan - OR (10)	10,054,172		930.2	3,892,300	6,161,872
9	2006 Transition Plan - WA (3)	1,623,722		920	668,151	955,571
10	2006 Transition Plan - ID (3)	1,830,583		920	610,194	1,220,389
11	2006 Transition Severance Costs - WY (3)		4,780,000	920	2,124,444	2,655,556
12	FAS 109 Deferred Income Taxes Electric	458,545,491		282	18,803,706	439,741,785
13	SB 1149 Implementation Costs OR Retail Access (5)	4,493,680	90,898	407.3	4,584,576	2
14	IDAI Costs No. CA Direct Access (5)	305,346		407.3	305,346	
15	Sch 781 Direct Access Shopping Incentive	520,471	412,477	407.3	933,793	-845
16	Glenrock Mine Excluding Reclamation UT (9)	2,428,823		930.2	1,302,399	1,126,424
17	Deferred Excess Net Power Costs - OR UE116	149,807	11,824			161,631
18	Deferred Excess Net Power Costs - WY (1)	880,619	8,393	555	889,012	
19	Deferred Excess Net Power Costs - CA	758,296	27,092	555	1,260,795	-475,407
20	Deferred Excess NPC - WY 2007 (1)	29,108,115	4,491,382	555	24,964,142	8,635,355
21	Deferred Excess Net Power Costs - WY 08		24,231,911			24,231,911
22	OR SB 408 Recovery (1)	213,053			213,053	
23	Environmental Costs (10)	7,055,544	1,172,340	925	1,193,011	7,034,873
24	Environmental Costs - WA (10)	(453,691)	75,498	925	169,907	-548,100
25	Reg Asset - Environmental Costs	1,561,958	2,915,356			4,477,314
26	Cholla Plant Transaction Costs (26)	10,756,572		557	1,122,424	9,634,148
27	Cholla Plant Transaction Costs - OR (26)	(515,709)	53,813			-461,896
28	Cholla Plant Transaction Costs - WA (26)	(929,643)	97,006			-832,637
29	Cholla Plant Transaction Costs - ID (26)	(315,995)	32,974			-283,021
30	Washington Colstrip #3 (22)	682,823		456	52,188	630,635
31	FAS 133 Derivative Net Regulatory Asset	256,023,770	186,118,359			442,142,129
32	Asset Retirement Obligations Regulatory Difference	52,853,403	14,674,732	230	10,245,517	57,282,618
33	FAS 158 Pension/Other Post Ret./SERP	226,252,933	366,256,821		28,650,426	563,859,328
34	RTO Grid West N/R Reg Asset	1,131,721		182.3	1,078,549	53,172
35	Contra Reg Asset - RTO Grid West	(1,131,721)	1,078,549			-53,172
36	RTO Grid West N/R - OR	878,879	74,460			953,339
37	RTO Grid West N/R - WY (3)	414,098		904	184,043	230,055
38	RTO Grid West N/R - ID (5)	108,649		904	27,163	81,486
39	Deferred UT Independent Evaluator Fee	300,511	760,239	235	1,154,000	-93,250
40	Deferred Intervenor Funding Grants - ID	28,865	35,160	928	28,865	35,160
41	Deferred Intervenor Funding Grants - OR	564,108	178,739	928	1,009,743	-266,896
42	Deferred Intervenor - CA (1)		251,206	928	70,777	180,429
43	Deferred Ind Evaluator Fee - OR		1,236,615			1,236,615
44	TOTAL	1,081,739,789	704,214,401		159,600,460	1,626,353,730

OPUC Data Request 241

In the same format as the response to DR No. 130, please provide a breakdown of all expenses incurred from July 2007 through June 2008 which related to the mandatory, enforceable reliability standards which became effective in June 2007 as well as April 2008. Please also identify the SAP account(s) to which these costs were booked.

Response to OPUC Data Request 241

Please refer to Attachment OPUC 241. Note that compliance costs were not tracked separately in the Company's accounting system prior to January 1, 2008. The costs provided here for 12 months ended June 2008 include six months ended December 2007; the data for that six-month period represents the Company's best estimate of compliance costs incurred in that period.

Department	Account	Actual 12 Months Ended 6/30/2008
General Counsel	921	112,656.26
Generation	557	108,325.18
	506	35,775.42
	535	19,662.10
Main Grid Planning	560	1,995,237.78
Transmission Development Planning	560	39,868.10
Investment Planning	560	77,020.98
	580	144,407.63
	590	54,708.70
Physical Security	921	4,101.44
Transmission & Distribution Operations	561	143,111.11
	580	8,788.90
	581	1,536.09
	588	119.88
	592	12,193.12
	593	6,986.07
IT Networking	561	2,211.69
	580	16,143.12
	921	829.20
	935	5,055.55
Finance	935	990.00
		2,789,728.32

OPUC Data Request 241

In the same format as the response to DR No. 130, please provide a breakdown of all expenses incurred from July 2007 through June 2008 which related to the mandatory, enforceable reliability standards which became effective in June 2007 as well as April 2008. Please also identify the SAP account(s) to which these costs were booked.

1st Revised Response to OPUC Data Request 241

Please refer to Attachment OPUC 241 1st Revised, which provides the actual expenses incurred for incremental costs related to mandatory, enforceable reliability standards for the 12 months ended June 2008 of $922,386.

Please note that the Company's original response to OPUC Data Request 241, dated May 26, 2009, included total compliance related costs incurred from July 2007 through June 2008. In this proceeding, the Company has included a normalizing adjustment for incremental costs related to enhanced reliability standards, therefore the data provided in the Company's original response representing "total" actual costs is not comparable to adjustment 4.17 included in the Company's filing. The incremental costs represent the costs over and above those in the base historical period related to the increased reliability requirements. The attachment also shows a reconciliation of the amounts provided as "total" actual costs in the Company's original response to OPUC Data Request 241 and the "incremental" costs incurred for the historical period.

Please refer to non-confidential Attachment OPUC 241 1st Revised on the enclosed CD.

Department			"Incremental" Actual 12 Months Ended 6/30/2008
General Counsel	General Counsel	921	52,848
Generation			-
			-
			-
Main Grid Planning	Main Grid Planning	560	-
Transmission Development Planning	Transmission Development Planning	560	632,466
Investment Planning			-
			-
	Investment Planning	590	-
Physical Security	Physical Security	921	22,170
Transmission & Distribution Operations	Transmission & Distribution Operations	561	88,072
	Transmission & Distribution Operations	580	-
	Transmission & Distribution Operations	581	88,401
			-
	Transmission & Distribution Operations	592	32,020
			-
IT Networking			-
			-
	IT Networking	921	-
			-
Finance	Finance	921	-
	Finance	560	829
	Finance	580	5,580
	Finance	581	-
Total	Total		922,386

These amounts represent incremental amounts related to new standards and had not been incurred in the past.

Department	Account	Reported in Attach OPUC 241 — "Total" Actual 12 Months Ended 6/30/2008			Actuals Reflected in Adj. 4.17 — "Incremental" Actual 12 Months Ended 6/30/2008	
General Counsel	921	112,656	General Counsel	921	52,848	
Generation	557	108,325			-	
	506	35,775			-	
	535	19,662			-	
Main Grid Planning	560	1,995,238	Main Grid Planning	560	-	These amounts are in the same FERC account, are managed by the same group &
Transmission Development Planning	560	39,868	Transmission Development Planning	560	632,466	were not specifically broken out between Main Grid and Development
Investment Planning	560	77,021			-	
	580	144,408			-	
	590	54,709	Investment Planning	590	-	
Physical Security	921	4,101	Physical Security	921	22,170	"Incremental" is additional employee time, not included in specific order used to accumulate "Total"
Transmission & Distribution Operations	561	143,111	Transmission & Distribution Operations	561	88,072	"Incremental" is additional employee time, not included in specific order used to accumulate "Total"
	580	8,789	Transmission & Distribution Operations	580	-	"Incremental" is additional employee time, not included in specific order used to accumulate "Total"
	581	1,536	Transmission & Distribution Operations	581	88,401	"Incremental" is additional employee time, not included in specific order used to accumulate "Total"
	588	120			-	"Incremental" is additional employee time, not included in specific order used to accumulate "Total"
	592	12,193	Transmission & Distribution Operations	592	32,020	"Incremental" is additional employee time, not included in specific order used to accumulate "Total"
	593	6,986			-	
IT Networking	561	2,212			-	
	580	16,143			-	
	921	829	IT Networking	921	-	
	935	5,056			-	
Finance	935	990	Finance	921	-	
	560	-	Finance	560	829	Amounts in finance accrued in bulk, not to the specific order used to accumulate "Total"
	580	-	Finance	580	5,580	Amounts in finance accrued in bulk, not to the specific order used to accumulate "Total"
	581	-	Finance	581	-	
Total		2,789,728	Total		922,386	

These amounts represent incremental amounts related to new standards and had not been incurred in the past.

Items that were not captured in "Total" costs	
	6,409
	230,663
	3,026,800

These amounts represent total costs identified as compliance related.

CASE: UE 210
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 300

Opening Testimony

July 24, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Michael Dougherty. I am the Program Manager for the Corporate Analysis and Water Regulation Section of the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/301.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to describe my adjustments to PacifiCorp's Distribution Operations and Maintenance (O&M) expenses and recommendations concerning the sale of Renewable Energy Certificates (RECs).

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared:

Exhibit Staff/302, consisting of 1 page; and

Exhibit Staff/303, consisting of 37 pages.

Q. PLEASE PROVIDE A SUMMARY OF YOUR ADJUSTMENTS.

A. The following table summarizes my adjustments to PacifiCorp's Distribution O&M expenses.

Table 1 – Summary of Distribution O&M Adjustments

CWIP Write-offs	$1,022,630
Meals and Entertainment	$87,432
Total	**$1,110,063**
Total Escalated to 2010	**$1,136,704**
Total increased for $26,099	**$1,162,803**

Using PacifiCorp's O&M "Operation" escalation rate of 2.4 percent,[1] the adjustment escalates to a 2010 amount of $1,136,704. I then took this amount and subtracted PacifiCorp's 4.20 Adjustment, *Adjust Non-Power Cost O&M to 2010 Target*, Distribution, Other Adjustments, Oregon-allocated amount of minus $26,099 to receive a total adjustment of $1,162,803.

Q. PLEASE EXPLAIN YOUR USE OF THE ESCALATION FACTOR.

A. In Exhibit PPL/702, page 4.8, PacifiCorp calculates the O&M escalation from June 2008 through December 2010 for accounts 500 to 935 (non-power cost accounts only) using industry specific escalation indices. In Exhibit PPL/703, page 4.8.8, PacifiCorp actually provides two Distribution escalation rates, 2.4 percent for Operations and a negative 1.3 percent for Maintenance. Since CWIP write-offs and meals and entertainment are more akin to operations than maintenance,[2] I used the operations escalation of 2.4 percent.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT CONCERNING PACIFICORP'S 4.20 ADJUSTMENT, ADJUST NON-POWER COST O&M TO 2010 TARGET.

[1] Exhibit PPL/703, page 4.8.8.

[2] CFR 18, Pt. 101 states on page 379 under 2. Maintenance "The cost of maintenance chargeable to various operating expense and clearing accounts include labor, materials, overheads, and other expenses incurred in maintenance work." The section lists items that are classified as maintenance.

A. In adjustment 4.20, PacifiCorp explains that the Company is not planning to spend more than the budgeted non-power cost O&M in calendar year 2010. As a result, the Company removes "Inflation and Labor Escalations" and "Other Adjustments" costs from different categories of expenses. For Distribution, the Company actually adds back $91,901 in "Other Adjustments" ($26,099 Oregon-allocated). In order to account for PacifiCorp's expense adjustment, I subtracted this amount from my escalated adjustment. Because PacifiCorp's adjustment was a negative $26,099 (Oregon-allocated), my adjustment actually increases due to subtracting a negative amount.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

ISSUE 1, CONSTRUCTION WORK IN PROGRESS (CWIP) WRITE-OFF EXPENSES

Q. PLEASE EXPLAIN THESE CONSTRUCTION WORK IN PROGRESS (CWIP) WRITE-OFF EXPENSES.

A. According to PacifiCorp's response to Staff Data Request No. 211,[3] the charges are cancelled CWIP projects and reserve adjustments to expenses. PacifiCorp states (emphasis added):

[3] Included in Exhibit Staff/303.

> The specific capital projects being written off are included in CWIP until such time as ***information is available that construction will not be completed and an asset not be placed in service.*** At that time, the costs are written off by crediting CWIP and debiting expense.

In its response to Staff Data Request No. 296,[4] PacifiCorp provided an extensive list of projects that were cancelled during the test year. Although PacifiCorp does not record the reasons why the capital jobs were cancelled in its accounting data, I was able to classify the Oregon-labeled entries into four main categories: Oregon New Revenue, Oregon Mandated, Public Accommodations, and Other (Replace, Upgrades, Temporary Connects). The following table summarizes the entries (also included in Staff Exhibit 303, Dougherty 6 - 9).

Table 2 – CWIP Write-offs

Category	**Amount**
Oregon – New Revenue	$704,795
Oregon – Mandated	$45,693
Oregon - Public Accommodations	$120,238
Other (Replace, Upgrade, Temp Connects)	$38,321
Total	**$909,047**

In its response to Staff Data Request No. 296, PacifiCorp notes that there are sometimes timing difference between the month cancelled and the month processed; however, the timing differences are relatively short. Additionally, the above total number only references Oregon-labeled entries. The difference between my Table 1 amount ($1,022,630) and the Table 2 amount ($909,047) results from both the timing difference and the system-labeled amounts.

[4] Included in Exhibit Staff/303.

Q. WHY SHOULD THESE EXPENSES NOT BE INCLUDED IN PACIFICORP'S REVENUE REQUIREMENTS?

A. Although these CWIP projects were written off as expenses, they started as construction projects that were to be placed in plant. PacifiCorp affirms this in its response to Staff Data Request No. 211[5] by stating "*construction will not be completed and an asset not be placed in service."* Because the projects were not placed in service, the projects were not used for providing utility service to Oregon customers. As a result, PacifiCorp should not be allowed to recover these expenses through customer rates.

Q. IF NOT IN CUSTOMERS RATES, HOW WILL PACIFICORP RECOVER THESE EXPENSES?

A. As the above table indicates, approximately 78 percent of the Distribution CWIP write-offs expenses were related to projects labeled "New Revenue". PacifiCorp's Rule 13 discusses Line Extensions and charges and allowances concerning line extensions. In addition, PacifiCorp's Schedule 300, lists PacifiCorp's Facilities Charges, Temporary Service Charge, and Contract Administration Credit.[6] As such, one way PacifiCorp could recover these expenses is to attempt to bill and recover the write-off amounts from the specific sources of new revenue. These costs should not be spread to all Oregon customers.

Concerning the projects listed as Mandated, Public Accommodations, and Other (Replace, Upgrade, Temporary Connections), PacifiCorp should not be

[5] Included in Exhibit Staff/303.
[6] Rule 13 and Schedule 300 are included in Staff/303.

allowed to recover these costs since these construction projects were never placed into service. Ballot Measure 9 (ORS 757.355 (1)) precludes recovery of investments that are used and useful in providing service to customers.

Q. DO YOU HAVE AN ALTERNATE RECOMMENDATION FOR THE COMMISSION TO CONSIDER?

A. Yes. As shown in Table 2, projects listed as Oregon – New Revenue total $704,795. If the projects were successfully completed, the revenues would have been spread to all customers. As such, an alternate recommendation would be to equally share these Oregon – New Revenue CWIP costs between customers and shareholders. A 50 / 50 sharing between shareholders and customers for these projects would result in customers assuming $352,398 of these costs. As a result, my total recommended Distribution O&M adjustments would be reduced to $810,405.

Because Ballot Measure 9 (ORS 757.355 (1)) precludes recovery of investments that are used and useful in providing service to customers, I do not propose a sharing of the other CWIP cost categories.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY ON CWIP WRITE-OFF ADJUSTMENTS?

A. Yes.

ISSUE 2, MEALS AND ENTERTAINMENT EXPENSES

Q. PLEASE EXPLAIN YOUR MEALS AND ENTERTAINMENT EXPENSE ADJUSTMENTS.

A. Staff routinely recommends a 50 / 50 sharing between shareholders and customers concerning meals and entertainment expenses. The following table summarizes the meals and entertainment expenses in PacifiCorp's Distribution O&M accounts. These amounts are also listed in Staff/300, Dougherty/1.

Table 3 – Meals and Entertainment Expenses

Category	**Amount**
Catering	$4,357
Meals & Entertainment	$50,716
Off-site Rentals (Employee Appreciation)	$7
On-site Meals	$17,806
Other Employee Expenses (Emp. Appreciation)	$14,547
Total	**$87,432**

In Commission Order No. 09 – 020 (UE 197), the Commission agreed with Staff's recommendation concerning meals and entertainment expenses and ordered the 50 percent sharing between customers and shareholders. The Commission stated on page 21:[7]

> We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders.

As a result, I recommend a 50 / 50 sharing of meals and entertainment expenses between customers and shareholders.

[7] Included in Exhibit Staff/303.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY CONCERNING O&M EXPENSES?

A. Yes.

ISSUE 3, RENEWABLE ENERGY CERTIFICATIONS (RECS)

Q. PLEASE EXPLAIN HOW PACIFICORP PLANS TO HANDLE REVENUE RECEIVED FROM THE SALE OF RENEWABLE ENERGY CERTIFICATES?

A. In order to meet Oregon's Renewable Portfolio Standard (RPS), PacifiCorp is currently banking Oregon's share of RECs. In adjustment 3.5, PacifiCorp allocates projected REC sales for the twelve months ending December 2010 from Oregon to the Company's remaining jurisdictions consistent with the Multi-state Process (MSP) Revised Protocol. According to PacifiCorp's response to Staff Data Request No. 230,[8] the adjustment is necessary to avoid giving states with RPS requirements (Oregon and California) credit for REC sales for their portion of RECs that are being banked rather than sold. PacifiCorp has been banking Oregon RECs to meet the RPS requirement. In its response to Staff Data Request No. 232,[9] the Company estimates that based on current owned or contracted renewable resources, PacifiCorp estimates that it may have sufficient RECs allocated to Oregon to meet RPS requirements for years 2011 through 2016.

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[8] Included in Exhibit Staff/303.
[9] Included in Exhibit Staff/303.

Q. HOW DID PACIFICORP TREAT THE SALES OF RECS IN ITS PREVIOUS GENERAL RATE CASE, DOCKET UE 179?

A. The REC revenue generated included in PacifiCorp's General Rate Case, Docket UE 170 was $444,001.[10] This revenue was recorded in Account 456, *Other electric revenue*. Because rates from UE 170 were effective January 1, 2007, customers received benefits of REC sales for the years 2007, 2008, and 2009.

Q. DO YOU AGREE WITH PACIFICORP'S ADJUSTMENT?

A. Yes. However, because PacifiCorp estimates that it will have sufficient RECs allocated to Oregon to meet RPS requirements for years 2011 through 2016, if the Company is able to and chooses to sell Oregon-allocated RECs, the Company should place the gain on the sale to the property sales balancing account for refund to customers with interest accrual from the date of sale using the Commission approved rate of return until amortization begins. This proposed treatment is consistent with Commission Order No. 07-083 (UP 236),[11] which established the sale of RECs as a property sale with gains on sale being placed in a property sales balancing account for return to customers. Additionally, PacifiCorp should report in its semi-annual Property Sales Balancing Account report any REC sales that occurred during the reporting period.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[10] Response to Staff Data Request No. 99. Included in Exhibit Staff/303.
[11] Included in Exhibit Staff/303.

CASE: UE 210
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

July 24, 2009

WITNESS QUALIFICATION STATEMENT

NAME:	MICHAEL DOUGHERTY
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	PROGRAM MANAGER, CORPORATE ANALYSIS AND WATER REGULATION
ADDRESS:	550 CAPITOL ST. NE, SALEM, OR 97308-2148
EDUCATION:	Master of Science, Transportation Management, Naval Postgraduate School, Monterey CA (1987) Bachelor of Science, Biology and Physical Anthropology, City College of New York (1980)
EXPERIENCE:	Employed with the Oregon Public Utility Commission from June 2002 to present, currently serving as the Program Manager, Corporate Analysis and Water Regulation. Also serve as Lead Auditor for the Commission's Audit Program. Performed a five-month job rotation as Deputy Director, Department of Geology and Mineral Industries, March through August 2004. Employed by the Oregon Employment Department as Manager - Budget, Communications, and Public Affairs from September 2000 to June 2002. Employed by Sony Disc Manufacturing, Springfield, Oregon, as Manager - Manufacturing, Manager - Quality Assurance, and Supervisor - Mastering and Manufacturing from April 1995 to September 2000. Retired as a Lieutenant Commander, United States Navy. Qualified naval engineer. Member, National Association of Regulatory Commissioners Staff Sub-Committee on Accounting and Finance.

CASE: UE 210
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

July 24, 2009

UE 210 - Distribution

July 2007 - June 2008 Costs

From DR 210 $ **14,553,565**

Month - DR 123	DR 123	Staff Adjustment	Staff Recommendation	
July 2007	$ 1,216,694	$ 85,134	$ 1,131,560	
August 2007	$ 1,830,357	$ 44,408	$ 1,785,949	
September 2007	$ 1,433,840	$ (19,486)	$ 1,453,326	
October 2007	$ 2,202,234	$ 84,185	$ 2,118,049	
November 2007	$ 1,460,185	$ 97,708	$ 1,362,477	
December 2007	$ (639,878)	$ 98,407	$ (738,285)	
January 2008	$ 17,964	$ 147,629	$ (129,665)	
February 2008	$ 562,544	$ 151,325	$ 411,219	
March 2008	$ 1,813,343	$ 95,949	$ 1,717,394	
April 2008	$ 1,593,261	$ 80,662	$ 1,512,599	
May 2008	$ 1,710,661	$ 98,069	$ 1,612,592	
June 2008	$ 1,354,228	$ 146,068	$ 1,208,160	
Total	**$ 14,555,433**	**$ 1,110,063**	**$ 13,445,375**	
DRI Escalated (2.4%)	**$ 14,904,763**	**$ 1,136,704**	**$ 13,768,064**	
PacifiCorp 4.20 Adjustment				
Labor & Inflation Component	$ 8,288,899			Page 4.20.1
Non-Labor Component	$ (91,901)	$ (26,099)		Page 4.20.1
Total Distribution Adjustment	**$ 14,904,763**	**$ 1,162,803**	**$ 13,741,960**	

By Category		
Auc Expense	$ 1,022,630	CWIP Write-offs
Catering	$ 4,357	50% Sharing
Meals & Entertainment	$ 50,716	50% Sharing
Off-site Rentals	$ 7	50% Sharing - Employee Appreciation
On-site Meals	$ 17,806	50% Sharing
Other Employee Expenses	$ 14,547	50% Sharing - Employee Appreciation
	$ 1,110,063	
	$ 1,136,704	**Escalated**
Alternate Adjustment *50 / 50 sharing of New Revenue CWIP Write-offs*	**$ 810,405**	

CASE: UE 210
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

July 24, 2009

distribution facilities according to the purpose for which used.

E. Land (other than rights of way) and structures used jointly for transmission and distribution purposes shall be classified as transmission or distribution according to the major use thereof.

15. *Hydraulic production plant (Major Utilities).*

For the purpose of this system of accounts hydraulic production plant means all land and land rights, structures and improvements used in connection with hydraulic power generation, reservoirs dams and waterways, water wheels, turbines, generators, accessory electric equipment, miscellaneous powerplant equipment, roads, railroads, and bridges, and structures and improvements used in connection with fish and wildlife, and recreation.

16. *Nuclear Fuel Records Required (Major Utilities).*

Each utility shall keep all the necessary records to support the entries to the various nuclear fuel plant accounts classified under "Assets and Other Debits," Utility Plant 120.1 through 120.6, inclusive, account 518, Nuclear Fuel Expense and account 157, Nuclear Materials Held for Sale. These records shall be so kept as to readily furnish the basis of the computation of the net nuclear fuel costs.

Operating Expense Instructions

1. *Supervision and Engineering (Major Utilities).*

The supervision and engineering includible in the operating expense accounts shall consist of the pay and expenses of superintendents, engineers, clerks, other employees and consultants engaged in supervising and directing the operation and maintenance of each utility function. Wherever allocations are necessary in order to arrive at the amount to be included in any account, the method and basis of allocation shall be reflected by underlying records.

ITEMS

Labor

1. Special tests to determine efficiency of equipment operation.
2. Preparing or reviewing budgets, estimates, and drawings relating to operation or maintenance for departmental approval.
3. Preparing instructions for operations and maintenance activities.
4. Reviewing and analyzing operating results.
5. Establishing organizational setup of departments and executing changes therein.
6. Formulating and reviewing routines of departments and executing changes therein.
7. General training and instruction of employees by supervisors whose pay is chargeable hereto. Specific instruction and training in a particular type of work is chargeable to the appropriate functional account (See Electric Plant Instruction 3(19)).
8. Secretarial work for supervisory personnel, but not general clerical and stenographic work chargeable to other accounts.

Expenses

9. Consultants' fees and expenses.
10. Meals, traveling and incidental expenses.

2. *Maintenance.*

A. The cost of maintenance chargeable to the various operating expense and clearing accounts includes labor, materials, overheads and other expenses incurred in maintenance work. A list of work operations applicable generally to utility plant is included hereunder. Other work operations applicable to specific classes of plant are listed in functional maintenance expense accounts.

B. Materials recovered in connection with the maintenance of property shall be credited to the same account to which the maintenance cost was charged.

C. If the book cost of any property is carried in account 102, Electric Plant Purchased or Sold, the cost of maintaining such property shall be charged to the accounts for maintenance of property of the same class and use, the book cost of which is carried in other electric plant in service accounts. Maintenance of property leased from others shall be treated as provided in operating expense instruction 3.

ITEMS

1. Direct field supervision of maintenance.
2. Inspecting, testing, and reporting on condition of plant specifically to determine the need for repairs, replacements, rearrangements and changes and inspecting and testing the adequacy of repairs which have been made.

3. Work performed specifically for the purpose of preventing failure, restoring serviceability or maintaining life of plant.

4. Rearranging and changing the location of plant not retired.

5. Repairing for reuse materials recovered from plant.

6. Testing for locating and clearing trouble.

7. Net cost of installing, maintaining, and removing temporary facilities to prevent interruptions in service.

8. Replacing or adding minor items of plant which do not constitute a retirement unit. (See electric plant instruction 10.)

3. *Rents.*

A. The rent expense accounts provided under the several functional groups of expense accounts shall include all rents, including taxes paid by the lessee on leased property, for property used in utility operations, except (1) minor amounts paid for occasional or infrequent use of any property or equipment and all amounts paid for use of equipment that, if owned, would be includible in plant accounts 391 to 398, inclusive, which shall be treated as an expense item and included in the appropriate functional account and (2) rents which are chargeable to clearing accounts, and distributed therefrom to the appropriate account. If rents cover property used for more than one function, such as production and transmission, or by more than one department, the rents shall be apportioned to the appropriate rent expense or clearing accounts of each department on an actual, or, if necessary, an estimated basis.

B. When a portion of property or equipment rented from others for use in connection with utility operations is subleased, the revenue derived from such subleasing shall be credited to the rent revenue account in operating revenues; provided, however, that in case the rent was charged to a clearing account, amounts received from subleasing the property shall be credited to such clearing account.

C. The cost, when incurred by the lessee, of operating and maintaining leased property, shall be charged to the accounts appropriate for the expense if the property were owned.

D. The cost incurred by the lessee of additions and replacements to electric plant leased from others shall be accounted for as provided in electric plant instruction 6.

4. *Training Costs.*

When it is necessary that employees be trained to specifically operate or maintain plant facilities that are being constructed, the related costs shall be accounted for as a current operating and maintenance expense. These expenses shall be charged to the appropriate functional accounts currently as they are incurred. However, when the training costs involved relate to facilities which are not conventional in nature, or are new to the company's operations, then see Electric Plant Instruction 3(19), for accounting.

Balance Sheet Chart of Accounts

ASSETS AND OTHER DEBITS

1. Utility Plant

101 Electric plant in service (Major only).
101.1 Property under capital leases.
102 Electric plant purchased or sold.
103 Experimental electric plant unclassified (Major only).
103.1 Electric plant in process of reclassification (Nonmajor only).
104 Electric plant leased to others.
105 Electric plant held for future use.
106 Completed construction not classified—Electric (Major only).
107 Construction work in progress—Electric.
108 Accumulated provision for depreciation of electric utility plant (Major only).
109 [Reserved]
110 Accumulated provision for depreciation and amortization of electric utility plant (Nonmajor only).
111 Accumulated provision for amortization of electric utility plant (Major only).
112–113 [Reserved]
114 Electric plant acquisition adjustments.
115 Accumulated provision for amortization of electric plant acquisition adjustments (Major only).
116 Other electric plant adjustments.
118 Other utility plant.
119 Accumulated provision for depreciation and amortization of other utility plant.
120.1 Nuclear fuel in process of refinement, conversion, enrichment and fabrication (Major only).
120.2 Nuclear fuel materials and assemblies—Stock account (Major only).
120.3 Nuclear fuel assemblies in reactor (Major only).
120.4 Spent nuclear fuel (Major only).
120.5 Accumulated provision for amortization of nuclear fuel assemblies (Major only).
120.6 Nuclear fuel under capital leases (Major only).

OPUC Data Request 211

As a follow-up to PacifiCorp's response to Staff Data Request No. 123, please explain the following entries in Attachment OPUC 123.

a. Please explain line items listed as AuC Expensed.

b. Please specifically explain AuC Expensed that is described as *"Power Delivery – Balance Sheet, PP CWIP Writeoffs - Distrib OREGON."* Why would CWIP write-offs be included as an expense item and not as a capital item?

c. PacifiCorp's Capitalization Policy states: *"All computer hardware and desktop software items acquired initially with a computer workstation should be capitalized. The addition (not replacement) of a non-property retirement unit hardware or desktop software item to an existing workstation should be capitalized if the cost exceeds the $500/one year capitalization threshold."* However, Attachment OPUC 123 has numerous entries of hardware ranging from $500 to over $15,000 (*Facility Inspection West – Map Production, November 2007*). Please explain why certain computer hardware over $500 is expensed and not capitalized. What references in the Capitalization Policy allows this type of treatment?

d. Please explain the Diesel Fuel Hedge entries. What is the duration of the current contract, and what entities are party to the contract? Does PacifiCorp plan to continue a Diesel Fuel hedge program in 2009 and 2010? Please explain.

e. Concerning pole rental expenses in FERC accounts 593 and 598, certain line items are described as *"ALB: JU $ paid for us on foreign poles"*. Please explain the term "foreign" as used by PacifiCorp for these poles. Are all of these poles being rented located in Oregon? If not, should these expenses be SNPD and not Situs? Please explain.

f. Please explain the *"Settlement Fees, Power Delivery – Balance Sheet"* entries.

Response to OPUC Data Request 211

a. The line items are monthly journal entries that charge cancelled CWIP projects and reserve adjustments to expense. Asset under Construction ("AuC") is an SAP term synonymous with CWIP.

b. The specific capital projects being written off are included in CWIP until such time as information is available that construction will not be completed and an asset not be placed in service. At that time, the costs are written off by crediting CWIP and debiting expense. The line items described as *"Power Delivery – Balance Sheet, PP CWIP Writeoffs - Distrib OREGON"* are for those specific cancelled CWIP projects that are Pacific Power distribution work in Oregon.

c. The costs referred to in *item c.* above regarding Facility Inspection West-Map Production, November 2007 were expensed and not capitalized due to the nature of the costs. These costs were primarily labor and material charges to maintain equipment.

Please see the following reference in PacifiCorp's Capitalization Policy which allows for this type of treatment.

3. ASSET RECOGNITION CRITERIA

Types of costs accounted for as expense and should not be included in capital are as follows:

- *Maintaining the life of plant*

d. The Company executes a diesel fuel hedge contract to stabilize fuel costs. The contract price per gallon is compared with the actual price per gallon and an entry is made to bring the actual fuel charges to the contract price. The diesel fuel hedge entries represent the adjustment for the distribution portion of the Company adjustment.

The current diesel fuel hedge contract duration is April 1, 2009 to November 30, 2009. The contract is between PacifiCorp and Credit Suisse Energy LLC. At this time, PacifiCorp plans to continue a diesel fuel hedge program in 2009 and 2010.

e. "Foreign" poles are those owned by third parties on which PacifiCorp has attached facilities. All poles with this description would be located in the state of Oregon.

f. There was $666,746 of settlement fees booked in the Power Delivery Balance Sheet in July 2007 to accrue a liability for the Multnomah County Business Income Tax (MCBIT) over-collection. The July accrual was booked to FERC account 598 and reclassified to FERC account 903.2 in September 2007. September 2007 also included $13,500 paid in settlement of a multi-party easement dispute. Please refer to the Confidential Attachment OPUC 211f for documentation.

Please refer to Confidential Attachment OPUC 211f on the enclosed CD.

UE-210/PacifiCorp
June 11, 2009
OPUC Data Request 296

OPUC Data Request 296

As a follow-up to PacifiCorp's response to Staff Data Request No. 211, please provide information in the following table format concerning cancelled test-year CWIP projects.

Project Name	Project Description	Reason Cancelled	Month Cancelled	Amount Debited to Expense

Response to OPUC Data Request 296

Please refer to Attachment OPUC 296 for cancelled CWIP projects that were expensed. This list includes those charged to FERC Distribution Expense account 598 (see OPUC Data Request 297) as well as those charged to various other accounts. The months shown on the attachment correspond to when the projects were removed from CWIP. Note, there are sometimes timing differences between the month actually cancelled and month processed, however the differences are relatively short. The projects listed can include multiple work orders representing separate jobs. As each work order is cancelled, a debit entry to expense is reflected in the month removed from CWIP. Therefore, a project may show monthly debit entries for separate work orders cancelled under a project description.

Reasons for cancelled projects are not maintained with the Company's CWIP computer records and are therefore not readily available; however, the Company will expedite any request for reasons for cancellation for any specific project to the extent possible

Please refer to non-confidential Attachment OPUC 296 on the enclosed CD.

	UE-210/PacifiCorp																	
	Cancelled CWIP projects Jan 2007 - May 2009						7	8	9	10	11	12	1	2	3	4	5	6
	Project_Definition	Project Description	Factor	FERC Account	Location	Total												
	DZME/2005/C/003	Green Spring Substation Sale in Place	OR	5980000	108	653									652.80			
	DALB/2007/C/002	Hazelwood Fry 115kV Ln Svc to PepsiCo	OR	5980000	108	3,860									3,859.50			
	DZME/2006/C/003	Line 3 Convert to 115kV	OR	5980000	108	51,953							51,952.53					
	DZAL/2003/C/001	Marys River Sub Incr Capacity 25MVA	OR	5980000	108	0												
	DKLA/2008/C/001	Modoc 5L36 Kla-Mo-Ya Expansion	OR	5980000	108	0										-		
	DORE/2009/C/DRK	Oregon - Asset Removal	OR	5980000	108	0												
M	DORE/9999/C/DM6	Oregon - Mandated - Joint Use	OR	5980000	108	8,254		1,106.93	374.40	534.15	802.29	427.88	1,604.55	2,255.73		933.84	213.94	
M	DORE/2009/C/DM7	Oregon - Mandated - Code Compliance	OR	5980000	108	0												
M	DORE/2008/C/DM6	Oregon - Mandated - Joint Use	OR	5980000	108	53									52.50			
M	DORE/2009/C/DM6	Oregon - Mandated - Joint Use	OR	5980000	108	0												
M	DORE/2009/C/DM3	Oregon - Mandated Environmental	OR	5980000	108	0												
M	DORE/2008/C/DM1	Oregon - Mandated Highway Relocations	OR	5980000	108	3,941				402.52					1,963.24	735.00		840.00
M	DORE/2009/C/DM1	Oregon - Mandated Highway Relocations	OR	5980000	108	0												
M	DORE/9999/C/DM1	Oregon - Mandated Highway Relocations	OR	5980000	108	17,092		149.19	(149.19)		149.19		8,365.00	4,344.57	641.82	3,591.40	-	
M	DORE/2008/C/DM4	Oregon - Mandated Neutral Extensions	OR	5980000	108	0												
M	DORE/9999/C/DM4	Oregon - Mandated Neutral Extensions	OR	5980000	108	0												
M	DORE/2008/C/DM2	Oregon - Mandated OH/UG Conversions	OR	5980000	108	363		363.16										
M	DORE/9999/C/DM2	Oregon - Mandated OH/UG Conversions	OR	5980000	108	15,991	255.59		2,408.95	577.10			3,621.53	3,840.05	2,730.60	213.94	2,343.43	
	DORE/2008/C/DM7	Oregon Mandated Code Compliance	OR	5980000	108	0												
45,693																		
N	DORE/2008/C/DN2	Oregon - New Revenue - Commercial	OR	5980000	108	19,402	207.52	1,713.86	415.04	402.52			1,504.64	402.52	3,724.89	7,247.07	3,783.65	
N	DORE/2009/C/DN2	Oregon - New Revenue - Commercial	OR	5980000	108	0												
N	DORE/9999/C/DN2	Oregon - New Revenue - Commercial	OR	5980000	108	152,551	13,221.51	21,180.23	3,222.37	9,746.17	13,175.80	13,288.98	20,729.28	22,832.79	13,112.88	13,598.16	7,691.47	751.44
N	DORE/9999/C/DN7	Oregon - New Revenue - Feeder Reinforce	OR	5980000	108	5,689				625.40		4,657.92	103.76		301.89			
N	DORE/2008/C/DN3	Oregon - New Revenue - Industrial	OR	5980000	108	0												
N	DORE/2009/C/DN3	Oregon - New Revenue - Industrial	OR	5980000	108	0												
N	DORE/9999/C/DN3	Oregon - New Revenue - Industrial	OR	5980000	108	34,220				28,450.79		160.46	5,448.33					160.25
N	DORE/2008/C/DN4	Oregon - New Revenue - Irrigation	OR	5980000	108	2,656											1,102.50	1,553.54
N	DORE/2009/C/DN4	Oregon - New Revenue - Irrigation	OR	5980000	108	0												
N	DORE/9999/C/DN4	Oregon - New Revenue - Irrigation	OR	5980000	108	15,354	748.79	2,619.87		1,147.78	2,941.68	1,496.32	723.43	1,711.52	3,270.23	694.40	-	
N	DORE/2008/C/DN1	Oregon - New Revenue - Residential	OR	5980000	108	43,110	2,754.59	1,177.59	1,620.01	2,616.38		11,009.63	1,432.39	10,740.25	1,203.88	4,150.61	4,622.14	1,782.87
N	DORE/2009/C/DN1	Oregon - New Revenue - Residential	OR	5980000	108	0												
N	DORE/9999/C/DN1	Oregon - New Revenue - Residential	OR	5980000	108	405,504	27,518.76	36,568.09	6,362.00	20,685.06	32,893.70	30,746.42	58,951.69	79,915.31	41,313.52	25,183.73	30,007.46	15,358.30
N	DORE/2008/C/DN6	Oregon - New Revenue - St Light & Other	OR	5980000	108	5,946		1,232.60					667.69		1,922.24	1,709.29		414.20
N	DORE/9999/C/DN6	Oregon - New Revenue - St Light & Other	OR	5980000	108	18,699	1,240.33	3,925.32	881.96	641.82		510.20	1,656.50	1,756.63	1,496.61	1,816.13	2,794.16	1,976.95
N	DORE/2008/C/DN7	Oregon - New Revenue -Feeder Reinforce.	OR	5980000	108	0												
N	DORE/2009/C/DN7	Oregon - New Revenue -Feeder Reinforce	OR	5980000	108	0												
N	DORE/9999/C/DN9	Oregon - New Revenue-SubTrans Reinforce	OR	5980000	108	214								213.94				
N	DORE/9999/C/DN9	Oregon - New Revenue-SubTrans Reinforce	SO	9350000	1	1,451	5,133.33											
704,795																		
P	DORE/2008/C/DM9	Oregon - Public Accomodations	OR	5980000	108	7,170				207.52	1,769.71	201.26		315.00	-	414.20	3,225.16	1,036.95
P	DORE/2009/C/DM9	Oregon - Public Accomodations	OR	5980000	108	0												
P	DORE/9999/C/DM9	Oregon - Public Accomodations	OR	5980000	108	113,068	5,719.68	9,199.41	12,902.75	8,639.54	8,077.42	3,882.39	21,986.45	15,906.47	7,943.98	12,611.35	7,084.14	(885.59)
120,238																		
R/U/T	DORE/9999/C/DR2	Oregon - Replace - Subst Meters & Relays	OR	5980000	108	0												
R/U/T	DORE/9999/C/DR3	Oregon - Replace - Substation Regulators	OR	5980000	108	1,586								1,586.00				
R/U/T	DORE/2008/C/DRA	Oregon - Replace - Underground Cable	OR	5980000	108	201								201.26				
R/U/T	DORE/9999/C/DRA	Oregon - Replace - Underground Cable	OR	5980000	108	1,620		603.78		855.76				160.25				
R/U/T	DORE/2008/C/DRC	Oregon - Replace OH Dist Lines - Poles	OR	5980000	108	2,885		452.84				855.76		1,576.34				
R/U/T	DORE/2009/C/DRC	Oregon - Replace OH Dist Lines - Poles	OR	5980000	108	0												
R/U/T	DORE/9999/C/DRC	Oregon - Replace OH Dist Lines - Poles	OR	5980000	108	2,758		451.95			899.04		(142.62)	1,499.79	50.32			
R/U/T	DORE/2008/C/DRB	Oregon - Replace Underground Vaults & Eq	OR	5980000	108	0												
R/U/T	DORE/2009/C/DRB	Oregon - Replace Underground Vaults & Eq	OR	5980000	108	0												
R/U/T	DORE/9999/C/DRB	Oregon - Replace Underground Vaults & Eq	OR	5980000	108	4,642	4,015.54					198.92				427.88		
R/U/T	DORE/9999/D/DNY	Oregon - Temp Line Extension < 1Yr	OR	5980000	108	4,586	-	830.29				-				320.77	3,435.13	
R/U/T	DORE/2008/C/DNT	Oregon - Temporary Connects > 1 Yr	OR	5980000	108	0												

	UE-210/PacifiCorp																	
R/U/T	DORE/2009/C/DNT	Oregon - Temporary Connects > 1 Yr	OR	5980000	108	0												
R/U/T	DORE/9999/C/DNT	Oregon - Temporary Connects > 1 Yr	OR	5980000	108	199					198.92							
R/U/T	DORE/2008/C/DU1	Oregon - Upgrade - Feeder Improvements	OR	5980000	108	0												
R/U/T	DORE/9999/C/DU1	Oregon - Upgrade - Feeder Improvements	OR	5980000	108	3,447		207.52		267.08			427.88	1,976.78	194.08			373.91
R/U/T	DORE/9999/C/DUA	Oregon - Upgrade-Safety Improvements	OR	5980000	108	2,071		(93.94)							320.91			1,843.76
R/U/T	DSPN/2006/C/004	Oregon PQM Installations FY06	OR	5980000	108	0												
R/U/T	DORE/2009/C/812	Oregon Repl Leaking-Weeping Dist Trnsfmr	OR	5980000	108	0												
R/U/T	DORE/9999/C/DR6	Oregon -Replace Sub Bushings, Glass, etc	OR	5980000	108	0												
R/U/T	DORE/2008/C/DRD	Oregon-Replace-Overhead Dist. Lines/othr	OR	5980000	108	905							311.28			331.11		262.50
R/U/T	DORE/2009/C/DRD	Oregon-Replace-Overhead Dist. Lines/othr	OR	5980000	108	0												
R/U/T	DORE/9999/C/DRD	Oregon-Replace-Overhead Dist. Lines/othr	OR	5980000	108	6,725	1,914.82	106.83		1,101.76	1,196.92		427.60	792.15	339.38	364.89	213.94	267.08
R/U/T	DORE/2008/C/DRI	Oregon-Replace-Storm and Casualty	OR	5980000	108	0												
R/U/T	DORE/2009/C/DRI	Oregon-Replace-Storm and Casualty	OR	5980000	108	0												
R/U/T	DORE/9999/C/DRI	Oregon-Replace-Storm and Casualty	OR	5980000	108	6,016	-	2,761.73		-		3,253.84						
R/U/T	DORE/2008/D/DNY	Oregon-Temp Line Extension < 1Yr	OR	5980000	108	679										678.88	-	
38,321																		
	DPRN/2007/C/001	Redmond Prine 115kV Ln Remington Rnc	OR	5980000	108	0												
	DMED/2007/C/003	So Medford Relo Facil at I-5 Interchange	OR	5980000	108	1,681						1,680.52						
	DWAS/9999/C/DRC	Wash. - Replace OH Dist Lines - Poles	OR	5980000	108	0												
	DWAS/9999/C/DRB	Wash. - Replace Underground Vaults & Eq	OR	5980000	108	1,602								1,602.45				
	DWAS/2008/C/DN1	Washington - New Revenue - Residential	OR	5980000	108	0												
	DZBE/2006/C/002	Yew Avenue Sub Const New Sub(Tetherow)	OR	5980000	108	0												
	TUTM/2005/C/030	90th So & Terminal Rplc Rlys&Comm Equip	SG	5730000	1	0												
	TPRC/2007/C/003	Andalex Mine Tap 46kV Line Relo Metering	SG	5730000	1	0												
	TMED/2007/C/005	BRO Relo for Wyndhaven Development	SG	5730000	1	1,913						7,116.26						
	TWYM/2005/C/026	Buffalo Replace Switch 1H259	SG	5730000	1	383					1,425.62							
	TUTM/2005/C/102	Camp Williams-Mona 345 kV No 4 Line	SG	5730000	1	-24					(87.98)							
	TKEM/2007/C/001	Chappel Crk Provide Svc to Jonah Field	SG	5730000	1	1,473								5,479.28				
	TCAM/2005/C/017	Copco 2-Delta:Req removal 2 anchor/guys	SG	5730000	1	0												
	TCAS/2008/C/002	Crow Indian Reservation Access Rd Permit	SG	5730000	1	0												
	TPRC/2007/C/001	Emery Moore 69kV Add 8-48 Miles 69kV	SG	5730000	1	0					(12.00)	12.00		-				
	CGEN/2007/C/718	Gen Sys Protection Relay Std Development	SG	5570000	1	0												
	TIDM/2004/C/005	Goshen-Sugarmill 161-Repl Rlys & Comm Eq	SG	5730000	1	0												
	CITS/2008/C/350	Grid r8.3	SG	5570000	1	0												
	TIDA/2008/C/LRF	Idaho - Rplc-OH LOC Trans-Othr	SG	5730000	1	0												
	TIDA/2008/C/TRF	Idaho - Rplc-OH MG Trans-Othr	SG	5730000	1	0												
	OREG/2007/C/001	Kern River REG Proj	SG	5570000	1	0												
	DZCL/2006/C/003	Line 1 Conv to 115kV Line 14 Cap Relief	SG	5730000	1	0												
	TCAL/9999/C/LRF	Loc Trans: CA - Repl OH Trn Ln - Othr	SG	5730000	1	48	178.47											
	TCAL/9999/C/LRE	Loc Trans: CA - Repl OHD Trn Ln - Pol	SG	5730000	1	1,522		2,415.12			735.94	(735.94)				3,248.16		
	TCAL/9999/C/LRI	Loc Trans: CA - Repl Storm & Casualty	SG	5730000	1	52	194.08											
	TCAL/9999/C/LU3	Loc Trans: CA - Upgrd Trans Imprvmts	SG	5730000	1	443	1,649.68											
	TORE/9999/C/LRF	Loc Trans: OR - Repl OH Trn Ln - Othr	SG	5730000	1	407					1,515.71							
	TORE/9999/C/LRE	Loc Trans: OR - Repl OHD Trn Ln - Poles	SG	5730000	1	288		4,832.53				(4,430.01)		670.54		6,637.22	(6,637.22)	
	TORE/9999/C/LR1	Loc Trans: OR - Swtchgr, Brkrs, Rclsr	SG	5730000	1	245		912.37										
	TORE/9999/C/LU3	Loc Trans: OR - Upgrd Trans Imprvmts	SG	5730000	1	0												
	TORE/9999/C/LM1	Loc Trans: OR Mandated Hwy Relo	SG	5730000	1	0								8,176.34	1,069.70	4,966.36	1,442.18	
	TORE/9999/C/LM9	Loc Trans: OR Mandated Public Accom	SG	5730000	1	5,391		4,404.26										
	TUTH/9999/C/LRF	Loc Trans: UT - Repl OH Trn Ln - Othr	SG	5730000	1	807		998.88				1,045.47	960.00					
	TUTH/9999/C/LRE	Loc Trans: UT - Rpl OH Trn Ln - Poles	SG	5730000	1	3,307		7,143.67					3,180.00			1,980.00		
	TUTH/9999/C/LR1	Loc Trans: UT - Swtchgr, Brkrs, Rclsr	SG	5730000	1	0												
	TUTH/9999/C/LU3	Loc Trans: UT - Upgrd Trans Imprvmts	SG	5730000	1	335		1,248.00										
	TUTH/9999/C/LM1	Loc Trans: UT Mandated Hwy Relo	SG	5730000	1	0												
	TUTH/9999/C/LM9	Loc Trans: UT Mandated Public Accom	SG	5730000	1	958	3,180.00		384.51									
	TWAS/9999/C/LRF	Loc Trans: WA - Repl OH Trn Ln - Othr	SG	5730000	1	500								1,463.82	397.84			
	TWAS/9999/C/LRI	Loc Trans: WA - Repl Storm & Casualty	SG	5730000	1	0												
	TWAS/9999/C/LRE	Loc Trans: WA - Rpl OH Trn Ln - Poles	SG	5730000	1	1,011								2,802.32	960.00			
	TWAS/9999/C/LM1	Loc Trans: WA Mandated Hwy Relo	SG	5730000	1	223		827.94										

UE-210/PacifiCorp																	
TWAS/9999/C/LM9	Loc Trans: WA Mandated Public Accom	SG	5730000	1	551								2,050.85				
TWYO/9999/C/LRE	Loc Trans: WY - Repl OH Trn Ln - Pole	SG	5730000	1	556						2,069.25						
TWYO/9999/C/LR1	Loc Trans: WY - Swtchgr, Brkrs, Rclsr	SG	5730000	1	0												
TMGM/2005/C/006	Main Grid Replace Interchange Meters	SG	5730000	1	0										-		
TMGM/2007/C/003	Main Grid Transmission Repl Metering	SG	5730000	1	220								383.36			433.83	
TWAM/2006/C/008	Marengo Windfarm-Install Switch Station	SG	5730000	1	82	304.00											
WMRP/2008/C/001	McFadden Ridge Wind Project (88.5 MW)	SG	5570000	1	0												
TORE/9999/C/TRF	MG Trans: OR - Repl OH Trn Ln - Othr	SG	5730000	1	887		3,299.36										
TORE/9999/C/TR2	MG Trans: OR - Repl Sub Meters & Rlys	SG	5730000	1	0												
TORE/9999/C/TU3	MG Trans: OR - Upgrade Trans Imprvmts	SG	5730000	1	52		194.08										
TUTH/9999/C/TRF	MG Trans: UT - Repl OH Trn Ln - Othr	SG	5730000	1	755			2,808.09									
TWAS/9999/C/TRE	MG Trans: WA - Repl OH Trn Ln - Poles	SG	5730000	1	288							1,072.11					
TWYO/9999/C/TR2	MG Trans: WY - Repl Sub Meters & Rlys	SG	5730000	1	0												
TORE/9999/C/TM1	MG: OR Mandated Hwy Relocation	SG	5730000	1	660			2,456.03									
TORE/9999/C/TM9	MG: OR Mandated Public Accom	SG	5730000	1	-30					(112.19)							
TUTM/2006/C/300	Moab Four Corners TOT 2B Path Upgrade	SG	5730000	1	0												
TWYM/2005/C/050	Mustang Rplc Rlys & Comm Equip Spence	SG	5730000	1	0												
TORE/2008/C/LM9	Oregon - Mand-LOC Trans Public Acc	SG	5730000	1	1,082			4,025.20									
TORE/2009/C/LM9	Oregon - Mand-LOC Trans Public Acc	SG	5730000	1	0												
TORE/2008/C/TRI	Oregon - Rplc-MG Trans Strm&Cas	SG	5730000	1	0												
TORE/2008/C/LRF	Oregon - Rplc-OH LOC Trans-Othr	SG	5730000	1	169								210.00	420.00			
TORE/2008/C/LRE	Oregon - Rplc-OH LOC Trans-Pole	SG	5730000	1	0												
TORE/2008/C/TRE	Oregon - Rplc-OH MG Trans-Pole	SG	5730000	1	3,131										11,650.12		
TORE/2008/C/LU3	Oregon - Upgrd-LOC Trans Imprv	SG	5730000	1	0												
DORE/9999/C/DRE	Oregon-Replace-Overhead Trans.Line-Poles	SG	5730000	1	0												
TUTM/2005/C/083	PINTO SUB Repl 3-345 Lightning Arresters	SG	5730000	1	1,264		4,702.52										
TWYM/2005/C/034	Platte Install Buss Differential Relay	SG	5730000	1	293										1,092.00		
TZRS/2007/C/008	R Springs Sub Repair Trsnf Parallel Eq	SG	5730000	1	0												
DMOA/2004/C/001	Rattlesnake Build 69kV Ln Rbld Feeder	SG	5730000	1	88,605									329,668.36			
CITC/2007/C/910	rLink - SAP xMII	SG	5570000	1	1,769						6,545.39						
TPAR/2007/C/004	Silvercrk Kamas 46kV Relo Tuhaye-Hideout	SG	5730000	1	0												
TIUT/2006/C/002	Spring Canyon Energy Interconnection	SG	5730000	1	0												
TUTM/2005/C/097	Summit-Vineyard Transmission Project	SG	5730000	1	6	22.76							-				
TWAM/2005/C/027	Swift #2 Plant Sub-Flood Rebuild	SG	5730000	1	0												
TMGM/2006/C/004	Transmission Relay Repl Zone 3 Setting	SG	5730000	1	4,071			15,146.72									
PDIT/2007/C/110	Transmission Scheduling for Malin Round	SG	5600000	1	106,718					309,048.26	465.15	-	87,548.87				
OLSP/2008/C/009	U0 Admin Building Ladder access project	SG	5530000	225	0												
OCCK/2007/C/020	U0 Boiler Blowdown Recovery	SG	5480000	310	0												
SHTN/2010/C/016	U1-Boiler Rear Reheat Replacement	SG	5060000	281	0												
SNAU/2008/C/079	U3 STUDY Coal Bunker Mass Flow CY 08	SG	5121200	270	0												
TAME/2008/C/001	UDOT East West Relo 345-138 12.5kV Lns	SG	5730000	1	0												
TIUT/2006/C/003	Upper Beaver Hydro Plant Project	SG	5730000	1	0												
TUTH/2008/C/LM9	Utah - Mand-LOC Trans Public Acc	SG	5730000	1	0												
DUTH/2008/C/DN9	Utah - New Revenue-SubTrans Reinforce	SG	5730000	1	0												
DUTH/2009/C/DN9	Utah - New Revenue-SubTrans Reinforce	SG	5730000	1	0												
TUTH/2008/C/LRI	Utah - Rplc-LOC Trans Strm&Cas	SG	5730000	1	0												
TUTH/2008/C/LRF	Utah - Rplc-OH LOC Trans-Othr	SG	5730000	1	0												
TUTH/2008/C/LRE	Utah - Rplc-OH LOC Trans-Pole	SG	5730000	1	0												
TUTH/2009/C/LRE	Utah - Rplc-OH LOC Trans-Pole	SG	5730000	1	0												
DUTH/9999/C/DRF	Utah-Replace-Overhead Trans.Line-Other	SG	5730000	1	0												
DUTH/9999/C/DU3	Utah-Upgrade-Transmission Improvements	SG	5730000	1	13,256					49,321.11							
TWAM/2005/C/016	Walla Walla-Hells Cyn 9/75 Relo Study	SG	5730000	1	51	189.97											
TWAS/2008/C/LM1	Wash - Mandted-LOC Trans Hwy Rel	SG	5730000	1	1,895								7,049.68				
TWAS/2008/C/LRE	Wash - Rplc-OH LOC Trans-Pole	SG	5730000	1	0												
TWYO/2008/C/LRF	Wyoming - Rplc-OH LOC Trans-Othr	SG	5730000	1	1,678										6,241.46		
TWYO/2008/C/TRF	Wyoming - Rplc-OH MG Trans-Othr	SG	5730000	1	0												
TWYO/2007/C/701	Wyoming Dist Asset Sales FY07	SG	5730000	1	0												
HKOR/2005/C/010	Pioneer Park Redesign/Reconstruction	SG-P	5390000	108	0												

	UE-210/PacifiCorp																	
	HIDA/2007/C/024	St Anthony Overhaul	SG-U	5390000	.462	0												
	Reserve	Change in Reserve Balance	SNPD	5980000	90	38,524	26,000.00	(67,000.00)	(277,000.00)	20,000.00	38,000.00	59,000.00	(1,000.00)	(45,000.00)	135,000.00	32,000.00	78,000.00	147,933.00
	Reserve	Change in Reserve Balance	SNPD	5980000	95	6,336	58,000.00	(88,000.00)	94,000.00	(17,000.00)	64,000.00	(46,452.00)	(157,548.00)	23,000.00	(117,000.00)	(30,000.00)	10,000.00	231,000.00
	DIDA/9999/C/DN3	Idaho - New Revenue - Industrial	SNPD	5980000	95	6,533												
	CFIN/2005/C/017	315 ER K2 CIC087 KWI Commercial RiskSys	SO	9210000	1	0												24,745.61
	DZAF/2004/C/002	Battlecreek New Substation Site	SO	9350000	1	0												
	TIUT/2006/C/008	Desert Power Project Interconnection	SO	9350000	1	35								(122.26)				
	CPRY/2007/C/011	Field Office Asphalt Work	SO	9350000	1	0												
	CPRY/2008/C/003	Field Office Asphalt Work	SO	9350000	1	0												
	CPRY/2007/C/010	Field Office General Capital	SO	9350000	1	0	(368.67)	368.67										
	CPRY/2007/C/008	Field Office HVAC Units	SO	9350000	1	919					3,251.38							
	CITS/2007/C/205	Gentran Upgrade	SO	9210000	1	758												
	CITC/2006/C/412	IP Telephony Project	SO	9210000	1	0												2,681.70
	CTRN/1999/C/027	KLAMATH FALLS CO-GEN PROJECT	SO	9350000	1	425												
	TAME/2006/C/001	Lehi Purch Property 138kV Switchyard	SO	9350000	1	3,730										(1,503.40)		
	DZME/2006/C/003	Line 3 Convert to 115kV	SO	9350000	1	1,257										13,199.36		
	TWAM/2006/C/008	Marengo Windfarm-Install Switch Station	SO	9350000	1	0							4,448.37					
	DORE/2008/C/VRV	Oregon Replace Deteriorated Vehicles	SO	9350000	1	0												
	DORE/9999/C/VRV	Oregon Replace Deteriorated Vehicles	SO	9350000	1	0												
	DSPN/2006/C/001	Satellite Comm Installation for FY06	SO	9350000	1	552		1,953.20										
	DZSL/2007/C/004	Skypark Sub: New 138-12.5kV Substation	SO	9350000	1	993				3,331.94		182.00						
	TIWA/2006/C/001	Tieton Hydro Power Project Interconnect	SO	9350000	1	0												
	DPOR/2006/C/005	Transformer Remote Temp Sensing Project	SO	9350000	1	0												
	TIUT/2006/C/003	Upper Beaver Hydro Plant Project	SO	9350000	1	0												
	TZRS/2007/C/005	Upper Green River Basin	SO	9350000	1	0												
	DUTH/2008/C/VRV	Utah Replace Deteriorated Vehicles	SO	9350000	1	0											1,141.20	(1,141.20)
	DUTH/9999/C/DRI	Utah-Replace-Storm and Casualty	SO	9350000	1	0												
	DCED/2006/C/004	W Cedar-Red Butte 138kV Ln Palladon Mine	SO	9350000	1	0												
	DWAS/9999/C/DU6	Wash. - Upgrade-Microwave/Fiber Comm.	SO	9350000	1	0												
	DWYO/9999/C/DR7	Wyo. - Replace - Mobile Communications	SO	9350000	1	201	712.16											
	DWYO/2008/C/VRV	Wyoming Repl Deteriorated Vehicles	SO	9350000	1	0												
						1,275,420												
													2008					

I. Line Extensions - Conditions and Definitions

A. Contracts

Before building an Extension, the Company may require the Applicant to sign a contract. Where a tenant occupies the service location, the Company may require the property owner to sign the contract.

B. Contract Minimum Billing

The Contract Minimum Billing is the greater of: (1) the Consumer's monthly bill; or, (2) 80% of the Consumer's monthly bill plus the Facilities Charges. Consumers on a seasonal rate receive an annual Contract Minimum Billing of the greater of: (1) the Consumer's annual bill; or, (2) 80% of the Consumer's annual bill plus the Annual Facilities Charge. The Annual Facilities Charge is twelve (12) times the Facilities Charges. Contract Minimum Billings begin on the date service is first made available by the Company, unless a later date is mutually agreed upon.

For Consumers electing Standard Offer or Direct Access Service, the charges for Supply Service, ESS charges and the Transition Adjustment are excluded from the Consumer's bill before calculating the Contract Minimum Bill. For these Consumers the Contract Minimum Billing is the greater of: (1) the Consumer's monthly bill; or, (2) 60% of the Consumer's monthly bill plus the Facilities Charges. Consumers on a seasonal rate receive an annual Contract Minimum Billing of the greater of: (1) the Consumer's annual bill; or, (2) 60% of the Consumer's annual bill plus the Annual Facilities Charge.

C. Engineering Costs

The Company includes designing, engineering and estimating in its Extension Costs. The Company may require the Applicant to advance the Company's estimated Engineering Costs, but not less than $200. The Company will apply this advance payment to its Extension Costs. If the Extension Allowance exceeds the Extension Costs, the Company will refund the excess up to the amount of the Applicant's or Consumer's advance.

If the Applicant or Consumer requests changes that require additional estimates, they must advance the Company's estimated Engineering Costs, but not less than $200 for each additional estimate. The Company will not refund or credit this payment.

D. Extension Allowance

The Extension Allowance is the portion of the Extension that the Company may provide, or allow, without cost to the Applicant. The portion will vary with the class of service that the Applicant requests and shall not exceed the Extension Costs. The Extension Allowance does not include additional costs resulting from: additional voltages; duplicate facilities; additional points of delivery; or any other Applicant requested facilities that add to, or substitute for, the Company's standard construction methods or preferred route. The Extension Allowance is not available to Consumers receiving electric service under special

(continued)

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I. Line Extensions - Conditions and Definitions (*continued*)

Extension Allowance *(continued)*

pricing contracts. Revenue used for calculating Extension Allowances will exclude charges and credits for Supply Service, ESS Charges and the Transition Adjustment.

E. Extension Costs

Extension Costs are the Company's total costs for constructing an Extension using the Company's standard construction methods, including services, transformers and meters, labor, materials and overhead charges.

F. Extension Limits

The provisions of this Rule apply to Line Extensions that require standard construction and will produce sufficient revenues to cover the ongoing costs associated with them. The Company will construct Line Extensions with special requirements or limited revenues under the terms of special contracts.

Examples of special requirements include, but are not limited to, unusual costs incurred for obtaining rights-of-way, overtime wages, use of special equipment and facilities, accelerated work schedules to meet the Applicant's request, or non-standard construction requirements.

G. Facilities Charges

The Facilities Charges are those costs associated with the ownership and maintenance of facilities built to provide service. Schedule 300 specifies the Facilities Charges.

H. Restrictions

An Extension of the Company's facilities is subject to these rules and other rules and restrictions. These may include, but are not limited to: laws of the United States; State law; executive and administrative proclamations; Commission orders or regulations; or, any lawful requirement of a governmental body.

I. Routes, Easements and Rights-of-Way

The Company will select the route of an Extension in cooperation with the Applicant. The Applicant must pay all costs of complete unencumbered rights-of-way, easements, or licenses to use land, and for any preparation or clearing the Company may require. The Applicant may acquire and prepare these, or if requested by the Applicant, the Company will do so at the Applicant's expense.

J. Rules Previously in Effect

Rule changes do not modify existing Extension contracts. If a Consumer advanced funds for an Extension under a rule or a contract previously in effect, the Company will make refunds for additional Consumers as specified in the previous rule or contract.

K. Service Conductors

The secondary-voltage conductors owned and maintained by the Company extending from the Company's facility to the Point of Delivery.

(continued)

II. Residential Extensions

A. Extension Allowances

The Extension Allowance for Residential Applications is $750. The Extension Allowance for Residential Applications in a Planned Development is $350. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction.

B. Additional Consumers, Advances and Refunds

A Consumer that pays for a portion of the construction of an Extension may receive refunds if additional Consumers connect to the Extension. The Consumer is eligible for refunds during the first five (5) years following construction of an Extension for up to three (3) additional Consumers. Each of the next three (3) Consumers utilizing any portion of the initial Extension must pay the Company, prior to connection, 25% of the cost of the shared facilities. The Company will refund such payments to the initial Consumer.

C. Remote and Seasonal Service

1. Contracts

The Company will make Extensions for Remote and Seasonal Residential Service according to a written contract. The contract will require the Applicant to advance the estimated cost of facilities in excess of the Extension Allowance. The Applicant shall also pay a Contract Minimum Billing for as long as service is taken, but in no case less than five (5) years.

2. Additional Applicants

During the first five years after the Company completes the Extension, each of the next three Applicants must pay an allocated share of the original Consumer's contribution. The Company will determine these shares taking into account: (a) how much of the original line the new Applicant shares; (b) the load sizes of the Applicant and the existing Consumers; and (c) the advances of the existing Consumers. The Applicant must pay this allocated share before the Company will provide service. The Company will refund this share to the existing Consumers.

Additional Applicants also must share the Facilities Charges of the existing Consumers. The Company will allocate the Facilities Charges in the same manner used for allocating the original advance.

The Applicant also must pay the estimated cost of any facilities exceeding the Extension Allowance.

D. Three Phase Residential Service

Where three-phase residential service is requested, the Applicant shall pay the difference in cost between single phase and three-phase service.

(continued)

II. Residential Extensions (*continued*)

E. Transformation Facilities

If an existing residential Consumer adds load, or if a new Consumer builds in a subdivision where secondary is available at the lot line, and the existing transformation facilities or service conductors are unable to serve the increased residential load, the increase will be treated as a standard line extension if the Consumer's demand exceeds the capacity of the existing facilities. Otherwise the facility upgrade shall be treated as a system improvement and not be charged to the Consumer.

F. Underground Extensions

The Company will construct line Extensions underground when requested by the Applicant or if required by local ordinance or conditions. The Applicant must pay for the conversion of any existing overhead facilities to underground, under the terms of Section VI of this Rule. The Applicant must provide all trenching and back filling, imported backfill material, conduits, and equipment foundations that the Company requires for the Extension. If the Applicant requests, the Company will provide these items at the Applicant's expense.

III. Nonresidential Extensions

A. Extension Allowance

1. 1,000 kW or less

The Company will grant Nonresidential Applicants requiring 1,000 kW or less an Extension Allowance of up to two times the revenue associated with Delivery Service which the Applicant is expected to incur in a year of normal operations. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction.

The Company may require the Consumer to pay a Contract Minimum Billing for five years.

2. Over 1,000 kW

The Company will grant Nonresidential Applicants requiring more than 1,000 kW an Extension Allowance of up to two times the revenue associated with Delivery Service which the Applicant is expected to incur in a year of normal operations. The Applicant must advance the costs exceeding the Extension Allowance. Fifty percent of the advance is due when the contract is executed with the remaining balance due upon completion of the Extension.

The Consumer must pay a Contract Minimum Billing for as long as service is taken, but in no case less than five years.

If service is terminated within the first ten (10) years, the Consumer must pay a termination charge equal to the Extension Allowance less 1/10th of the allowance for each year service was taken.

(*continued*)

III. Nonresidential Extensions (*continued*)

3. Remote Service
The Company will grant Applicants for Remote Nonresidential Service an Extension Allowance of up to two times the revenue associated with Delivery Service the Applicant is expected to incur in a year of normal operations. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction. The Applicant must also pay a Contract Minimum Billing for as long as service is taken, but in no case less than five years.

B. Additional Consumers, Advances and Refunds

1. Initial Consumer - 1,000 kW or less
A Consumer that pays for a portion of the construction of an Extension may receive refunds if additional Consumers connect to the Extension. The Consumer is eligible for refunds during the first five (5) years following construction of an Extension for up to three (3) additional Consumers. Each of the next three Consumers utilizing any portion of the initial Extension must pay the Company, prior to connection, 25% of the cost of the shared facilities. The Company will refund such payments to the initial Consumer.

2. Initial Consumer - over 1,000 kW
A Consumer that pays for a portion of the construction of an Extension may receive refunds if additional Consumers connect to the Extension. The Consumer is eligible for refunds during the first five (5) years following construction of an Extension for up to three (3) additional Consumers. Each of the next three Consumers utilizing any portion of the initial Extension must pay the Company, prior to connection, a proportionate share of the cost of the shared facilities. The Company will refund such payments to the initial Consumer.

Proportionate Share = (A + B) x C

Where:
A = [Shared footage of line] x [Average cost per foot of the line]

B = Cost of the other shared distribution equipment, if applicable

C = [New additional connected load]/[Total connected load]

3. Adjustment of Contract Minimum Billing
Additional Consumers also must share the Facilities Charges of the existing Consumers. The Company will allocate the Facilities Charges in the same manner used for allocating the original advance.

(continued)

III. Nonresidential Extensions (*continued*)

C. Underground Extensions

The Company will construct line Extensions underground when requested by the Applicant or if required by local ordinance or conditions. The Applicant must pay for the conversion of any existing overhead facilities to underground, under the terms of Section VI of this Rule. The Applicant must provide all trenching and backfilling, imported backfill material, conduits, and equipment foundations that the Company requires for the Extension. If the Applicant requests, the Company will provide these items at the Applicant's expense.

D. Street Lighting

The Extension Allowance to streetlights taking service under Rate Schedules 51/751 or 53/753 is equal to five times the annual revenue from the lights to be added. The Applicant must advance costs exceeding the Extension Allowance prior to the lights being added.

IV. Extensions to Planned Developments

A. General

Planned developments, including subdivisions and mobile home parks, are areas where groups of buildings or dwellings may be constructed at or about the same time. The Company will install facilities in developments before there are actual Applicants for service under the terms of a written contract.

B. Allowances and Advances

For nonresidential developments the Developer must pay a non-refundable advance equal to the Company's estimated installed costs to make primary service available to each lot. For residential developments the Company will provide the Developer an Extension Allowance of $400 for each lot. The Developer must pay a non-refundable advance for all other costs to make secondary voltage service available to each lot. For both nonresidential and residential developments the Company may require the Developer to pay for facilities to provide additional service reliability or future development.

C. Refunds

The Company will make no refunds for facilities installed within a development. A Developer that pays for a portion of the construction of an Extension to reach a development may receive refunds if additional Consumers connect to the Extension outside the development. The Developer is eligible for refunds during the first five (5) years following construction of an Extension to reach the development for up to three (3) additional Consumers. Each of the next three Consumers using any portion of the Extension to reach a development must pay the Company, prior to connection, 25% of the cost of the shared facilities. The Company will refund such payments to the Developer.

(*continued*)

IV. Extensions to Planned Developments *(continued)*

D. Underground Extensions
The Company will construct line Extensions underground when requested by the Developer or required by local ordinances or conditions. The Developer must pay for the conversion of any existing overhead facilities to underground, under the terms of Section VI of this Rule. The Developer must provide all trenching and backfilling, imported backfill material, conduits, and equipment foundations that the Company requires for the development. If the Developer requests, the Company will provide these items at the Developer's expense.

V. Extension Exceptions

A. Applicant Built Line Extensions

1. General
An Applicant may contract with someone other than the Company to build a Line Extension. The Applicant must contract with the Company before starting construction of a Line Extension. When the Applicant has completed construction of the Line Extension and the Company approves it, the Company will connect it to the Company's facilities and assume ownership.

2. Liability and Insurance
The Applicant assumes all risks for the construction of an Applicant Built Line Extension. Before starting construction, the Applicant must furnish a certificate naming the Company as an additional insured for a minimum of $1,000,000. The Applicant may cancel the policy after the Company accepts ownership of the Line Extension.

3. Advance for Design, Specifications, Material Standards and Inspections
The Applicant must advance the Company's estimated costs for design, specifications, material standards and inspections. When the Applicant has completed construction, the Company will determine its actual costs and may adjust that portion of the Applicant's advance. If the actual costs exceed the Applicant's advance, the Applicant must pay the difference before the Company will accept and energize the Line Extension. If the actual costs are less than the Applicant's advance, the Company will refund the difference.

The Company will estimate the frequency of inspections and convey this to the Applicant prior to the signing of the contract. For underground Line Extensions, the Company may require that an inspector be present whenever installation work is done.

(continued)

V. Extension Exceptions (*continued*)

4. **Construction Standards**
The Applicant must construct the Line Extension in accordance with the Company's design, specifications, and material standards and along the Company's selected route. Otherwise, the Company will not accept or energize the Line Extension.

5. **Transfer of Ownership**
Upon approval of the construction, the Company will assume ownership of the Line Extension. The Applicant must provide the Company unencumbered title to the Line Extension.

6. **Rights-of-Way**
The Applicant must provide to the Company all required rights-of-way, easements and permits in accordance with paragraph 1. I. of this Rule.

7. **Contract Minimum Billing**
The Company may require the Applicant to pay a Contract Minimum Billing as defined in paragraph 1. B. of this Rule.

8. **Deficiencies in Construction**
If, within 24 months of the time the Company energized the Line Extension, it determines that the Applicant provided deficient material or workmanship, the Applicant must pay the cost to correct the deficiency.

9. **Line Extension Value**
The Company will calculate the value of a Line Extension using its standard estimating methods. The Company will use the Line Extension Value to calculate Contract Minimum Billings, reimbursements, and refunds.

10. **Line Extension Allowance**
After assuming ownership, the Company will calculate the appropriate Extension Allowance. The Company will then reimburse the Applicant for the construction costs covered by the Extension Allowance, less the cost of any Company provided equipment or services, but in no case more than the Line Extension Value.

B. Duplicate Service Facilities
The Company will furnish Duplicate Service Facilities if the Consumer advances the estimated costs for facilities in excess of those which the Company would otherwise provide. The Consumer also must pay Facilities Charges for the Duplicate Facilities for as long as service is taken, but in no case less than five years.

(*continued*)

V. Extension Exceptions (*continued*)

C. Emergency Service
The Company will grant Applicants requesting Emergency Service an Extension Allowance equal to the estimated increase in annual revenue the Applicant will pay the Company. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction. The Applicant must also pay a Contract Minimum Billing for as long as service is taken, but in no case less than five years.

D. Intermittent Service Facilities
The Company will serve Intermittent loads provided the Consumer advances the estimated cost of facilities above the cost of facilities which the Company would otherwise install. The Consumer also must pay a Contract Minimum Billing for as long as service is taken. If load fluctuations become a detriment to other Consumers, the Company may modify the facilities and adjust the Contract Minimum Billing.

E. Temporary Service
The Company will provide Temporary Service by written agreement under the following provisions:

1. The Consumer pays a Temporary Service Charge. This charge equals
a) the estimated installation cost, plus
b) the estimated removal cost, plus
c) the estimated cost for rearranging any existing facilities, less
d) the estimated salvage value of the facilities required to provide Temporary Service.

2. The Consumer pays a Contract Minimum Billing; and

3. The Consumer pays any advances required for sharing previous Extensions.

If a temporary Consumer takes service continuously for 60 consecutive months from the date the Company first delivered service, the Company will classify them as permanent and refund any payment the Consumer made over that required of a permanent Consumer. The Company will not refund the Facilities Charges.

Schedule 300 specifies the charges for Temporary Service that requires only service conductors and a self-contained meter.

VI. Relocation or Replacement of Facilities

A. Relocation of Facilities
If requested by an Applicant or Consumer the Company will: relocate distribution facilities on to, or adjacent to, the Consumer's premises; and/or, replace existing overhead distribution facilities with comparable underground.

(continued)

VI. Relocation or Replacement of Facilities *(continued)*

A. Relocation of Facilities *(continued)*

For overhead to underground relocations, the new underground system must not impair the use of the remaining overhead system. The Applicant or Consumer must elect either: to provide all trenching and back filling, imported backfill material, conduits, and equipment foundations that the Company requires for the Extension; or, to pay the Company to provide these items.

In addition, the Applicant or Consumer must advance the following:

1. The estimated installed cost of the new facilities plus the estimated removal expense of the existing facilities, less

2. The estimated salvage value of the removed facilities.

This Advance is not refundable. The Company is not responsible for allocating costs and responsibilities among multiple Applicants.

B. Local Governments

When a local government requires the conversion of overhead to underground of distribution facilities at Company's expense, said conversion shall be conditioned by the following:

1. Applicant shall have paid the cost of all necessary excavating, road crossings, trenching, back filling, raceways, ducts, vaults, transformer pads, other devices peculiar to underground service, plus the original cost, less depreciation, less salvage value, plus removal costs of the existing overhead distribution facilities no longer used or useful by reason of the conversion.

2. Company shall collect the conversion costs from the Consumers located within the boundaries of the local government, provided that the local government may direct Company to collect conversion costs from only a portion of the Consumers located within the boundaries of the local government.

3. Conversion costs incurred by the utility shall be accumulated in a separate account in Company's books with interest accruing from the date Company incurs the cost. The rate of such interest shall be equal to the effective cost of the senior security issue which most recently preceded the incurrence of the cost.

4. Company shall collect the conversion costs and interest over a reasonable period of time subject to approval of The Public Utility Commission of Oregon. Said pay-back shall not exceed the depreciable life of the facilities. Collection shall begin as soon as practicable after the end of the year in which the conversion costs are incurred.

(continued)

VI. Relocation or Replacement of Facilities *(continued)*

B. Local Governments *(continued)*

5. Conversion costs to be recovered from each Consumer shall be calculated by applying a uniform percentage to each Consumer's total monthly bill for service rendered within the boundaries of the local government. Said conversion costs will be shown as a separate item on individual Consumer bills.

6. When the total conversion cost during one calendar year incurred by Company, required by local government, does not exceed five one hundredths of one percent (.05%) of Company's annual revenues derived from Consumers residing within the boundaries of the local government, said conversions shall be made at Company's expense with no collection of conversion costs from Consumers of the local government.

7. This rule applies to conversions upon which construction has commenced on or after August 13, 1984.

VII. Contract Administration Credit

Consumers may waive their right to receive refunds on a Line Extension advance. Consumers who waive this right will receive a Contract Administration Credit up to the amount specified in Schedule 300. The Consumer's choice to receive the Contract Administration Credit must be made at the time the Extension advance is paid.

PACIFIC POWER & LIGHT COMPANY
CHARGES AS DEFINED BY THE RULES AND REGULATIONS

OREGON
SCHEDULE 300

Purpose
The purpose of this Schedule is to list the charges referred to in the General Rules and Regulations.

Available
In all territory served by the Company in Oregon.

Applicable
For all Consumers utilizing the services of the Company as defined and described in the General Rules and Regulations.

Service Charges

Rule No.	Sheet No.	Description	Charge
2	D-1	**Demand Pulse Access Charge:**	$1,500.00
2	D-4	**Portfolio Ballot Processing**	
		First ballot processed per year	Free
		All other ballots processed	$ 5.00
6	H-1	**Meter Charges:**	
		Meter Repairs/Replacement	Actual Repair/ Replacement Cost
8	J-1&2	**Meter Test for Accuracy:**	
		Once in twelve months	No Charge
		Two or more times in twelve months	$ 50.00 each
8	J-1	**Meter Verification Fee**	$ 20.00 per unit
8	J-2	**Interval Meter Charge**	
		Small Nonresidential Consumers	Actual Cost
9	K-1	**Deposit:**	
		Normal office hours	
		Residential	
		Established high risk	1/6 estimated annual billing
		Nonresidential	
		No established credit or established high risk	1/6 estimated annual billing
		Agricultural Pumping	
		No established credit or established high risk	amount not to exceed estimated season's billing

(continued)

- **Service Charges** *(continued)*

Rule No.	Sheet No.	Description	Charge
10	L-1	**Late Payment Charge:**	1.5% of amount not paid in full each month
10	L-2	**Returned Payment Charge:**	$ 20.00
11	M-5	**Reconnection Charge:**	
		Request for reconnect during regular business hours: Monday through Friday, except holidays 8:00 A.M. to 5:00 P.M.	$30.00
		Request for reconnect during non-regular business hours: Monday through Friday, except holidays 8:00 A.M. to 6:00 P.M. *	$75.00
		Saturday, Sunday & Holidays 8:00 A.M. to 6:00 P.M.	$175.00
		*Note: No reconnections will be scheduled after 7:00 P.M.	
11	M-5	**Pole Cut Reconnect Charge:**	
		Request for reconnect during regular business hours: Monday through Friday, except holidays 8:00 A.M. to 5:00 P.M.	$100.00
		Request for reconnect during non-regular business hours: Monday through Friday, except holidays 8:00 A.M. to 6:00 P.M. *	$175.00
		Saturday, Sunday & Holidays 8:00 A.M. to 6:00 P.M.	$275.00
		*Note: No reconnections will be scheduled after 7:00 P.M.	
11	M-5	**Field Visit Charge:**	$20.00
11	M-5	**Tampering/Unauthorized Reconnection**	$75.00

(continued)

Service Charges *(continued)*

Rule No.	Sheet No.	Description	Charge
11-2	M-7	**Service Connection Charge:** Request for reconnect during regular business hours: Monday through Friday, except holidays 8:00 A.M. to 5:00 P.M.	No Charge
		Request for reconnect during non-regular business hours: Monday through Friday, except holidays 5:00 P.M. to 6:00 P.M.	$75.00
		Saturday, Sunday & Holidays 8:00 A.M. to 6:00 P.M.	$175.00
11-2	M-7	**Trouble Call Charge:**	Actual Costs May Be Charged
11-2	M-7	**Other Work at Consumer's Request:**	Actual Costs May Be Charged
13	O-2	**Facilities Charges:** For facilities installed at Consumer's expense	0.67% of installed cost per month
		For facilities installed at Company's expense	1.67% of installed cost per month
13	O-9	**Temporary Service Charge:** Service Drop and Meter only	Single phase $85.00 Three phase $115.00
13	O-11	**Contract Administration Credit**	$250.00
21	W-3	**Pre-Enrollment Usage Information:** Bill Register History per Meter Validated Interval Data (15 – 60 minute) per Meter Analyzed Interval Meter Data	 $2.00 per year $10.00 per month Cost Based Price
21	W-3	**Pre-Enrollment Payment History:**	$2.00 per page

(continued)

Service Charges *(continued)*

Rule No.	Sheet No.	Description	Charge
21	W-10	**Change of Service Election:**	
		Off-cycle Meter Read	
		Standard meter	$17.00
		On-site interval meter	$96.00
		Remote access interval meter	$15.15
21	W-13	**Consumer-Initiated Change to Standard Offer or Emergency Default Service:**	$20.00
25	Y-1	**Customer Guarantee Credit 1: Restoring Supply After an Outage**	$50.00
		For each additional 12 hours	$25.00
25	Y-1	**Customer Guarantee Credit 2: Appointments**	$50.00
25	Y-1	**Customer Guarantee Credit 3: Switching on Power**	$ 50.00
25	Y-2	**Customer Guarantee Credit 4: Estimates for New Supply**	$ 50.00
25	Y-2	**Customer Guarantee Credit 5: Responding to Bill Inquiries**	$ 50.00
25	Y-2	**Customer Guarantee Credit 6: Resolving Meter Problems**	$ 50.00
25	Y-2	**Customer Guarantee Credit 7: Notifying of Planned Interruptions**	$ 50.00

Staff also proposes removing 100 percent of civic activities recorded in Administrative & General (A&G) accounts, noting "the Commission has not previously allowed regulated utilities to recover contributions to charities, community affairs, and economic development organizations through rates charged for regulated services. . . . In addition, Commission policy does not require customers to support causes in which they do not believe."[79]

PGE asserts that these discretionary costs are appropriately included in rates, because these miscellaneous expenses create a business culture that allows the utility to attract and retain qualified workers.[80]

Resolution

We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders. We also adopt Staff's recommendation with respect to contributions to charities, community affairs, and economic development organizations. PGE provides no rationale to change our existing policies, and we conclude that all contributions to charities, community affairs, and economic development organizations should be disallowed. PGE's 2009 revenue requirement is reduced by $710,000 to reflect the disallowance of these expenses.

We also acknowledge PGE's removal of Directors' Compensation and Officer Vehicles from the proposed 2009 test-year budget. The total revenue-requirement reduction for miscellaneous expenses is $1.18 million.

i. Senate Bill 408 Ratio Adjustment

Senate Bill 408 (SB 408) requires the Commission to establish certain ratios in general ratemaking proceedings, which will be used to determine the amounts of "taxes collected" from customers for the purpose of the SB 408 true-up of "taxes paid" to "taxes collected." PGE believes that, in setting the tax rate and margin ratios here for SB 408 purposes, the Commission should consider the impact of costs that have been disallowed. PGE explains that, "[t]o do otherwise would effectively allow customers to receive tax benefits from utility costs for which customers are not responsible."[81]

Staff opposes PGE's proposal as an attempt to insulate its shareholders from sharing the tax benefit of disallowed expenses with ratepayers when truing up the amount of taxes collected. Staff believes PGE's request is inconsistent with the terms of SB 408, as well as Commission rules implementing the bill.[82] According to Staff, the Commission indirectly addressed this issue when it declined PGE's request for a deferral

[79] *Id.*, citing Staff/300, Ball-Dougherty/15.
[80] PGE Opening Brief at 37, citing PGE/2700, Piro-Tooman/12.
[81] PGE/2300, Tooman-Tinker/24.
[82] *See* ORS 757.268 and OAR 860-022-0041.

UE-210/PacifiCorp
May 26, 2009
OPUC Data Request 230

OPUC Data Request 230

Please describe, in more detail than provided in Exhibit PPL/702, Page 3.0.1, the basis for the PacifiCorp proposed REC adjustment. As a result of the adjustment to Oregon, does PacifiCorp increase the level (and revenue) of sold RECs to other states? Please explain.

Response to OPUC Data Request 230

The REC adjustment described on Page 3.0.1 results from the Company banking, rather than selling Oregon's and California's shares of system RECs, and selling all or a portion of remaining RECs not subject to RPS or an RPS banking provision. REC revenues that are by default allocated to all states using the SG factor are reallocated to non-RPS states as demonstrated on page 3.5.1 of Exhibit PPL/702. This adjustment is necessary to avoid giving states with RPS requirements credit for REC sales for their portion of RECs that are being banked rather than sold.

UE-210/PacifiCorp
May 26, 2009
OPUC Data Request 232

OPUC Data Request 232

Please repeat data request No. 231 with the assumption that PacifiCorp will produce new RECs associated with its owned or contracted for renewable resources. Identify for each year the number of new RECs that will be produced.

Response to OPUC Data Request 232

Based upon the same assumptions described in the Company's response to OPUC Data Request 231 but assuming new RECs from Company owned or contracted renewable resources, PacifiCorp estimates it may have sufficient RECs allocated to Oregon to meet the compliance requirements for the years 2011 through 2016.

Please refer to Confidential Attachment OPUC 232. This confidential information is provided subject to the terms and conditions of the protective order in this proceeding.

Please refer to Confidential Attachment OPUC 232 on the enclosed CD.

UE-210/PacifiCorp
April 23, 2009
OPUC Data Request 99

OPUC Data Request 99

Concerning RECs, please provide the REC revenue included in PacifiCorp's Oregon General Rate Case (UE 179). Please provide work papers that demonstrate REC revenue was recorded in Account 456 (UE 179 – Exhibit PPL/901, PacifiCorp Revenue Summary 3.0.2).

Response to OPUC Data Request 99

The REC revenue included in PacifiCorp's Oregon General Rate Case (Docket: UE 179) was $444,001. This was recorded in FERC Account 456 and SAP Account 301945. The Company considers the workpapers to be of utmost commercial sensitivity and thus Highly Confidential, and requests special handling arrangements. Please contact Joelle Steward at 503-813-5542 to discuss arrangements for review.

ORDER NO. 07-083

ENTERED 03/05/07

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UP 236

In the Matter of	)	
	)	ORDER
PORTLAND GENERAL ELECTRIC	)	
	)	
Application for Approval to Sell Tradable Renewable Energy Credits.	)	
	)	

DISPOSITION: APPLICATION APPROVED WITH CONDITIONS

On November 14, 2006, the Public Utility Commission of Oregon (Commission) received an application from Portland General Electric Company (PGE or company), pursuant to ORS 757.480 and OAR 860-027-0025, requesting authorization from the Commission to sell Tradable Renewable Energy Credits (TRCs) and an accounting order to record all proceeds and fees related to net proceeds from TRC sales in the property sale deferred account.

OPINION

Under ORS 757.480 and OAR 860-027-0025, a public utility doing business in Oregon shall first obtain Commission approval for any transaction to sell, lease, assign or otherwise dispose of property. Based on a review of the application and the Commission's records, the Commission finds that the application satisfies applicable statutes and administrative rules. At its Public Meeting on February 27, 2007, the Commission adopted Staff's recommendation to approve the sale of TRCs and grant an accounting order. Staff's recommendation is attached as Appendix A and is incorporated by reference.

ORDER

IT IS ORDERED that the application of Portland General Electric Company is approved, subject to the following conditions:

1. Portland General Electric Company will provide the Commission access to all books of account, as well as documents, data, and records that pertain to the sale of Tradable Renewable Energy Credits.

2. Portland General Electric Company will not sell more than $1 million of Tradable Renewable Energy Credits, or for a term of more than two

years, in any single sales transaction. Portland General Electric Company may sell up to 100 percent of its Tradable Renewable Energy Credits produced through June 30, 2007. During the period July 1, 2007, to December 31, 2007, and in subsequent calendar years, Portland General Electric Company may sell no more than one-half of the Tradable Renewable Energy Credits produced during the period. Any exception to this condition will require an amended application.

3. Portland General Electric Company will notify the Commission in advance of any substantive changes to the sale and transfer of Tradable Renewable Energy Credits, including any material change in price or quantities that exceed the expectations noted in Portland General Electric Company's application.

4. Portland General Electric Company will provide the Commission the final Gain Calculation with all supporting documentation concerning the final figures and record this information in the property sale deferred account, which is filed with the Commission on a semi-annual basis.

5. The Commission reserves the right to review all financial aspects of this transaction in any rate proceeding or alternative form of regulation.

6. The energy associated with Tradable Renewable Energy Credits sold by Portland General Electric Company will not be reported with environmental attributes as part of Portland General Electric Company's energy mix. Additionally, any Tradable Renewable Energy Credits sold will not be reported as owned for any renewable resource program. The Tradable Renewable Energy Credits sold by Portland General Electric Company should also not be sold to any affiliates without Commission approval. Further, Portland General Electric Company will not intentionally sell Tradable Renewable Energy Credits to any third parties or brokers for the purpose of supplying Tradable Renewable Energy Credits back to Portland General Electric Company to meet requirements for renewable resource programs or any future Renewable Portfolio Standard.

7. Portland General Electric Company will clearly communicate to customers that the Tradable Renewable Energy Credits from renewable resources meeting customers' energy needs may be sold, that the renewable energy attributes have been sold when the company sells Tradable Renewable Energy Credits, that such sales may result in lower customer electric bills and/or acquisition of additional renewable resources, and that any renewable energy associated with Tradable

Renewable Energy Credit sales will be based on net system mix for reporting purposes.

8. Portland General Electric Company will analyze, in its Integrated Resource Planning process, the valuation and risks associated with the disposition of Tradable Renewable Energy Credits, including their value for compliance with a potential Renewable Portfolio Standard or regulations on greenhouse gas emissions.

9. Portland General Electric Company will use the Western Renewable Energy Generation Information System (WREGIS) for Tradable Renewable Energy Credit wholesale sales under this property sale deferred account, once WREGIS is operational.

Made, entered, and effective MAR 0 5 2007.

BY THE COMMISSION:

Becky L. Beier

Becky L. Beier
Commission Secretary

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: February 27, 2007

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** N/A

DATE: February 20, 2007

TO: Public Utility Commission

FROM: Michael Dougherty

THROUGH: Lee Sparling and Marc Hellman

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UP 236) Application for 1) authorization from the Oregon Public Utility Commission to sell Tradable Renewable Energy Credits (TRCs); and 2) an accounting order to record all proceeds and fees, related to net proceeds from TRC sales in the property sale deferred account.

STAFF RECOMMENDATION:

Staff recommends that the Commission approve Portland General Electric's (PGE or Company) application to sell wholesale TRCs and provide an accounting order as requested with the following conditions:

1. PGE will provide the Commission access to all books of account, as well as documents, data, and records that pertain to the sale of TRCs.

2. PGE will not sell more than $1 million of TRCs, or for a term of more than two years, in any single sales transaction. PGE may sell up to 100 percent of its TRCs produced through June 30, 2007. During the period July 1, 2007, to December 31, 2007, and in subsequent calendar years, PGE may sell no more than one-half of the TRCs produced during the period. Any exception to this condition will require an amended application.

3. PGE will notify the Commission in advance of any substantive changes to the sale and transfer of TRCs including any material change in price or quantities that exceed the expectations noted in PGE's application.

4. PGE will provide the Commission the final Gain Calculation with all supporting documentation concerning the final figures and record this information in the

property sale deferred account, which is filed with the Commission on a semi-annual basis.

5. The Commission reserves the right to review all financial aspects of this transaction in any rate proceeding or alternative form of regulation.

6. The energy associated with TRCs sold by PGE will not be reported with environmental attributes as part of PGE's energy mix. Additionally, any TRCs sold will not be reported as TRCs owned for any renewable resource program. The TRCs sold by PGE should also not be sold to any affiliates without Commission approval. Further, PGE will not intentionally sell TRCs to any third parties or brokers for the purpose of supplying TRCs back to PGE to meet requirements for renewable resource programs or any future Renewable Portfolio Standard (RPS).

7. PGE will clearly communicate to customers that TRCs from renewable resources meeting customers' energy needs may be sold, that the renewable energy attributes have been sold when the company sells TRCs, that such sales may result in lower customer electric bills and/or acquisition of additional renewable resources, and that any renewable energy associated with TRC sales will be based on net system mix for reporting purposes.

8. PGE will analyze in its Integrated Resource Planning process the valuation and risks associated with the disposition of TRCs, including their value for compliance with a potential RPS or regulations on greenhouse gas emissions.

9. PGE will use the Western Renewable Energy Generation Information System (WREGIS) for TRC wholesale sales under this property sale deferred account, once WREGIS is operational.

DISCUSSION:

PGE filed this application on November 14, 2006, pursuant to ORS 757.480 and OAR 860-027-0025.

Tradable Renewable Credits (TRCs)
A TRC represents the beneficial environmental attributes of one megawatt-hour (MWh) generated from a specific renewable resource. TRCs are created as renewable power is generated. According to PGE, there is increasing interest in purchasing TRCs due to

new consumer demand, corporate commitments, and regulations such as Renewable Portfolio Standard (RPS) requirements.

PGE purchases bundled energy (renewable energy plus TRCs) from the Vansycle Ridge and Klondike II wind generating facilities. Additional TRCs will be available when Phase I of the Biglow Canyon wind generation facility becomes operational.

PGE expects to conduct about four TRC sales transactions per year from these facilities, and anticipates that each sale will be less than $1 million. However, PGE has considered the possibility of single transactions of $1 million or more, and has requested that the Commission provide PGE the option to file an amended application for such transactions.

The TRC Market

According to PGE, the market for TRC sales is still in the process of development and there is a great deal of flux in terms of sales pricing and timing for obtaining the best prices. Also, the TRC market is built on public perception and support, and the newer the TRC (or vintage) the higher the prices that are typically available on the market.

Markets are fragmented based on location, resource type, and timing. As an example of the variability of prices for TRCs on a nation-wide basis, the recent range of pricing for several different types of TRCs include the following: solar: $30-$50; biomass/low-impact hydro: $0.50-$3; wind: $0.50-$15; landfill gas: $1-$3; and geothermal: $1-$10.[1]

PGE believes it will need to have some flexibility to conduct sales transactions when market conditions and timing are best. In the past, PGE has not sold TRCs outside its optional renewable energy programs for retail customers, and the company will be working to develop its expertise in this area.

PGE's TRCs

PGE has long-term purchase agreements with the wind projects previously mentioned (the Vansycle agreement ends November 6, 2028, and the Klondike II agreement ends December 1, 2035), which include the associated TRCs. PGE seeks to take advantage of sales opportunities while the vintage of these TRCs will yield reasonable market values.

With no RPS in place today, and only a fraction of tags from the Klondike II project dedicated to the company's new Renewable Future program, PGE currently owns excess TRCs. However, the company is unable to estimate future sales quantities or revenues because such an estimation might be influenced by many factors including

[1] Cost information provided by PGE.

actual energy production at the wind plants, market value and liquidity for TRCs, changes in regulation (e.g., an RPS or restrictions on greenhouse gas emissions), and the composition of PGE's resource portfolio at the time of each sale.

Although PGE plans to hold an adequate portion of its available TRCs from the Klondike II wind generation facility in reserve for the Stable Rate Pilot Program (Renewable Future Option), the company has no plans to hold any additional TRCs in a "bank" to meet future needs or potential regulatory changes. Rather, PGE will establish any necessary reserve as it learns of regulatory changes or other market influences, and as it gains more experience and competence in this market. At the end of each year, after year-end true-ups, any excess reserve TRCs for the Stable Rate program will also be available for sale.

PGE has decided to remain fluid in terms of the methods employed to sell TRCs. For instance, PGE may sell some TRCs directly, or may use a primary broker, depending on the situation and conditions at the time of each sale. PGE expects that broker fees may range between 1 percent and 6 percent of total sales. PGE also expects to incur some minimal internal costs, such as program management and accounting costs, which should be relatively small and will be recorded to existing operating accounts. PGE does not currently plan to act as a broker for other utilities or power marketers for the sale of TRCs in the future.

PGE may sell bundled energy, which would include the TRCs plus either renewable energy or non-renewable energy. In addition, PGE will provide attestations for TRC sales that are similar to the attestations the company receives from Green Mountain Energy Company for PGE's retail customer programs. PGE's wholesale TRC sales transactions will be Green-e certifiable, and PGE will adopt any Western Renewable Energy Generation Information System (WREGIS) requirements associated with these sales once WREGIS is operational.

Although PGE currently has no plans to enter any additional long-term agreements for TRCs, or construct renewable energy facilities for investment purposes in relation to the sale of TRCs, the Company may consider such plans as market and regulatory conditions change in the future.

<u>Accounting Order</u>
PGE has requested an accounting order which would allow the company to record TRC sales as property transactions and apply interest at the same rate as accumulated property sales. These proceeds would then be amortized back to customers, in the same manner as property sales, using Schedule 105 (Regulatory Adjustments). All

TRC sales transactions would also be included in the semi-annual property sales report that is submitted to the Commission.

Three conference calls were conducted: January 12, 2007, with PGE, Staff, the Citizens' Utility Board (CUB), and Renewable Northwest Project (RNP); January 29, 2007, with PGE, Staff and RNP; and February 15, 2007, with PGE and Staff. As a result of these discussions, Staff revised its proposed condition 2 and added conditions 7 and 8. As modified, all parties do not disagree with the recommendations set forth.

Because of the changing market for TRCs, proposed minimum portfolio standards for renewable resources, and potential requirements related to greenhouse gas emissions, Staff initially sought to limit TRC sales to one-half the amount PGE owns in any calendar year. Staff obtained further clarification from the Oregon Department of Energy (ODOE) on PGE's ability to use TRCs produced during 2006 and 2007 toward any future RPS requirement. ODOE advised Staff that consistent with RPS discussions at the November 2006 meeting of the Renewable Energy Working Group, Senate Bill 373/House Bill 2209 will propose unlimited banking of TRCs. However, TRCs must be certified by WREGIS, which is not expected to be operational until mid-2007.

Therefore, Staff proposes that PGE be allowed to sell all TRCs produced through June 2007.[2] Staff notes, however, that with the potential for unlimited banking, PGE should carefully consider sales of TRCs produced after that time. Further, if and when an RPS bill is enacted, PGE will be better able to determine an appropriate on-going sales strategy.

Condition 7 provides notice to customers of the change in PGE's treatment of TRCs. Selling instead of retaining TRCs will return revenues to customers that may result in lower electric bills. Consideration of TRC sales value also may allow PGE to acquire more renewable resources. Condition 7 further ensures proper disclosure of power sources when the company sells TRCs. For example, when the company sells TRCs associated with energy from a contracted or owned wind plant, the energy will be reported in the company's power source label as the regional net system mix, rather than a renewable resource.

[2] TRCs produced during the previous calendar year have market value. For example, the national Green-E standard allows TRCs that are generated in the calendar year in which the product is sold, the first three months of the following calendar year, or the last six months of the prior calendar year. Not all TRCs that are sold are Green-E certified.

Condition 8 commits PGE to analyzing the valuation and risks associated with the disposition of TRCs as part of its Integrated Resource Planning process. This analysis will take into account compliance with possible mandates related to minimum portfolio standards for renewable resources, greenhouse gas emissions, and may include retention, purchase, sales, and/or retirement of TRCs.

PROPOSED COMMISSION MOTION:

PGE's application be approved subject to the nine recommended conditions.

CASE: UE 210
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 400

Opening Testimony

July 24, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Ed Durrenberger. I am a Senior Analyst in the Electric and Natural Gas Division of the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/401.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony has two purposes. The first is to identify and explain several adjustments to the rate base proposed by Pacific Power (PacifiCorp or company) in its general rate case filing. The second is to review the prudence of PacifiCorp's decisions to acquire the Lake Side and Chehalis generating plants.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/402, consisting of 5 pages.

<u>Rate Base Adjustments</u>

Q. PLEASE SUMMARIZE YOUR RATE BASE ADJUSTMENTS.

A. I propose the following reductions to PacifiCorp's proposed rate base:

1. Transmission Plant Additions:
   - a. Three Mile Knoll Sub -$6.7 million
   - b. Chappel Creek/Cimarex Energy -$4.2 million
   - c. Glenrock Wind Interconnection -$3 million

d. Eurus 7 Mile Hills Interconnection -$1.5 million

e. McClellan–Emigration Tap -$2 million

2. Other Wind Plant Additions:

a. High Plains -$1.5 million

b. Seven Mile Hill II -$0.2 million

c. Glenrock III -$0.3 million

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO THE COST OF THE THREE MILE KNOLL SUBSTATION.

A. I propose that the capital costs allowed to be included in rate base for this project be reduced from $56 million to $32 million, resulting in an Oregon allocated reduction to rate base of $6.7 million. The Three Mile Knoll Substation represents the single most expensive non-plant addition to rate base in the entire filing. The company provided details of this project, including plans of the facility, in its response to Staff Data Requests 273 (*See* Exhibit Staff/402 Durrenberger/1-2). The information provided suggests that PacifiCorp has included costs identified as part of a possible future expansion of the substation. The Three Mile Knoll substation plans describe a transmission level substation with a single 230-138 kV transformer and other switching gear as described in the write-up that accompanies Section 8 of PPL Exhibit 702. The company's rate base request seems to include the cost for the fully built-out configuration, because they describe facilities such as a second 230-138 KV transformer, which plainly are identified as part of a possible future expansion. Despite the further information provided in response to Staff Data Request No. 332, (*See* Exhibit Staff/ 402 Durrenberger/3-4), questions remain about what exactly is included in the substation budget. As a check on the reasonableness of the substation costs, I asked the Bonneville Power Administration (BPA) for a cost range for similar transmission voltage substations. The BPA indicated that budgetary numbers used for similarly situated substations would range from $17 to $25 million.

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO THE COST OF THE CHAPPEL CREEK/ CIMAREX ENERGY LINE EXTENTION.

A. I propose that the capital cost PacifiCorp included in rate base for this project be reduced by $4.2 million, on an Oregon allocated basis. PacifiCorp provided a description of the various upgrades in response to Staff Data Request No. 333 (*See* Staff Exhibit/ 402 Durrenberger/5). The company appears to be upgrading a section of its current 69 kV distribution system to a 230 kV transmission level voltage and extending the line to the new customer's facility. Normally, a new customer would receive a line extension allowance and be responsible for all additional costs for a new service connection. Furthermore, general distribution system improvements in Wyoming would typically be paid for by Wyoming customers and is consistent with the Revised Protocol in that distribution costs are allocated state situs. My adjustment attributes all the costs associated with the high voltage 230 kV lines and equipment to Cimarex Energy, applies the line extension allowance, and treats the other expansion costs as the company suggests. This methodology results in an Oregon allocated adjustment to rate base of $4.2 million from the company's initial request.

Q. PLEASE DESCRIBE YOUR ADJUSTMENTS TO THE COSTS OF THE GLENROCK WIND INTERCONNECTION AND THE SEVEN MILE HILLS INTERCONNECTION.

A. I propose that the $3 million capital cost associated with the Glenrock Wind interconnection and the $1.5 million capital cost associated with the Eurus 7 Mile Hills interconnection not be included in PacifiCorp's rate base. The plant additions to rate base for these two facilities already include expenses for the interconnections and PacifiCorp's proposal would double count the expenses.

Q. PLEASE DESCRIBE YOUR ADJUSTMENTS TO THE COSTS OF THE MCCLELLAND-EMIGRATION TAP UPGRADE.

A. I propose that the costs of the McClelland- Emigration Tap be allocated solely to Utah customers. This reliability upgrade serves a narrow subset of Utah customers and does not benefit Oregon customers in any way. I propose a $2 million reduction to PacifiCorp's proposed rate base, on an Oregon allocated basis. I view these costs are more akin to distribution costs and not transmission costs given the need and use of the line.

Q. PLEASE DESCRIBE YOUR THREE ADJUSTMENTS ASSOCIATED WITH THE "OTHER WIND PLANT ADDITIONS".

A. The final three adjustments to wind plant capital costs are intended to remove costs not considered to be capital costs from "Other Wind Plan Additions to rate base". The costs are for "Capital Surcharge" and "Contingencies" which were included in the overall wind plant costs are not appropriate additions to rate base. This adjustment reduces Oregon allocated rate base buy $2 million.

<u>Lake Side</u>

Q. PLEASE DESCRIBE THE LAKE SIDE POWER PLANT THAT PACIFICORP INTENDS TO ADD TO RATE BASE.

A. The Lake Side Power Plant (Lake Side), is located in Vineyard, Utah, a short distance south of Salt Lake City, near Orin Utah and east of Utah Lake. The facility is a natural gas fueled combined cycle combustion turbine (CCCT) power plant comprised of two Siemens Westinghouse 501F gas turbine generators, two heat recovery steam generators a single steam turbine and the associated equipment and facilities. The plant capacity is approximately 548 megawatts (MW). The plant operates as a baseload resource, but has the flexibility to operate as a peaking facility if required. The Project was developed by Summit Energy on the site of an old steel mill. The facilities were supplied and built by Siemens Westinghouse and PacifiCorp took over control and began operation of this plant in September 2007.

Q, IF THE PLANT HAS BEEN IN OPERATION SINCE 2007 WHY IS PACIFICORP JUST NOW REQUESTING THAT IT BE ADDED TO THE RATE BASE?

A. The plant was not yet in operation at the time of PacifiCorp's last general rate case, UE 179, which occurred in 2006. Even though the test year in that case was 2007, parties agreed that Lake Side capital costs did not belong in the rate base for that rate case. However as part of a stipulation in that case, the dispatch benefits from operating the plant have been included in PacifiCorp's net variable power costs and in rates since the plant began operation in 2007. PacifiCorp's testimony at PPL/400 Tallman/8-9 discusses the treatment of Lake Side costs in rates so far. The company contends that Oregon customers have already received significant benefits associated with the plant without the matching fixed costs.

Q. CAN YOU DESCRIBE THE PROCESS THAT WAS USED TO FIRST DETERMINE THE NEED FOR A NEW RESOURCE

A. PacifiCorp uses an integrated resource planning (IRP) process to evaluate the load growth and resource need in its service areas. In the case of Lake Side, the 2003 IRP, Docket No. LC 31, identified a need for supply side resources in the east-side of the PacifiCorp service territory for 2007. The resource need was in response to a forecast that expected rapid growth in the number of new customers coming on the PacifiCorp system and expanding industrial load growth primarily in Utah's Wasatch Front area. The 2003 IRP identified, among other things, the need for a 570 MW baseload resource on the east-side of the system beginning in 2007. The Commission acknowledged the 2003 IRP and the action item to acquire an east-side resource in Order No. 03-508. For the purposes of my evaluation of the prudence of PacifiCorp's decision to acquire the Lake Side resource, I have concluded that the 2003 IRP adequately establishes the need for the resource.

Q. PLEASE DESCRIBE THE PROCESS THAT WAS USED BY PACIFICORP TO SELECT THE LAKE SIDE PROJECT.

A. PacifiCorp selected the Lake Side CCCT as the winning bid from its 2003-A request for proposals (2003-A RFP). The 2003-A RFP solicited bids for east-side baseload resources.

Q. DID PACIFICORP FOLLOW THE COMMISSION APPROVED BIDDING PROCESSES IN CHOOSING THE LAKE SIDE PLANT?

A. Yes. The 2003-A RFP was filed with the Commission. In Order No 03-356, the Commission found the request to be consistent with the 2003 IRP and compliant with its competitive bidding guidelines. In the order the Commission conditions its approval by requiring that PacifiCorp use an independent evaluator (IE) to audit the bid evaluation process. PacifiCorp secured the services of Navigant Consulting (Navigant) as the independent evaluator. Navigant made sure PacifiCorp's evaluation of the bids was reasonable, fair and unbiased. The outcome of the 2003-A RFP was the Lake Side CCCT resource and the decision was reviewed and endorsed by the Oregon IE. I conclude that PacifiCorp followed Commission requirements in selecting a preferred resource for meeting the need for an east-side baseload resource.

Q. WHAT DID THE PLANT COST?

A. The total capital cost for Lake Side is reported to be $1,477,780 in 2009. Prior to the base year, in 2007, $338,432,481 was added to the recorded rate base as the capital costs for Lake Side. The total amount that PacifiCorp wishes to include in rate base for Lake Side is $339.9 million; on an Oregon allocated basis the Lake Side plant represents an increase to regulated rate base of $91 million.

Q. WHAT DO YOU CONCLUDE ABOUT THE PRUDENCE OF PACIFICORP'S DECISION TO ACQUIRE THE LAKE SIDE PLANT?

A. I conclude that PacifiCorp's decision to acquire the Lake Side CCCT was prudent. My analysis has shown that Lake Side was acquired in response to a baseload resource need identified in the 2003 IRP. The 2003 IRP action plan was acknowledged by the Commission in Order No, 03-508. My analysis has also shown that Lake Side was the winning bid in the 2003-A RFP. This competitive bidding process was guided by Commission Order No. 03-356 and overseen by an impartial IE. Therefore, I conclude that the need for a plant was real, the bid process that selected Lake Side was reasonable, fair and unbiased, and that the plant costs, resulting from the competitive bidding process, represented a fair market value at the time the contract was signed.

Chehalis

Q. PLEASE DESCRIBE THE CHEHALIS POWER PLANT THAT PACIFICORP INTENDS TO ADD TO RATE BASE.

A. The Chehalis Power Generating Plant (Chehalis or Plant) is a 520 MW natural gas fueled electric generation plant that consists of two GE 7FA dry, low NOx combustion turbine generators; two heat recovery steam generators that supply a single steam turbine generator. The plant is located near the town of Chehalis Washington, 80 miles north of Portland, Oregon. It was built approximately six year ago and has been in service since that time. The power plant is interconnected to the Bonneville Power Administration transmission system.

Q. PLEASE DESCRIBE THE PROCESS THAT WAS USED BY PACIFICORP TO ACQUIRE THE CHEHALIS POWER PLANT.

A. PacifiCorp has indicated that it had been aware of this plant as a possible acquisition since late 2006. In early 2008, the plant owner informed the company that other parties were also looking at the plant. At this point PacifiCorp took steps to enter into a fact-finding investigation and a non-binding negotiation with the owner. These negotiations ultimately lead to the purchase and sale agreement (PSA) executed in September of 2008.

Q. DID PACIFICORP SEEK A WAIVER OF THE COMMISSION'S COMPETITIVE BIDDING GUIDELINES BEFORE ACQUING THE CHEHALIS PLANT?

A. Yes. Concurrent with entering into negotiations with the plant owner, PacifiCorp filed a petition, docketed as UM 1374, requesting a waiver of the Commission's competitive bidding guidelines. The Commission's guidelines, prescribed in Order No. 06-446, provide that an exemption can be granted from the guidelines to allow a utility to take advantage of a time-limited resource opportunity that presents unique value to customers. PacifiCorp contended that the Chehalis Plant represented such an opportunity. The company indicated that the RFP process would take longer to complete than the time limited deadline contained in the purchase and sale agreement and that customers would therefore lose the benefits of the acquisition.

Q. DID THE COMMISSION GRANT PACIFICORP'S WAIVER REQUEST?

A. Yes. The Commission directed the company to allow the IE to evaluate the Chehalis opportunity. Staff performed its own review of the resource opportunity. Both recommended the approval of the waiver petition and the Commission concurred in Order No. 08-376.

Q. DID THE ORDER GIVE PACIFICORP PRE-APPROVAL TO BUY THE PLANT?

A. No. All Order No. 08-379 allowed for was a waiver of competitive bidding guidelines. The decision to buy resources rests with the utility and the utility also bears the burden of proving, when it seeks to include the resource in rates, that the acquisition was prudent.

Q. WHAT ARGUMENT DOES PACIFICORP OFFER MAKE TO INDICATE THAT ITS DECISION TO PURCHASE THE CHEHALIS PLANT WAS PRUDENT?

A. The company argues that:

1. The plant supplies the 2012 energy and capacity needs identified in the 2007 IRP Update.
2. The plant was purchased at a price point that was significantly lower than the current installation costs of a new plant, as well as the expected installation costs of a similar resource in 2012.

3. The purchase of the facility now at the negotiated price in the PSA rather than waiting to acquire a resource in 2012, as indicated in the 2007 IRP, reduces the present value of the resource portfolio by $142 million over the twenty year planning horizon.
4. The acquisition of an existing resource reduces or eliminates certain risks associated with permitting and constructing a new plant, such as price escalation, construction delay costs, and unforeseen problems in securing permits, fuel delivery agreement and transmission rights.

Q. PLEASE ELABORATE ON THE NEED IDENTIFIED IN THE 2007 IRP.

A. The 2007 IRP and the subsequent 2007 IRP Update modeled load-resource balances for the next twenty years. The models took in to account the company's expectations for load growth and resource availability, including the expiration of a significant amount of long term power purchase agreements at the end of 2011 and the beginning of 2012. By 2012, the deficit in peak capacity was expected to be 2,400 MW system-wide. Subsequently in 2008, as part of the 2007 IRP Update, the capacity deficit was determined to be about 1,900 MW on a system-wide basis (*See* Exhibit PPL/604), with a 575 MW deficit in PacifiCorp's western control area (*See* Exhibit PPL/603, Table 9) where the Chehalis plant is located.

Q. DOES THE CHEHALIS PLANT SATISFY THE NEED IDENTIFIED IN THE 2007 IRP?

A. Yes. Although the Chehalis Plant does not satisfy the entire system deficit in 2012, the company contends that the plant provides increasing benefits as loads grow and existing contracts expire. The plant also provides operational flexibility needed to integrate wind resources as they are added to meet renewable portfolio requirements. Even though the load-resource balance does not show a need for the plant right away, PacifiCorp shows that it was available for purchase on a time limited basis at sufficiently favorable terms that provided compelling economic benefits to customers. The economic analysis provided as part of the company testimony (See Exhibit PPL/601 and Confidential Exhibit PPL/602), as well as the evaluation performed in UM 1374 by the IE, both indicate that customers are better off with the Chehalis acquisition, than they would be waiting to acquire a similar resource in 2012.

Q. WHAT DO YOU CONCLUDE ABOUT THE PRUDENCE OF PACIFICORP'S DECISION TO ACQUIRE THE CHEHALIS PLANT?

A. I conclude that PacifiCorp's decision to acquire the Chehalis plant was prudent. I agree with the findings of the IE that the Chehalis acquisition was a time limited resource opportunity that presented a unique value to customers. PacifiCorp has demonstrated through its IRP planning process that there is a need for resources on the west-side of its system. PacifiCorp provided evidence in confidential Exhibit PPL/501 that it was able to enter into a PSA at terms favorable to the company relative to new plant costs. Although I did not personally review any of the 2012 RFP proposals, the bid prices, in capital cost per kW are consistent with my independent research regarding the cost of new plants. I conclude that the Chehalis plant was bought for a very good price and that on the basis of what was known at the time about expected loads, the state of the technology, and market prices, the acquisition of the Chehalis Plant was prudent and it will provide benefits to Oregon customers both now and in the future.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 210
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualification Statement

July 24, 2009

WITNESS QUALIFICATION STATEMENT

NAME:	Ed Durrenberger
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst
ADDRESS:	550 Capitol St. NE, Ste. 215, Salem, Oregon 97301
EDUCATION:	B.S. Mechanical Engineering Oregon State University, Corvallis, Oregon
EXPERIENCE:	I have been employed at the Public Utility Commission of Oregon since February of 2004. My current responsibilities include staff research, analysis and technical support on a wide range of electric and natural gas cost recovery issues including net variable power costs and PURPA Qualifying Facility pricing and interconnection.
OTHER EXPERIENCE:	I have over twenty years of engineering, operations and maintenance experience with industrial boiler plants and associated equipment and utilities. I also have project management experience both in industrial chemical and manufacturing environment and in the high tech manufacturing environment.

CASE: UE 210
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

July 24, 2009

OPUC Data Request 273

Regarding line 12: Please provide more complete information about the Threemile Knoll Substation transmission capital addition including;

a. A description of the need and engineering analysis indicating that the proposed alternative represents the most economic/practical alternative.
b. A total break-down of parts and costs including but not limited to site permits, licenses and development expenses, electrical equipment descriptions and costs, materials such as wires, poles and building materials, engineering design costs, construction labor and project management project management, fire, spill prevention and security systems and miscellaneous and contingency costs.
c. A complete break-down of the line relocation costs.
d. Site location maps, lay-out drawings and one line design drawings
e. Any other relevant information that would substantiate the project costs.

Response to OPUC Data Request 273

a. The Threemile Knoll Substation provides the least cost option to fulfill PacifiCorp's obligations to serve Goshen area load and to maintain existing transfer capability on Path C which is fully committed.

   The need for Threemile Knoll Substation arises from the fact that load growth near Goshen, Idaho exceeds capabilities at PacifiCorp's Goshen Substation.

   In addition, Threemile Knoll Substation addresses the projected decline in the southbound rating of Path C between Idaho and Utah. The existing 820 MW of transfer capability is fully subscribed by firm users and must be maintained. The contracts are (1) 85 MW wheeling from Idaho to UAMPS and (2) 665 MW point-to-point transmission rights sold to PacifiCorp Merchant. 70 MW is reserved for transmission reliability margin (TRM). Path C southbound capability is expected to decline from the present 820 MW to 765 MW in 2008, with further declines beyond 2008. Threemile Knoll will increase Path C capacity by off-loading the critical thermally limited Goshen-Grace 161 kV line.

   Two 700 MVA transformers will be required at Threemile Knoll to meet the requirement that during an extended outage of one transformer, the remaining transformer must be able to supply the entire load without curtailments, path transfers, or criteria violations.

   Other alternatives considered:

1: Reconductor Grace-Goshen 161 kV Line and increase Goshen Transformer – Not Recommended
To serve forecast load growth at Goshen Substation, a third 345/161 kV transformer would be required no later than 2008. The costs for this project are estimated at $17 million due to space limitations and the existing bus arrangement at the Goshen substation. Preliminary design indicates that some underground cabling would be required to accommodate a third autotransformer at the site. In addition, restoring Path C capability to its current level would involve the rebuilding of the Grace-Goshen 161 kV line ($34.2 million), a new Grace 161/138 kV 300 MVA transformer ($5.7 million) and a new series reactor on the American Falls-Malad 138 kV line ($1.6 million). Rebuilding the Grace-Goshen line would require a new ROW permit across the Shoshone Indian Reservation. The time requirements to negotiate a new ROW permit are uncertain. The present value of the revenue requirements of this alternative is greater than that for the recommended alternative. This alternative is not recommended.

2: Do Nothing (Not Feasible)
Path C is presently fully committed and utilized in the southbound direction and any decline in capability requires an investment to restore capability to its present level in order to fulfill existing firm transmission contracts, which can be renewed indefinitely by the contract holder.

b. Please refer to Attachment OPUC 273b, which provides a schedule reflecting project to date costs through April 2009 by work breakdown structure as captured in the company's cost accounting system (SAP).

c. Please refer to the Company's response to subpart b above; specifically Attachment OPUC 273b.

d. Please refer to Attachment OPUC 273d.

e. None.

Please refer to non-confidential Attachments OPUC 273 –(b,d) on the enclosed CD.

UE-210/PacifiCorp
July 6, 2009
OPUC Data Request 332

OPUC Data Request 332

This question is a follow up to Staff DR 273:

- Please provide a complete cost break down of the Three Mile Knoll Sub.
- Explain the differences between the equipment and construction planned for this Sub. and the similarly proposed transmission Sub at Oquirrh.
- Please explain any mitigating factors that explain why the capital costs of the Three Mile Knoll Sub are so much larger that Oquirrh.
- Staff believes that the overall project prices that are forecast for the transmission level substations are higher than industry standards. Is there any reason that PacifiCorp should have higher costs than similarly situated cohorts for their transmission equipment?

Response to OPUC Data Request 332

1. Please refer to Attachment OPUC 332, which provides a complete cost breakdown of the Three Mile Knoll Substation project as of June 23, 2009.

2. Both the Three Mile Knoll substation project and the Oquirrh Substation project have similar 345 kV line connections and 345-138 kV, 700 MVA transformers. Each substation will have multiple 138 kV transmission lines exiting the stations. However, there are some significant differences in the equipment and construction between Three Mile Knoll and Oquirrh, which include:

    - The Three Mile Knoll project has two 345-138 kV transformers while Oquirrh has only one.
    - The relay protection scheme at Three Mile Knoll is more complicated due to the generator drop schemes associated with the Jim Bridger plant. More extensive relay upgrades are needed at the Jim Bridger Substation, the Goshen Substation, the Grace Substation and the Soda Substation than are needed on the Oquirrh project.
    - The Three Mile Knoll project requires additional communication work.
    - The Three Mile Knoll project includes installation of a 345 kV reactor which isn't needed at the Oquirrh substation.
    - The Three Mile Knoll substation requires the removal of the existing Caribou Substation.
    - Three Mile Knoll is located in a rural area, while Oquirrh is located in a metro area,where construction costs are lower.

3. Please refer to the Company's response item 2 above. In addition, the amount included in the Company's filing for the Oquirrh substation project is understated. The current forecast for the Oquirrh substation project is approximately $51 million. The Company intends to make this update in its rebuttal filing.

4. The Company is not aware to which industry standard Staff is comparing the forecast project prices in this case. However, the Company's procurement policies are designed to ensure projects are competitively priced. When making any comparison like the one suggested in this request one must consider multiple factors, including:

   - The time and state of the market when the project was competitively tendered, including but not limited to commodity costs, interest rates, and resource availability;
   - Design specifications;
   - Physical geography (rural construction conditions will add significant cost increases to projects when the labor force has to be imported, and where housing and other worker needs are limited);
   - Weather patterns and environmental aspects;
   - Land rights of way;
   - Key products used and depth of the supplier base.

Please refer to non-confidential Attachment OPUC 332 on the enclosed CD.

UE-210/PacifiCorp
July 6, 2009
OPUC Data Request 333

OPUC Data Request 333

This question is a follow up to Staff DR 271:

- Please explain what facilities are being paid for by the new customer.
- Absent the new customer's electrical needs would any of the other existing customers being served by the company require expansion to the substation, higher voltage feeds or other transmission or distribution level upgrades included in the Chappel Creek Capital project?

Response to OPUC Data Request 333

Please refer to Attachment OPUC 333 which provides details of the additional facilities required for the Chappel Creek 230kV: Cimarex Energy Company - 50 MW Service project and Cimarex's associated contributions for each facility.

In addition to new requests for service from larger customers in Sublette County, Wyoming, such as Cimarex and Air Products, many small commercial and industrial customers in the Big Piney and Pinedale area have requested additional service. Since the 69 kV transmission line between Labarge and Big Piney has reached voltage and thermal limits, all customers in Sublette County will benefit from these transmission and distribution upgrades. This project includes a significant amount of betterment to compensate for the voltage and thermal limit risk within the area. A portion of the betterment work associated with this project was accelerated last winter to avoid voltage and thermal problems in the Pinedale area. The treatment of this project in the Company's filing reflects Wyoming line extension policy and the Revised Protocol inter-jurisdictional allocation methodology.

Please refer to non-confidential Attachment OPUC 333 on the enclosed CD.

CASE: UE 210
WITNESS: Lisa Gorsuch

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

July 24, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Lisa Gorsuch. I am employed by the Public Utility Commission of Oregon (OPUC) as a Utility Analyst in the Electric and Natural Gas Division. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/501.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am responsible for reviewing certain labor related expenses in PacifiCorp Corporation's (PacifiCorp) rate case. Based upon my review, I propose an adjustment to test period expenses and rate base related to PacifiCorp's employee incentives (S-9).

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. In addition to my Witness Qualification Statement provided in Staff/501, I prepared Exhibit Staff/502, which provides documents and calculations supporting my proposed adjustment. Exhibit Staff/502 consists of ten pages.

Q. PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENT FOR ISSUE S-9.

A. I propose to reduce PacifiCorp's Operation and Maintenance Expense (O&M) by $3.552 million and its rate base by $1.419 million based on this Commission's traditional sharing of employee incentive costs between customers and shareholders. A summary of my proposed incentive adjustment is provided in Exhibit Staff/502, Gorsuch/1-2.

Q. WHAT INCENTIVE PLAN EXPENSES DID PACIFICORP INCLUDE IN UE 210?

A. PacifiCorp's rate case includes approximately $33 million in incentive-related expenses on a systemwide basis ($9.7 million Oregon-allocated).

Q. DID PACIFICORP MAKE ANY ADJUSTMENTS TO PROJECTED TEST PERIOD INCENTIVE EXPENSES TO REFLECT THE COMMISSION'S POLICY ON ALLOWANCE OF INCENTIVE EXPENSES IN RATES?

A. No. PacifiCorp did not include any adjustments to reflect the Commission's historical policies on sharing of incentive expenses between shareholders and customers. PacifiCorp states that it is seeking to include the full costs of the Annual Incentive Plan in rates. *See* PPL/800, Wilson/8.

Q. WHAT ARE THE COMMISSION'S HISTORICAL RATEMAKING POLICIES ON INCENTIVE EXPENSES?

A. The Commission's policies are to disallow 100 percent of officers' bonuses and incentives because typically they are based solely on increased earnings and the financial performance of the utility, which benefit shareholders; disallow 75 percent of performance-based incentives because they are generally focused on increased earnings and, therefore, are more beneficial to shareholders; and disallow 50 percent of merit-based bonuses because they equally benefit shareholders and ratepayers. *See generally*, UG 132, Order No. 99-697(relevant pages), provided in Exhibit Staff/502, Gorsuch/3-4.

Q. IS YOUR PROPOSED ADJUSTMENT BASED ON THE COMMISSION'S POLICIES ON ALLOWANCE OF INCENTIVE EXPENSES?

A. Yes. My adjustment proposes to disallow 100 percent of UE 210 expenses related to officers' incentives and 50 percent of non-officers' merit-based incentives, consistent with the Commission's general policies on incentives. My adjustment also takes into consideration the ratemaking recommendations of PacifiCorp's incentive programs in *Staff Audit Report of PacifiCorp, Audit Number 2008-002* dated March 11, 2009 at 18-20. (Staff Audit Report). The Staff Audit Report summarizes PacifiCorp's incentive plans following the acquisition of PacifiCorp by MidAmerican Energy Holdings Company (MEHC).[1] According to the Company, PacifiCorp does not have a long term incentive plan. While MEHC does have a long term incentive plan, PacifiCorp states that it will not seek recovery of these costs from Oregon customers. The Staff Audit Report pages are included in Exhibit Staff/502, Gorsuch/5-7.

Q. WHAT ARE YOUR CONCLUSIONS AFTER REVIEWING PACIFICORP'S RESPONSES TO STAFF'S DATA REQUESTS FOR DETAILS OF PACIFICORP'S CURRENT INCENTIVE PLANS UNDER MEHC VERSUS THE INCENTIVE PLANS PRIOR TO THE ACQUISITION IN 2006?

A. PacifiCorp's response to Staff's Data Request 324 supports PacifiCorp's statements regarding the structure of the test period incentive plans providing benefits to customers. However, the incentive plans equally benefit shareholders. For this reason, it is appropriate to disallow 50 percent of

[1] Pursuant to OAR 860-014-0050(1) (e), Staff requests that the Commission take official notice of the Staff Audit Report.

merit-based bonuses consistent with the Commission's historical policies related to incentive expenses in rates. I recommend the Commission adopt Staff's proposed reductions to test period incentive expense of $3.552 million and to rate base of $1.419 million. *See* Exhibit Staff/502, Gorsuch/8-12.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 210
WITNESS: Lisa Gorsuch

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualification Statement

July 24, 2009

WITNESS QUALIFICATION STATEMENT

NAME:	Lisa Gorsuch
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst/Rates & Tariffs
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.
EDUCATION:	College-level coursework in financial accounting, business law, business management, and economics. The Center For Public Utilities at New Mexico University. The National Association of Regulatory Utility Commissioners' Annual Regulatory Studies Program at Michigan State University.
EXPERIENCE:	Utility Analyst with the Public Utility Commission of Oregon since April 2008. Primarily responsible for review of electric and natural gas company tariff filings and other electric and natural gas company rates and costs. Provide expertise to Consumer Services Division on consumer-related issues. Compliance Specialist with the Public Utility Commission of Oregon from June 2004 until April 2008. Responsibilities included acting as a liaison between the public, regulated utilities and various Commission staff. Review of proposed tariffs, administrative rules, and policies for evaluation of the potential impact on consumers and the regulated utilities. Identified trends, services, and policies where no statute, rule or precedent applied and recommended the appropriate action.
OTHER EXPERIENCE:	Enforcement Agent with the Oregon Department of Revenue as a member of a multijurisdictional task force including Oregon Department of Justice and Oregon State Police from June 1999 until May 2004. Responsibilities included investigating cases of tax evasion involving smuggling of illegal cigarette and other tobacco products. Review of administrative rules, and compliance and enforcement standards for multiple tax programs. Serving as liaison between task force and Oregon State Legislators to determine appropriate tax rate, and legislative concepts for two different tax programs.

CASE: UE 210
WITNESS: Lisa Gorsuch

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support
Of Opening Testimony

July 24, 2009

Pacific Power & Light
UE 210
Test Year December 31, 2010
000's of Dollars

Staff Adjustment S-X

This adjustment disallows 100% of officer bonuses and 50% of the Annual Incentive Plan bonuses that apply to all other employees.

(Please round your answers to the nearest $1,000)

Description/ Account No.	Company Filing	Staff	Adjustment
Bonus Adjustment: O&M	$6,930	$3,378	($3,552)
Bonus Adjustment: Rate Base	$2,769	$1,350	($1,419)

Staff Initiator:
Lisa Gorsuch

PacifiCorp - UE 210 - Bonus Adjustment S-9

Bonuses and Incentive Pay
DR #279e

	Actual				Forcast in Filing	
	2005	2006	2007	2008	2009	2010
Exempt	45,484,524	31,720,425	28,066,767	30,507,698		
Non-Exempt	1,919,428	1,271,654	1,130,256	1,307,811		
Officer	2,447,104	881,228	678,925	861,849		
Total	49,851,056	33,873,307	29,875,948	32,677,359	33,422,632	34,429,153

Average and Year-End Full-Time and Part-Time Headcount (2005-2008) Budgeted FTE (2009-2010)
Excludes mine employees
DR #279b

Year		**Union**	**Non-exempt**	**Exempt**	**Officers**	**Total**
2005	Average	3,305	446	2,227	13	5,991
	12/31/2005	3,372	460	2,217	11	6,060
2006	Average	3,388	424	2,110	9	5,931
	12/31/2006	3,377	397	1,914	9	5,697
2007	Average	3,362	381	1,898	7	5,648
	12/31/2007	3,347	389	1,925	8	5,669
2008	Average	3,366	405	1,964	8	5,742
	12/31/2008	3,369	412	2,013	8	5,802
2009	Budgeted					
	12/31/2009	3466.5	388.5	2,211.50	8	6,074.50
2010	Budgeted	3470.5	388.5	2,210.50	8	6,077.50
	12/31/2010					

	2005	2006	2007	2008	2009	2010
Exempt	91.24%	93.64%	93.94%	93.36%		
Non-Exempt	3.85%	3.75%	3.78%	4.00%		
Officer	4.91%	2.60%	2.27%	2.64%		
Total	100.00%	100.00%	100.00%	100.00%		

Oregon Allocated Bonuses		**$ 9,700,000**
	Officer	
2005	NA	
2006	2.60%	
2007	2.27%	
2008	2.64%	
Total	7.51%	
Average (2006 - 2008)	2.50%	
Officer Bonuses Disallowed		$ 242,871
Oregon Allocated Bonuses (less Officer Bonuses)		**$ 9,457,129**
50% Bonuses Disallowed	$ 4,728,565	
Oregon Bonuses Allowed 50% Allowed	$ 4,728,565	
50% Bonuses Disallowed	$ 4,728,565	
Officer Bonuses Disallowed	$ 242,871	
Total Adjustment	$ 4,971,435	

Staff Proposed Adjustment (000s)

Total Adjustment	($4,971)
Bonus Adjustment: O&M	($3,552)
Bonus Adjustment: Rate Base	($1,419)

ISSUE S-15: BONUS ADJUSTMENT

Summary of Issue

Two questions are presented regarding performance bonuses. For non-officer performance bonuses, NW Natural proposes a 50/50 sharing with shareholders and ratepayers, while Staff proposes a 75 percent disallowance. For merit-based bonuses, NW Natural proposes that 100 percent of the non-officers' bonuses be included in utility expense. Staff recommends a 50/50 sharing for both non-officers' and union employees' merit-based bonuses.

Positions of the Parties

NW Natural first contends that performance bonuses paid to supervisors and managers be shared 50/50 between customers and shareholders. The company believes that the 50/50 sharing of non-officer bonuses is reasonable because the bonuses are designed to make the company's total compensation package for these employees competitive with comparable jobs in the regional labor market.

Second, NW Natural proposes that 100 percent of the non-officers merit-based bonuses, Key Goals program, be included in rates. NW Natural explains that there are five Key Goals, three of which directly relate to customer interests. These include rate stability, customer satisfaction, and productivity. The other two goals, profitability and market share, benefit customers over time. Because the Key Goal program benefits customers, NW Natural maintains that the merit-based bonuses—including those paid to union employees—should be included in utility expense.

Staff proposes a 75 percent disallowance of performance-based bonuses, and a 50/50 sharing of merit-based bonuses. Staff explains that the Commission has traditionally disallowed 75 percent of performance-based bonuses, because they are generally focused on the company's increased earnings and, therefore, bring more benefit to shareholders. It adds that the Commission has generally allowed equal sharing of merit-based bonuses, because they equally benefit shareholders and ratepayers. It contends that the company's Key Goals program should be similarly treated, noting that shareholders clearly benefit through increase earnings if the profitability and market share goals are achieved. Finally, it contends that the Commission should apply these recommendations to all bonuses, including those paid to union employees. It notes that the Commission has always treated union bonuses in the same manner, because the same rationale applies.

Commission Resolution

After our review, we find Staff's bonus adjustments to be reasonable and adopt them. Staff's recommendations are consistent with past ratemaking treatment of bonuses in prior electric and natural gas rate cases. NW Natural has not persuaded us that a change in policy is warranted.

ISSUE S-18: CIS

Summary of Issue

The history of NW Natural's Customer Information System (CIS) development is complex. The analysis of the argument is also difficult, caused primarily by the different approaches used by the parties to evaluate the CIS. There are, however, just two primary questions presented for Commission resolution.

First, the Commission must decide the standard of review for the recovery of NW Natural's CIS investment. Second, the Commission must determine whether the CIS stipulation allows for a reasonable level of CIS recovery and, therefore, should be approved. To fully understand this issue, a review of the history of NW Natural's CIS development is necessary.

Facts

In 1991, NW Natural began an effort to develop a new CIS to serve its residential and commercial accounts. The company's old CIS, the Legacy system, had been constructed in stages beginning in the 1960s. Over the years, NW Natural made numerous modifications and upgrades to the system, but encountered increasing reliability problems and functional limitations. Moreover, the Legacy system was not Year-2000 compliant.

After a bidding process, NW Natural hired IBM to perform a study on CIS implementation strategies. Based on the results of the study, NW Natural awarded a fixed-price contract to IBM for the development of a customized CIS. The overall projected budget, as approved by NW Natural's Board of Directors, was $24 million, which included a $12 million fixed fee to be paid to IBM for its services. NW Natural hoped to have the new system in place and operational by January 1996.

The CIS project was intended to proceed in five phases, whereby each succeeding phase added increased functionality. The first phase, called Application Function Group 1 (AFG1), was intended to allow inquiry of customer data that had been converted from the Legacy system. During AFG1 development, however, the project team experienced significant difficulties in two primary areas. The first problem pertained to the use of an object-oriented database. The project team initially chose to use a relational database[11] in combination with an object-oriented graphical user

[11] A relational database essential stores data in a matrix format of columns and rows, while an object-oriented

	UE 179	2006	2007
Total Oregon Severance Payments	$242,800	$11,943,459	$1,107,901

** $3.38 million of the 2007 amount was recorded by PacifiCorp as a regulatory asset.*

As the above table indicates, severance costs were high in 2006 after the acquisition of PacifiCorp in 2006. However, in 2008, the Company no longer incurred any severance costs.

The Commission approved an accounting order for PacifiCorp's transition costs in Order No. 07-211 (UM 1263), dated May 29, 2007, which occurred from the MEHC acquisition. The accounting order included employee severance costs from anticipated workforce reductions. According to the order, the expected savings would be related to salary savings from employees whose positions were eliminated or who voluntarily terminated as a result of the acquisition. As mentioned above, PacifiCorp experienced significant workforce costs reductions in 2007 compared to 2006 levels.

According to the Order, amortization of all transition costs were to begin on April 1, 2007 and be amortized on a straight line basis over a period of five years. Additionally, parties agreed that PacifiCorp will provide a cost/benefit study at the time it seeks ratemaking treatment of these costs, and that in the next rate case, the recovery of transition costs will be a separately identified issue. As such, PacifiCorp will need to demonstrate that the benefits exceeded the costs.

As discussed under the wage/salary section, it appears that costs of the severance packages were greater than the wage/salary savings during the 2006-2007 time period. With that said, other savings may have been realized by the Company. In this case, PacifiCorp would need to demonstrate actual and tangible savings. It should be noted that cost savings over a period of several years is the most appropriate comparator to severance costs.

Compensation Incentive Policy and Plans

According to the Company's Annual Incentive Plan (AIP):

> PacifiCorp's Annual Incentive Plan provides performance awards based on the following: achieving the goals of PacifiCorp, Pacific Power, Rocky Mountain Power and PacifiCorp Energy; individual performance; company management of risk and safety; and success in addressing new issues and opportunities that may arise during the course of the year. Awards will be made based upon measurable achievement of results. Achievement will be measured by senior management. This approach supports the philosophy of

incentive compensation as pay at risk that is earned based on the company, business unit and individual performance.

Employee goals are established by the employees under the direction of managers at the beginning of each year and are measured by managers through the year-end performance review process. Such goals are set at an individual level and may relate to job-specific financial or performance targets are other measurable targets.

The following table highlights PacifiCorp payments concerning its Annual Incentive Program. Because payment amounts are not determined until December of each year the table does not include 2008 amounts. Two annual incentive payments were made in CY 2006: one in June to close out ScottishPower's fiscal year ending March 2006; the second in December for the MEHC 2006 fiscal year, which was the 9-month period April to December 2006.

Table 7 – PacifiCorp's Incentive Payments

	6-2-06 AIP Payment	12-10-06 AIP Payment	12-10-07 AIP Payment
NEOs	$1,405,159	$615,975	$585,000
Other Executives	$93,280	$235,000	$280,000
Other Management	$19,339,756	$10,027,973	$12,810,722
Non-bargaining	$17,445,435	$11,185,326	$13,117,358
Bargaining	$239,409	$170,431	$6,629
Total	**$38,523,039**	**$22,234,704**	**$26,799,709***
Oregon Incentive Payments			
	UE 179	**2006**	**2007**
Total	$9,613,069	$10,234,115	$9,072,467

**During 2007, PacifiCorp paid $1.22 million in bonuses other than AIP.*

PacifiCorp submitted preliminary 2008 incentive amounts that have not been audited confidentially. As such, Staff does not include these amounts in the report.

The Commission has not allowed regulated utilities to charge customers for bonuses paid to company executives that are based on the financial performance of the utility or its parent company. That is, the Commission's policy is to disallow 100 percent of officers' bonuses because they are based on increased earnings. (Order 99-033 at 62; Order 97-171 at 74-76.) In the case of PacifiCorp, rate case staff may want to consider both the NEOs and Other Executives as officers and recommend disallowance of the two costs.

In addition, non-officer bonuses should be associated directly with regulated operations and provide measurable benefits to ratepayers; that is, tied to goals promoting cost savings and productivity rather than simply growth. The Commission's policy is to disallow 75 percent of performance-based bonuses (because they are generally focused on increased earnings and, therefore, bring more benefit to shareholders) and disallow 50 percent of merit-based bonuses (because they equally benefit shareholders and ratepayers). Union bonuses are treated in the same manner as non-union bonuses. (Order 99-697 at 44-45; Order 99-033 at 62.)

When the 2006 AIP is annualized, the resulting amount is $29,646,272. As a result, 2007 AIPs were approximately $2,846,563 (9.6 percent) lower than the annualized 2006 amount. This reduction may be a result of the Company's workforce reductions and the non-officer incentive reductions may be considered a benefit when the Company requests to recover transition costs outlined in docket UM 1263. However, any savings that resulted from officer incentive payments should not be considered a benefit that exceeded costs because officer incentives are normally disallowed at 100 percent. As such, any reduction would be a shareholders savings and not a customer savings.

According to the Company, PacifiCorp does not have a long term incentive plan. Although MEHC does have a long term incentive plan, PacifiCorp states that it will not seek recovery of these costs from Oregon customers.

Budget

Operational Budget

Staff reviewed PacifiCorp's fiscal years 2007 and 2008 operational budgets. Both budgets were identified as confidential, and as such, Staff did not include specific numerical information. However, the 2008 budget shows a projected increase in operating income as compared to the 2007 budget. Later in the report, Staff will examine actual performance as it compares to budget for calendar year 2007.

Capital Budget

According to PacifiCorp, PacifiCorp's biennial Integrated Resource Planning (IRP) results are incorporated into the annual 10-year capital budget planning process along with related transmission, distribution, and infrastructure needed to maintain system reliability. The resulting levels of investment are evaluated to determine the effect on customer costs and company returns, including operations and maintenance (O&M) costs, rate increases, earnings, and cash flows to determine if the investments are appropriate.

UE-210/PacifiCorp
June 30, 2009
OPUC Data Request 324

OPUC Data Request 324

Please provide a detailed explanation of PP&L's criteria (goals) used to determine the distribution of bonuses to all employees (including officers). In this explanation, please include how many times a year bonuses are given and when they are given. Please provide the percentage of the bonuses that are performance-based (focused on increased earnings, bringing more benefit to shareholders) and the percentage of bonuses that are merit-based (equally benefitting shareholders and ratepayers)? Please provide FERC account details for employee bonuses. Finally, please explain how PP&L's current bonus program under MEHC differs from its previous program.

Response to OPUC Data Request 324

All non-union employees are eligible for participation in PacifiCorp's Annual Incentive Plan program ("AIP"). A portion of each employee's total compensation is tied to the incentive plan. Please refer to Attachment OPUC 324-1 for the 2009 AIP document. The award distribution is based on:

1. The employee's performance against their individual goals, which are established at the beginning of the plan year and set to encourage efficiency and effectiveness within the business;
2. The employee's performance in the areas of safety and compliance; and
3. The performance of the overall business against its established goals.

AIP performance awards are made once a year with the distribution occurring on December 17 and are based on the calendar/fiscal year performance. As described in PPL/800, Wilson/4, the Company's pay philosophy is to encourage high performance from its employees by putting some of the market-based total compensation "at risk." The employees' individual goals that are used to determine whether and how much of the "at risk" portion to award each year are focused on improving the operational efficiency of the business and delivering benefit to the Company's customers. The goals are not tied to results that directly bring benefit to shareholders. As such, no proportion of the incentive plan awards may be classified as performance-based or merit-based based on the definitions provided above.

For information on incentive opportunities specific to the Company's Named Executive Officers, please refer to the Executive Compensation section of PacifiCorp's 2008 SEC Form 10-K for the year ended December 31, 2008. The Executive Compensation section begins on page 118. The SEC Form 10-K is available at the following link:
http://www.pacificorp.com/File/File88145.pdf

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As identified in the 10-K, the LTIP program is determined based on earnings targets at the MEHC level and is treated as a below-the-line expense. No costs related to this program are included in this proceeding.

Please refer to Attachment OPUC 324-2 for the FERC account details for employee bonuses.

The annual incentive plan currently in place has been consistent in design and application since March 2006. Prior to March 2006 (under the ownership of Scottish Power), the incentive plan was segmented into three performance measurement areas: total company, business unit, and individual. The allocation of these performance areas was as follows (with the maximum award being two times the annual target):

- 10% of maximum award – based on performance as measured by the PacifiCorp balanced scorecard
- 30% of maximum award – based on performance as measured by the Business unit balanced scorecard in which the employee was employed
- 60% of maximum award – based on performance as measured by the overall individual performance rating/assessment

Under the Scottish Power approach, the Company used "balanced scorecards" to evaluate each employee's incentive. The PacifiCorp and business unit balanced scorecards consisted of four categories: financial, stakeholder/customer, employee and process.

The key differences between the current and prior incentive plans are that in the current plan, the Company calculates the total incentive amount eligible for distribution each year based on the competitive target incentive level, and the Company seeks to recover only that level of incentive that maintains its market (average) competitive level. In contrast, under the prior plan, the Company frequently made total awards above a competitive target level. In addition, the prior plan included a combination of financial performance and operational efficiency metrics.

Please refer to non-confidential Attachments OPUC 324 -1 and 324 -2 on the enclosed CD.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

2009 Annual Incentive Plan

Introduction and Objectives

PacifiCorp's Annual Incentive Plan provides performance awards based on the following: achieving the goals of PacifiCorp, Pacific Power, Rocky Mountain Power and PacifiCorp Energy; individual performance; company management of risk and safety; and success in addressing new issues and opportunities that may arise during the course of the year. Awards will be made based upon measurable achievement of results. Achievement will be measured by senior management. This approach supports the philosophy of incentive compensation as pay at risk that is earned based on the company, business unit and individual performance.

Plan Details

Eligibility

- All regular, full- and part-time nonrepresented employees of PacifiCorp are eligible to participate in the Annual Incentive Plan (AIP).
- A participant must be employed in an incentive-eligible position on or before Sept. 1, 2009 to be eligible to receive an award. Any employee hired after Sept. 1, 2009 is not eligible.
- Employees who are employed for less than the plan term due to retirement, disability, or death will be considered eligible and may receive a prorated award at the discretion of management, reflective of achievement of goals, company and individual performance, and other factors.
    - Employees who are on a qualified leave during the plan term will be eligible for participation in the plan.
- Employees who are employed for less than the plan term due to a termination for cause, voluntary resignation, are affiliated with the Hiring Hall, are contractors or are bargaining unit employees are ineligible for participation.

Please note:

- *Award recipients who are "inactive" but eligible (retirees/displaced/deceased) can expect to receive their awards approximately two weeks after active employees.*
- *Bargaining unit employees who transfer into incentive-eligible positions must have been employed in their incentive-eligible positions on or before Sept. 1, 2009 in order to be eligible for participation.*
- *Those transferring from bargaining unit to incentive-eligible positions will have their awards calculated based on eligible earnings while in incentive-eligible positions only. (Eligible earnings accumulated while occupying bargaining unit jobs will NOT be considered as eligible earnings for the purposes of incentive payment.)*

Plan Term

The plan term is Jan. 1, 2009 through Dec. 31, 2009.

Plan Components

Incentive awards are structured to achieve a target incentive payout. Target award percentages are based on job classification derived from competitive market data.

All participants will have an award opportunity based upon company, business unit and individual performance as measured and assessed by senior management.

Company and business unit performance will be evaluated based on meeting objectives established in operating and business plans and the organization's success in responding to unexpected events.

Any adjustments for individual performance will be reviewed by each president (business unit leader) and a final decision made in collaboration with senior management prior to final award determination.

Eligible Earnings

For full plan year participants, awards under the plan will be based on the greater of eligible earnings or annualized salary, as described below. For partial year participation and part-time employees, awards will be based on eligible earnings only.

- Regular pay
- Overtime pay
- 401(k) pre-tax employee deferrals
- Pre-tax insurance plan contributions and reimbursement account contributions

Please note:

- Bonuses of any kind are not considered part of eligible earnings for the purposes of AIP calculation.

Payment of Awards

Payment is targeted for Dec. 17, 2009, pending approvals.

UE-210/PacifiCorp
OPUC Data Request 324

FERC Acct	FERC Acct Description	Locatn	Locatn Description	Total
4265000	OTHER DEDUCTIONS	1	GENERAL OFFICE AND ALL OTHER	4,828.40
5012000	FUEL HANDLING COSTS - COAL	1	GENERAL OFFICE AND ALL OTHER	56,638.76
5020000	STEAM EXPENSES	385	BLUNDELL GEOTHERMAL STEAM FIELD	5,273.40
5060000	MISCELLANEOUS STEAM POWER EXPENSES	250	CARBON PLANT COMMON FACILITIES AND SUBST	245,256.16
5060000	MISCELLANEOUS STEAM POWER EXPENSES	260	GADSBY PLANT COMMON FACILITIES AND SUBST	131,515.54
5060000	MISCELLANEOUS STEAM POWER EXPENSES	270	NAUGHTON PLANT COMMON FACILITIES AND SUB	430,371.55
5060000	MISCELLANEOUS STEAM POWER EXPENSES	280	HUNTINGTON PLANT COMMON FACILITIES AND S	451,999.09
5060000	MISCELLANEOUS STEAM POWER EXPENSES	300	HUNTER PLANT COMMON FACILITIES	636,297.28
5060000	MISCELLANEOUS STEAM POWER EXPENSES	380	BLUNDELL GEOTHERMAL PLANT COMMON & SUBST	45,757.68
5060000	MISCELLANEOUS STEAM POWER EXPENSES	514000	DAVE JOHNSTON STEAM PLANT	505,043.80
5060000	MISCELLANEOUS STEAM POWER EXPENSES	517000	JIM BRIDGER PLANT	827,984.05
5060000	MISCELLANEOUS STEAM POWER EXPENSES	519000	WYODAK PLANT	234,291.11
5063000	MISC STEAM POWER EXPENSES - JVA CUTBACK CREDIT	300	HUNTER PLANT COMMON FACILITIES	(97,670.20)
5063000	MISC STEAM POWER EXPENSES - JVA CUTBACK CREDIT	517000	JIM BRIDGER PLANT	(303,259.66)
5063000	MISC STEAM POWER EXPENSES - JVA CUTBACK CREDIT	519000	WYODAK PLANT	(37,437.66)
5350000	OPERATION SUPERVISION AND ENGINEERING	1	GENERAL OFFICE AND ALL OTHER	994,187.10
5460000	OPERATION SUPERVISION AND ENGINEERING	310	CURRANT CREEK TOTAL PLANT COMMON	(17,605.90)
5480000	GENERATION EXPENSES	210	West Valley Common Facilities	11,153.25
5480000	GENERATION EXPENSES	225	LAKE SIDE COMMON & DYNAMO SUBSTATION	35,036.15
5480000	GENERATION EXPENSES	264	GADSBY GAS TURBINE PEAKERS	3,469.00
5480000	GENERATION EXPENSES	310	CURRANT CREEK TOTAL PLANT COMMON	49,783.67
5490000	MISC OTHER POWER GENERATION EXPENSES	1	GENERAL OFFICE AND ALL OTHER	32,394.60
5490000	MISC OTHER POWER GENERATION EXPENSES	225	LAKE SIDE COMMON & DYNAMO SUBSTATION	37,147.50
5490000	MISC OTHER POWER GENERATION EXPENSES	310	CURRANT CREEK TOTAL PLANT COMMON	36,395.50
5530000	MAINT OF GENERATING AND ELECTRIC PLANT	225	LAKE SIDE COMMON & DYNAMO SUBSTATION	39,989.39
5530000	MAINT OF GENERATING AND ELECTRIC PLANT	310	CURRANT CREEK TOTAL PLANT COMMON	32,673.50
5570000	OTHER EXPENSES	1	GENERAL OFFICE AND ALL OTHER	5,629,883.10
5570000	OTHER EXPENSES	906	INTERWEST MINING COMPANY	475,313.16
5600000	OPERATION SUPERVISION AND ENGINEERING	1	GENERAL OFFICE AND ALL OTHER	784,065.41
5800000	OPERATION SUPERVISION AND ENGINEERING	90	PACIFIC POWER (WA, OR, CA)	4,761,239.81
5880000	MISC DISTRIBUTION EXPENSES	1	GENERAL OFFICE AND ALL OTHER	88,978.30
5900000	MAINTENANCE SUPERVISION AND ENGINEERING	95	ROCKY MOUNTAIN POWER (ID, WY, UT)	3,027,207.15
5980000	MAINTENANCE OF MISC DISTRIBUTION PLANT	95	ROCKY MOUNTAIN POWER (ID, WY, UT)	31,890.00
9032000	CUSTOMER ACCOUNTING - BILLING	1	GENERAL OFFICE AND ALL OTHER	31,932.75
9036000	CUSTOMER ACCOUNTING - COMMON	1	GENERAL OFFICE AND ALL OTHER	2,353,537.08
9036000	CUSTOMER ACCOUNTING - COMMON	90	PACIFIC POWER (WA, OR, CA)	396,083.57
9084000	DSM DIRECT EXPENSES	1	GENERAL OFFICE AND ALL OTHER	75,928.00
9200000	ADMINISTRATIVE AND GENERAL SALARIES	1	GENERAL OFFICE AND ALL OTHER	5,747,140.48
9200000	ADMINISTRATIVE AND GENERAL SALARIES	90	PACIFIC POWER (WA, OR, CA)	1,338,180.97
9200000	ADMINISTRATIVE AND GENERAL SALARIES	95	ROCKY MOUNTAIN POWER (ID, WY, UT)	802,945.36
9350000	MAINTENANCE OF GENERAL PLANT	1	GENERAL OFFICE AND ALL OTHER	185,736.45
	Total GL Account 500410 Incentive(Performance Share)			**30,121,574.65**

CASE: UE 210
WITNESS: Ming Peng

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony

July 24, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Ming Peng. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/601.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I recommend adjustments to test year 2010 depreciation expenses and reserves, and amortization expense and reserves from those submitted in PacifiCorp's (Company, PPL) UE 210 filing. I review the depreciation and amortization filing submitted by Company witness R. Bryce Dalley in Exhibit PPL/700.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. My Witness Qualification Statement is in Exhibit Staff/601.

Q. WHAT IS A SUMMARY OVERVIEW OF YOUR TESTIMONY?

A. In general, PacifiCorp has been appropriately using the depreciation rates adopted by the Commission docket UM 1329, effective January 1, 2008. My adjustments in this case relate to corresponding changes in depreciation expense resulting from I recommended changes to plant.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

ADJUSTMENT IDENTIFICATION

Q. PLEASE DESCRIBE THE PROCESS YOU USED IN PREPARING THIS TESTIMONY.

A. I requested the Company provide me with data used to calculate the composite depreciation and amortization rates used in the Company's filing. I prepared data requests and reviewed the Company's responses. I also attended two Company-sponsored workshops to acquire a better understanding of materials submitted with the filing.

Q. WHAT FACTORS AFFECT CALCULATIONS OF DEPRECIATION EXPENSE AND RESERVES, AND AMORTIZATION EXPENSE AND RESERVES?

A. Relevant factors include depreciation and amortization rates; accumulated depreciation and amortization balances; the dates and amounts of capital additions, retirements, and transfers; and Oregon allocation factors.

Q. WHAT TEST PERIOD DID THE COMPANY USE TO DETERMINE THE REVENUE REQUIREMENT IN THIS CASE?

A. The forecast test period used by the Company in this proceeding is the twelve month period ending December 31, 2010.

Q. PLEASE SUMMARIZE THE PROCESS USED TO ADJUST DEPRECIATION EXPENSE AND RESERVES, AND AMORTIZATION EXPENSE AND RESERVES.

A. The depreciation and amortization expenses for the 2010 test period are calculated by applying functional composite depreciation and amortization rates to projected plant balances. My analysis included the steps described below.

1. I reviewed the composite depreciation and amortization rates for each FERC account. Rates generated and used in my analysis complied with those approved by the Commission in Docket UM 1329, effective January 1, 2008.
2. I reviewed accumulated depreciation and amortization balances, including the balances as of the end of relevant periods beginning December 31, 2006 (the ending date from Docket UM 1329) through June 30, 2008 (July 1, 2008 is the beginning date of the base period in this proceeding).
3. I requested and reviewed Company-provided data associated with the dates and amounts of capital additions, retirements, and transfers.
4. I calculated the expenses of and reserves for both depreciation and amortization based on Staff adjustments to capital additions and to the Company's Oregon allocation factors. These adjustments were provided by Staff sponsoring testimony in Exhibits Staff/100 (Garcia) and Staff/1000 (Clark), respectively. As I used the Oregon allocation factors from the Company's filing for purposes of this testimony, my adjustments may be revised should Staff propose a change to one or more of the Company's allocation factors. Calculations supporting my adjustments are found in my workpapers.

IMPACTS OF ADJUSTMENTS

Q. WHAT ADJUSTMENTS TO EXPENSES OF AND RESERVES FOR DEPRECIATION AND AMORTIZATION DO YOU RECOMMEND?

A. My recommended adjustments are set forth below in Table 1. A description of the adjustment follows Table 1.

Table 1

Adjustments related to Depreciation and Amortization

based on projected Plant as of 12/31/2010, Dollars in (000's)

Description/ Account No.	PPL/702 Tab 6 Line#	PPL Oregon	Staff Proposed	Staff Adjustment[1]
Expense				
Depreciation Expense	22	26,581	23,804	($2,777)
Amortization Expense	23	494	-123	($617)
Reserve				
Depreciation Reserve	51	-183,568	-181,057	$2,511
Amortization Reserve	52	-21,759	-21,288	$471

<u>Depreciation Expense Adjustment -$2.8 million</u>

I reduced the Company's depreciation expense by $2.8million based on Staff Plant Addition adjustments. My adjustment represents the Oregon allocated portion. Calculations are based on monthly balances.

[1] Staff's adjustments to Amortization Expense were based the Company's response to Staff Data Request #173-2, which listed 70 items of intangible plant, not on the 28 items in the Company's "Lead Sheet 6.1.1."

<u>Amortization Expense Adjustment -$617,000</u>

I reduced the Company's amortization expense by $617,000 based on Staff adjustments to Intangible Plant. My adjustment represents the Oregon allocated portion. Calculations are based on monthly balances.

<u>Depreciation Reserve Adjustment $2.5 million</u>

I reduced the Company's depreciation reserve, or accumulated depreciation, based on Staff Plant adjustments. Calculations are based on monthly balances.

<u>Amortization Reserve Adjustment $471,000</u>

I reduced the Company's amortization reserve, or accumulated amortization, based on Staff adjustments to Intangible Plant. Calculations are based on monthly balances.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 210
WITNESS: Ming Peng

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualification Statement

July 24, 2009

WITNESS QUALIFICATION STATEMENT

NAME: MING PENG (Ms.)

EMPLOYER: PUBLIC UTILITY COMMISSION OF OREGON

TITLE: SENIOR ECONOMIST

ADDRESS: 550 CAPITOL ST. N.E. SUITE 215, SALEM, OR 97301-2551

EDUCATION & TRAINING:

Certified Rate of Return Analyst (CRRA)
Society of Utility and Regulatory Financial Analysts 2002

NARUC Annual Regulatory Studies Program
Michigan State University, East Lansing 1999

Master of Science, Agricultural Economics
University of Idaho, Moscow 1990

Bachelor of Science, Statistics
People's University of China, Beijing 1983

EXPERIENCE:

SENIOR ECONOMIST 1999 - present
Public Utility Commission of Oregon. Working in areas including Industrial Property Retirement and Depreciation Rates, Cost of Capital Analysis, Fixed Income Security Analysis, Financial Risk Analysis on Merger & Acquisition, Electricity Load and Price Forecasting, Weather Normalization, Public Utility Auditing, Market Competition Survey Analysis for Telecom Industry, Sampling Design for Revenue Issues.

INDUSTRY ANALYST 1996-1998
Weyerhaeuser Company. Forecasted product demand, price trends, and price elasticity. Established the process (specific methods and techniques) for market, investment, and economic analyses. Selected the analytical techniques most appropriate for any given problem.

ECONOMIST (Natural Resources) 1992-1996
Idaho Department of Water Resources. Conducted economic research. Developed analysis in evaluating policy and planning alternatives; determined the financial and economic feasibility of proposed natural resource projects using economic modeling and investment analysis.

CASE: UE 210
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 700

Opening Testimony

July 24, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Paul Rossow. I am a Utility Analyst employed by the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/701, Rossow/1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain, on an Oregon basis, Staff's recommended Uncollectible Expense adjustment to PacifiCorp's rate case filing in Docket UE 210.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes, I prepared Exhibit Staff/701, consisting of 1 page.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT.

A. My adjustment focuses on PacifiCorp's Uncollectible Expense. I propose an adjustment that reduces PacifiCorp's Uncollectible Expense by $963,000 (Issue S-2). In addition, I am recommending that the uncollectible rate used in determining revenue sensitive costs be reduced from 0.531 percent, as proposed by PacifiCorp, to 0.430 percent (Issue S-2.1).

Q. DID PACIFICORP MAKE ANY UNCOLLECTIBLE ACCOUNTS EXPENSE ADJUSTMENT TO FERC ACCOUNT 904?

A. No. The requested price change in this proceeding reflects a percentage of uncollectible expense in the gross-up factor as shown on page 1.3 of Exhibit PPL/702 at the rate of 0.531 percent. This percentage is calculated using the percentage of uncollectible expenses in the test period divided by the test year General Business Revenues.

Q. DOES STAFF AGREE WITH PACIFICORP THAT ITS OREGON SITUS EXPENSE AMOUNT OF $5,042,637 IS A REASONABLE AMOUNT TO USE FOR ITS ONGOING LEVEL OF UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. No.

Q. PLEASE EXPLAIN.

A. The $5,042,637 is the amount PacifiCorp expensed on its books during the test year. However, that is only a factor in determining an appropriate rate case expense. In addition to the $5,042,637 PacifiCorp projects as book expense for December 2010 Pro Forma results, reinstatements and cash recoveries should be removed to have a proper level of uncollectible accounts expense for rate making purposes. PacifiCorp should not be allowed double recovery; once from customer reimbursements and once from rate payers in the uncollectible rate.

Q. WHAT WOULD BE A REASONABLE LEVEL OF UNCOLLECTIBLE ACCOUNTS EXPENSE FOR PACIFICORP?

A. The most reasonable method of determining uncollectible expense for rate making purposes is to first take the gross charge-offs less the reinstatements and cash recoveries, which will give the net write-offs for the year. The net write-offs should then be divided by the general business revenues, which will provide the proper rate that should be used for calculating uncollectible accounts expense for both the ongoing level and pro forma.

I used PacifiCorp's actual net write-off amounts of $3,568,696 in 2006, $3,641,030 in 2007, and $4,649,323 in 2008 to come up with a three year average level of net write-offs of $3,953,016. The three year average of net write-offs is then escalated by using PacifiCorp's Global Insight Customer Accounts factor to arrive at an escalated 2010 uncollectible expense amount of $4,079,513. Once the escalated 2010 uncollectible expense was calculated, I then divided the $4,079,513 by PacifiCorp's test year-adjusted general business revenues in the amount of $949,341,303, resulting in an uncollectible rate of 0.430 percent.

Q. DOES PACIFICORP APPLY ENERGY ASSISTANCE FUNDS TO OREGON CUSTOMERS' ACCOUNTS?

A. Yes. For the years 2006, 2007, and 2008 PacifiCorp has applied energy assistance funds to customers' accounts in the amounts of $7,855,454, $8,694,727, and $10,541,485, respectively. These funds can be applied towards customers' electric bill payment assistance and will continue to aid in the reduction of uncollectible expense.

Q. WHAT IS STAFF'S UNCOLLECTIBLE ADJUSTMENT RECOMMENDATION?

A. I recommend that the Commission apply the procedure of using a three year average of net write-offs when calculating an uncollectible rate. This would provide PacifiCorp with an uncollectible rate of 0.430 percent, which provides an uncollectible expense of $4,079,513. The adjustment provides a reasonable estimate for the expected level of this expense after properly removing reinstatements and cash recoveries. This overall adjustment is to decrease uncollectible accounts expense to better reflect the actual cost to PacifiCorp.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 210
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualification Statement

July 24, 2009

WITNESS QUALIFICATION STATEMENT

NAME: Paul Rossow

EMPLOYER: Public Utility Commission of Oregon

TITLE: Utility Analyst, Electric and Natural Gas Division, Rates and Tariffs

ADDRESS: 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.

EDUCATION: Professional Accounting and Computer Application Diplomas
Trend College of Business 1987

EXPERIENCE: I have been employed with the Public Utility Commission of Oregon as a Utility Analyst since October of 2002. Current responsibilities include research issues relating to energy utilities. I have actively participated in regulatory proceedings in Oregon, including UE 147, UE 167, UE 170, UE 179, UE 180, UE 197, UG 152, UG 153, and UG 181.

I have attended the Utility Rate School sponsored by the Committee on Water of the National Association of Regulatory Utility Commissioners in May of 2005 and the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2005.

CASE: UE 210
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Opening Testimony

July 24, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Steve Storm. I am employed by the Public Utility Commission of Oregon as the Program Manager of the Economic and Policy Analysis Section. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is included as Exhibit Staff/801.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I develop the cost of common equity[1] estimates for the rate-regulated property of PacifiCorp dba Pacific Power and Light ("PacifiCorp"). I provide a point estimate recommendation, as well as a range of estimates, of PacifiCorp's cost of common equity for consideration by the Public Utility Commission of Oregon ("Commission") in establishing PacifiCorp's authorized return on equity (ROE) within PacifiCorp's current general rate case in Docket No. UE 210. Additionally, I provide a recommended capital structure associated with the recommended ROE and the recommended rate of return (ROR) based on recommendations in my testimony and the recommended costs of

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[1] Common equity, or common stock, is an "ownership" investment of, say, a corporation, where stockholders "have a general preemptive right to anything of value that the company may wish to distribute." Holders of common stock are the owners of the corporation, unlike holders of preferred stock or debt securities of the corporation. *See* Brealey and Myers; *Principals of Corporate Finance*, 3rd Edition, 1988, page 305.

preferred stock and of long-term debt as presented in Staff/900, Ordonez. The costs of long-term debt, of preferred equity, of common equity, and PacifiCorp's capital structure are collectively identified as issue S-0.

My testimony constitutes Staff's response, in part, to that provided by PacifiCorp witnesses Hadaway (PPL/200) and Williams (PPL/300).

Q. DID YOU PREPARE ANY EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/802, consisting of 30 pages; Exhibit Staff/803, consisting of seven pages; Exhibit Staff/804, consisting of 21 pages; Exhibit Staff/805, consisting of 26 pages; Exhibit Staff/806, consisting of one page; Exhibit Staff/807, consisting of one page; Exhibit Staff/808, consisting of 40 pages; Exhibit Staff/809, consisting of 28 pages; Exhibit Staff/810, consisting of 39 pages; and Exhibit Staff/811, consisting of two pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The organization of my testimony is as follows:

A. A summary of recommendations;
B. A brief discussion of return and risk associated with investments in common equity;
C. A discussion of my cost of equity estimation, including the Discounted Cash Flow (DCF) model, comparable companies used, inputs and sensitivities, and capital structure implications;

D. A discussion of PacifiCorp's DCF models and associated PacifiCorp-recommended rates of return on common equity;[2] and

E. A discussion of other methods used by PacifiCorp to estimate cost of equity.

SUMMARY OF RECOMMENDATIONS

Q. WHAT ARE YOUR SUMMARY RECOMMENDATIONS?

A. Table 1 (following) illustrates returns on long-term debt, preferred stock, and common stock; as well as capital structure; as currently authorized, as proposed in PacifiCorp's direct testimony, and as recommended in this testimony.

I recommend a return on equity of 9.4% with a capital structure as proposed by PacifiCorp;[3] i.e., 51.2% common stock, 0.3% preferred stock, and 48.5% long-term debt. This results in a recommended rate of return, when combined with Staff's recommendations[4] for the cost of preferred stock and the cost of long-term debt, of 7.68%. The recommended ROE of 9.4% for PacifiCorp meets the *Hope* and *Bluefield* standards, as well as those established by Oregon Revised Statue (ORS) 756.040. This level of authorized return on equity for

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[2] Reference to "common equity" and "equity" within this portion of testimony are meant to be synonymous. Where reference to some other form of equity is intended, the form will be specified. Similarly, the terms "common stock" and "stock" within this portion of testimony are used synonymously and are equivalent to "common equity" and "equity."

[3] *See* PPL/300 Williams/3.

[4] *See* Staff/900 Ordonez for Staff's recommended costs of preferred equity and of long-term debt.

PacifiCorp supports establishing “fair and reasonable rates” that are both “commensurate with the return on investments in other enterprises having corresponding risks” and “sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital.”[5]

Table 1

PacifiCorp Capital Structure and Component Returns

		Percent of Total	Authorized Return	Weighted Average
Currently Authorized (UE-179)				
Component				
Long Term Debt		49.00%	6.320%	3.097%
Preferred Stock		1.00%	6.300%	0.063%
Common Stock		50.00%	10.000%	5.000%
	Total	100.00%		8.16%
PacifiCorp Proposed (UE-210)				
Component				
Long Term Debt		48.50%	5.979%	2.900%
Preferred Stock		0.30%	5.414%	0.016%
Common Stock		51.20%	11.000%	5.632%
	Total	100.00%		8.55%
Staff Recommended (UE-210)				
Component				
Long Term Debt		48.50%	5.882%	2.853%
Preferred Stock		0.30%	5.048%	0.015%
Common Stock		51.20%	9.400%	4.813%
	Total	100.00%		7.68%

[5] *See* ORS 756.040(1)(a) and (b).

RISKS AND RETURNS OF COMMON EQUITY INVESTMENTS

Q. WHAT DOES "RISK" MEAN WITH RESPECT TO COMMON EQUITY INVESTMENTS?

A. The literature of finance[6] typically defines risk as the variability in outcomes, where outcomes are divergent investor returns[7] over some holding period when compared with an expected return for the asset held. Risk has two aspects: unique risk and market risk. Unique risk is that applicable to only to the common stock of a specific company;[8] i.e., "unique" to that company. The terms unsystematic risk, idiosyncratic risk, and diversifiable risk are other terms by which the concept of unique risk is known. Unique risk potentially can be eliminated by the addition of diversifying investments[9] to an investment portfolio. As emphasized by the authors of a widely used corporate finance textbook,[10] "the risk of a well-diversified portfolio depends on the market risk of the securities included in the portfolio" (emphasis added).

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6 This discussion follows that in Brealey and Myers, *op. cit*., especially that on page 132ff.

7 Investor returns are total returns; i.e., those resulting from dividends paid as well as from realized gains or losses due to security price changes.

8 I recognize companies can and do have different classes of common stocks, typically differing in voting rights.

9 A diversifying investment in this context is one whose returns are imperfectly correlated with the portfolio as a whole.

10 Brealey and Myers, *op. cit.*, page 134.

Q. HOW IS THE MARKET RISK OF A SPECIFIC STOCK MEASURED?

A. The market risk[11] of a specific stock, in a well-diversified portfolio, is the sensitivity of the stock's return to those of the stock market as a whole. This measure of sensitivity is termed "beta" and is typically represented by the Greek letter β, or beta.[12]

Q. WHAT IS A "WELL-DIVERSIFIED PORTFOLIO?"

A. A well-diversified stock portfolio is one whose dispersion of returns, measured by standard deviation, approaches that of the stock market as a whole. The stock market as a whole, by definition, has a beta of 1.0, so a well-diversified portfolio also has a beta of 1.0 (or very nearly so). If returns of a stock portfolio are perfectly (and positively) correlated[13] with the stock market as a whole, the portfolio has a beta

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[11] Market risk is also known as systematic risk and as undiversifiable risk.

[12] The beta (β) of an asset or portfolio is a number describing the relation of its returns with that of the market as a whole. An asset with a beta of zero (0) means that its returns are not at all correlated with the market; the returns of the asset are independent from those of the market. A positive beta means that the asset's returns generally follow those of the market. A negative beta shows that the asset's returns inversely follow those of the market; the asset generally decreases in value if the market goes up and vice versa.

The formula for the beta of an asset within a portfolio is

$$\beta_a = \frac{\mathrm{Cov}(r_a, r_p)}{\mathrm{Var}(r_p)},$$

where r_a measures the rate of return of the asset, r_p measures the rate of return of the portfolio, and $\mathrm{Cov}(r_a,r_p)$ is the covariance between the rates of return. In the Capital Asset Pricing Model (CAPM) formulation, the portfolio is the market portfolio that contains all risky assets, and so the r_p terms in the formula are replaced by r_m, the rate of return of the market.

Beta is also referred to as financial elasticity or correlated relative volatility, and can be thought of as a measure of the sensitivity of the asset's returns to market returns, and the asset's non-diversifiable risk (or systematic risk or market risk).

[13] Perfectly (and positively) correlated means the correlation coefficient (a statistical measure) between portfolio returns and market returns is +1.0.

of exactly 1.0. Additionally, since the market beta is 1.0, the beta of the "average" stock is 1.0.

Q. HOW, WITHIN THE CONSTRUCT OF A WELL-DIVERSIFED PORTFOLIO, ARE RISK AND RETURN RELATED?

A. The answer to this question forms a good deal of that part of finance theory concerned with investments.[14] A basic conclusion is that investments with higher undiversifiable risks require, in well-functioning capital markets, a higher expected rate of return than do investments having lower nondiversifiable risks.

Q. WHY IS THE RELATIONSHIP BETWEEN RISK AND RETURN IMPORTANT TO CONSIDER WHEN ESTABLISHING A RATE OF RETURN REGULATED UTILITY'S AUTHORIZED RETURN ON EQUITY?

A. Understanding this relationship serves to define boundaries around a fair rate of return on common equity for utilities operating under one or more rate of return regulatory regimes. The average annual return,[15] including dividends, of Standard & Poor's S&P 500 index[16] from 1926

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[14] A working definition of investment theory might be that it is the body of knowledge used to support the decision-making process of choosing investments for various purposes. Topics included are portfolio theory, a variety of asset pricing models, and the efficient market hypothesis.

[15] Average annual returns cited in my testimony, unless otherwise specified, are of the geometric mean construction.

[16] The S&P 500 is a market capitalization-weighted index of 500 large companies and is used as a proxy for the entire U.S. stock market. *See* the S&P 500 fact sheet at http://www2.standardandpoors.com/spf/pdf/index/SP_500_Factsheet.pdf .

through 2000 was 10.7%.[17,18] This index has performed less well since 2000, as implied by the following quote from Standard & Poor's:

> "From January 1926 through March 2009 the annualized total return for the S&P 500 was 9.51% per year vs. 9.69% for December 2008. The dividend component consists of 44.00% of the return vs. 43.27% for December 2008. The annualized return consists of both capital appreciation and dividends reinvested."[19]

Assuming the S&P 500 index is an adequate representation of the U.S. stock market,[20] the average beta of stocks in the index is (positive) 1.0. Betas[21] from the *Value Line Investment Survey* (Value Line) for companies in both mine and PacifiCorp's groups of comparable companies[22] average less than 1.0, at 0.70 and 0.69,

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17 *See* in Exhibit Staff/802 a prepublication version of Roger Ibbotson's "Stock Market Returns in the Long Run: Participating in the Real Economy," page 4. The 10.7% annual average total return was calculated on a geometric basis. *See* also "Long-Run Stock Returns: Participating in the Real Economy," by R. Ibbotson and P. Chen, *Financial Analysts Journal*, January/February 2003, Vol. 59, No. 1: pages 70 – 87.

18 *See* also PPL/212 Hadaway/1, where the annual average total return of "large company stocks" over the period 1926 – 2007 on a geometric basis is 10.4%.

19 From the Standard & Poor's website at http://www2.standardandpoors.com/portal/site/sp/en/us/page.topic/indices_500dividend/2,3,2,2,0,0,0,0,0,1,1,0,0,0,0,0.html .

20 Stocks in the S&P 500 index account for approximately 75% of the U.S. equity market's total value. *See* http://www2.standardandpoors.com/spf/pdf/index/SP_500_Factsheet.pdf .

21 Per Value Line at http://www.valueline.com/sup_glossb.html , Value Line betas are based on "the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index." Notably, composition of the NYSE Composite Index is less than 64% U.S. companies; i.e., a considerable part of the index consists of non-U.S. stocks. *See* http://www.nyse.com/about/listed/nya_characteristics.shtml .

22 I use the terms "comparable companies," "peer companies," and "cohort companies" synonymously in this testimony. A discussion of my comparable companies and a

respectively. This indicates the comparable companies, whether those of Staff or of PacifiCorp, on average have less market risk than the stock market as a whole. A logical conclusion is that a forward-looking long-term fair rate of return on equity (ROE), all else being equal,[23] is less than the historical (1926 forward) annual average return, including dividends, of the S&P 500 index. This would seem to hold whether the historical rate of return on the index is the 10.7% annual average rate from 1926 through 2000 or the lower (than 10.7%) annual average rate from 1926 through the more recent past; e.g., 9.7% through December, 2008. Less risk implies a lower expected return on equity required by investors.

STAFF'S COST OF EQUITY ESTIMATION

Q. DID YOU USE VALUES FROM COMPARABLE COMPANIES TO ESTIMATE PACIFICORP'S COST OF EQUITY?

A. Yes. As PacifiCorp is indirectly and wholly owned by MidAmerican Energy Holdings Company (MEHC), PacifiCorp's common stock is not publicly traded. Therefore, market valuation of PacifiCorp is not directly observable.

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brief discussion regarding certain attributes of PacifiCorp's comparable companies are presented later in this testimony.

[23] Implications of relaxing certain *ceteris paribus* assumptions, such as that pertaining to capital structure, are discussed later in this testimony.

I selected a group of peer companies by starting with the 54 electric utilities covered by Value Line. The screening criteria were sequentially applied,[24] reducing the 54 companies to a 13 company cohort group. My criteria were:

1. No dividend decline in past five years;[25]
2. Value Line forecast of dividend growth ≥ 0%;
3. S&P Issuer credit rating of BBB or better;
4. Long-term debt between 45% and 55% of capital structure;
5. No mergers within the past five years; and
6. Revenue from regulated activities ≥ 70% of total revenues.

I also removed Hawaiian Electric Industries, Inc., which survived each of the six screens, due to the special circumstances of this company.[26] Table 2 (following) lists the 12 companies I found to be "comparable" to PacifiCorp[27] and those companies PacifiCorp found "comparable."

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[24] Data used for screening companies included both year-end 2007 and year-end 2008 data.

[25] This criterion eliminates companies that, within the past five years, have reduced or eliminated dividends. Dividend growth rates for such companies, including companies re-establishing dividend payments previously eliminated, may be uncharacteristically high, even "exceptionally high." *See*, in Docket No. UE 147, PPL/200 Hadaway/14 beginning at 16.

[26] Hawaiian Electric Industries (HEI) was removed as the company's banking subsidiary, American Savings Bank (ASB), is an unusual business for a "utility company" to own. ASB's 2008 earnings included a $35.6 million net charge related to a balance sheet restructuring per HEI's 2008 Annual Report to Shareholders.

[27] *See* also Exhibit Staff/803, which contains Value Line data and certain calculated results for both my comparable companies and those of PacifiCorp.

Table 2

Companies Comparable to PacifiCorp

	Ticker	Staff	Company
Allete Inc.	ALE		✓
Alliant Energy Corp	LNT		✓
Consolidated Edison, Inc.	ED	✓	✓
DPL Inc.	DPL		✓
DTE Energy Co.	DTE	✓	✓
Duke Energy Corp.	DUK		✓
Edison International	EIX		✓
Empire District Electric Co.	EDE	✓	
Entergy Corp.	ETR	✓	✓
FirstEnergy Corp.	FE	✓	
FPL Group Inc.	FPL	✓	✓
Idacorp, Inc.	IDA	✓	✓
NSTAR	NST		✓
PG&E Corp.	PCG		✓
Portland General	POR		✓
Progress Energy Inc.	PGN	✓	✓
Sempra Energy	SRE		✓
Southern Co.	SO	✓	✓
Vectren Corporation	VVC	✓	✓
Wisconsin Energy Corporation	WEC	✓	✓
Xcel Energy, Inc	XEL	✓	✓
Total		12	19

Q. WHAT TYPES OF MODELS DID YOU USE TO DEVELOP STAFF'S RECOMMENDED RETURN ON EQUITY FOR PACIFICORP?

A. I relied on a multistage DCF model[28] for estimating the expected return on common equity required by PacifiCorp's investors. Staff used this type of DCF model in previous dockets, including those involving PacifiCorp.[29] The model is a three-stage DCF model[30] requiring the following metrics as inputs: a "current" market price per share; a "current" book value per share; estimates for the years 2009 through 2014 for book value per share, earnings per share (EPS), and dividends per share (DPS); and a forecast long-term sustainable growth rate.[31] The three stages of the model refer to the period of years 2009 through 2014 (1st Stage), which uses Value Line forecasts for the non-current values listed above; a long-term growth period of 2015 through 2048 (2nd Stage); and a terminal valuation in 2048 (3rd Stage).[32] My multistage DCF model has a 40 year valuation timeframe.

The "current" market price used for the analysis was the average of the closing prices for each comparable company (see Table 2) on three consecutive Tuesdays in June of this year: the 16th, 23rd, and

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28 *See* Exhibit Staff/811 for the mathematical expression of my multistage DCF model.

29 *See* the Commission's discussion of multistage versus single stage DCF models in Order No. 01-777, page 27.

30 My DCF model might also be described as a two-stage model with a terminal valuation.

31 My multistage DCF model directly applies the long-term growth estimate to earnings per share over the 2015 through 2048 period. Earnings per share for the 2009 through 2014 period are from Value Line.

32 The terminal valuation produces an explicit estimation of the stock price, which is then "sold," producing the terminal "cash flow."

30th. The “current” book value is the average of the comparable companies’ 2008 figures as provided by Value Line.[33]

Q. HOW ARE STOCK PRICES AND VALUE LINE-PROVIDED ACTUAL AND ESTIMATED FINANCIAL METRICS FOR THE COMPARABLE COMPANIES USED IN STAFF’S MULTISTAGE DCF MODEL?

A. All model inputs[34] from the comparable companies are averaged, producing a “composite” company from the group of companies; i.e., for a given input variable, the DCF model uses the mean of values for the comparable companies.

Q. DID YOUR ANALYSIS PRODUCE A RANGE OF RETURNS ON EQUITY?

A. Yes. Depending on the combinations of input variable values chosen, the model produces a range of ROE estimates, including my recommended range of ROE for Commission consideration of 8.7% to 10.1%. Notably, using values from PacifiCorp’s group of comparable companies in my multistage DCF model,[35] with the same method and timing for calculating stock prices and the same timing of Value Line

[33] Using an average of the 2008 and projected 2009 Value Line Book Values, to more closely correspond with the June, 2009 prices, changed the estimated ROE by 1 basis point, or 0.01%

[34] These inputs included Value Line data on the year-end 2008 book value and 2009 through 2014 forecasts of book value, earnings per share, and dividends per share.

[35] Of the 19 companies in PacifiCorp’s group of comparable companies, 10 appear in my group of comparable companies; i.e., 10 of my 12 comparable companies are in PacifiCorp’s group as well. *See* Table 2.

inputs,[36] produced the same 9.4% ROE I recommend. Somewhat similarly, modifying the design of my model from the 40 year valuation timeframe to the 150 year valuation timeframe two-stage design used in PacifiCorp's multistage DCF model also produced the same 9.4% ROE result.

Q. WHAT DO YOU CONCLUDE FROM THESE RESULTS?

A. I conclude that differences in valuation horizon[37] and selection of comparable companies[38] are not responsible for any material differences in results between PacifiCorp's multistage DCF model and mine.

Q. GIVEN THIS RESULT OF COMPARABLE COMPANY ANALYSIS, WHAT ARE, FOR THIS CASE, THE IMPORTANT CONSIDERATIONS IN YOUR THREE-STAGE DCF MODEL?

A. A very important consideration is how to choose or develop the long-term sustainable growth rate[39] used in my DCF model for growing both

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[36] That is to say, the same three (for East, Central, and West) issues of the Value Line publication.

[37] That is, the difference between my 40 year valuation horizon with terminal valuation in year 2048 multistage DCF model and my 150 year valuation horizon through year 2158 multistage DCF model.

[38] My conclusion as to the group of comparable companies is qualified in that it is specifically based on these two groups of comparable companies. Other groups of comparable companies could be selected that would not necessarily support this same conclusion. Additionally, my conclusion is qualified by being limited to the data used in parameter values for both PacifiCorp's models and mine.

[39] This conclusion has been reached before. *See*, in Docket No. UE 179, Staff/800 Morgan/4 at 16: "…the main driver of the differences in DCF results are related to the input assumptions related to growth rates…"

earnings and dividends (investor "cash flows") over the period 2015 through 2048.

Additionally, my multistage DCF model is somewhat sensitive to the stock price parameter. As an example, making no other adjustments other than reducing the stock prices for the comparable companies by 10% increased the ROE from my recommended 9.4% value to 10.0%; alternatively, increasing the stock prices by 10% reduced the ROE from 9.4% to 9.0%.

Q. HOW DID YOU ESTIMATE THE APPROPRIATE LONG-TERM SUSTAINABLE GROWTH RATE?

A. I considered alternative approaches to estimating a long-term sustainable earnings growth rate. First, historical earnings per share growth were examined for the cohort group of companies. For all but two of my comparable companies, earnings per share (EPS) data from Value Line were available for 1993 forward. The remaining two companies had Value Line earnings available from 1999 forward. I developed compound average annual growth rates in EPS from this data. The 12 comparable companies, on average, experienced an average annual growth rate in earnings per share of 2.4%, using both timeframes of 9 and 12 years.[40] The average growth rate for the 10 companies' earnings per share over the 15 year (1994 – 2008) period

[40] This rate is the average for all 12 of the comparable companies of the historical average annual growth rate regardless of the length of time over which any companies' rate was computed; i.e., two of the companies had only a nine year history.

was 2.1% and average values by company ranged from a negative 1.3% to a positive 7.5%. Even though earnings growth is necessary to sustain long-term growth in dividends,[41] I concluded 2.4% was too low for use as the long-term sustainable growth rate as it yields implausible results.[42]

Next, I assessed Value Line's estimated 2012 – 2014 average rate of earnings per share growth over the period 2006 – 2008 for the comparable companies. I do not view the 6.1% average of Value Line's forecast near-term annual average earnings per share growth rates as sustainable over the long-term,[43] as it approximates long-term forecasts of annual average nominal[44] GDP growth that I consider highly optimistic.[45] Additionally, the forecast near-term future annual average growth rates for the 10 comparable companies having

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41 While dividends paid can, for a period of time, exceed aggregate earnings for one or more preceding periods, over a sufficiently long period earnings must exceed dividends; i.e., the long-term payout ratio must be no more than 1.0. Additionally, the growth rate in earnings must be no less than the growth rate in dividends over some long, but finite term.

42 This rate of long-term growth produces an ROE estimate of 5.6%. Note that the average earnings per share growth rate over the 15 year period averaged 2.3% for the nine companies appearing in both Staff's and PacifiCorp's groups and having available 1994 – 2008 annual average growth rates.

43 I discuss the use of an annual average growth rate exceeding 6% for the long-term sustainable growth rate later in this testimony.

44 A nominal growth rate is one that includes the effect of changes in price level; a real growth rate is one not including such an effect.

45 An annual growth rate of 6.1% may, in some economic environments, be a reasonable near-term nominal GDP growth estimate; e.g., as the economy recovers from a recession. This would be most plausible over shorter periods, such as growth for one or two calendar quarters (on a seasonally adjusted annualized basis). Similarly, Value Line's 6.1% earnings growth forecast, essentially a five years forward forecast, does not seem an unreasonable rate of earnings growth for regulated electric utilities, on average, as their businesses recover from the current recession.

available 1994 – 2008 annual average growth rates averaged 6.4%, a rate that is over 300% of the 2.1% average annual earnings growth rate experienced by these same 10 companies, on average, over the 15 year 1994 – 2008 period. The historical annual average growth rate for the 14 companies in the PacifiCorp group of comparable companies having available 1994 – 2008 annual average growth rates was 3.2% over the 1994 – 2008 period, and averaged 6.1% annually for the near-term future; i.e., the near-term future average earnings per share growth rate, as forecast by Value Line for these 14 companies, is almost twice (190% of) their historical 15 year average annual earnings growth rate. Acknowledging that perhaps earnings per share growth over the last 15 years have been atypical, on average, for these companies, I believe a long-term sustainable annual average growth rate exceeding 6% to be highly unlikely.

I considered different versions of GDP forecasts for use in estimating the long-term sustainable earnings growth rate. One estimate used the average of three forecasts of nominal GDP for the five-year period 2014 through 2019. Forecasts of nominal GDP, by the Office of Management and Budget (OMB), the Congressional Budget Office (CBO), and the April, 2009 Blue Chip Consensus (*See* Table 12-2 on page 172 of the document in Exhibit Staff/804) were analyzed.[46,47]

[46] This analysis consisted of averaging the three nominal GDP forecasts for 2019 and for 2014. From these two calculations, a compound annual growth rate (CAGR) of 4.4% for the period 2015 through 2019 was calculated.

This yielded an average annual growth rate of 4.4% over the 2015 – 2019 period, which, when used as the long-term sustainable average annual growth rate, produced an estimated PacifiCorp ROE of 8.7%.

This approach has two issues. First, inflation is not directly considered, in that growth rates in forecast nominal GDP are used. Secondly, projecting a forecast of 5 to 10 years in the future (2014 to 2019)[48] forward for up to 40 years[49] into the future (through 2048) appears to be an insufficiently robust methodology in light of available alternatives.

Q. HOW DID YOU OVERCOME THESE TWO ISSUES IN ESTIMATING AN APPROPRIATE LONG-TERM SUSTAINABLE GROWTH RATE?

A. I developed a forecast of inflation using the TIPS[50] breakeven approach of estimating inflationary expectations.[51] This involved

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47 These forecasts were relatively similar; in fact, surprisingly so. OMB's CAGR is 4.4%, CBO's is 4.0%, and the Blue Chip Consensus' is 4.8%. OMB forecasts of nominal GDP are not typically considered to be "severely depressed" (see PPL/200 Hadaway/32 lines 20 through 22) and this may be particularly true in an environment of rapidly growing Federal budget deficits.

48 The source for the OMB, CBO, and Blue Chip Consensus forecasts did not provide nominal GDP forecasts beyond 2019.

49 Projection over an even longer period, such as 150 years, would seem to be even more problematic.

50 Treasury Inflation-Protected Securities (or TIPS) are the inflation-indexed notes and bonds issued by the U.S. Treasury. The principal is adjusted to the Consumer Price Index, the commonly used measure of inflation. The coupon rate is constant, but generates a different amount of interest when multiplied by the inflation-adjusted principal, thus protecting the holder against inflation. TIPS are currently offered in 5-year, 7-year, 10-year and 20-year maturities.

51 *See*, in Exhibit Staff/805, "Inflationary Expectations: How the Market Speaks," S. Kwan, *Federal Reserve Bank of San Francisco's Economic Letter*, Number 2005-25, October 3, 2005. *See* also in Exhibit Staff/805 "Empirical TIPS," R. Roll, *Financial Analysts Journal*, January/February 2004, Vol. 60, No. 1: pages 31 - 53

constructing a forward curve of dollars, priced in terms of today's dollar;[52] i.e., a forecast of future price levels. This inflation forecast provided an average annual inflation rate forecast for 2015 through 2029 of 2.3%.[53] An advantage is that such a forecast is actually "being made" by economic agents (investors) collectively having considerable amounts (trillions of dollars) at risk. The market for debt securities issued by the U.S. Treasury is almost certainly the world's largest financial market for securities of a single issuer.

The 2.3% result was extended an additional 19 years to apply to the long-term growth rate for the entire Stage 2 period (2015 – 2048, or the remaining valuation horizon) of my multistage DCF model.

Next, I developed real growth rates by analyzing historical growth rates in real GDP for a variety of periods. These periods and growth rates are presented in Table 3[54] (following).

The average annual rate of real growth I selected is 2.8%. This was the growth rate for both[55] the 1979 through 2008 period, as well as for the 1989 through 2008 period; both periods spanning multiple decades. Periods including the period 1959 through 1968 were not

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[52] This analysis used U.S. Treasury securities' interest rate averages for the months of May and June, 2009, available in the Federal Reserve's Statistical Release H.15. I rounded-up the resulting average of 2.24% to 2.3%.

[53] *See* Exhibit Staff/806 for the graph of the forecasted future price levels produced by this method, using the average interest rates for June, 2009.

[54] *See* also the chart of these growth rates in Exhibit Staff/807. Real GDP growth rates have declined over the 1949 through 2008 period.

[55] The two growth rates are equal after rounding to one decimal place.

chosen due to the significant impact on the economy of U.S. military involvement in southeast Asia. For different reasons,[56] I also excluded the period 1969 through 1978.

Table 3

U.S. Real Gross Domestic Product

Historical Period	Annual Average Real GDP Growth
1949 – 2008	3.3%
1959 – 2008	3.3%
1969 – 2008	2.9%
1979 – 2008	2.8%
1989 – 2008	2.8%
1999 – 2008	2.6%

Source: Federal Reserve

Charts 1 and 2 (following) illustrate actual and trend real GDP over the periods 1949 through 2008 and 1979 through 2008, respectively.[57] Note, in Chart 1, that actual real GDP was above trend for most of the period. One observation is that the cumulative excess of actual over trend in the early years of this period was reduced later in the period; i.e., the growth rate was higher in the earlier part of this period than in

56 This “decade” was unusual in several respects. In particular, average annual inflation, as measured by the GDP Implicit Price Deflator, was 6.3% over this period. The period had an extremely large price shock related to energy costs, which contributed to at least a portion of this period being contemporaneously described as one of “stagflation.” For a discussion involving the non-transitory effect of the 1973 oil price shock on the growth rate of the U.S. economy, see in Exhibit Staff/808 “The Great Crash, the Oil Price Shock, and the Unit Root Hypothesis,” by P. Perron, *Econometrica*, Vol. 56, No. 6 (November, 1989), page 1362.

57 While the growth rates are presented as annual percents rounded to a single decimal place, growth rates used to construct the real GDP trend lines in Charts 1 and 2 were not rounded.

the later. (*See* John Cochrane's "How Big is the Random Walk in GNP" from the October, 1988 *Journal of Political Economy* in Exhibit Staff/809 for an assessment of real GNP[58] growth having mean-reversionary versus random walk qualities.)

Also, note that the 1979 through 2008 period captures several business cycles, with peaks identified by the National Bureau of Economic Research in January, 1980; July, 1981; July, 1990; March, 2001; and December, 2007.[59]

The combination of the 2.3% projected annual inflation rate for the 2015 – 2048 period and the projected 8% annual rate of real GDP growth over the same period provides a nominal GDP annual growth rate of 5.16%.[60]

[58] While Cochrane's paper pertains to fluctuations in real per capita Gross National Product (GNP) (*see* page 898), I assume the same or very similar assessments hold for my estimated trend for real Gross Domestic Product (GDP). The key difference between the two measures revolves around "who does what where;" i.e., GDP is the total output of a region (e.g., the U.S.), and GNP is the total output of all nationals of a region (e.g., of all Americans).

[59] See "US Business Cycle Expansions and Contractions," at http://wwwdev.nber.org/cycles/cyclesmain.html .

[60] By "compounding," or multiplying, the two rates; i.e., (1 + 0.023) X (1 + 0.028) – 1 = 0.0516, or 5.16% (rounded to two decimal places).

Chart 1

Trend of 3.3% Annually

Real GDP 1949 - 2008

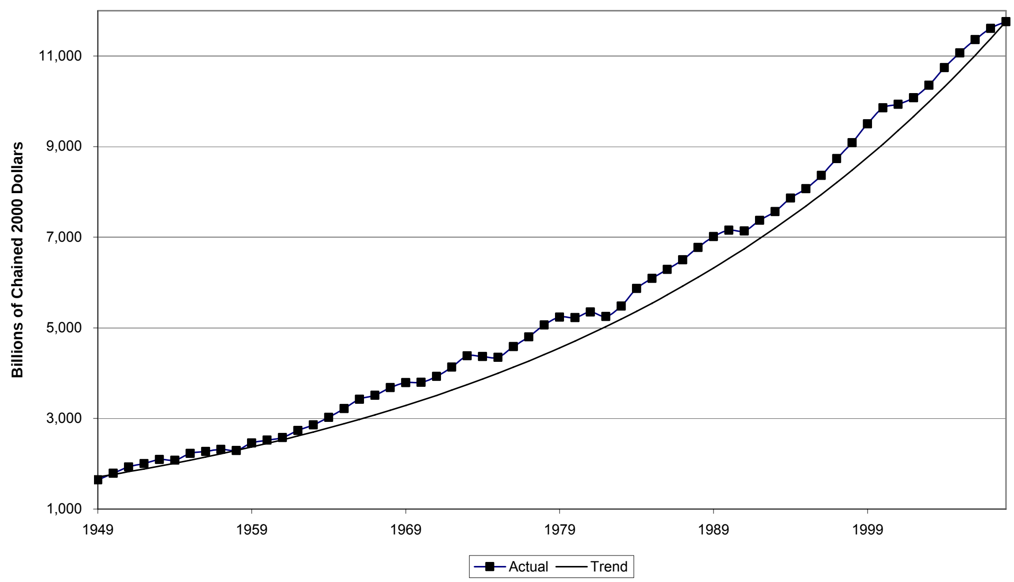
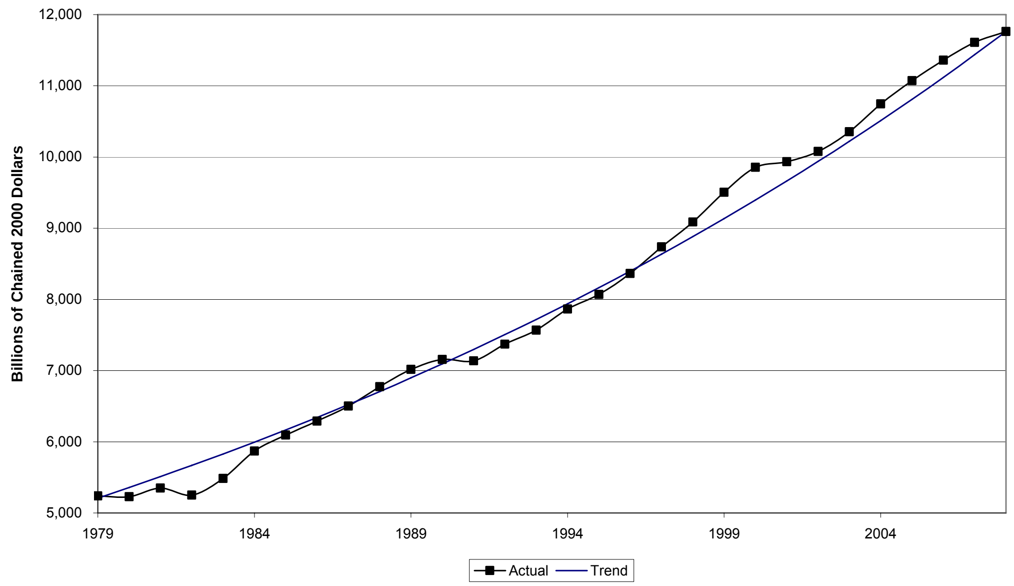


Chart 2

Trend of 2.8% Annually

Real GDP 1979 - 2008

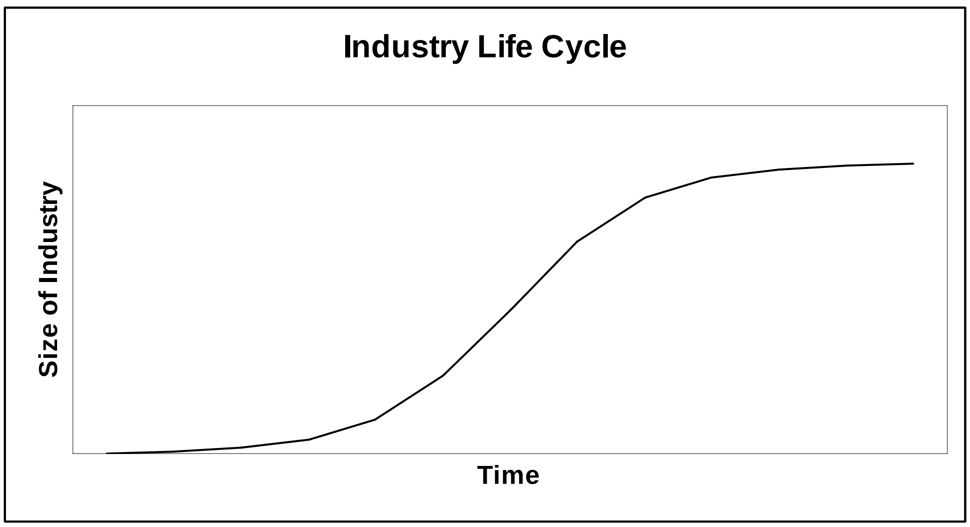


Source: Federal Reserve

Q. IS 5.16% YOUR ESTIMATED LONG-TERM SUSTAINABLE ANNUAL GROWTH RATE FOR THE COMPARABLE COMPANIES?

A. No. The electric utility industry in the U.S. is a mature industry. Chart 4 is a conceptual graph of the successive phases of growth through which a product or service, a product (or service) line, or an industry pass.[61]

Chart 3



The U.S. electric utility industry is well past the "high growth"[62] phase of the industry's lifecycle and is in the "mature" phase; i.e., the right-hand portion of the graph in Chart 3. This phase is characterized by slower growth and is well represented in the graph in Exhibit

[61] The functional (mathematical) form of the equation producing this graph is a logistic function.

[62] The "high growth" phase is the steep section of the curve in the middle of the graph. Slower rates of growth pertain to both a nascent and to a mature industry, which are respectively positioned on the left and right portions of the curve.

PPL/209 Hadaway/23,[63] where total kilowatt hour (kWh) electricity sales, a unit measure, is clearly shown to be growing at a materially slower rate than real GDP over the 1984 through 2008 period.[64] This long-term secular trend will continue. Therefore, the future long-term growth rate in nominal earnings for the industry is highly likely to be less than the future long-term growth rate in nominal GDP.[65]

The following regarding electric utility stocks is from the February 26, 2009 Standard and Poor's *Industry Surveys – Electric Utilities*: "For firms in the S&P Electric Utilities index…shares tend to trade at a discount to the market multiple *because of the slow-growth nature of utilities' regulated operations*"[66] (emphasis added). Presumably, by "slow-growth nature," Standard and Poor's is making an implicit growth comparison with an average of all industries or the economy as a whole. [67,68]

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63 The graph is on page 26 of the cited document.

64 Note in particular the "less than real GDP" rate of growth in kWh sales from, say, 1992 forward.

65 The only way this is not possible is if electricity unit prices increase not only at a higher rate than general inflation, but also at a rate sufficiently high to more than offset lower than real GDP rate of growth in electricity volumes. See also the graph "Cost of Electricity vs. Consumer Prices" in Exhibit PPL/209 Hadaway/17, where, by visual inspection, it appears the "electricity component of CPI" price measure has not risen at a rate greater than the rate of overall price inflation as measured by the Consumer Price Index (CPI) over the 1992 through 2008+ period. In other words, over the past 16 years, the price of electricity has increased at a rate similar to (not greater than) consumer prices generally.

66 *See* Exhibit PPL/209 Hadaway/28 (page 26 of the document, last paragraph).

67 Arguably, S&P is, contrary to my interpretation, comparing "slow-growth nature of utilities' regulated operations" with the growth for electric utilities overall or for electric utilities' non-regulated operations. This is, in part, the reason my screen of comparable companies includes a criterion that revenue from regulated activities account for 70% or more of the total revenue.

I reduced the projected rate of growth in nominal GDP by 5 percent to reflect earnings of the comparable companies growing at a lower long-term sustainable rate than nominal GDP. Another way of stating this is that my expectation for the long-term sustainable earnings growth rate of my comparable companies is, on average, 5 percent less than my expectation of the long-term growth rate for nominal GDP. After this reduction, my estimated long-term sustainable organic growth rate[69] for the comparable companies is 4.91%.[70,71]

I will continue reviewing information regarding both historical and projected rates of growth for the U.S. electric utility industry. Should I become aware of information which results in an updated estimation of a long-term sustainable rate of growth for use in my DCF model, such information will be incorporated within my subsequent testimony and, if appropriate, my recommended ROE.

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68 Also note that this “slow-growth nature” pertains to future growth; the market establishes stock prices on a forward-looking basis. While S&P may be describing historical growth, they must also be describing a “slow growth” future; otherwise market multiples for electric utility stocks would be higher.

69 This growth rate is applicable, within my three-stage DCF model and on a per share basis, to the averages of the comparable companies’ dividends, earnings, book value, retained earnings, and market price over the 2015 through 2048 period.

70 This estimate of long-term sustainable growth is consistent with Staff estimates in prior proceedings. Staff’s witness in Docket No. UE 179 recommended a “range of long-term growth rates of 4.0 to 5.0 percent, which is based upon a principled review of analysts’ forecasts, sustainable growth, and historic growth.” See, in UE 179, Staff/800 Morgan/22 at 22.

71 Note that this rate (4.91%) is much higher than the historic rates of earnings per share growth for the 15 year (1994 through 2008) period discussed above; i.e., rates averaging 2.1% for 10 of my comparable companies and 3.2% for 14 of PacifiCorp’s comparable companies.

I view a long-term sustainable growth rate equaling 95% of the long-term nominal GDP growth rate as almost certainly the upper threshold given the apparent maturity of the U.S. electric utility industry.

Q. WHAT IS YOUR RECOMMENDED ROE CONSISTENT WITH ASSUMING A LONG-TERM SUSTAINABLE ANNUAL AVERAGE GROWTH RATE OF 4.91%?

A. The 4.91% annual average growth rate provides an ROE of 9.62%, to which an adjustment was required in order to reflect differing levels of risk associated with different capital structures.

I reviewed the 2010 capital structures for the comparable companies projected by Value Line[72,73] and found the difference in the proportion of capital structure in common equity between that proposed by PacifiCorp and the average of my comparable companies is sufficient for a downward adjustment to my estimated ROE of 9.62%, derived above; i.e., the 9.62% result was derived using a group

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72 That forward-looking capital structures for the comparable companies are appropriate to use, as compared with, say, year-end 2008, is clear. PacifiCorp's test year is 2010 and PacifiCorp's proposed capital structure is for 2010. Additionally, the Value Line 2010 projections used by Staff have been available for some time; any impact of these projections (including the market's assessment regarding the accuracy of Value Line's projections) has been incorporated into the stock price of each of the comparable companies.

73 While my comparable companies screen has a criterion of long-term debt being between 45% and 55% of total capital structure, the screening used data from both 2007 and 2008 Form 10-Ks. Value Line projects long-term debt as a percent of the 2010 total capital structure for two companies in Staff's group to be outside the range of the screening criterion: Consolidated Edison, Inc. (40% long-term debt) and Entergy Corp. (60% long-term debt).

of companies having, on average, more risk than PacifiCorp due to the lower portion of capital structure in common equity than that proposed by PacifiCorp,[74] as documented in Table 4 (following). I based the reduction on Commission guidance, as provided in Order No. 01-777:

> "It is well understood by finance practitioners and theoreticians that the cost of equity drops as the percentage of common equity in the capital structure increases. Because the average amount of common equity in the capital structure of the comparable group of electric companies was 45.14 percent compared to 52.16 percent for PGE, it necessarily follows that PGE has a lower cost of equity. PGE's capital structure is therefore less risky, and its cost of common equity should be adjusted accordingly."[75]

The Commission reduced PGE's authorized ROE 25 basis points (bps), or 3.56 bps per percent increase in the capital structure represented by common equity of the comparable (to PGE) companies vis-à-vis that of PGE. This equates to a 0.18% reduction from the 9.62% ROE estimated for my comparable companies at their average prospective 2010 capital structure, or 9.44%; which I round to 9.4% as the recommended point estimate of PacifiCorp's cost of common equity.

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[74] This follows from Proposition II of the Miller-Modigliani (M & M) theory, where the expected rate of return on the common stock of a firm using leverage (having debt) increases in proportion to the debt-equity (D/E) ratio. If debt decreases and equity increases (the situation pertaining here, going from the capital structure of my comparable companies to PacifiCorp's less-leveraged proposed capital structure), then the D/E ratio declines, as does the expected rate of return to common stock (or equity). See Brealey and Myers, *op. cit.*, page 391.

[75] Order No. 01-777 at 36.

Table 4

Estimated 2010 Capital Structure

	Pacificorp[76] Proposed	Average of Staff's Comparable Companies[77]
Common Equity	51.2%	46.2%
Preferred Equity	0.3%	1.3%
Long-term Debt	48.5%	52.5%
Total[78]	100.0%	100.0%

Q. WHAT SENSITIVITIES AROUND THE RECOMMENDED PACIFICORP ROE OF 9.4% DID YOU DEVELOP FROM YOUR MULTISTAGE DCF MODEL?

A. Several sensitivities were developed using my multistage DCF model (*see* Table 5, following). The principal consideration centered on the long-term sustainable growth rate, as previously discussed. In addition to the 2.3% inflation rate in the base case,[79] four sensitivities were developed with a 2.5% inflation rate, which provided a 5.37% nominal

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[76] *See* Exhibit PPL/300 Williams/3 for the PacifiCorp's proposed 2010 test year capital structure (actually the capital structure as of December 31, 2009; *see* PPL/300 Williams/2).

[77] The means of the comparable companies' common equity percents and long-term debt percents were used, consistent with the methodology for developing inputs from the comparable companies used in my multistage DCF model. The sum of the two means was subtracted from 100% to derive the percent of the comparable companies' capital structure composed of preferred equity, which is not supplied by Value Line,

[78] The average capital structure for my group of comparable companies, using percents rounded to one decimal, totals 100.1%. The percent of Common Equity was rounded down (from 46.25% to 46.20%) to achieve a total of 100.0%.

[79] Base case refers to the combination of input values providing Staff's recommended ROE of 9.4%.

GDP growth rate. As can be seen in Table 5, increasing the rate of long-term inflation by 20 bps versus the base case served to increase the ROE from the recommended 9.4% to 9.7%. Increasing the long-term sustainable annual growth rate from 4.91% to 5.16%, which is the growth rate not reflecting any adjustment for industry “maturity,” increased the ROE from the recommended 9.4% to 9.8%.

Table 5

ROE Sensitivities

Inflation Rate	Real GDP Growth	Nominal GDP Growth	Industry Growth Relative to GDP	Long-Term Annual Growth Rate	Modeled ROE	Adjust for PacifiCorp-proposed Capital Structure	Adjusted ROE
		4.40%	100%	4.40%	8.88%	-0.18%	8.7%
2.3%	2.8%	5.16%	100%	5.16%	9.98%	-0.18%	9.8%
2.3%	2.8%	5.16%	95%	4.91%	9.62%	-0.18%	9.4%
2.3%	2.8%	5.16%	90%	4.65%	9.25%	-0.18%	9.1%
2.3%	2.8%	5.16%	85%	4.39	8.87%	-0.18%	8.7%
2.5%	2.8%	5.37%	100%	5.37%	10.28%	-0.18%	10.1%
2.5%	2.8%	5.37%	95%	5.10%	9.90%	-0.18%	9.7%
2.5%	2.8%	5.37%	90%	4.83%	9.51%	-0.18%	9.3%
2.5%	2.8%	5.37%	85%	4.56%	9.12%	-0.18%	8.9%

PACIFICORP'S MULTISTAGE DCF MODEL

Q. SHOULD THE COMMISSION CONSIDER PACIFICORP'S SINGLE-STAGE DCF MODEL?

A. No. I recommend the Commission not consider results from single-stage, constant growth DCF models in this proceeding due to the inherent limitations of this form of DCF model.[80]

Q. PACIFICORP USED 6.2% AS THE LONG-TERM SUSTAINABLE AVERAGE ANNUAL GROWTH RATE IN ITS TWO-STAGE DCF MODEL. WHAT ARE YOUR THOUGHTS REGARDING USE OF THIS RATE?

A. I view the use of 6.2% as the long-term sustainable average annual growth rate in Stage 2 of PacifiCorp's two-stage DCF model to be highly problematic. First, consider Dr. Hadaway's "trend" in using nominal GDP growth rates based on historical growth in nominal GDP. Dr. Hadaway used the average historic nominal GDP growth rate of multiple and overlapping periods in Docket No. UE 170, where his long-term sustainable growth rate was 6.6%.[81] In Docket No. UE 179 his long-term sustainable growth rate was also 6.6%.[82,83] Dr. Hadaway

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[80] *See* Order No. 01-777 at 27, where the Commission in a previous docket rejected consideration of results from parties' single-stage DCF models. The Commission also rejected consideration results from parties' single-stage DCF models in UE 116. *See* Order No. 01-787 at 24.

[81] *See*, in Docket No. UE 170, PPL/200 Hadaway/23 at 6 and, in the same docket, PPL/203 Hadaway/4.

[82] *See*, in Docket No. UE 179, Staff/800 Morgan/19.

[83] The long-term (nominal) GDP growth rate used by Dr. Hadaway in a DCF model in a recent Utah docket was 6.5%. *See*, in Exhibit Staff/810, the testimony of Committee

has two different long-term nominal GDP growth rates in testimony in this proceeding. The first is 6.9%,[84] which he reduces by 70 basis points to 6.2% based on the reasoning that:

> "(t)he data also show, however, that in the more recent years since 1980, lower inflation has resulted in lower overall GDP growth. For this reason, I gave more weight to the more recent years in my GDP forecast. This approach is consistent with the concept that more recent data should have a greater effect on expectations and with generally lower near- and intermediate-term growth rate forecasts that presently exist."[85]

I calculate the annual average growth rate for real GDP (without inflation) for the period 1949 through 2008 as 3.3%, for the period 1949 through 1980 as 3.7%, and for the period 1981 through 2008 as 2.9%. Obviously rates for other than inflation have declined over the 1949 – 2008 period; the annual average rate for real GDP growth declined from 3.7% for the 1949 through 1980 period (of 32 years) to 2.9% for the 1981 through 2008 period (of 28 years). I used the period 1979 through 2008 period for evaluating the growth rate in real GDP for just this reason. See Perron's 1989 conclusion, in Exhibit Staff/808, regarding the impact of the 1973 oil price shock on economic growth rates in the U.S. "Only two events (shocks)

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of Consumer Services' Witness Daniel J. Lawton in Utah's Docket No. 08-035-38, Section I, page 28 at 776.

84 *See* PPL/200 Hadaway/31 at 18.

85 PPL/200 Hadaway/31 beginning at 18.

have had a permanent effect on the various macroeconomic variables: the Great Crash of 1929 and the oil price shock of 1973." "…the 1973 oil price shock was followed by a change in the slope of the trend for most aggregates, i.e., a slowdown in growth."[86]

I calculate the annual average change in the Implicit GDP Price Deflator,[87] a broad measure of inflation, for the period 1949 through 2008 as 3.4%, for the period 1949 through 1980 as 3.8%, and for the period 1981 through 2008 as 3.0%. For the last 20 years, spanning the 1989 through 2008 period, the annual average inflation rate (by this measure) has been 2.4%. This is why I recommend a PacifiCorp ROE based in part on a forecast of 2.3% annual average inflation over the 2015 through 2048 period and why I offer a sensitivity analysis with a 2.5% annual average inflation rate over this period. A declining trend in inflation over recent history is why I strongly prefer the decomposition of any forecasted GDP growth rate into real growth and inflation, when such a rate is used in developing a long-term sustainable growth rate for utility financial metrics such as earnings and dividends.[88]

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[86] *See*, in Exhibit Staff/808, "The Great Crash, the Oil Shock, and the Unit Root Hypothesis," by P. Perron, *Econometrica*, Vol. 56, No. 6 (November, 1989), page 1362 of the article.

[87] The Implicit GDP Price Deflator is an index, with its numerical values allowing transformations of historical nominal GDP values to historical real GDP values (and vice versa). The data was obtained from the U.S. Bureau of Economic Analysis at http://www.bea.gov/national/nipaweb/DownSS2.asp .

[88] *See* also in Docket No. UE 179, Exhibit Staff/800 Morgan/20 at 16.

Developing forecasts of inflation and of real growth allows assessment of each component separately; less is concealed and more is transparent. This approach also facilitates the use of a market-based measure of inflationary expectations.

Let us also consider the 6.2% nominal GDP growth rate forecast in the context of recent history. In the last recovery from recession, from the trough in November of 2001 to the peak in December of 2007, nominal GDP growth averaged 5.4% annually. For the immediately preceding recovery, from the trough in March of 1991 to the peak in March of 2001, nominal GDP growth averaged 5.5% annually.[89] If the economy has not exceeded a 5.5% annual average rate of nominal growth on a trough-to-peak basis[90] in the past 18 years and over the full course (trough-to-peak) of two business cycles, a projection of a 6.2% annual average rate over an extended future period must be viewed with skepticism.

Q. DO YOU HAVE ANY OTHER ISSUES WITH PACIFICORP'S LONG-TERM SUSTAINABLE GROWTH RATE OF 6.2%?

A. Yes. This rate is used in PacifiCorp's two-stage DCF model to grow dividends over a 146 year timeframe; 2013 through 2158. It seems remarkable that a mature industry—or any specific company in a

[89] Source: Bureau of Economic Analysis, Table 1.1.5. I used the seasonally adjusted annualized rate (SAAR) of nominal GDP of the quarter for which the NBER designated the month of a trough or peak. The compound quarterly average growth rates obtained were exponentiated by 4 to provide annual rates.

[90] A trough-to-peak calculation of nominal GDP growth rates overstates the "true" average over some adjacent period.

mature industry—in our own time might be viewed as likely to grow at the average rate of nominal GDP over a 146 year future period. Brigham and Houston's conjecture, as cited by Dr. Hadaway, that "(o)n this basis, one might expect the dividend of an average, or "normal," company to grow at a rate of 5 to 8 percent a year"[91] requires further examination. Without disputing here the logic that an average company might increase dividends at the same rate as nominal GDP, I do not believe the authors intended their reasoning to extend to a situation in which a company growing at the average rate of nominal GDP growth at the beginning of a 146 year period will still be growing at that rate at the end of the period, or, alternatively, at the same average rate over such a period. "Normal" when extended this many years surely does not mean the same company in the same industry.[92]

I also note that the 15 year historical average annual rate of growth in average earnings, for the 14 companies in the PacifiCorp's group of comparable companies for which data to calculate such a rate are available from Value Line, over the 1994 through 2008 period, was 3.2%. Average annual growth in nominal

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[91] As cited in Exhibit PPL/200 Hadaway/30 at 12.

[92] I omit a discussion of a prospective survivorship bias or the tendency for failed companies to be excluded from performance studies because they no longer exist. This tendency often causes the results of studies to <u>skew</u> <u>higher</u> because only companies which were successful enough to survive until the end of the period are included. *See* e.g., "Financial Modeling of the Equity Market: From CAPM to Cointegration," by Fabozzi, Focardi, and Kolm; 2006, page 426.

GDP over this period was 5.2%; i.e., average earnings for these companies grew at approximately 62% of the nominal GDP rate. Again, the U.S. electric utility industry is a mature industry.

Q. DID YOU CROSS-CHECK YOUR GROWTH RATE IN PACIFICORP'S MULTISTAGE DCF MODEL AND PACIFICORP'S GROWTH RATE IN STAFF'S MULTISTAGE DCF MODEL?

A. Yes. Using my 4.91% growth rate in PacifiCorp's model[93] provided an ROE of 9.9% and using PacifiCorp's 6.2% growth rate in my model provided an ROE of 11.3%.[94] I should note that other changes have occurred since PacifiCorp's filing that make the former comparison less than fully symmetrical; e.g., as of this writing, dividend and earnings estimates have tended down and share prices have tended up.[95] Each of these tendencies serves to overstate the result produced by using my growth rate in PacifiCorp's model. The 11.3% ROE result when using 6.2% as a sustainable long-term growth rate, on the other hand, is directly comparable to my results, using the same values for the other input parameters as those providing my recommended ROE of 9.4%.

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[93] "As-is," with no other parameter changes. I used the electronic spreadsheet file "Hadaway Exhibit PPL-205 (DCF)."

[94] The modeled ROE was 11.44%, which I reduced by 0.18% for the differences in risk associated with different capital structures to 11.26%, which rounds to 11.3%.

[95] *See* Exhibit PPL/200 Hadaway/36 at 4: "(w)hile the DCF results, based on lower stock prices and higher resulting yields, have increased…" The converse is also true.

RISK PREMIUM MODELS FOR ESTIMATING ROE

Q. WHAT RISK PREMIUM MODELS DOES PACIFICORP USE TO ESTIMATE PACIFICORP'S ROE?

A. Dr. Hadaway develops three risk premium models,[96] all providing similar estimates of PacifiCorp's ROE. All three models use some cost of long-term debt as a base to which a risk premium for common equity of electric utilities is added. Two of the models use a 6.4% cost of long-term debt for single-A utility bonds, based on the three month average for the months of December, 2008 through February, 2009.[97] The third model uses a 6.91% cost of long-term debt[98] based on a projected yield of single-A utility bonds, which is based on a 321 basis point credit spread[99] over a projected 30-year Treasury bond rate of 3.7%.[100]

From these costs of long-term debt, Dr. Hadaway estimates Pacificorp's ROE at 10.73% (a 4.33% premium over the 6.4% debt cost); at 10.9% (a 4.5% premium over the 6.4% debt cost); and at 11.03% (a 4.12% premium over the 6.91% debt cost).

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96 The three models use what has been referred to as the "Risk Positioning Method." *See, e.g.*, Order No. 01-777 at 32.

97 *See* PPL/200 Hadaway/21.

98 *See* PPL/200 Hadaway/36.

99 *See* PPL/203 Hadaway/2. The 321 bps is based on single-A utility spreads over 30-year Treasury yields over the December, 2008 through February, 2009 period.

100 *See* PPL/203 Hadaway/3. I presume the projected 30-year Treasury rate used is the four quarter average of projected 2009 yields, which is 3.73%.

Q. WHAT THOUGHTS DO YOU HAVE ON THIS APPROACH AND THE RESULTING ESTIMATED RETURNS ON EQUITY?

A. Two of these models use historical authorized electric utility rates of return on equity[101] as a basis[102] for estimating PacifiCorp's ROE. The Commission has provided clear guidance on such methods, such as that in Order No. 01-777:

> "Capital market conditions, not regulatory decisions, determine a utility's cost of equity. While we agree that regulatory agencies generally make every effort to capture those market conditions, a review of past decisions cannot replace an independent analysis of current market conditions and how they affect the particular utility. Moreover, ROE determinations are made not just in the traditional rate cases, but also in a range of other proceedings, such as industry restructuring plans, merger approval cases, or performance-based regulatory plans. Thus, the ROE awards may have been based, in part, on other unknown parameters relevant in that particular docket."[103]

Additionally, this approach has multiple defects, at least some of which have been previously identified:

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[101] *See* Exhibit PPL/200 Hadaway/33 at 21 through Hadaway/34 line 2. *See* also Table 5 at Exhibit PPL/200 Hadaway/36, and Exhibits PPL/206 and PPL/207.

[102] Authorized ROEs (AROEs) are regressed against a measure of utility interest rates over the 1980 through 2008 period. Thus, the use of an estimated "interest rate coefficient," for historic AROEs for estimating a interest-rate-contingent risk premium and the subsequent use of this risk premium to estimate PacifiCorp's ROE is clearly using the outcomes of past ROE decisions to estimate PacifiCorp's recommended ROE. *See* also Exhibit PPL/206 and 207.

[103] Order No. 01-777 at 34. *See* also Order No. 01-787 at 32, where the Commission adheres to "our prior determination that, while other ROE determinations may provide confirmation of a decision, they should not be used as an independent method on which to base an award." *See* also Order No. 99-697 at 23 (and at 19, paragraph 3).

"First, the ROE is only one component involved in establishing an overall revenue requirement. Requesting the Commission to base its ROE decision on ROEs of other jurisdictions is equivalent to taking one cost element in isolation out of another states' rates and putting it into Oregon rates. In addition, cost of equity is just one of many rate-making issues and return on equity is not independent of all of these issues. For example, the use of power costs adjustments, deferred accounting, and the use of future test periods could result in lower costs of equity required by investors when compared to states that have different practices.

Second, Dr. Hadaway's reasoning is circular. As an author of a text focusing on the utility industry has stated: "It would be hopelessly circular to set a fair return based on the past actions of other regulators, much like observing a series of duplicate images in multiple mirrors."[104] For example, if all regulators adopted this practice then no Commission would be free to update ROE and their decisions would always be based upon outdated information.

Third, it is notable that this model includes data spanning a period where interest rates were the highest in history. If the model were applied using current and forecast data, it would likely indicate a lagging effect and demonstrate that the average ROE is lower than indicated in Dr. Hadaway's regression analysis."[105]

[104] This citation appears in the original testimony: "Morin, Roger, Regulatory Finance - Utilities' Cost of Capital, Public Utility Reports, 1994, p. 395."

[105] *See*, in Docket UE 179, Exhibit Staff/800 Morgan/23 – 24. A citation removed from the original, (i.e., "…hopelessly circular…") refers to Morin, Roger, "Regulatory Finance – Utilities' Cost of Capital," in Public Utility Reports, 1994, page 395.

Dr. Hadaway's estimated ROEs using results of historical authorized ROEs (i.e., 11.03% and 10.9%) should be disregarded.

Q. ONE OF DR. HADAWAY'S RISK PREMIUM MODELS DID NOT USE HISTORICAL AUTHORIZED RATES OF RETURN ON EQUITY. WHAT ARE YOUR THOUGHTS ON THIS MODEL SPECIFICALLY?

A. This model, from which an estimated ROE of 10.9% was derived, used historical U.S. stock market returns and coincident returns from long-term bonds, using data from Morningstar (formerly Ibbotson).[106] This issue of the Morningstar data had a long-term average annual return on "large company stocks" over the 1926 through 2007 period of 10.4%. From this, Dr. Hadaway subtracted the average annual return on "long-term corporate bonds" of 5.9% to get an equity risk premium of 4.5%.[107,108] He then added 4.5% to the 6.4% estimated cost of long-term debt to obtain the (4.5% + 6.4% =) 10.9% estimated ROE. Note, in Exhibit PPL/212 Hadaway/1, the following: the historical average return of long-term government bonds was 5.5%, of intermediate-term government bonds 5.3%, and of U.S Treasury Bills 3.7%—all over the same, long-term, 1926 through 2007 timeframe. Some implications are that, on the basis of the information presented, the historical equity risk

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[106] *See* Exhibit PPL/200 Hadaway/35.

[107] *See* Exhibit PPL/212 Hadaway/1. *See* also PPL/200 Hadaway/35 - 36.

[108] Clearly it is an average of geometric construction that is relevant here. Returns on equity are not authorized in Oregon on a rolling, one-year-forward, test year basis; these are presumably the circumstances in which use of an average of arithmetic mean construction is most defensible.

premium of “large company stocks” when compared with “long-term government bonds” was (10.7% - 5.5% =) 5.2%, with “intermediate government bonds” was (10.7% - 5.3% =) 5.0%, and with U.S. Treasury Bills was (10.7 – 3.7 =) 7.0%. Averages of the May and June, 2009 monthly averages for these securities were, respectively, 4.38% (5.5%), 3.29% (5.3%), and 0.18% (3.7%) (parenthetical values are the long-term average values from the Morningstar data).[109] These imply, with the equity premia calculated above, estimated returns on equity of (5.2% + 4.4% =) 9.6% using long-term government bonds, (5.0% + 5.0% =) 10.0% using intermediate government bonds, and (7.0% + 0.2% =) 7.2% using U.S. Treasury bills. The average of the two ROE estimates based on equity risk premia over the two longer-term maturities is 9.8%.[110]

Dr. Hadaway presents no supporting rationale, analysis, or quantitative evidence that indicate using single-A utility bond yields,[111] as a basis to which a risk premium is added to derive an estimated electric utility ROE, is a superior approach or result to any of the above methods and results.[112]

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[109] Source: Federal Reserve Statistical Release H.15. Average yields are for, respectively, the 3-month Treasury bill (secondary market), the 10-year Treasury note, and the 30-year Treasury bond.

[110] Note this result is unadjusted for electric utilities (e.g., comparable companies) having less risk than the “average stock.” Nor is any consideration provided for divergent capital structures.

[111] *See* Exhibit PPL/203 Hadaway/2.

[112] I do acknowledge that yields on the short end of the yield curve (T-bills) are currently impacted by atypical governmental policy actions.

Q. DO YOU HAVE ANY ADDITIONAL THOUGHTS ON THE USE OF THIS MODEL?

A. Yes. Intrinsic and fundamental to the model (large company ROE estimated at 10.7%; equity premium over long-term corporate bonds of 4.5%) is the assumption that the market risk of the common stocks of electric utility companies equal that of the stock market as a whole ("large company stocks"); i.e., a beta of 1.0. As I discussed in the "Risk and Return" section, electric utility stocks have materially less market risk on average than the market as a whole.[113] And market risk is the only risk that matters.

Q. ANY ADDITIONAL THOUGHTS ON RISK PREMIUM MODELS?

A. Exhibit Staff/802, Roger Ibbotson's "Stock Market Returns in the Long Run: Participating in the Real Economy" contains several items of interest pertaining to risk premium modeling, equity returns, and risk:

1. Ibbotson estimated the forward-looking long-term equity risk premium by a process that included decomposition of historical equity returns into multiple supply factors, including inflation and per capita GDP. This is supportive of the methodology I used in developing a long-term average annual growth rate for use in Staff's DCF model. See page 1.

2. He estimated the long-term equity risk premium (relative to the long-term government bond yield) to be 4% (on a geometric basis). See page 1.

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[113] Recall the beta of my group of comparable companies averaged 0.70 and the beta of PacifiCorp's comparable companies averaged 0.69.

3. The “bulk of the 1926 through 2000 historical equity return is attributable to dividend payments and nominal earnings growth.” This is supportive of DCF modeling generally, but specifically of methodologies using forecasted nominal earnings. See page 1.

4. Fama and French estimated long-term equity risk premia of 2.55% (based on dividend growth) and 4.32% (based on earnings growth), both on a geometric basis. See page 2.

5. Welch’s survey of 226 academic financial economists regarding equity risk premium expectations found an average long horizon forecast of almost 4%.[114] See page 3.

Q. WHAT ARE YOUR SUMMARY THOUGHTS REGARDING THE ESTIMATION OF A RETURN ON COMMON EQUITY FOR PACIFICORP THAT RESULTS IN “FAIR AND REASONABLE RATES?”

A. I recommend the Commission authorize an ROE for PacifiCorp of 9.4%. This recommendation is based on results obtained using a multistage DCF model that explicitly models both future real and nominal growth in earnings in a method calibrated with a market-based forecast of average inflation explicitly extending forward 20 years through 2029. Earnings are forecast to grow at a rate, consistent with my belief that the U.S. electric utility industry is a mature industry, lower than that for nominal GDP.

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[114] *Ibid.* page 3.

I explicitly adjust for the effect of capital structure on returns expected by common equity investors and provide multiple sensitivities on key input parameters. I identify stocks of companies in the U.S. electric utility industry as clearly being less risky than the stock market as a whole, with the conventional metric of risk (beta) for my group of comparable companies averaging 70% of that of the market.

PacifiCorp provides a DCF model previously rejected for consideration by the Commission[115] and two risk premium models having intrinsic construction[116] previously (and repeatedly) rejected for consideration by the Commission. These models, and the estimated ROEs resulting, should also be rejected by the Commission for use in this proceeding.

PacifiCorp's remaining risk premium model is insufficiently supported in testimony and, due to an assumption that is erroneous in the extreme,[117] overstates the estimated ROE for PacifiCorp. I recommend the Commission reject this model's results.

PacifiCorp's remaining approach for estimating PacifiCorp's cost of common equity is a two-stage DCF model. The cost of equity estimated using this model ranges from 11.0% to 11.1%.[118] A key

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115 This is the single-stage, or Gordon growth, DCF model.

116 These models' construction includes the use of an estimated coefficient relating historical authorized returns with a measure of interest rates.

117 This being the assumption that electric utility stocks have market risks equal with those of large company stocks generally.

118 *See* Table 5 in Exhibit PPL/200 Hadaway/36

assumption providing these results is the use of an estimated sustainable average long-term growth rate of 6.2%. Growth at this level is both unlikely and unsustainable for the U.S. electric utility industry over the 150 year valuation timeframe in PacifiCorp's two-stage DCF model. I recommend the Commission reject any estimated ROE for PacifiCorp predicated on an estimated long-term sustainable average growth rate exceeding 6%.

Using my estimated sustainable average long-term growth rate of 4.91% in <u>PacifiCorp's</u> two-stage DCF model[119]—with no other changes or adjustments for a different capital structure[120]—provided an ROE estimate of 9.9%. Use of updated prices and Value Line forecasts[121] of earnings and dividends for PacifiCorp's comparable companies would, at this time, undoubtedly <u>reduce</u> the ROE estimate from 9.9%. I recommend the Commission authorize a return on equity of 9.4% for PacifiCorp with the capital structure as proposed by PacifiCorp in its filing.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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[119] I used the electronic spreadsheet file "Hadaway Exhibit PPL-205 (DCF)."

[120] Recall PacifiCorp proposes a capital structure with 51.2% common equity. PacifiCorp's comparable companies average 48.5% common equity and my group of comparable companies average 46.2% common equity.

[121] That is, updated to be contemporaneous with those used for my comparable companies.

CASE: UE 210
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualification Statement

July 24, 2009

WITNESS QUALIFICATION STATEMENT

NAME	Steven T. Storm
EMPLOYER	Public Utility Commission of Oregon
TITLE	Program Manager, Economic Research and Financial Analysis Division
ADDRESS	550 Capitol Street NE Suite 215 Salem, Oregon 97301-2148
EDUCATION	M.B.A. University of Oregon; Eugene, Oregon A.B. (Economics); Harvard; Cambridge, Massachusetts
EXPERIENCE	I have been employed by the Public Utility Commission of Oregon since October 2007. I am currently the Program Manager of the Economic and Policy Analysis Section. My responsibilities include leading a team of analysts engaged in economic and financial research and providing technical support on a wide range of policy issues involving electric, gas, and telecommunications utilities. I have testified before the Commission on policy and technical issues in UE 197 and UE 200. Prior regulatory experience includes 4 years in which my responsibilities included developing responses to data requests regarding the financial analysis of new products and services at US WEST Communications.
OTHER EXPERIENCE	I was a self-employed financial planner for 8 years following an 18 year career in management positions engaged in pricing and cost analysis; financial analysis, planning and management; and strategic planning in the publishing and telecommunications industries. I managed the pricing (rate spread and rate design) and cost accounting functions in the Directory department of Pacific Northwest Bell and its successor company, US WEST Direct for 5 years. I was responsible for departmental budgeting and management reporting functions for 3 years at US West Direct and was responsible for corporate financial planning, analysis, and management reporting for 1 year at Electric Lightwave. I have 7 years experience in capital budgeting, financial analysis, and strategic planning functions at US West Communications.

CASE: UE 210
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 802

Exhibits in Support
Of Opening Testimony

July 24, 2009

Stock Market Returns in the Long Run:
Participating in the Real Economy

(Forthcoming Financial Analyst Journal)

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July 9, 2002

ABSTRACT

We estimate the forward-looking long-term equity risk premium by extrapolating the way it participated in the real economy. We decompose the 1926-2000 historical equity returns into supply factors including inflation, earnings, dividends, price to earnings ratio, dividend payout ratio, book value, return on equity, and GDP per capita. There are several key findings: First, the growth in corporate productivity measured by earnings is in line with the growth of overall economic productivity. Second, P/E increases account for only a small portion of the total return of equity (1.25% of the total 10.70%). The bulk of the return is attributable to dividend payments and nominal earnings growth (including inflation and real earnings growth). Third, the increase in factor share of equity relative to the overall economy can be more than fully attributed to the increase in the P/E ratio. Fourth, there is a secular decline in the dividend yield and payout ratio, rendering dividend growth alone a poor measure of corporate profitability and future growth. Contrary to several recent studies, our supply side model forecast of the equity risk premium is only slightly lower than the pure historical return estimate. The long-term equity risk premium (relative to the long-term government bond yield) is estimated to be about 6% arithmetically, and 4% geometrically. Our estimate is in line with both the historical supply measures of the public corporations (i.e., earnings) and the overall economic productivity (GDP per capita).

I. INTRODUCTION

Numerous authors are directing their efforts toward estimating expected returns on stocks incremental to bonds.[1] These equity risk premium studies can be categorized into four groups based on the approaches they have taken. The first group of studies try to derive the equity risk premiums from historical returns between stocks and bonds as was done in Ibbotson and Sinquefield (1976a,b). The second group, which includes our current paper, uses fundamental information such as earnings, dividends, or overall economic productivity to measure the expected equity risk premium. The third group adopts demand side models that derive expected equity returns through the payoff demanded by investors for bearing the risk of equity investments, as in the Ibbotson, Siegel, and Diermeier (1984) demand framework, and especially in the large body of literature following the seminal work of Mehra and Prescott (1985). The fourth group relies on opinions of investors and financial professionals through broad surveys.

Our paper uses supply side models. We first used this type of model in Diermeier, Ibbotson, and Siegel (1984). There have been numerous other authors who have also used supply side models, usually focusing on the Gordon (1962) constant dividend growth model. For example, Siegel (1999) predicts that the equity risk premium will shrink in the future due to low current dividend yields and high equity valuations. Fama and French (2002) use a longer time period (1872 to 1999) to get historical expected geometric equity risk premiums of 2.55% using dividend growth rates, and 4.32% using earnings growth rates.[2] They argue that the increase in P/E ratio has resulted in a realized equity risk premium that has been higher than ex ante expected. Campbell and Shiller (2001) argue for low returns, because they believe the current market is overvalued. Arnott and Ryan (2001) argue that the forward-looking equity risk premium is actually negative. This stems from using the low current dividend yield plus their very low forecast dividend growth.

Arnott and Bernstein (2002) argue similarly that the forward-looking equity risk premium is near zero or negative. We later argue that mixing the current low dividend yields and payout ratios with historical dividend yield growth violates Miller and Modigliani (1961) dividend theory.

The survey results generally support somewhat higher equity risk premiums. For example, Welch (2000) conducted a survey among 226 academic financial economics on equity risk premium expectations. The survey shows that the geometric long horizon equity risk premium forecast is almost 4%.[3] Graham and Harvey (2001) conducted a multi-year survey of CFOs of U.S. corporations, they find that the expected 10-year geometric average equity risk premium ranges from 3.9% to 4.7%.

In this paper, we link historical equity returns with factors commonly used to describe the aggregate equity market and overall economic productivity. Unlike some studies, our results are portrayed on a per share basis (per capita in the case of GDP). The factors include inflation, earnings per share, dividends per share, price to earnings ratio, dividend payout ratio, book value per share, return on equity, and GDP per capita.[4] We first decompose the historical equity returns into different sets of components based on six different methods. Then, we examine each of the components within the six methods. Finally, we forecast the equity risk premium through supply side models using historical data.

Our long-term forecasts are consistent with the historical supply of U.S. capital market earnings and GDP per capita growth over the period 1926-2000. In an important distinction from the forecasts of many others, our forecasts assume market efficiency and a constant equity risk premium.[5] Thus the current high P/E ratio represents the market's forecast of higher earnings growth rates. Furthermore, our forecasts are consistent with Miller and Modigliani (1961) theory so that dividend payout ratios do not affect P/E ratios and high earnings retention rates (usually associated with low yields) imply higher per share future growth. To the extent that corporate cash is not used for reinvestment, it is assumed to be used to repurchase a company's own shares or perhaps more frequently to purchase other companies' shares. Finally, our forecasts treat inflation as a pass-through, so that the entire analysis can be done in real terms.

II. THE SIX METHODS FOR DECOMPOSING HISTORICAL EQUITY RETURNS

We present six different methods of decomposing historical equity returns. The first two methods (especially method 1) are models based entirely on historical returns. The other four methods are models of the supply side. We evaluated each method and its components by applying historical data from 1926 to 2000. The historical equity return and earnings data used in this study are obtained from Wilson and Jones (2002).[6] The average compounded annual return for the stock market over the period 1926-2000 is 10.70%. The arithmetic annual average return is 12.56% and the standard deviation is 19.67%. In as much as our methods use geometric averages, we focus on components of the geometric return (10.70%). Later in the paper when we do our forecasts, we convert geometric average returns to arithmetic average returns.

Method 1 – Building Blocks Method

Ibbotson and Sinquefield (1976a,b) develop a building blocks method to explain equity returns. The three building blocks are inflation, real risk-free rate, and equity risk premium. Inflation is represented by the changes in the Consumer Price Index (CPI). The equity risk premium and the real risk-free rate for year t, ERP_t and RRf_t , are given by

$$ERP_t = \frac{1+R_t}{1+Rf_t} - 1 = \frac{R_t - Rf_t}{1+Rf_t} \tag{1}$$

$$RRf_t = \frac{1+Rf_t}{1+CPI_t} - 1 = \frac{Rf_t - CPI_t}{1+CPI_t} \tag{2}$$

$$R_t = (1+CPI_t)\times(1+RRf_t)\times(1+ERP_t) - 1 \tag{3}$$

R_t is the return of U.S. stock market represented by the S&P 500 index. Rf_t is the return of risk-free assets represented by the income return of long-term U.S. government bonds. The compounded average for equity return is 10.70% from 1926-2000. For the equity risk premium, we can interpret that investors were compensated 5.24% per year for investing in common stocks rather than long-term risk-free assets like the long-term US government bonds.[7] This also shows that roughly half of the total historical equity return has come from the equity risk premium, and the other half is from inflation and long-term real risk-free rate. The average U.S. equity returns from 1926 and 2000 can be reconstructed as follows:

$$\begin{aligned} \overline{R} &= (1+\overline{CPI})\times(1+\overline{RRf})\times(1+\overline{ERP}) - 1 \\ 10.70\% &= (1+3.08\%)\times(1+2.05\%)\times(1+5.24\%) - 1 \end{aligned} \tag{4}$$

Method 2 – Capital Gain and Income Method

The equity return can be broken into capital gain (cg) and income return (Inc) based on the form in which the return is distributed. Income return of common stock is distributed to investors through dividends, while capital gain is distributed through price appreciation. Real capital gain

(Rcg) can be computed by subtracting inflation from capital gain. The equity return in period t can then be decomposed as follows:

$$R_t = [(1+CPI_t)\times(1+Rcg_t)-1]+Inc_t+Rinv_t \tag{5}$$

The average income return is calculated to be 4.28%, the average capital gain is 6.19%, and the average real capital gain is 3.02%. $Rinv$, the re-investment return, averages 0.20% from 1926 to 2000. The average U.S. equity return from 1926 to 2000 can be computed according to

$$\begin{aligned}\overline{R} &= \left[(1+\overline{CPI})\times(1+\overline{Rcg})-1\right]+\overline{Inc}+\overline{Rinv}\\ 10.70\% &= [(1+3.08\%)\times(1+3.02\%)-1]+4.28\%+0.20\%\end{aligned} \tag{6}$$

Figure 1 shows the decomposition of the building blocks method and the capital gain and income method from 1926 to 2000.

Method 3 – Earnings Model

The real capital gain portion of the return in the capital gain and income method can be broken into growth in real earnings per share (g_{REPS}) and growth in the price to earnings ratio ($g_{P/E}$),

$$Rcg_t = \frac{P_t}{P_{t-1}}-1 = \frac{P_t/E_t}{P_{t-1}/E_{t-1}}\times\frac{E_t}{E_{t-1}}-1 = (1+g_{P/E,t})\times(1+g_{REPS,t})-1 \tag{7}$$

Therefore, the equity's total return can be broken into four components: inflation; the growth in real earnings per share; the growth in the price to earnings ratio; and income return.

$$R_t = [(1+CPI_t)\times(1+g_{REPS,t})\times(1+g_{P/E,t})-1]+Inc_t+Rinv_t \tag{8}$$

The real earnings of US equity increased 1.75% annually from 1926. The P/E ratio was 10.22 at the beginning of 1926. It grew to 25.96 at the end of 2000. The highest P/E (136.50) was recorded during the depression in 1932 when earnings were near zero, while the lowest (7.26) was recorded in 1979. The average year-end P/E ratio is 13.76.[8] Figure 2 shows the price to earnings ratio from 1926 to 2000. The U.S. equity returns from 1926 and 2000 can be computed according to

$$\begin{aligned}\overline{R} &= \left[(1+\overline{CPI})\times(1+\overline{g_{REPS}})\times(1+\overline{g_{P/E}})-1\right]+\overline{Inc}+\overline{Rinv} \\ 10.70\% &= \left[(1+3.08\%)\times(1+1.75\%)\times(1+1.25\%)-1\right]+4.28\%+0.20\%\end{aligned} \quad (9)$$

Method 4 – Dividends Model

Dividend (Div) equals the earnings times the dividend payout ratio (PO); therefore, the growth rate of earnings can be calculated by the difference between the growth rate of dividend and the growth rate of the payout ratio.

$$EPS_t = \frac{Div_t}{PO_t} \quad (10)$$

$$(1+g_{REPS,t}) = \frac{(1+g_{RDiv,t})}{(1+g_{PO,t})} \quad (11)$$

We substitute dividend growth and payout ratio growth for the earnings growth in equation 8. The equity's total return in period t can be broken into five components: 1) inflation; 2) the growth rate of the price earnings ratio; 3) the growth rate of the dollar amount of dividend after inflation; 4) the growth rate of the payout ratio; and 5) the dividend yield.

$$R_t = \left[(1+CPI_t)\times(1+g_{P/E,t})\times\frac{(1+g_{RDiv,t})}{(1+g_{PO,t})}-1\right]+Inc_t+Rinv_t \quad (12)$$

Figure 3 shows the annual income return (dividend yield) of U.S. equity from 1926 to 2000. The dividend yield dropped from 5.15% at the beginning of 1926 to only 1.10% at the end of 2000. Figure 4 shows the year-end dividend payout ratio from 1926 to 2000. On average, the dollar amount of dividends grew 1.23% after inflation per year, while the dividend payout ratio decreased 0.51% per year. The dividend payout ratio was 46.68% at the beginning of 1926. It decreases to 31.78% at the end of 2000. The highest dividend payout ratio (929.12%) was recorded in 1932, while the lowest was recorded in 2000. The U.S. equity returns from 1926 and 2000 can be computed according to

$$\overline{R} = \left[(1+\overline{CPI})\times(1+\overline{g_{P/E}})\times\frac{(1+\overline{g_{RDiv}})}{(1+\overline{g_{PO}})} - 1 \right] + \overline{Inc} + \overline{Rinv} \tag{13}$$

$$10.70\% = \left[(1+3.08\%)\times(1+1.25\%)\times\frac{1+1.23\%}{1-0.51\%} - 1 \right] + 4.28\% + 0.20\%$$

Method 5 – Return on Book Equity Model

We can also break the earnings into book value of equity (BV) and return on equity (ROE).

$$EPS_t = BV_t \times ROE_t \tag{14}$$

The growth rate of earnings can be calculated by the combined growth rate of BV and ROE.

$$(1+g_{REPS,t}) = (1+g_{RBV,t})(1+g_{ROE,t}) \tag{15}$$

We substitute BV growth and ROE growth for the earnings growth in the equity return decomposition. The equity's total return in period t can be computed by,

$$R_t = \left[(1+CPI_t)\times(1+g_{P/E,t})\times(1+g_{RBV,t})\times(1+g_{ROE,t}) - 1 \right] + Inc_t + Rinv_t \tag{16}$$

We estimate that the average growth rate of the book value after inflation is 1.46% from 1926 to 2000.[9] The average ROE growth per year is calculated to be 0.31% during the same time period.

$$\overline{R} = \left[(1+\overline{CPI})\times(1+\overline{g_{P/E}})\times(1+\overline{g_{BV}})\times(1+\overline{g_{ROE}})-1\right]+\overline{Inc}+\overline{Rinv}$$
$$10.70\% = [(1+3.08\%)\times(1+1.25\%)\times(1+1.46\%)\times(1+0.31\%)-1]+4.28\%+0.20\% \tag{17}$$

Method 6 - GDP Per Capita Model

Diermeier, Ibbotson, and Siegel (1984) proposed a framework to analyze the aggregate supply of financial asset returns. Since we are only interested in the supply model of the equity returns in this study, we developed a slightly different supply method based on the growth of the economic productivity. This method can be expressed by the following equation:

$$R_t = \left[(1+CPI_t)\times(1+Rg_{GDP/POP,t})\times(1+g_{FS,t})-1\right]+Inc_t+Rinv_t \tag{18}$$

The return of the equity market over the long run can be decomposed into four components: 1) inflation; 2) real growth rate of the overall economic productivity (the GDP per capita ($g_{GDP/POP}$)); 3) the increase of the equity market relative to the overall economic productivity (increase in the factor share of equities in the overall economy (g_{FS})); and 4) dividend yields. Instead of assuming a constant factor share, we examine the historical growth rate of factor share relative to the overall growth of the economy.

Figure 5 shows the growth of the stocks market, GDP per capita, earnings, and dividends initialized to unity at the end of 1925. In the early 1930s, the stock market, earnings, dividends, and GDP per capita level dropped significantly. Overall, GDP per capita slightly outgrew earnings and dividends, but they all grew at approximately the same rate. In other words, overall economic productivity increased slightly faster than corporate earnings and dividends through the past 75 years. Although GDP per capita outgrew earnings and dividends, the overall stock market price grew faster than GDP per capita. This is primarily because the P/E ratio increased 2.54 times during the same time period. We calculate that the average annual increase in the factor share of the equity market relative to the overall economy to be 0.96%. The factor share increase is less than the annual increase of P/E ratio (1.25%) over the same time period. This suggests that the increase in the equity market share relative to the overall economy can be fully attributed to the increase in the P/E ratio.

$$\overline{R} = \left[(1+\overline{CPI})\times(1+\overline{Rg_{GDP/POP}})\times(1+\overline{g_{FS}})-1\right]+\overline{Inc}+\overline{Rinv} \tag{19}$$
$$10.70\% = [(1+3.08\%)\times(1+2.04\%)\times(1+0.96\%)-1]+4.28\%+0.20\%$$

Summary of Historical Equity Returns and its Components

Figure 6 shows the decomposition of models two through six into their components. The differences across the five models are the different components that represent the capital gain portion of the equity returns.

There are several important findings. First, as shown in Figure 5, the growth in corporate earnings is in line with the growth of the overall economic productivity. Second, P/E increases account for only 1.25% of the 10.70% total equity returns. Most of returns are attributable to dividend payments and nominal earnings growth (including inflation and real earnings growth). Third, the increase in relative factor share of the equity can be fully attributed to the increase in the P/E ratio. Overall economic productivity outgrew both corporate earnings and dividends from 1926 through 2000. Fourth, despite the record earnings growth in the 1990s, the dividend yield and the payout ratio declined sharply, which renders dividends alone a poor measure for corporate profitability and future earnings growth.

III. THE LONG -TERM FORECAST OF THE SUPPLY OF EQUITY RETURNS

Supply side models can be used to forecast the long-term expected equity return. The supply of stock market returns is generated by the productivity of the corporations in the real economy. Over the long run, the equity return should be close to the long run supply estimate. In other words, investors should not expect a much higher or a much lower return than that produced by the companies in the real economy. We believe the investors' expectations on the long-term equity performance should be based on the supply of equity returns produced by corporations.

The supply of equity returns consists of two main components: current returns in the form of dividends and long-term productivity growth in the form of capital gains. We focus on three supply side models: the earnings model, the dividend model, and the GDP per capita model (Method 3, Method 4, and Method 6 in section III).[10] We study the components of the three methods. Specifically, we identify which components are tied to the supply of equity returns, and which components are not. Then, we estimate the long-term sustainable return based on historical information on these supply components.

Method 3F – Forward-Looking Earnings Model

According to the earnings model (equation 8), the historical equity return can be broken into four components: the income return; inflation; the growth in real earnings per share; and the growth in the P/E ratio. Only the first three of these components are *historically* supplied by companies. The growth in P/E ratio reflects investors' changing prediction of *future* earnings growth. Although we forecast that the past supply of corporate growth will continue, we do not forecast any change in investors' predictions. Thus, the supply of the equity return (SR) only includes inflation, the growth in real earnings per share, and income return.

$$SR_t = [(1+CPI_t)\times(1+g_{REPS,t})-1]+Inc_t+Rinv_t \tag{20}$$

The long-term supply of U.S. equity returns based on the earnings method is 9.37%. This model uses the historical income return as an input for reasons that are discussed in the later section "Differences Between the Earnings Model (3F) and the Dividends Model (4F)".

$$\begin{aligned}\overline{SR} &= [(1+\overline{CPI})\times(1+\overline{g_{REPS}})-1]+\overline{Inc}+\overline{Rinv}\\ 9.37\% &= [(1+3.08\%)\times(1+1.75\%)-1]+4.28\%+0.20\%\end{aligned} \tag{21}$$

The supply side equity risk premium ($SERP$) based on the earnings model is calculated to be 3.97%. This is shown in Figure 7.

$$\overline{SERP} = \frac{(1+\overline{SR})}{(1+\overline{CPI})\times(1+\overline{RRf})}-1=\frac{1+9.37\%}{(1+3.08\%)\times(1+2.05\%)}-1=3.97\% \tag{22}$$

Method 4F – Forward-Looking Dividends Method

The forward-looking dividend model is also referred to as the constant dividend growth model (or the Gordon model), where the expected equity return equals the dividend yield plus the expected dividend growth rate. The supply of the equity return in the Gordon model includes inflation, the growth in real dividend, and dividend yield. As is commonly done with the constant dividend growth model, we have used the current dividend yield of 1.10%, instead of the historical dividend yield of 4.28%. This reduces the estimate of the supply of equity returns to 5.44%. The equity risk premium is estimated to be 0.24%. Figure 8 shows the equity risk premium estimate based on the earnings model and the dividends model. In the next section, we show why we disagree with the dividends model and prefer to use the earnings model to estimate the supply side equity risk premium.

$$\overline{SR} = \left[(1+\overline{CPI})\times(1+\overline{g_{RDiv}})-1\right]+Inc(00)+\overline{Rinv}$$
$$5.54\% = [(1+3.08\%)\times(1+1.23\%)-1]+1.10\%+0.20\% \qquad (23)$$

$$\overline{SERP} = \frac{(1+\overline{SR})}{(1+\overline{CPI})\times(1+\overline{RRf})}-1 = \frac{1+5.54\%}{(1+3.08\%)\times(1+2.05\%)}-1 = 0.24\% \qquad (24)$$

Differences Between the Earnings Model (3F) and the Dividends Model (4F)

There are essentially two differences between the earnings model (3F) and the dividends model (4F). The two differences are reconciled in the two right bars (4F') in Figure 8. The differences relate to the low current payout ratio, and the high current P/E ratio.

First, the earnings model uses the historical earnings growth to reflect the growth in productivity, while the dividend model uses historical dividend growth. Historical dividend growth underestimates historical earnings growth because of the decrease in the payout ratio. Overall, the dividend growth underestimated the increase in earnings productivity by 0.51% per year from 1926 to 2000. The low current payout ratio is also reflected in today's low dividend yield. The payout ratio is at a historic low of 31.8%, compared to the historical average payout of 59.2%. Applying such a low rate forward would mean that even more earnings would be retained in the future than in the historical period. Had more earnings been retained, the historic earnings growth would have been 0.95% per year higher. Thus, it is necessary to adjust the 1.10% current yield upward by 0.95% assuming the historical average dividend payout ratio.

Using the current dividend payout ratio in the dividend model, 4F, creates two errors, both of which violate Miller and Modigliani (1961) theory. The firms' dividend payout ratio only affects the form in which shareholders receive their returns, (i.e. dividends or capital gains), but not their total return. Using the low current dividend payout ratio should not affect our forecast, thus the dividend model has to be upwardly adjusted by 1.46% (both 0.51% and 0.95%), so as not to violate M&M Theory. Firms today likely have such low payout ratios in order to reduce the tax burden of their investors. Instead of paying dividends, many companies reinvest earnings, buy back shares or use their cash to purchase other companies.[11]

The second difference between models 3F and 4F is related to the current P/E ratio (25.96) being much higher than the historical average (13.76). The current yield (1.10%) is at a historic low both because of the previously mentioned low payout ratio and because of the high P/E ratio. Even assuming the historical average payout ratio, the current dividend yield would be much lower than its historical average (2.05% vs. 4.28%) This difference is geometrically estimated to be 2.28% per year. The high P/E ratio can be caused by 1) mis-pricing; 2) low required rate of return; and/or 3) high expected future earnings growth rate. Mis-pricing is eliminated by our assumption of market efficiency. A low required rate of return is eliminated since we assume a constant equity risk premium through the past and future periods that we are trying to estimate. Thus, we interpret the high P/E ratio as the market expectation of higher earnings growth.[12]

$$\begin{aligned}\overline{SR} &= \left[(1+\overline{CPI})\times(1+\overline{g_{RDiv}})\times(1-\overline{g_{PO}})-1\right]+Inc(00)+AY+AG+\overline{Rinv} \\ 9.67\% &= \left[(1+3.08\%)\times(1+1.23\%)\times(1+0.51\%)-1\right]+1.10\%+0.95\%+2.28\%+0.20\%\end{aligned} \tag{25}$$

To summarize, there are three differences between the earnings model and the dividends model. The first two differences relate to the dividend payout ratio and are direct violations of the Miller

& Modigliani (1961) theorem. We interpret that the third difference is due to the expectation of higher than average earnings growth, predicted by the high current P/E ratio. These differences reconcile the earnings and dividend models. Equation 25 presented model 4F', which reconciles the difference between the earnings model and the dividends model.

Geometric vs. Arithmetic

The estimated equity returns (9.37%) and equity risk premiums (3.97%) are geometric averages. The arithmetic average is often used in portfolio optimization. There are several ways to convert the geometric average into an arithmetic average. One method is to assume the returns are independently log-normally distributed over time. Then the arithmetic and geometric roughly follows the following relationship:

$$R_A = R_G + \frac{\sigma^2}{2}, \qquad (26)$$

where R_A is the arithmetic average, R_G is the geometric average, and σ^2 is the variance. The standard deviation of equity returns is 19.67%. Since almost all the variation in equity returns is from the equity risk premium (rather than the risk free rate), we need to add 1.93% to the geometric equity risk premium estimate to convert into arithmetic. $R_A = R_G + 1.93\%$. Adding the 1.93 percent to the geometric estimate, the arithmetic average equity risk premium is estimated to be 5.90% for the earnings model.

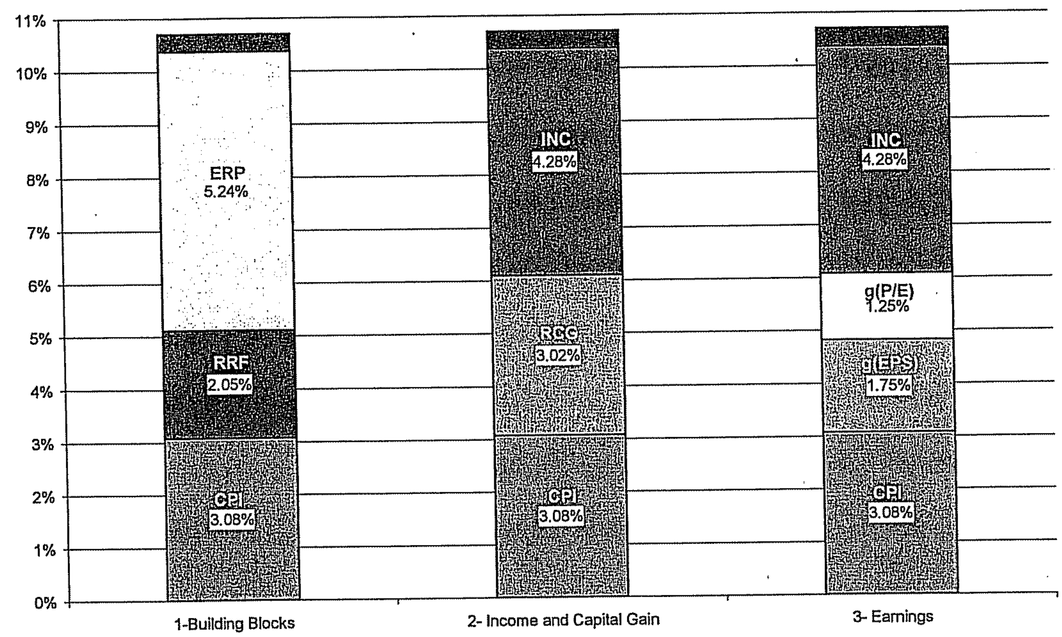
To summarize, the long-term supply of equity return is estimated to be 9.37% (6.09% after inflation) conditional on the historical average risk free rate. The supply side equity risk premium is estimated to be 3.97% geometrically and 5.90% arithmetically.[13]

IV. CONCLUSIONS

We adopt a supply side approach to estimate the forward looking long-term sustainable equity returns and equity risk premium. We analyze historical equity returns by decomposing returns into factors commonly used to describe the aggregate equity market and overall economic productivity. These factors include inflation, earnings, dividends, price-to-earnings ratio, dividend-payout ratio, book value, return on equity, and GDP per capita. We examine each factor and its relationship with the long-term supply side framework. We forecast the equity risk premium through supply side models using historical information. A complete tabulation of all the numbers from all models is presented in Appendix. Contrary to several recent studies on equity risk premium that declare the forward looking equity risk premium to be close to zero or negative, we find the long-term supply of equity risk premium is only slightly lower than the straight historical estimate. The equity risk premium is estimated to be 3.97% in geometric terms and 5.90% on an arithmetic basis. This estimate is about 1.25% lower than the straight historical estimate. The differences between our estimates and the ones provided by several other recent studies are principally due to the inappropriate assumptions used, which violate the Miller and Modigliani Theorem. Also our models interpret the current high P/E ratios as the market forecasting high future growth, rather than a low discount rate or an overvaluation. Our estimate is in line with both the historical supply measures of the public corporations (i.e., earnings) and the overall economic productivity (GDP per capita).

Our estimate of the equity risk premium is far closer to the historical premium than being zero or negative. This implies that stocks are expected to outperform bonds over the long run. For long-term investors, such as pension funds or individuals saving for retirement, stocks should continue to one of the favored asset classes in their diversified portfolios. Due to our lowered equity risk premium estimate (compared to historical performance), some investors should lower their equity allocations and/or increase their savings rate to meet future liabilities.

Figure 1: Decomposition of Historical Equity Returns 1926-2000
Geometric Mean = 10.70%



ERP is equity risk premium, RRF is the real risk free rate, CPI is the Consumer Price Index (inflation), INC is dividend income, RCG is real capital gain, g(P/E) is growth rate of P/E ratio, and g(EPS) is growth rate of earnings per share. The block on the top is the re-investment return plus the geometric interactions among the components. Including the geometric interactions ensures the components sums up to 10.70% in this and subsequent figures. Table 1 in the appendix gives the detailed information on the reinvestment and geometric interaction for all the methods.

Figure 2: P/E Ratio 1926-2000

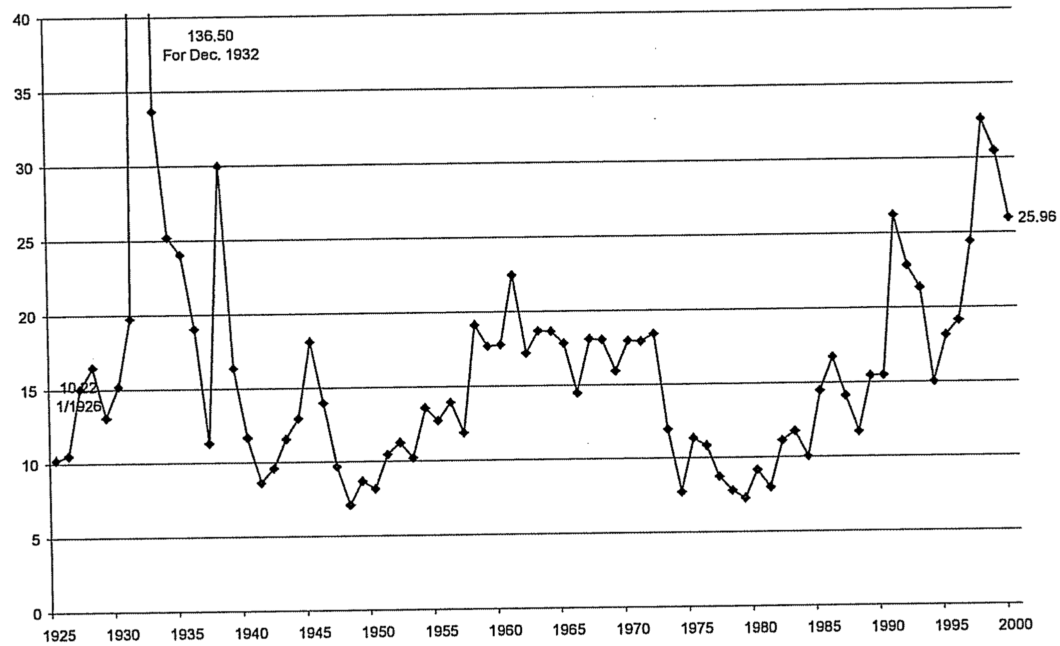


Figure 3: Income Return (Dividend Yield) % 1926-2000

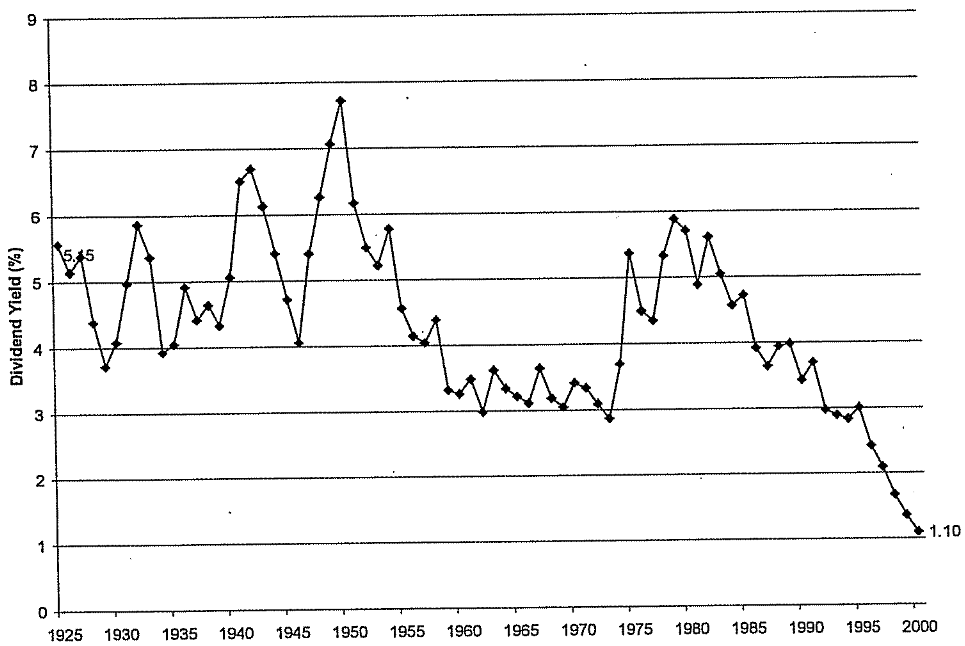


Figure 4: Dividend Payout Ratio % 1926-2000

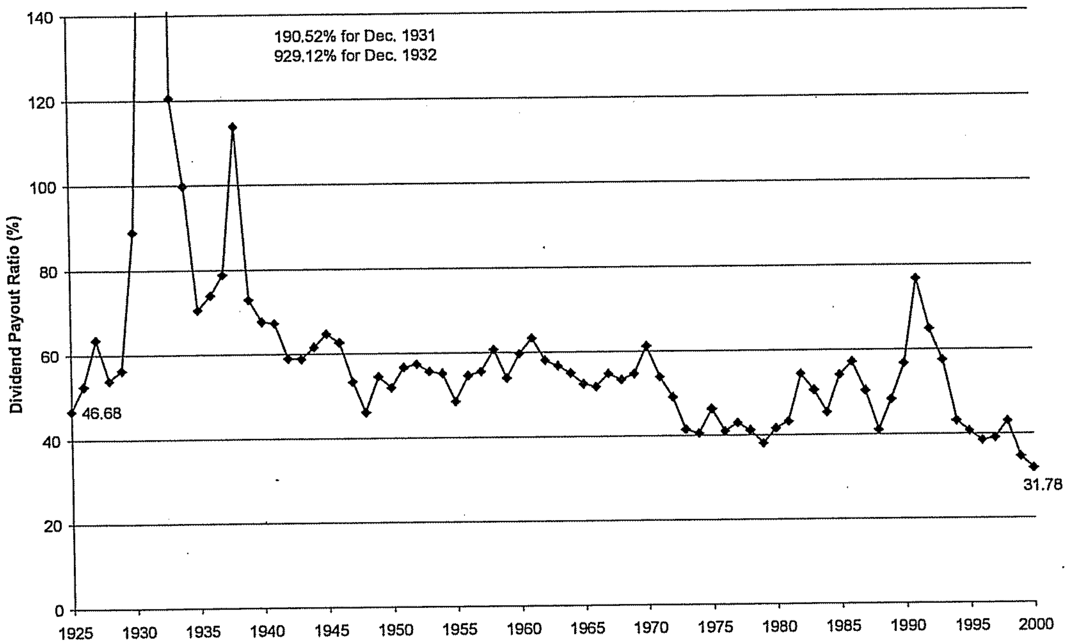


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Figure 5: Growth of $1 at the beginning of 1926
1926-2000

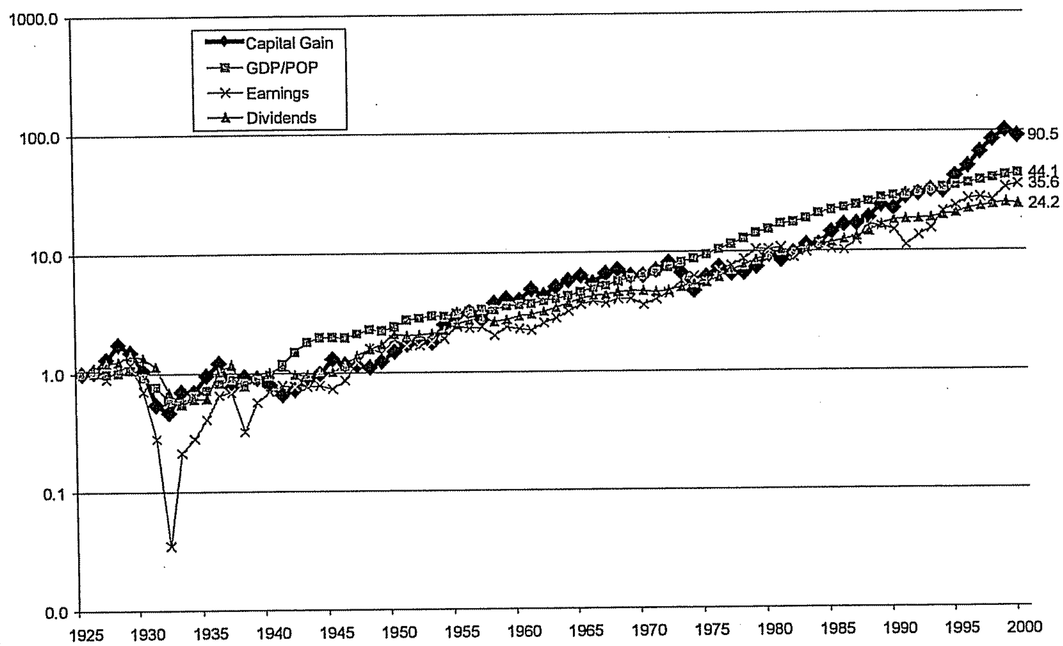
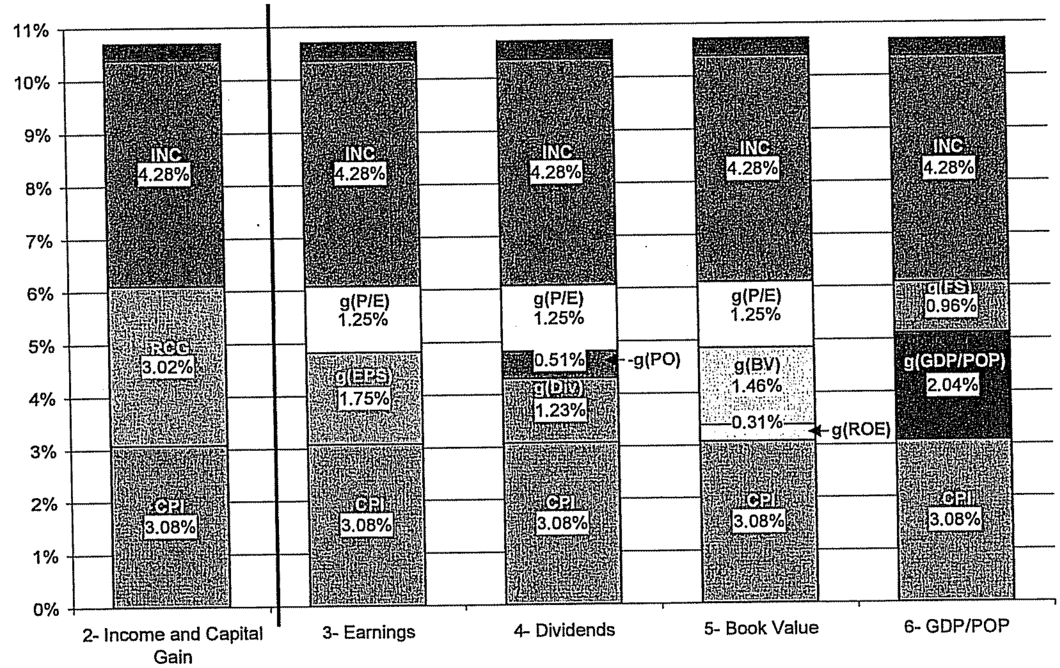


Figure 6: Decomposition of Historical Equity Returns 1926-2000



g(PO) is growth rate of dividend payout ratio, g(Div) is growth rate of dividend, g(BV) is the growth rate of book value, g(ROE) is the growth rate of return on book equity, g(FS) is the growth rate of equity factor share, and g(GDP/POP) is the growth rate of GDP per capita.

Figure 7: Historical Earnings and Forecasted Equity Returns Based on Earnings Models: Model 3, 3F, & 3F(ERP)

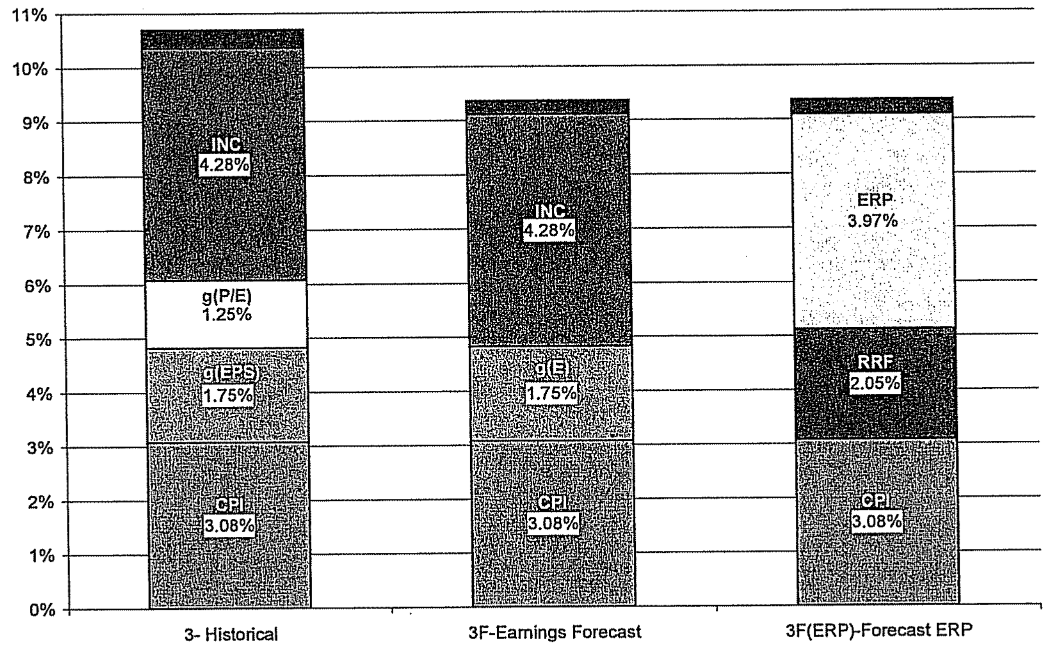
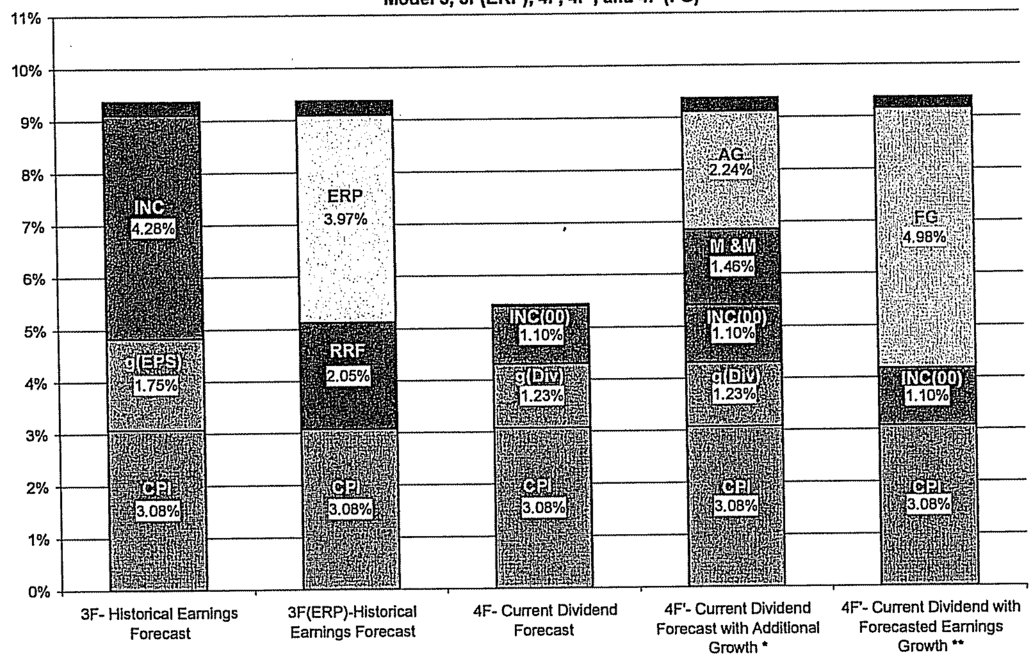


Figure 8: Historical vs. Current Dividend Yield Forecasts Based on Earnings and Dividend Models: Model 3, 3F(ERP), 4F, 4F', and 4F'(FG)



INC(00) is the dividend yield in the year 2000.

* Model 4F' attempts to correct the errors in model 4F: a) add 1.46% to correct Miller and Modigliani (M&M) violations; b) add the additional growth (AG), 2.24%, implied by the high current market P/E ratio.
** Based on Model 4F', we forecast the real earnings growth rate (FG) will be 4.98%.

Appendix

Table 1 Historical and Forecasted Equity Returns – All Models (Percent).

	Sum (%)	Inflation =3.08%	Real Risk-Free Rate=2.05%	Equity Risk Premium=5.24%	Real Capital Gain=3.02%	g(Real EPS)=1.75%	g(Real Div)=1.23%	- g(Div Payout Ratio)= 0.51%	g(BV)= 1.25%	g(ROE) = 0.31%	g(P/E)= 1.25%	g(Real GDP/POP)=2.04%	g(FS-GDP/POP)=1.96%	Income Return= 4.28%	Reinvestment + Interaction	Additional Growth =2.28%	Forecasted Earnings Growth =4.98%
Historical																	
Method 1	10.70	3.08	2.05	5.24											0.33		
Method 2	10.70	3.08			3.02									4.28	0.32		
Method 3	10.70	3.08				1.75					1.25			4.28	0.34		
Method 4	10.70	3.08					1.23	0.51			1.25			4.28	0.35		
Method 5	10.70	3.08							1.25%	0.31%	1.25			4.28	0.31		
Method 6	10.70	3.08										2.04	0.96	4.28	0.32		
Forecast with Historical Dividend Yield																	
Method 3F	9.37	3.08				1.75								4.28	0.26		
Method 3F (ERP)	9.37	3.08	2.05	3.97											0.27		
Method 6F	9.67	3.08										2.04		4.28	0.27		
Method 6F (ERP)	9.67	3.08	2.05	4.25											0.29		
Forecast with Current Dividend Yield																	
Method 4F	5.44	3.08					1.23							1.10*	0.03		
Method 4F (ERP)	5.44	3.08	2.05	0.24											0.07		
Method 4F'	9.37	3.08					1.23	0.51						2.05**	0.21	2.28	
Method 4F' (FG)	9.37	3.08												1.10*	0.21		4.98

*2000 dividend yield

** Adjust the 2000 dividend yield up 0.95% assuming the historical average dividend payout ratio.

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[1] In our study, we define the equity risk premium as the difference between the long-run expected return on stocks and the long-term risk free (U.S. Treasury) yield. We do all of our analysis in geometric form, then convert at the end so the estimate is expressed in both arithmetic form and geometric form. Some other studies, including Ibbotson & Sinquefield (1976a,b), used the short-term U.S. Treasury Bills as the risk free rate.

[2] It is sometimes difficult to compare estimates from one study with another, due to changing points of reference. The equity risk premium estimate can be significantly different simply due to the use of arithmetic vs. geometric, or long-term risk free rate vs. short-term risk free rate (Treasury Bills), or the bond's income return (yield) vs. the bond's total return, or long-term strategic forecast vs. short-term market timing estimate. A more detailed discussion on arithmetic vs. geometric can be found in section III.

[3] Welch's (2000) survey reported a 7% equity risk premium measured as the arithmetic difference between equity and U.S. Treasury bill returns. To make an apple to apple comparison, we converted the 7% number into a geometric equity risk premium relative to the long term U.S. Government bond income return, which gives an estimate of almost 4%.

[4] Each per share quantity is per share of the S&P 500 portfolio. Hereafter, we will merely refer to each factor without always mentioning per share, for example, earnings instead of earnings per share.

[5] There are many theoretical models that suggest that the equity risk premium is dynamic over time. However, recent empirical studies (e.g. Goyal & Welch (2001)) and Ang & Bekaert (2001)) show there is no evidence of long-horizon return predictability by either earnings or dividend yields. Therefore, instead of trying to build a model for a dynamic equity risk premium, we assume that the long-term equity risk premium is constant. This provides a benchmark for analysis and discussion.

[6] We updated the series with data from Standard & Poor's to include the year 2000.

[7] The 5.24% is the compounded average of the historical equity risk premium. The arithmetic average is 7.02%. Unless specified, we use geometric averages in the calculations for the entire study.

[8] The average P/E ratio is calculated by reversing the average E/P ratio from 1926 to 2000.

[9] Book Values are calculated based on the book-to-market ratios reported in Vuolenteenaho (2000). The aggregate book-to-market ratio is 2.0 in 1928 and 4.1 in 1999. We use the book value growth rate calculated during 1928 to 1999 as the proxy for the growth rate during 1926 to 2000. The average ROE growth rate is calculated from the derived book value and the earnings data.

[10] We decided not to use model 1, 2, and 5 in forecasting, because the forecast of model 1 & 2 would be identical to the historical estimate reported in section II. The forecast of model 5 would require more complete book value and ROE data than we currently have available.

[11] The current tax code provides incentives for firms to distribute cash through share repurchases rather than through dividends. Green and Hollifield (2001) find that the tax savings through repurchases are on the order of 40-50% of the taxes that would have been paid by distributing dividends.

[12] Contrary to the efficient market models, Shiller (2000) and Campbell and Shiller (2001) argue that the price to earnings ratio appears to forecast the future stock price change.

[13] We could use the GDP Per Capita model to estimate the long-term equity risk premium as well. The GDP Per Capita model implies the long run stock returns should be in line with the productivity of the overall economy. The equity risk premium estimated using the GDP Per Capita model would be slightly higher than the ERP estimate from the earnings model. This is because the GDP Per Capita grew slightly faster than corporate earnings. A similar approach can be found in Diermeier, Ibbotson, and Siegel (1984), which proposed using the growth rate of the overall economy as a proxy for the growth rate in aggregate wealth in the long run.

CASE: UE 210
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 803

Exhibits in Support Of Opening Testimony

July 24, 2009

UE 210 PP&L

Comparable Companies

Staff Comparable Companies	Ticker	Region	Value Line Report	Forecast Dividend per Share 2009	2010	2011	2012	2013	2014	2012-14 % Growth vs. 2006-08
Consolidated Edison, Inc.	ED	East	5/29/09	2.36	2.38	2.40	2.42	2.44	2.46	1.0%
DTE Energy Co.	DTE	Central	6/26/09	2.12	2.12	2.27	2.43	2.50	2.58	3.0%
Empire District Electric Co.	EDE	Central	6/26/09	1.28	1.28	1.33	1.38	1.40	1.42	1.5%
Entergy Corp.	ETR	Central	6/26/09	3.00	3.20	3.38	3.55	3.80	4.05	6.5%
FirstEnergy Corp.	FE	East	5/29/09	2.20	2.20	2.37	2.53	2.65	2.77	4.5%
FPL Group Inc.	FPL	East	5/29/09	1.89	2.00	2.08	2.16	2.30	2.44	6.0%
Idacorp, Inc.	IDA	West	5/8/09	1.20	1.20	1.20	1.20	1.20	1.20	0.0%
Progress Energy Inc.	PGN	East	5/29/09	2.48	2.50	2.52	2.53	2.56	2.59	1.0%
Southern Co.	SO	East	5/29/09	1.73	1.80	1.86	1.92	2.00	2.08	4.0%
Vectren Corporation	VVC	Central	6/26/09	1.35	1.39	1.43	1.46	1.51	1.56	3.0%
Wisconsin Energy Corporation	WEC	Central	6/26/09	1.35	1.55	1.70	1.86	2.15	2.44	13.5%
Xcel Energy, Inc.	XEL	West	5/8/09	0.97	1.00	1.03	1.07	1.10	1.13	3.0%
Mean Value				1.83	1.89	1.96	2.04	2.13	2.23	3.9%

PP&L Comparable Companies	Ticker	Region	Value Line Report	2009	2010	2011	2012	2013	2014	2012-14 % Growth vs. 2006-08
Allete Inc.	ALE	Central	6/26/09	1.76	1.80	1.83	1.86	1.92	1.98	3.0%
Alliant Energy Corp	LNT	Central	6/26/09	1.50	1.60	1.69	1.79	1.92	2.05	7.0%
Consolidated Edison, Inc.	ED	East	5/29/09	2.36	2.38	2.40	2.42	2.44	2.46	1.0%
DPL Inc.	DPL	Central	6/26/09	1.14	1.18	1.22	1.25	1.30	1.35	3.5%
DTE Energy Co.	DTE	Central	6/26/09	2.12	2.12	2.27	2.43	2.50	2.58	3.0%
Duke Energy Corp.	DUK	East	5/29/09	0.94	0.98	1.04	1.10	1.10	1.10	0.0%
Edison International	EIX	West	5/8/09	1.25	1.28	1.36	1.43	1.50	1.57	4.5%
Entergy Corp.	ETR	Central	6/26/09	3.00	3.20	3.38	3.55	3.80	4.05	6.5%
FPL Group Inc.	FPL	East	5/29/09	1.89	2.00	2.08	2.16	2.30	2.44	6.0%
Idacorp, Inc.	IDA	West	5/8/09	1.20	1.20	1.20	1.20	1.20	1.20	0.0%
NSTAR	NST	East	5/29/09	1.53	1.63	1.74	1.84	1.95	2.06	5.5%
PG&E Corp.	PCG	West	5/8/09	1.68	1.80	1.92	2.04	2.20	2.37	7.5%
Portland General	POR	West	5/8/2009	1.01	1.07	1.14	1.21	1.30	1.39	7.0%
Progress Energy Inc.	PGN	East	5/29/09	2.48	2.50	2.52	2.53	2.56	2.59	1.0%
Sempra Energy	SRE	West	5/8/2009	1.56	1.72	1.82	1.92	2.10	2.28	8.5%
Southern Co.	SO	East	5/29/09	1.73	1.80	1.86	1.92	2.00	2.08	4.0%
Vectren Corporation	VVC	Central	6/26/09	1.35	1.39	1.43	1.46	1.51	1.56	3.0%
Wisconsin Energy Corporation	WEC	Central	6/26/09	1.35	1.55	1.70	1.86	2.15	2.44	13.5%
Xcel Energy, Inc	XEL	West	5/8/09	0.97	1.00	1.03	1.07	1.10	1.13	3.0%
Mean Value				1.62	1.69	1.77	1.84	1.94	2.03	4.6%

Common Comparable Companies	Ticker	Region	Value Line Report	2009	2010	2011	2012	2013	2014	2012-14 % Growth vs. 2006-08
Consolidated Edison, Inc.	ED	East	5/29/09	2.36	2.38	2.40	2.42	2.44	2.46	1.0%
DTE Energy Co.	DTE	Central	6/26/09	2.12	2.12	2.27	2.43	2.50	2.58	3.0%
Entergy Corp.	ETR	Central	6/26/09	3.00	3.20	3.38	3.55	3.80	4.05	6.5%
FPL Group Inc.	FPL	East	5/29/09	1.89	2.00	2.08	2.16	2.30	2.44	6.0%
Idacorp, Inc.	IDA	West	5/8/09	1.20	1.20	1.20	1.20	1.20	1.20	0.0%
Progress Energy Inc.	PGN	East	5/29/09	2.48	2.50	2.52	2.53	2.56	2.59	1.0%
Southern Co.	SO	East	5/29/09	1.73	1.80	1.86	1.92	2.00	2.08	4.0%
Vectren Corporation	VVC	Central	6/26/09	1.35	1.39	1.43	1.46	1.51	1.56	3.0%
Wisconsin Energy Corporation	WEC	Central	6/26/09	1.35	1.55	1.70	1.86	2.15	2.44	13.5%
Xcel Energy, Inc	XEL	West	5/8/09	0.97	1.00	1.03	1.07	1.10	1.13	3.0%
Mean Value				1.85	1.91	1.99	2.06	2.16	2.25	4.1%

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Comparable Companies

Staff Comparable Companies	Ticker	Region	Value Line Report	2009	2010	2011	2012	2013	2014
				Dividend Yield per Share (based on recent share prices)					
Consolidated Edison, Inc.	ED	East	5/29/09	6.4%	6.5%	6.5%	6.6%	6.6%	6.7%
DTE Energy Co.	DTE	Central	6/26/09	6.8%	6.8%	7.3%	7.7%	8.0%	8.2%
Empire District Electric Co.	EDE	Central	6/26/09	7.9%	7.9%	8.2%	8.5%	8.6%	8.7%
Entergy Corp.	ETR	Central	6/26/09	3.9%	4.2%	4.4%	4.6%	5.0%	5.3%
FirstEnergy Corp.	FE	East	5/29/09	5.7%	5.7%	6.1%	6.5%	6.9%	7.2%
FPL Group Inc.	FPL	East	5/29/09	3.3%	3.5%	3.7%	3.8%	4.0%	4.3%
Idacorp, Inc.	IDA	West	5/8/09	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%
Progress Energy Inc.	PGN	East	5/29/09	6.7%	6.7%	6.8%	6.8%	6.9%	7.0%
Southern Co.	SO	East	5/29/09	5.6%	5.8%	6.0%	6.2%	6.5%	6.8%
Vectren Corporation	VVC	Central	6/26/09	5.8%	6.0%	6.1%	6.3%	6.5%	6.7%
Wisconsin Energy Corporation	WEC	Central	6/26/09	3.4%	3.9%	4.2%	4.6%	5.4%	6.1%
Xcel Energy, Inc.	XEL	West	5/8/09	5.4%	5.6%	5.7%	5.9%	6.1%	6.3%
Mean Value				5.5%	5.6%	5.8%	6.0%	6.3%	6.5%

PP&L Comparable Companies	Ticker	Region	Value Line Report	2009	2010	2011	2012	2013	2014
Allete Inc.	ALE	Central	6/26/09	6.2%	6.3%	6.4%	6.5%	6.7%	6.9%
Alliant Energy Corp	LNT	Central	6/26/09	6.0%	6.4%	6.7%	7.1%	7.6%	8.2%
Consolidated Edison, Inc.	ED	East	5/29/09	6.4%	6.5%	6.5%	6.6%	6.6%	6.7%
DPL Inc.	DPL	Central	6/26/09	5.0%	5.2%	5.4%	5.5%	5.7%	5.9%
DTE Energy Co.	DTE	Central	6/26/09	6.8%	6.8%	7.3%	7.7%	8.0%	8.2%
Duke Energy Corp.	DUK	East	5/29/09	6.5%	6.8%	7.2%	7.6%	7.6%	7.6%
Edison International	EIX	West	5/8/09	4.0%	4.1%	4.3%	4.6%	4.8%	5.0%
Entergy Corp.	ETR	Central	6/26/09	3.9%	4.2%	4.4%	4.6%	5.0%	5.3%
FPL Group Inc.	FPL	East	5/29/09	3.3%	3.5%	3.7%	3.8%	4.0%	4.3%
Idacorp, Inc.	IDA	West	5/8/09	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%
NSTAR	NST	East	5/29/09	4.9%	5.2%	5.6%	5.9%	6.2%	6.6%
PG&E Corp.	PCG	West	5/8/09	4.5%	4.8%	5.1%	5.4%	5.8%	6.3%
Portland General	POR	West	5/8/2009	5.2%	5.6%	5.9%	6.3%	6.8%	7.2%
Progress Energy Inc.	PGN	East	5/29/09	6.7%	6.7%	6.8%	6.8%	6.9%	7.0%
Sempra Energy	SRE	West	5/8/2009	3.2%	3.5%	3.7%	3.9%	4.3%	4.7%
Southern Co.	SO	East	5/29/09	5.6%	5.8%	6.0%	6.2%	6.5%	6.8%
Vectren Corporation	VVC	Central	6/26/09	5.8%	6.0%	6.1%	6.3%	6.5%	6.7%
Wisconsin Energy Corporation	WEC	Central	6/26/09	3.4%	3.9%	4.2%	4.6%	5.4%	6.1%
Xcel Energy, Inc	XEL	West	5/8/09	5.4%	5.6%	5.7%	5.9%	6.1%	6.3%
Mean Value				5.1%	5.3%	5.6%	5.8%	6.1%	6.3%

Common Comparable Companies	Ticker	Region	Value Line Report	2009	2010	2011	2012	2013	2014
Consolidated Edison, Inc.	ED	East	5/29/09	6.4%	6.5%	6.5%	6.6%	6.6%	6.7%
DTE Energy Co.	DTE	Central	6/26/09	6.8%	6.8%	7.3%	7.7%	8.0%	8.2%
Entergy Corp.	ETR	Central	6/26/09	3.9%	4.2%	4.4%	4.6%	5.0%	5.3%
FPL Group Inc.	FPL	East	5/29/09	3.3%	3.5%	3.7%	3.8%	4.0%	4.3%
Idacorp, Inc.	IDA	West	5/8/09	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%
Progress Energy Inc.	PGN	East	5/29/09	6.7%	6.7%	6.8%	6.8%	6.9%	7.0%
Southern Co.	SO	East	5/29/09	5.6%	5.8%	6.0%	6.2%	6.5%	6.8%
Vectren Corporation	VVC	Central	6/26/09	5.8%	6.0%	6.1%	6.3%	6.5%	6.7%
Wisconsin Energy Corporation	WEC	Central	6/26/09	3.4%	3.9%	4.2%	4.6%	5.4%	6.1%
Xcel Energy, Inc	XEL	West	5/8/09	5.4%	5.6%	5.7%	5.9%	6.1%	6.3%
Mean Value				5.2%	5.4%	5.6%	5.7%	6.0%	6.2%

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Comparable Companies

Staff Comparable Companies	Ticker	Region	Value Line Report	2009	2010	2011	2012	2013	2014	2012-14 % Growth vs. 2006-08
				Forecast Earnings per Share						
Consolidated Edison, Inc.	ED	East	5/29/09	3.15	3.35	3.53	3.71	3.80	3.90	2.5%
DTE Energy Co.	DTE	Central	6/26/09	3.00	3.25	3.48	3.70	4.00	4.30	7.5%
Empire District Electric Co.	EDE	Central	6/26/09	1.55	1.70	1.77	1.83	2.00	2.17	8.5%
Entergy Corp.	ETR	Central	6/26/09	6.60	7.20	7.36	7.52	8.00	8.48	6.0%
FirstEnergy Corp.	FE	East	5/29/09	3.80	3.60	4.32	5.04	5.25	5.46	4.0%
FPL Group Inc.	FPL	East	5/29/09	4.25	4.85	5.01	5.18	5.75	6.33	10.0%
Idacorp, Inc.	IDA	West	5/8/09	2.30	2.40	2.51	2.63	2.75	2.87	4.5%
Progress Energy Inc.	PGN	East	5/29/09	3.10	3.25	3.32	3.38	3.60	3.82	6.0%
Southern Co.	SO	East	5/29/09	2.35	2.50	2.68	2.87	3.00	3.14	4.5%
Vectren Corporation	VVC	Central	6/26/09	1.85	2.05	2.09	2.13	2.25	2.37	5.5%
Wisconsin Energy Corporation	WEC	Central	6/26/09	3.10	3.70	3.92	4.14	4.50	4.86	8.0%
Xcel Energy, Inc.	XEL	West	5/8/09	1.50	1.60	1.74	1.87	2.00	2.13	6.5%
Mean Value				3.05	3.29	3.48	3.67	3.91	4.15	6.1%

PP&L Comparable Companies										
Allete Inc.	ALE	Central	6/26/09	2.10	2.25	2.51	2.78	2.75	2.72	-1.0%
Alliant Energy Corp	LNT	Central	6/26/09	2.25	2.55	2.80	3.06	3.20	3.34	4.5%
Consolidated Edison, Inc.	ED	East	5/29/09	3.15	3.35	3.53	3.71	3.80	3.90	2.5%
DPL Inc.	DPL	Central	6/26/09	2.20	2.40	2.42	2.44	2.65	2.86	8.0%
DTE Energy Co.	DTE	Central	6/26/09	3.00	3.25	3.48	3.70	4.00	4.30	7.5%
Duke Energy Corp.	DUK	East	5/29/09	1.15	1.20	1.27	1.33	1.40	1.47	5.0%
Edison International	EIX	West	5/8/09	2.85	3.10	3.60	4.10	4.25	4.40	3.5%
Entergy Corp.	ETR	Central	6/26/09	6.60	7.20	7.36	7.52	8.00	8.48	6.0%
FPL Group Inc.	FPL	East	5/29/09	4.25	4.85	5.01	5.18	5.75	6.33	10.0%
Idacorp, Inc.	IDA	West	5/8/09	2.30	2.40	2.51	2.63	2.75	2.87	4.5%
NSTAR	NST	East	5/29/09	2.40	2.55	2.77	2.99	3.25	3.51	8.0%
PG&E Corp.	PCG	West	5/8/09	3.25	3.45	3.71	3.97	4.25	4.53	6.5%
Portland General	POR	West	5/8/2009	1.80	1.90	2.01	2.13	2.25	2.37	5.5%
Progress Energy Inc.	PGN	East	5/29/09	3.10	3.25	3.32	3.38	3.60	3.82	6.0%
Sempra Energy	SRE	West	5/8/2009	4.45	5.00	5.23	5.46	5.75	6.04	5.0%
Southern Co.	SO	East	5/29/09	2.35	2.50	2.68	2.87	3.00	3.14	4.5%
Vectren Corporation	VVC	Central	6/26/09	1.85	2.05	2.09	2.13	2.25	2.37	5.5%
Wisconsin Energy Corporation	WEC	Central	6/26/09	3.10	3.70	3.92	4.14	4.50	4.86	8.0%
Xcel Energy, Inc	XEL	West	5/8/09	1.50	1.60	1.74	1.87	2.00	2.13	6.5%
Mean Value				2.82	3.08	3.26	3.44	3.65	3.86	5.6%

Common Comparable Companies										
Consolidated Edison, Inc.	ED	East	5/29/09	3.15	3.35	3.53	3.71	3.80	3.90	2.5%
DTE Energy Co.	DTE	Central	6/26/09	3.00	3.25	3.48	3.70	4.00	4.30	7.5%
Entergy Corp.	ETR	Central	6/26/09	6.60	7.20	7.36	7.52	8.00	8.48	6.0%
FPL Group Inc.	FPL	East	5/29/09	4.25	4.85	5.01	5.18	5.75	6.33	10.0%
Idacorp, Inc.	IDA	West	5/8/09	2.30	2.40	2.51	2.63	2.75	2.87	4.5%
Progress Energy Inc.	PGN	East	5/29/09	3.10	3.25	3.32	3.38	3.60	3.82	6.0%
Southern Co.	SO	East	5/29/09	2.35	2.50	2.68	2.87	3.00	3.14	4.5%
Vectren Corporation	VVC	Central	6/26/09	1.85	2.05	2.09	2.13	2.25	2.37	5.5%
Wisconsin Energy Corporation	WEC	Central	6/26/09	3.10	3.70	3.92	4.14	4.50	4.86	8.0%
Xcel Energy, Inc	XEL	West	5/8/09	1.50	1.60	1.74	1.87	2.00	2.13	6.5%
Mean Value				3.12	3.42	3.56	3.71	3.97	4.22	6.1%

Comparable Companies

Staff Comparable Companies	Ticker	Region	Value Line Report	2008	2009	2010	2011	2012	2013	2014	2012-14 % Growth vs. 2006-08
				Book Value per Share							
Consolidated Edison, Inc.	ED	East	5/29/09	35.43	36.25	37.45	38.69	39.94	41.60	43.26	4.0%
DTE Energy Co.	DTE	Central	6/26/09	36.77	37.20	37.90	38.94	39.98	41.00	42.03	2.5%
Empire District Electric Co.	EDE	Central	6/26/09	15.56	15.75	16.05	16.60	17.15	17.50	17.85	2.0%
Entergy Corp.	ETR	Central	6/26/09	42.07	43.00	47.25	52.03	56.80	60.75	64.70	6.5%
FirstEnergy Corp.	FE	East	5/29/09	27.17	28.75	30.20	32.77	35.34	37.00	38.67	4.5%
FPL Group Inc.	FPL	East	5/29/09	28.57	31.00	33.95	36.76	39.57	43.25	46.93	8.5%
Idacorp, Inc.	IDA	West	5/8/09	27.76	29.10	30.60	32.21	33.82	35.60	37.38	5.0%
Progress Energy Inc.	PGN	East	5/29/09	32.55	31.95	33.05	34.56	36.06	36.80	37.54	2.0%
Southern Co.	SO	East	5/29/09	17.08	18.10	19.10	20.06	21.03	22.25	23.47	5.5%
Vectren Corporation	VVC	Central	6/26/09	16.68	17.85	19.05	20.24	21.43	22.80	24.17	6.0%
Wisconsin Energy Corporation	WEC	Central	6/26/09	28.54	30.15	32.10	33.79	35.49	37.75	40.02	6.0%
Xcel Energy, Inc.	XEL	West	5/8/09	15.35	15.90	16.50	17.32	18.15	19.00	19.86	4.5%
Mean Value				26.96	27.92	29.43	31.16	32.90	34.61	36.32	4.8%

PP&L Comparable Companies

PP&L Comparable Companies	Ticker	Region	Value Line Report	2008	2009	2010	2011	2012	2013	2014	2012-14 % Growth vs. 2006-08
Allete Inc.	ALE	Central	6/26/09	25.37	26.00	26.65	27.32	27.99	29.00	30.02	3.5%
Alliant Energy Corp	LNT	Central	6/26/09	25.56	26.45	26.70	28.30	29.90	31.15	32.40	4.0%
Consolidated Edison, Inc.	ED	East	5/29/09	35.43	36.25	37.45	38.69	39.94	41.60	43.26	4.0%
DPL Inc.	DPL	Central	6/26/09	8.41	9.80	10.80	11.59	12.37	13.90	15.43	11.0%
DTE Energy Co.	DTE	Central	6/26/09	36.77	37.20	37.90	38.94	39.98	41.00	42.03	2.5%
Duke Energy Corp.	DUK	East	5/29/09	16.50	16.65	16.85	17.34	17.84	17.75	17.66	-0.5%
Edison International	EIX	West	5/8/09	29.21	30.70	32.40	34.34	36.27	39.00	41.73	7.0%
Entergy Corp.	ETR	Central	6/26/09	42.07	43.00	47.25	52.03	56.80	60.75	64.70	6.5%
FPL Group Inc.	FPL	East	5/29/09	28.57	31.00	33.95	36.76	39.57	43.25	46.93	8.5%
Idacorp, Inc.	IDA	West	5/8/09	27.76	29.10	30.60	32.21	33.82	35.60	37.38	5.0%
NSTAR	NST	East	5/29/09	16.74	17.60	18.55	19.67	20.79	22.00	23.21	5.5%
PG&E Corp.	PCG	West	5/8/09	25.97	27.65	29.00	31.21	33.43	35.75	38.07	6.5%
Portland General	POR	West	5/8/2009	21.64	21.20	22.00	23.13	24.25	25.00	25.75	3.0%
Progress Energy Inc.	PGN	East	5/29/09	32.55	31.95	33.05	34.56	36.06	36.80	37.54	2.0%
Sempra Energy	SRE	West	5/8/2009	32.75	35.60	38.75	42.26	45.77	49.75	53.73	8.0%
Southern Co.	SO	East	5/29/09	17.08	18.10	19.10	20.06	21.03	22.25	23.47	5.5%
Vectren Corporation	VVC	Central	6/26/09	16.68	17.85	19.05	20.24	21.43	22.80	24.17	6.0%
Wisconsin Energy Corporation	WEC	Central	6/26/09	28.54	30.15	32.10	33.79	35.49	37.75	40.02	6.0%
Xcel Energy, Inc	XEL	West	5/8/09	15.35	15.90	16.50	17.32	18.15	19.00	19.86	4.5%
Mean Value				25.42	26.43	27.82	29.46	31.10	32.85	34.60	5.2%

Common Comparable Companies

Common Comparable Companies	Ticker	Region	Value Line Report	2008	2009	2010	2011	2012	2013	2014	2012-14 % Growth vs. 2006-08
Consolidated Edison, Inc.	ED	East	5/29/09	35.43	36.25	37.45	38.69	39.94	41.60	43.26	4.0%
DTE Energy Co.	DTE	Central	6/26/09	36.77	37.20	37.90	38.94	39.98	41.00	42.03	2.5%
Entergy Corp.	ETR	Central	6/26/09	42.07	43.00	47.25	52.03	56.80	60.75	64.70	6.5%
FPL Group Inc.	FPL	East	5/29/09	28.57	31.00	33.95	36.76	39.57	43.25	46.93	8.5%
Idacorp, Inc.	IDA	West	5/8/09	27.76	29.10	30.60	32.21	33.82	35.60	37.38	5.0%
Progress Energy Inc.	PGN	East	5/29/09	32.55	31.95	33.05	34.56	36.06	36.80	37.54	2.0%
Southern Co.	SO	East	5/29/09	17.08	18.10	19.10	20.06	21.03	22.25	23.47	5.5%
Vectren Corporation	VVC	Central	6/26/09	16.68	17.85	19.05	20.24	21.43	22.80	24.17	6.0%
Wisconsin Energy Corporation	WEC	Central	6/26/09	28.54	30.15	32.10	33.79	35.49	37.75	40.02	6.0%
Xcel Energy, Inc	XEL	West	5/8/09	15.35	15.90	16.50	17.32	18.15	19.00	19.86	4.5%
Mean Value				28.08	29.05	30.70	32.46	34.23	36.08	37.93	5.1%

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Comparable Companies

Staff Comparable Companies	Ticker	Region	Value Line Report	Closing Price 6/16/09	6/23/09	6/30/09	3-Day Average Closing Price
Consolidated Edison, Inc.	ED	East	5/29/09	36.44	36.26	37.42	36.71
DTE Energy Co.	DTE	Central	6/26/09	31.17	30.83	32.00	31.33
Empire District Electric Co.	EDE	Central	6/26/09	16.24	16.11	16.52	16.29
Entergy Corp.	ETR	Central	6/26/09	76.48	75.77	77.52	76.59
FirstEnergy Corp.	FE	East	5/29/09	39.22	38.03	38.75	38.67
FPL Group Inc.	FPL	East	5/29/09	56.75	56.93	56.86	56.85
Idacorp, Inc.	IDA	West	5/8/09	24.82	25.29	26.14	25.42
Progress Energy Inc.	PGN	East	5/29/09	36.63	36.88	37.83	37.11
Southern Co.	SO	East	5/29/09	30.12	31.10	31.16	30.79
Vectren Corporation	VVC	Central	6/26/09	23.37	22.91	23.43	23.24
Wisconsin Energy Corporation	WEC	Central	6/26/09	40.03	39.69	40.71	40.14
Xcel Energy, Inc.	XEL	West	5/8/09	17.87	17.67	18.41	17.98
Mean Value				35.76	35.62	36.40	35.93

PP&L Comparable Companies	Ticker	Region	Value Line Report	6/16/09	6/23/09	6/30/09	3-Day Average Closing Price
Allete Inc.	ALE	Central	6/26/09	28.51	28.11	28.75	28.46
Alliant Energy Corp	LNT	Central	6/26/09	24.61	24.77	26.13	25.17
Consolidated Edison, Inc.	ED	East	5/29/09	36.44	36.26	37.42	36.71
DPL Inc.	DPL	Central	6/26/09	22.16	22.89	23.17	22.74
DTE Energy Co.	DTE	Central	6/26/09	31.17	30.83	32.00	31.33
Duke Energy Corp.	DUK	East	5/29/09	14.23	14.39	14.59	14.40
Edison International	EIX	West	5/8/09	31.44	31.50	31.46	31.47
Entergy Corp.	ETR	Central	6/26/09	76.48	75.77	77.52	76.59
FPL Group Inc.	FPL	East	5/29/09	56.75	56.93	56.86	56.85
Idacorp, Inc.	IDA	West	5/8/09	24.82	25.29	26.14	25.42
NSTAR	NST	East	5/29/09	30.92	30.76	32.11	31.26
PG&E Corp.	PCG	West	5/8/09	37.20	37.47	38.44	37.70
Portland General	POR	West	5/8/2009	19.27	19.00	19.48	19.25
Progress Energy Inc.	PGN	East	5/29/09	36.63	36.88	37.83	37.11
Sempra Energy	SRE	West	5/8/2009	48.70	48.64	49.63	48.99
Southern Co.	SO	East	5/29/09	30.12	31.10	31.16	30.79
Vectren Corporation	VVC	Central	6/26/09	23.37	22.91	23.43	23.24
Wisconsin Energy Corporation	WEC	Central	6/26/09	40.03	39.69	40.71	40.14
Xcel Energy, Inc	XEL	West	5/8/09	17.87	17.67	18.41	17.98
Mean Value				33.20	33.20	33.96	33.45

Common Comparable Companies	Ticker	Region	Value Line Report	6/16/09	6/23/09	6/30/09	3-Day Average Closing Price
Consolidated Edison, Inc.	ED	East	5/29/09	36.44	36.26	37.42	36.71
DTE Energy Co.	DTE	Central	6/26/09	31.17	30.83	32.00	31.33
Entergy Corp.	ETR	Central	6/26/09	76.48	75.77	77.52	76.59
FPL Group Inc.	FPL	East	5/29/09	56.75	56.93	56.86	56.85
Idacorp, Inc.	IDA	West	5/8/09	24.82	25.29	26.14	25.42
Progress Energy Inc.	PGN	East	5/29/09	36.63	36.88	37.83	37.11
Southern Co.	SO	East	5/29/09	30.12	31.10	31.16	30.79
Vectren Corporation	VVC	Central	6/26/09	23.37	22.91	23.43	23.24
Wisconsin Energy Corporation	WEC	Central	6/26/09	40.03	39.69	40.71	40.14
Xcel Energy, Inc	XEL	West	5/8/09	17.87	17.67	18.41	17.98
Mean Value				37.37	37.33	38.15	37.62

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Comparable Companies

				Value Line Capital Structure Estimated 2010 Composition			Select Statistics			
Staff Comparable Companies	Ticker	Region	Value Line Report	Common Equity	Long-term Debt	Preferred	Value Line Beta	Market to Book	S&P Org. Rating[1]	Staff Numerical Assignment
Consolidated Edison, Inc.	ED	East	5/29/09	50.0%	40.0%	10.0%	0.65	1.01	A-	7
DTE Energy Co.	DTE	Central	6/26/09	44.0%	56.0%	0.0%	0.75	0.84	BBB	9
Empire District Electric Co.	EDE	Central	6/26/09	46.5%	53.5%	0.0%	0.75	1.03	BBB-	10
Entergy Corp.	ETR	Central	6/26/09	38.5%	60.0%	1.5%	0.70	1.78	BBB	9
FirstEnergy Corp.	FE	East	5/29/09	48.0%	52.0%	0.0%	0.85	1.34	BBB	9
FPL Group Inc.	FPL	East	5/29/09	46.0%	54.0%	0.0%	0.75	1.83	A	6
Idacorp, Inc.	IDA	West	5/8/09	53.5%	46.5%	0.0%	0.70	0.87	BBB	9
Progress Energy Inc.	PGN	East	5/29/09	45.5%	54.5%	0.0%	0.65	1.16	BBB+	8
Southern Co.	SO	East	5/29/09	43.0%	54.0%	3.0%	0.55	1.70	BBB+[1]	8
Vectren Corporation	VVC	Central	6/26/09	51.5%	48.5%	0.0%	0.75	1.30	A-	7
Wisconsin Energy Corporation	WEC	Central	6/26/09	42.5%	57.0%	0.5%	0.65	1.33	BBB+	8
Xcel Energy, Inc.	XEL	West	5/8/09	46.0%	53.5%	0.5%	0.65	1.13	BBB+	8
Mean Value				46.250%	52.458%	1.292%	0.70	1.28	BBB+	8.17
PP&L Comparable Companies										
Allete Inc.	ALE	Central	6/26/09	53.5%	46.5%	0.0%	0.70	1.09	BBB+	8
Alliant Energy Corp	LNT	Central	6/26/09	57.0%	38.0%	5.0%	0.70	0.95	BBB+	8
Consolidated Edison, Inc.	ED	East	5/29/09	50.0%	40.0%	10.0%	0.65	1.01	A-	7
DPL Inc.	DPL	Central	6/26/09	47.0%	53.0%	0.0%	0.60	2.32	A-	7
DTE Energy Co.	DTE	Central	6/26/09	44.0%	56.0%	0.0%	0.75	0.84	BBB	9
Duke Energy Corp.	DUK	East	5/29/09	57.5%	42.5%	0.0%	0.65	0.87	A-	7
Edison International	EIX	West	5/8/09	44.5%	52.0%	3.5%	0.80	1.02	BBB-	10
Entergy Corp.	ETR	Central	6/26/09	38.5%	60.0%	1.5%	0.70	1.78	BBB	9
FPL Group Inc.	FPL	East	5/29/09	46.0%	54.0%	0.0%	0.75	1.83	BBB	9
Idacorp, Inc.	IDA	West	5/8/09	53.5%	46.5%	0.0%	0.70	0.87	BBB	9
NSTAR	NST	East	5/29/09	49.5%	49.5%	1.0%	0.65	1.78	A+	5
PG&E Corp.	PCG	West	5/8/09	49.5%	49.0%	1.5%	0.60	1.36	BBB+	8
Portland General	POR	West	5/8/2009	48.0%	52.0%	0.0%	0.70	0.91	BBB+	8
Progress Energy Inc.	PGN	East	5/29/09	45.5%	54.5%	0.0%	0.65	1.16	BBB+	8
Sempra Energy	SRE	West	5/8/2009	55.0%	44.0%	1.0%	0.90	1.38	BBB+	8
Southern Co.	SO	East	5/29/09	43.0%	54.0%	3.0%	0.55	1.70	BBB+[1]	8
Vectren Corporation	VVC	Central	6/26/09	51.5%	48.5%	0.0%	0.75	1.30	A-	7
Wisconsin Energy Corporation	WEC	Central	6/26/09	42.5%	57.0%	0.5%	0.65	1.33	BBB+	8
Xcel Energy, Inc	XEL	West	5/8/09	46.0%	53.5%	0.5%	0.65	1.13	BBB+	8
Mean Value				48.5%	50.0%	1.4%	0.69	1.30	BBB+	7.95
Common Comparable Companies										
Consolidated Edison, Inc.	ED	East	5/29/09	50.0%	40.0%	10.0%	0.65	1.01	A-	7.00
DTE Energy Co.	DTE	Central	6/26/09	44.0%	56.0%	0.0%	0.75	0.84	BBB	9.00
Entergy Corp.	ETR	Central	6/26/09	38.5%	60.0%	1.5%	0.70	1.78	BBB	9.00
FPL Group Inc.	FPL	East	5/29/09	46.0%	54.0%	0.0%	0.75	1.83	A	6.00
Idacorp, Inc.	IDA	West	5/8/09	53.5%	46.5%	0.0%	0.70	0.87	BBB	9.00
Progress Energy Inc.	PGN	East	5/29/09	45.5%	54.5%	0.0%	0.65	1.16	BBB+	8.00
Southern Co.	SO	East	5/29/09	43.0%	54.0%	3.0%	0.55	1.70	BBB+[1]	8.00
Vectren Corporation	VVC	Central	6/26/09	51.5%	48.5%	0.0%	0.75	1.30	A-	7.00
Wisconsin Energy Corporation	WEC	Central	6/26/09	42.5%	57.0%	0.5%	0.65	1.33	BBB+	8.00
Xcel Energy, Inc	XEL	West	5/8/09	46.0%	53.5%	0.5%	0.65	1.13	BBB+	8.00
Mean Value				46.1%	52.4%	1.6%	0.68	1.30	BBB+	7.90

1 Rating for Southern Power Co.

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Comparable Companies

				Historical Earnings per Share						
							Compound Annual Growth Rate			2012-14 % Growth
			Value Line				1993-	1999-		vs.
Staff Comparable Companies	Ticker	Region	Report	1993	1999	2008	2008	2008	Available	2006-08
Consolidated Edison, Inc.	ED	East	5/29/09	2.66		3.36	1.6%		1.6%	2.5%
DTE Energy Co.	DTE	Central	6/26/09	3.34		2.73	-1.3%		-1.3%	7.5%
Empire District Electric Co.	EDE	Central	6/26/09	1.16		1.17	0.1%		0.1%	8.5%
Entergy Corp.	ETR	Central	6/26/09	2.62		6.20	5.9%		5.9%	6.0%
FirstEnergy Corp.	FE	East	5/29/09		2.50	4.38		6.4%	6.4%	
FPL Group Inc.	FPL	East	5/29/09	1.38		4.07	7.5%		7.5%	10.0%
Idacorp, Inc.	IDA	West	5/8/09	1.97		2.18	0.7%		0.7%	4.5%
Progress Energy Inc.	PGN	East	5/29/09		2.55	2.96		1.7%	1.7%	
Southern Co.	SO	East	5/29/09	1.57		2.25	2.4%		2.4%	4.5%
Vectren Corporation	VVC	Central	6/26/09	1.48		1.63	0.6%		0.6%	5.5%
Wisconsin Energy Corporation	WEC	Central	6/26/09	1.81		3.03	3.5%		3.5%	8.0%
Xcel Energy, Inc.	XEL	West	5/8/09	1.43		1.46	0.1%		0.1%	6.5%
Mean Value							2.1%	4.0%	2.4%	6.4%
PP&L Comparable Companies										
Allete Inc.	ALE	Central	6/26/09						n/a	
Alliant Energy Corp	LNT	Central	6/26/09		2.19	2.54		1.7%	1.7%	
Consolidated Edison, Inc.	ED	East	5/29/09	2.66		3.36	1.6%		1.6%	2.5%
DPL Inc.	DPL	Central	6/26/09	0.95		2.12	5.5%		5.5%	8.0%
DTE Energy Co.	DTE	Central	6/26/09	3.34		2.73	-1.3%		-1.3%	7.5%
Duke Energy Corp.	DUK	East	5/29/09						n/a	
Edison International	EIX	West	5/8/09	1.57		3.68	5.8%		5.8%	3.5%
Entergy Corp.	ETR	Central	6/26/09	2.62		6.20	5.9%		5.9%	6.0%
FPL Group Inc.	FPL	East	5/29/09	1.38		4.07	7.5%		7.5%	10.0%
Idacorp, Inc.	IDA	West	5/8/09	1.97		2.18	0.7%		0.7%	4.5%
NSTAR	NST	East	5/29/09	1.14		2.22	4.5%		4.5%	8.0%
PG&E Corp.	PCG	West	5/8/09	2.33		3.22	2.2%		2.2%	6.5%
Portland General	POR	West	5/8/2009						n/a	
Progress Energy Inc.	PGN	East	5/29/09		2.55	2.96		1.7%	1.7%	
Sempra Energy	SRE	West	5/8/2009	1.81		4.43	6.1%		6.1%	5.0%
Southern Co.	SO	East	5/29/09	1.57		2.25	2.4%		2.4%	4.5%
Vectren Corporation	VVC	Central	6/26/09	1.48		1.63	0.6%		0.6%	5.5%
Wisconsin Energy Corporation	WEC	Central	6/26/09	1.81		3.03	3.5%		3.5%	8.0%
Xcel Energy, Inc	XEL	West	5/8/09	1.43		1.46	0.1%		0.1%	6.5%
Mean Value				1.86	2.37	3.01	3.2%	1.7%	3.0%	6.1%
Common Comparable Companies										
Consolidated Edison, Inc.	ED	East	5/29/09	2.66		3.36	1.6%		1.6%	2.5%
DTE Energy Co.	DTE	Central	6/26/09	3.34		2.73	-1.3%		-1.3%	7.5%
Entergy Corp.	ETR	Central	6/26/09	2.62		6.20	5.9%		5.9%	6.0%
FPL Group Inc.	FPL	East	5/29/09	1.38		4.07	7.5%		7.5%	10.0%
Idacorp, Inc.	IDA	West	5/8/09	1.97		2.18	0.7%		0.7%	4.5%
Progress Energy Inc.	PGN	East	5/29/09		2.55	2.96		1.7%	1.7%	
Southern Co.	SO	East	5/29/09	1.57		2.25	2.4%		2.4%	4.5%
Vectren Corporation	VVC	Central	6/26/09	1.48		1.63	0.6%		0.6%	5.5%
Wisconsin Energy Corporation	WEC	Central	6/26/09	1.81		3.03	3.5%		3.5%	8.0%
Xcel Energy, Inc	XEL	West	5/8/09	1.43		1.46	0.1%		0.1%	6.5%
Mean Value				2.03	2.55	2.99	2.3%	1.7%	2.3%	6.1%

CASE: UE 210
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 804

Exhibits in Support
Of Opening Testimony

July 24, 2009

Staff/804
Storm/1

Analytical Perspectives

Budget of the U.S. Government

Fiscal Year 2010

EXECUTIVE OFFICE OF THE PRESIDENT OF THE UNITED STATES
OFFICE OF MANAGEMENT AND BUDGET

Office of Management and Budget
www.budget.gov

THE BUDGET DOCUMENTS

A New Era of Responsibility: Renewing America's Promise contains the Budget Message of the President, information on the President's priorities, and budget overviews organized by agency. This document was published on February 26, 2009.

Since publication of this initial volume, the Administration has produced updated budget estimates based on new technical and other information. The following volumes are based on those new estimates, and updated summary tables were published in the following volume.

Updated Summary Tables, May, 2009, Budget of the United States Government, Fiscal Year 2010 contains a set of summary tables updated and expanded from the February FY 2010 President's Budget overview.

Analytical Perspectives, Budget of the United States Government, Fiscal Year 2010 contains analyses that are designed to highlight specified subject areas or provide other significant presentations of budget data that place the budget in perspective. This volume includes economic and accounting analyses; information on Federal receipts and collections; analyses of Federal spending; information on Federal borrowing and debt; baseline or current services estimates; and other technical presentations. The *Analytical Perspectives* volume also contains supplemental material with several detailed tables, including tables showing the budget by agency and account and by function, subfunction, and program, that is available on the Internet and as a CD-ROM in the printed document.

Historical Tables, Budget of the United States Government, Fiscal Year 2010 provides data on budget receipts, outlays, surpluses or deficits, Federal debt, and Federal employment over an extended time period, generally from 1940 or earlier to 2010 or 2014.

To the extent feasible, the data have been adjusted to provide consistency with the 2010 Budget and to provide comparability over time.

Appendix, Budget of the United States Government, Fiscal Year 2010 contains detailed information on the various appropriations and funds that constitute the budget and is designed primarily for the use of the Appropriations Committees. The *Appendix* contains more detailed financial information on individual programs and appropriation accounts than any of the other budget documents. It includes for each agency: the proposed text of appropriations language; budget schedules for each account; legislative proposals; explanations of the work to be performed and the funds needed; and proposed general provisions applicable to the appropriations of entire agencies or group of agencies. Information is also provided on certain activities whose transactions are not part of the budget totals.

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Internet. All budget documents, including documents that are released at a future date, spreadsheets of many of the budget tables, and a public use budget database are available for downloading in several formats from the Internet at *www.budget.gov / budget*. Links to documents and materials from budgets of prior years are also provided.

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GENERAL NOTES

1. All years referred to are fiscal years, unless otherwise noted.
2. Detail in this document may not add to the totals due to rounding.

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ECONOMIC ASSUMPTIONS AND ANALYSES

12. ECONOMIC ASSUMPTIONS

In April, the U.S. economy was in the sixteenth month of a deep recession. In its early stages, the recession was relatively mild, but in the last quarter of 2008, real gross domestic product (GDP) fell at an annualized rate of 6.3 percent.[1] Unemployment has also risen sharply in recent months. The latest data suggest another large decline in output occurred in the first quarter of 2009, which could make for the deepest drop in economic activity since World War II.

The recession is not limited to the United States. Other industrial countries are experiencing similar declines in output and employment, and world trade is contracting. Meanwhile, financial institutions around the world have been seized by paralyzing uncertainty about the underlying value of the assets they hold, crippling lending and contributing to further declines in asset prices. Falling asset prices have hammered household wealth and caused consumers to reduce spending.

The Federal Government has adopted fiscal and monetary policies to counter the downward drag from private reductions in spending and investment. In February, the Congress and the President enacted the American Recovery and Reinvestment Act, an economic stimulus measure, which will replace demand withdrawn by the private sector. This Budget extends and strengthens several key measures in the Recovery Act. Meanwhile, monetary policy has effectively lowered short-term interest rates to zero and the Federal Reserve has expanded its balance sheet in novel ways so as to support continued lending in the private sector. The Administration is also taking steps to buttress the financial system and the housing sector.

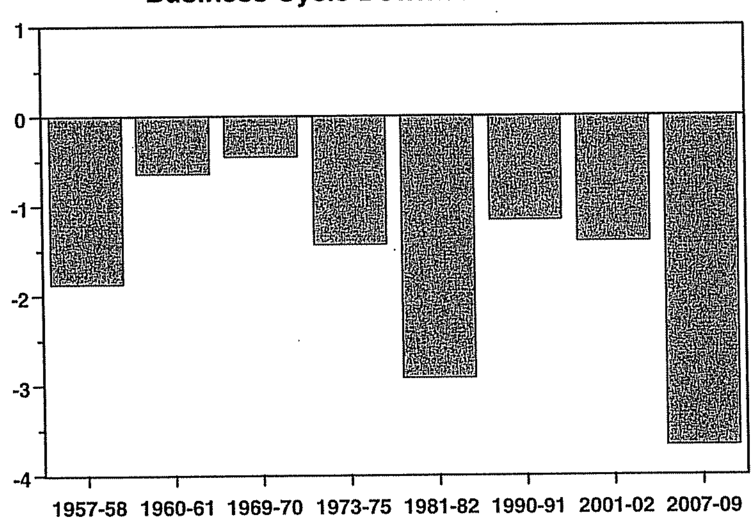
These policies are expected to stabilize the economy and stimulate a recovery by the end of 2009. The recovery is projected to gain momentum in 2010 and to strengthen further in 2011-2012. By the end of 2013, the unemployment rate is projected to fall to 5 percent, which is a sustainable level, and real GDP is projected to be growing at its potential, around 2.6 percent per year.

Recent Economic Performance

According to the business cycle's unofficial scorekeeper, the National Bureau of Economic Research (NBER), the most recent economic expansion ended more than a year ago in December 2007. The economy has been in recession since then. In May, it will be the longest recession since before World War II. The contraction has also been unusually deep as measured by the decline in payroll employment (see Chart 12-1). Other measures such as the rise in the unemployment rate also imply that this is one of the most severe recessions since the Great Depression.

[1] In the Budget, economic performance is discussed in terms of calendar years. Budget figures are discussed in terms of fiscal years.

Chart 12-1. Percentage Decline in Payroll Employment Business Cycle Downturns since 1955



Housing Markets: The downturn had its origin in the housing market. In hindsight, it is clear that by the early years of this decade, housing prices had become caught up in a speculative bubble that finally burst. Housing prices have fallen sharply since 2006, and investment in housing has plummeted, reducing the annual average rate of real GDP growth by an average of 1 percentage point per quarter since mid-2006. Initially, it appeared as if the decline in housing might be contained within that industry and throughout 2006-2007 the broader economy continued to expand despite the drag from declining residential investment.

In August 2007, however, the accumulating problems in the housing market led to a worldwide crisis of confidence in the banks and credit markets, and through that channel the housing crisis initiated a widespread economic contraction. Although much of the needed adjustment in relative housing prices appears to have occurred (see chart below), further price declines may yet occur in response to the continuing economic downturn. Monthly housing starts were running at less than a 600,000 annual rate in early 2009. This is the lowest level ever recorded for this series, which dates from 1959. In normal times, at least 1-1/2 million starts a year are needed to accommodate the needs of an expanding population and to replace older units as they wear out. The Administration expects housing starts to reach bottom this year and to begin a robust recovery as relative housing prices stabilize. Even so, it will take time to work off the accumulated inventory of unsold homes and for existing homeowners to see the equity value of their property begin to rise again.

The Rise and Fall of World Oil Prices: In the winter of 2006-2007, world oil prices were around $60/barrel for light crude, and regular gasoline was selling for around $2.25/gallon. Then oil prices began to spike upward as surging worldwide demand came up against limited worldwide production capacity. Over the next 18 months, oil prices shot up to over $140/barrel and gasoline prices briefly topped $4/gallon. This price increase had a depressing effect on sales of motor vehicles, especially popular but less fuel-efficient sport utility vehicles (SUVs) and light trucks. In July 2008, at the peak of the oil price spike, total vehicle sales were down 19 percent from the previous year. Higher fuel costs also shook consumer confidence and hurt retail sales of other products. Since the 1970s, oil price spikes have often contributed to the swings in the U.S. business cycle, and that appears to have happened again last year as the fall-off in motor vehicle demand cut sharply into consumer spending.

As the world economy has weakened, energy prices have reversed direction and returned to lower levels. In early April 2009, light crude oil was selling for around $50 per barrel and regular gasoline was selling for around $2 per gallon. The unwinding of the energy shock should contribute to the expected recovery this year. With lower fuel prices, motor vehicle sales are expected to begin to recover.

The Financial Crisis: In August 2007, the United States subprime mortgage market became the focal point for a worldwide financial crisis. Subprime mortgages are classified as mortgages going to borrowers who do not meet the standard criteria for borrowing at the lowest prevailing interest rate, either because of low income, a poor credit history, lack of a down payment, or other reasons. In the spring of 2007, there were over $1 trillion in such mortgages, and with house prices falling many of these mortgages were on the brink of default.

As banks and other investors suddenly lost confidence in the value of these high-risk mortgages and the securities based on them, banks became much less willing to

Chart 12-2. Relative House Prices Have Fallen Substantially

Case-Shiller National Home Price Index Divided by the CPI Rent Component, 1987=100

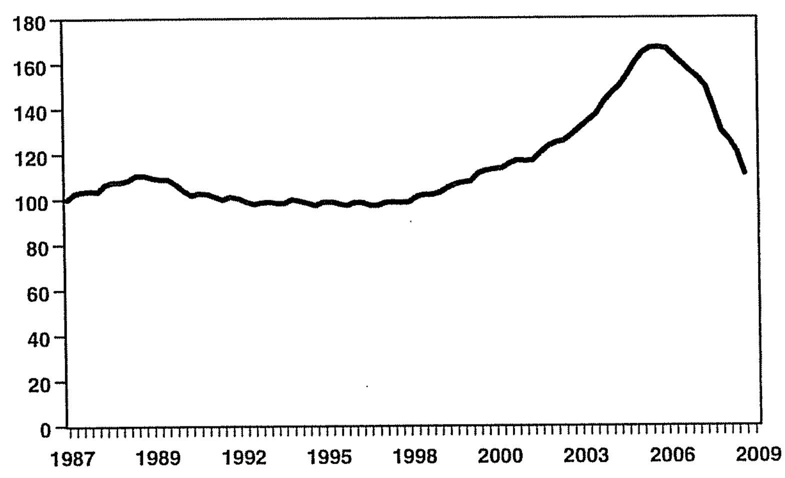
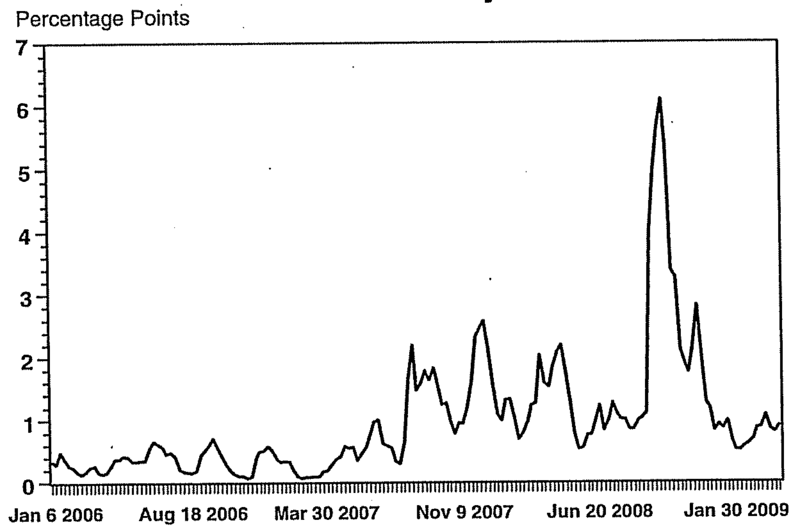


Chart 12-3. One-Month LIBOR Spread over One-Month Treasury Yield

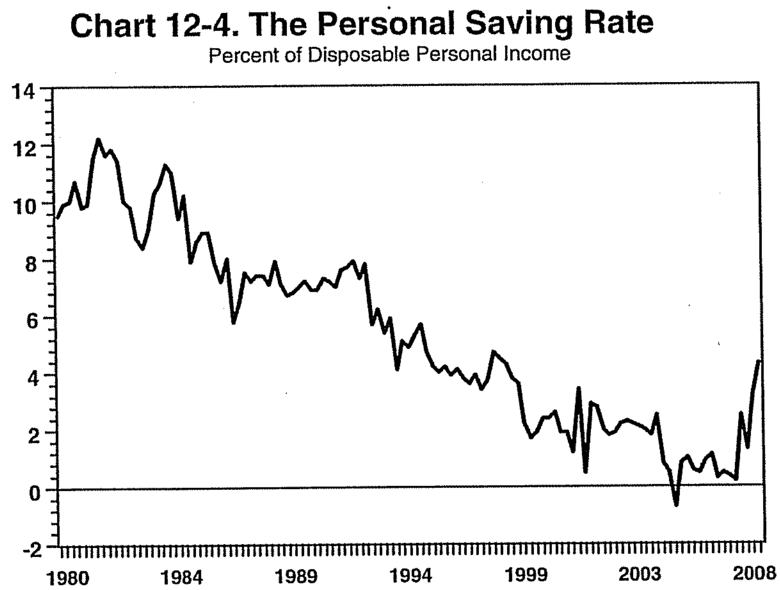


lend to each another. Money market participants outside the banks became unwilling to lend to one another as well. Financial market participants of all kinds were uncertain of the degree to which other participants' balance sheets had been contaminated. The heightened uncertainty was reflected in unprecedented spreads between interest rates on Treasury securities, which are regarded as free of default risk, and various types of financial market debt. One especially telling differential is the spread between the yield on short-term U.S. Treasury securities, and the London interbank lending rate (LIBOR) which banks charge to one another for short-term lending in dollars. Historically, this differential has amounted to only 30 or 40 basis points. In August 2007, it shot up to over 2 percent, and it has remained elevated since then (see chart above).

The credit crunch that began in August 2007 quickly extended throughout the world's financial markets. At the time the threat appeared severe but limited. The problem was perceived to be with the relatively new and unusually risky mortgages that had spread throughout the financial system through the use of mortgage-backed securities, and other sophisticated financial products based on them. Conventional home mortgages along with other forms of consumer and business credit were not seen as being at special risk. Even so, by December 2007, the six-year old economic expansion had run its course. The combination of negative shocks in housing, energy markets, banking and finance brought it to a close. As 2008 began, payroll employment started to decline, and the unemployment rate, which had already reached bottom in March 2007, continued to rise.

Throughout 2008, employment was falling but until mid-year real GDP continued to expand. A stimulus package of income tax rebates and business tax cuts passed early in the year helped postpone the worst effects of the recession for several months. However, in September 2008, the long-established investment banking firm of Lehman Brothers failed and that failure reignited the credit crunch, pushing yield spreads to new and dizzying heights. Two days following the failure of Lehman Brothers, the Federal Government stepped in to prevent the failure of the insurance giant American International Group (AIG), seeking to avoid an even wider spread financial panic. The value of other asset-backed securities came into question, and even money market mutual funds experienced large withdrawals. Since then finance ministries and central banks around the world have tried with some success to contain the damage from the spreading crisis, and risk spreads are narrower today than they were six months ago. Nevertheless, uncertainty remains high, and the repercussions from the financial crisis have deepened the recession in the broader world economy, which in turn has fed back to weaken financial institutions further.

Negative Wealth Effects and Consumption: Between the third quarter of 2007 and the fourth quarter of 2008, the net worth of American households declined by $13 trillion, or 20 percent. The decline in the stock market and falling house prices were the main reasons for the drop in household wealth. Americans reacted to this massive loss of wealth by trying to save more. The household saving rate, which had been declining since the 1980s and had fallen to just 0.6 percent in 2007, shot up to over 4 percent in January and February, to reach its highest level in over a decade. In the long-run, increased saving is desirable because it raises future living standards. However, a sudden increase in the desire to save implies a corresponding reduction in consumer demand and that fall-off in consumption has had a devastating effect on the economy. In last year's third quarter, real consumer spending fell for the first time since 1991, and it fell even more in the



fourth quarter. As of January 2009, the monthly level of real consumer spending was exactly where it had been two years earlier at the beginning of 2007. These sharp declines helped to push down overall real GDP growth to -6.3 percent at an annual rate in the fourth quarter, while raising the personal saving rate to heights not seen since the 1990s.

Policy Background

The Administration and the Federal Reserve have taken a series of actions to reverse the decline in demand that caused the recession. On the fiscal side, the most important step was the passage in February of the American Recovery and Reinvestment Act. This bill will dispense $825 billion in tax reductions and new spending, most of it within the next eighteen months, and it is expected to have a major effect on employment and economic growth. The 2010 Budget will extend these actions through tax reduction for middle-class families and through investments in health care, energy, education, and our armed forces. These measures will provide for a sustained recovery with enhanced security and improved productivity. Meanwhile, the Federal Reserve has lowered interest rates and made credit widely available to stimulate the economy.

***Fiscal Policy*:** The Federal budget affects the economy through many diverse channels. For an economy in a deep recession, the most important of these is the budget's effect on aggregate demand. In a slumping economy, the level of aggregate demand is the main determinant of how much is produced and how many workers will be employed. Federal spending on goods and services can substitute for missing private spending while changes in taxes and transfers can contribute to demand by enabling people to spend more than they otherwise would. The American Recovery and Reinvestment Act bolsters aggregate demand in several ways while laying the foundation for a sustained recovery. It increases spending on goods and services at the Federal level; it provides assistance to State Governments; it includes large tax reductions for middle-class families; and it extends unemployment and other benefits which will allow people to maintain spending levels.

Key provisions of the Act include:

- The Making Work Pay tax credit, which extends tax relief to 95 percent of workers and their families.
- A total of $308 billion in tax relief.
- A $111 billion investment in infrastructure and science.
- A doubling of renewable energy production capacity over the three years through 2011.
- Subsidized health insurance coverage for unemployed workers, which acts like a tax reduction by allowing families to continue paying their other bills while avoiding reductions in consumption.
- The largest Federal investment in education in history.
- A total of about $180 billion in State and local fiscal relief.
- An increase of $81 billion in funding for unemployment insurance and other programs to protect the most vulnerable.

The Recovery Act was designed to go into effect quickly, so that the money will be spent when it can do the most good in stimulating real economic growth and reducing unemployment as the economy begins to recover from the recession.

The 2010 Budget necessarily increases the deficit in the near term to deal with the recession and get the economy growing again, but in the medium term as the economy recovers, the Budget provides a path to lower deficits and a more stable ratio of Federal debt to GDP. The increase in the deficit is an extraordinary but necessary response to an inherited crisis. It is also temporary. If the 2010 Budget is adopted, the deficit will be cut in half by 2012.

In the long run, the most important macroeconomic effects of the Federal budget are on the allocation of saving and the level of private investment. Large budget deficits become harmful in a long-run context because they entail some combination of reduced funds available to finance domestic investment or increased borrowing from abroad to finance that domestic investment. Either way, budget deficits reduce future national income—either because the nation does not have as much productivity-enhancing capital in the future or because we owe larger liabilities to foreign creditors. In the extreme, sustained deficits could seriously harm the economy. Large deficits would also limit the Government's maneuvering room to handle crises in the future.

Health Reform Is Needed for Long-Run Fiscal Stability: The health reforms proposed in this budget are the key to achieving long-run fiscal stability. Without significant health reform it will be impossible to rein in Federal spending as required for fiscal stabilization, since in the absence of reform the Government's major health programs – Medicare and Medicaid – are projected to be the most rapidly growing programs in the budget by a large margin. A successful health reform that slows the growth of per capita health care costs is also the essential ingredient for expanding health insurance coverage without permanently adding to the projected level of long-run spending.

Monetary Policy: The Federal Reserve is responsible for monetary policy. Traditionally, it has acted cautiously, but in the current crisis the Fed has boldly proceeded to create new institutions and open new channels for monetary policy. The reason for departing from past practice is that the traditional tool of monetary policy – adjusting short-term interest rates – has proved insufficient in stimulating growth and preventing unemployment in the current recession. Short-term interest rates in the United States have been reduced from 5-1/4 percent in July 2007 to near zero in December 2008, and it is not possible for them to go any lower.

In light of the floor on short-term interest rates, the Federal Reserve has sought to increase credit availability in several novel ways. First, it has taken action to make sure that financial institutions have access to short-term credit. The financial crisis has been marked by a reluctance of financial institutions to lend to one another. The Federal Reserve has tried to counter that reluctance by making credit directly available to institutions that need liquidity.

The Federal Reserve has been willing to lend generously to banks, but that lending by itself does not necessarily induce the banks to lend to their customers, and the Federal Reserve's bank lending does not provide liquidity to nonbank financial markets such as the commercial paper market. To address these problems, the Federal Reserve has created facilities to provide credit to the commercial paper market directly and to provide backup liquidity for money market mutual funds, in a way taking the place of private banks which have been crippled by the financial crisis. The Federal Reserve together with Treasury has expanded another facility to lend against AAA-rated asset-backed securities collateralized by student loans, auto loans, credit card loans, and business loans guaranteed by the Small Business Administration (SBA). The Federal Reserve has also decided to buy longer-term securities for its portfolio. Traditionally, the Federal Reserve has limited its open market operations to short-term Government securities, but it will now begin to acquire long-term debt including the debt of the government-sponsored enterprises (GSEs) and mortgage-backed securities guaranteed by Federal agencies. In this way, the Federal Reserve is acting to bring downward pressure on long-term interest rates which have not fallen as much as the short-term rates traditionally targeted by monetary policy.

The Federal Reserve's actions have helped ease the credit crisis as evidenced by a decline in the interest rate spread between U.S. Treasuries and other securities. Although the LIBOR spread remains elevated, it has declined from around 4 percent late last year to under 1 percent in early April. The expanded credit facilities have caused a huge increase in the Federal Reserve's balance sheet. Federal Reserve assets have increased from around $1 trillion to over $2 trillion. This large increase holds the potential for an explosive increase in the Nation's money supply. So far that has not occurred, because much of the increase in Federal Reserve liabilities has gone into idle reserves of the banks. Because of this and because the weaknesses in the economy are expected to dampen future price increases, current inflation risks are low. The Federal Reserve is prepared to reduce the assets on its balance sheet promptly as the economy recovers from the current recession and the crisis in the financial sector eases, as a result, future inflation risks should be manageable.

Financial Stabilization Policies: In the past 100 days, the administration has moved aggressively to remedy the problems plaguing financial markets. The Administration is implementing a Financial Stability Plan which is designed to clean up and strengthen the nation's banking system by bringing in private capital to restart lending, and get credit flowing again to consumers and businesses. This plan began with a forward-looking capital assessment exercise for the 19 U.S. banking institutions with assets in excess of $100 billion. The exercise was designed to ensure that these institutions have sufficient capital to withstand more stressful economic conditions, should such conditions arise.

The second component of the Financial Stability Plan is aimed at starting a market for the troubled real-estate related assets that are at the center of the current crisis. The plan includes provisions for the Federal Government to join private investors in buying mortgage-backed

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Table 12–1. ECONOMIC ASSUMPTIONS[1]
(Calendar years; dollar amounts in billions)

	2007 Actual	Projections 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gross Domestic Product (GDP):													
Levels, dollar amounts in billions:													
Current dollars	13,808	14,281	14,291	14,902	15,728	16,731	17,739	18,588	19,415	20,279	21,181	22,124	23,108
Real, chained (2000) dollars	11,524	11,671	11,527	11,893	12,372	12,937	13,474	13,870	14,231	14,601	14,981	15,371	15,771
Chained price index (2000 = 100), annual average	119.8	122.4	124.0	125.3	127.1	129.3	131.6	134.0	136.41	138.87	141.37	143.91	146.51
Percent change, fourth quarter over fourth quarter:													
Current dollars	4.9	1.7	1.4	4.8	6.0	6.5	5.6	4.5	4.5	4.4	4.4	4.5	4.4
Real, chained (2000) dollars	2.3	-0.2	0.3	3.5	4.4	4.6	3.8	2.6	2.6	2.6	2.6	2.6	2.6
Chained price index (2000 = 100)	2.6	1.9	1.0	1.2	1.5	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Percent change, year over year:													
Current dollars	4.8	3.4	0.1	4.3	5.5	6.4	6.0	4.8	4.5	4.4	4.4	4.4	4.4
Real, chained (2000) dollars	2.0	1.3	-1.2	3.2	4.0	4.6	4.2	2.9	2.6	2.6	2.6	2.6	2.6
Chained price index (2000 = 100)	2.7	2.2	1.2	1.1	1.5	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Incomes, billions of current dollars:													
Corporate profits before tax	1,886	1,609	1,588	1,708	1,821	1,945	2,081	2,157	2,224	2,308	2,427	2,574	2,716
Employee compensation	7,812	8,048	8,102	8,441	8,931	9,493	10,049	10,549	11,040	11,554	12,086	12,623	13,199
Wages and salaries	6,362	6,543	6,575	6,838	7,236	7,692	8,142	8,548	8,941	9,347	9,778	10,207	10,671
Other taxable income[2]	3,096	3,177	3,194	3,423	3,669	3,872	4,021	4,168	4,323	4,484	4,658	4,857	5,070
Consumer Price Index (all urban):[3]													
Level (1982-84 = 100), annual average	207.3	215.2	214.0	217.5	221.3	225.8	230.5	235.3	240.3	245.3	250.5	255.7	261.1
Percent change, fourth quarter over fourth quarter	4.0	1.5	0.8	1.6	1.8	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Percent change, year over year	2.9	3.8	-0.6	1.6	1.8	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Unemployment rate, civilian, percent:													
Fourth quarter level	4.8	6.9	8.1	7.7	6.8	5.6	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Annual average	4.6	5.8	8.1	7.9	7.1	6.0	5.2	5.0	5.0	5.0	5.0	5.0	5.0
Federal pay raises, January, percent:													
Military[4]	2.7	3.5	3.4	2.9	NA	NA	NA	NA	NA	NA	NA	NA	NA
Civilian[5]	2.2	3.5	2.9	2.0	NA	NA	NA	NA	NA	NA	NA	NA	NA
Interest rates, percent:													
91-day Treasury bills[6]	4.4	1.4	0.2	1.6	3.4	3.9	4.0	4.0	4.0	4.0	4.0	4.0	4.0
10-year Treasury notes	4.6	3.7	2.8	4.0	4.8	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2

NA = Not Available

[1] Based on information available as of end of January 2009.
[2] Rent, interest, dividend, and proprietors' income components of personal income.
[3] Seasonally adjusted CPI for all urban consumers.
[4] Percentages apply to basic pay only; percentages to be proposed for years after 2010 have not yet been determined.
[5] Overall average increase, including locality pay adjustments. Percentages to be proposed for years after 2010 have not yet been determined.
[6] Average rate, secondary market (bank discount basis).

securities. Removing these assets from the banks' balance sheets is a key step to restoring the financial system to normal functioning. The final component of the Financial Stability Plan aims to unfreeze secondary markets for loans to consumers and businesses using public resources to leverage private investors through the Term Asset-Backed Securities Loan Facility of the Federal Reserve.The Administration has also undertaken a Homeowner Affordability and Stability Plan to help millions of Americans refinance their mortgages at lower interest rates. This initiative aims to reach borrowers who are current on their mortgages and have played by the rules but who are at high risk of foreclosure if prices fall further. Many of these borrowers live in communities where home values have fallen 20 percent or more and who find themselves unable to refinance at today's low interest rates because their loan-to-value ratio is above 80 percent. For the 4 to 5 million such homeowners with conforming loans either owned or guaranteed by Freddie Mac and Fannie Mae, this initiative will allow these borrowers to refinance at today's low rates, reducing the chance that they will default if prices fall further.

A second part of this plan would reach out to an additional 3 to 4 million American families who, because they have high mortgage-debt to income ratios or because their mortgage exceeds their home value, are at high risk of default. This component of the plan will provide incentive payments to owners, servicers, and lenders to make loan modifications to bring down interest rates so that the borrower's monthly mortgage payment is no greater than 31 percent of his or her income. A final part of the Homeowner Affordability and Stability Plan increases the Government's funding commitment to support Fannie Mae and Freddie Mac as they work to keep mortgage rates down and increase the size of their loan portfolios.

Economic Projections

The Administration's economic projections underlying the Budget estimates are summarized in Table 12–1. The assumptions are based on information available as of late January 2009. This section discusses the Administration's projections and the next section compares these projections with those of the Congressional Budget Office (CBO) and the Blue Chip Consensus.

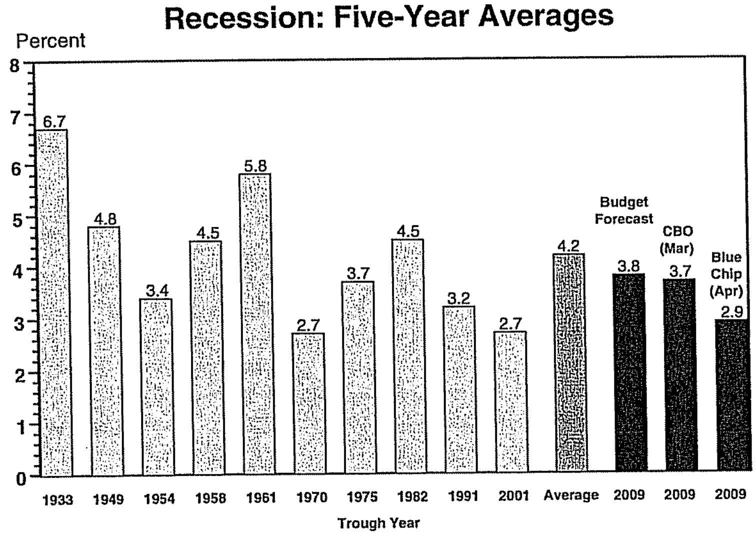
Real GDP and the Unemployment Rate: Real GDP is now estimated to have fallen 0.8 percent from the fourth quarter of 2007 through the end of 2008. This was the first four-quarter decline in real GDP since 1991. The year ended on an especially weak note with real GDP dropping at a 6.3 percent annual rate in the fourth quarter, the largest decline in a single quarter since 1982. Payroll employment has declined every month since December 2007, and the unemployment rate has risen substantially. In March, the national unemployment rate reached 8.5 percent, the highest it has been since 1983. Broader measures of labor underutilization record a similar increase. The broadest measure of unemployment and underemployment reported by the Bureau of Labor Statistics has increased from 7.9 percent in December 2006 to 15.6 percent in March.

The Administration projects an economic recovery will begin in the second half of the year sparked by the American Recovery and Reinvestment Act. By the end of the year, real growth is expected to have reached 3-1/2 percent at an annual rate, a pace that is maintained through 2010. In 2011-2013, the rate of growth in real GDP is projected to accelerate to around 4-1/2 percent annually for several quarters. This rapid growth is expected to push down the unemployment rate, which is projected to return to 5.0 percent by the end of 2013.

As shown in the chart below, the Administration's projections for real GDP growth over the next five years imply a recovery that is a bit below average. It is true that recent recoveries have been somewhat weaker, but the last two expansions were preceded by very mild recessions, which left less pent-up demand when conditions improved. Some analysts believe the recovery from the current recession will be weak, because it will be crippled by continuing problems in the financial sector. The Administration takes the view that the steps it has already taken along with future actions will resolve those financial problems in a timely manner. Although the economic downturn so far in 2009 has been more severe than the Administration expected when the forecast was finalized, if the financial system begins to function more normally, there is every reason to expect a somewhat stronger recovery given the depth of the current recession.

Estimate of Jobs Saved or Created: The President's Council of Economic Advisers has estimated that the Recovery Act will create or save 3-1/2 million jobs by the end of 2010. This estimate is based on "multipliers" from standard macroeconomic models which suggest that extra

Chart 12-5. Economic Growth Following a Recession: Five-Year Averages



government spending on goods and services leads to a total increment in aggregate demand equal to 1.6 times the increase in Federal spending, while a tax reduction has a multiplier of 1.0 for a permanent reduction (one-time tax rebates have a much smaller multiplier).

Longer Term Growth: The Administration forecast does not attempt to project cyclical developments beyond the next few years. The long-run projection for real economic growth and unemployment assumes that they will maintain trend values in the years following the return to full employment. In the nonfarm business sector, productivity growth is assumed to hold to its recent trend of around 2.3 percent per year, while nonfarm labor supply grows at a rate of around 0.7 percent per year, so nonfarm business output grows approximately 3.0 percent per year. Real GDP growth, reflecting the slower measured growth in activity outside the nonfarm business sector, proceeds at a rate of 2.6 percent. That is markedly slower than the average growth rate of real GDP since 1947 – 3.3 percent per year. In the 21st century, economic growth in the United States is likely to be permanently slower than it was in earlier eras because of the slowdown in labor force growth that is expected to occur beginning with the retirement of the post-World War II "baby boom" generation.

Is Real GDP a Random Walk? Not Exactly: The Administration forecast reflects traditional business cycle analysis in which a period of weak or negative growth is followed by a recovery and expansion during which real GDP grows above trend for a time. This is consistent with the natural rate hypothesis and Okun's Law. Okun's Law holds that faster than normal growth is needed to reduce unemployment from an elevated level to its long-run value. Alternatively, some economists believe that real GDP behaves more like a random walk (with drift) in which the best possible projection of future growth is simply the long-run average growth rate observed in the past. On this view, there would be no reason to project above-normal growth at any time.

It has proven difficult to resolve this issue empirically. Official statistics for real GDP extend back to 1947 on a quarterly basis, but that is not long enough to settle the issue definitively. Furthermore, the right answer could well be a blend of the two views, in which real GDP grows at an above-normal rate following a recession but does not return to the previous trend level, but to a somewhat lower level. There also appear to be breaks in the data where the long-run average growth rate shifts up or down, which complicates the statistical testing for randomness. Indeed, the Administration forecast includes such a break in the growth trend because of the expected slowdown in labor force growth.

Unemployment: In the forecast, the unemployment rate converges on 5.0 percent, which the Administration believes is a rate consistent with stable price inflation. When the forecast was finalized in early February, the unemployment rate was expected to peak at an annual average over 8 percent, but economic developments since the forecast was made suggest that unemployment may peak at an even higher rate, even on an annual average basis. The decline in unemployment projected for 2010-2013 is consistent with the Okun's Law relationship mentioned above and the Administration's assumption for potential growth in real GDP. As the official unemployment rate declines, so should the broader measures of labor underutilization.

Inflation: Inflation was volatile in 2008, in large part because of fluctuations in energy prices. Over the 12 months of the year, the CPI fell by 0.1 percent, but during the course of the year, the monthly inflation rate varied between 0.9 percent and -1.7 percent (not annualized). The price declines at the end of the year were the steepest in the post World War II period. The inflation rate is expected to remain subdued over the next few years, mainly because of economic weakness which has depressed the labor market and suppressed producers' pricing power. With the recovery path assumed in the Administration forecast, the risk of outright deflation appears minimal. In the long-run, the Administration assumes that the rate of change in the CPI will average 2.1 percent and that the GDP price index will increase at a 1.8 percent annual rate. These values are within the Federal Reserve's comfort zone for inflation.

Interest Rates: Interest rates on Treasury securities fell sharply in late 2008, which brought both short-term and long-term rates to their lowest levels in decades. So far in 2009, short-term Treasury rates have remained near zero, and the ten-year yield remains near 3 percent. Investors have sought the security of Treasury debt during the heightened financial uncertainty of the last several months. In the projection period, interest rates are expected to rise as financial concerns are alleviated and the economy recovers from recession. The 91-day Treasury bill rate is projected to reach 4.0 percent and the 10-year rate 5.2 percent by 2013, at which point unemployment will have reached its long-run value and the annual growth rate of real GDP will have stabilized at 2.6 percent. These forecast rates are historically low, reflecting lower inflation in the forecast than for most of the post World War II period. After adjusting for inflation, the projected real interest rates are close to their historical averages.

Income Shares: The share of labor compensation in GDP was low by historical standards in 2008 and is expected to rise over the forecast period. As a share of GDP employee compensation was 56.4 percent in 2008 and it is expected to rise to around 57.1 percent toward the end of the 10-year forecast horizon. In the expansion that ended in 2007, labor compensation tended to lag behind the growth in productivity. Output per hour in nonfarm business grew at an average annual rate of 2.3 percent, while real hourly compensation adjusted for the increase in product prices was increasing at a rate of only 1.6 percent. In 2008 the differential narrowed from 0.6 percent to 0.2 percent, and in the forecast, the Administration assumes that compensation will keep pace with productivity.

While the overall share of labor compensation is expected to increase, the wage share is expected to remain roughly flat. The share of employee fringe benefits which supplement taxable wages and salaries takes up most of the increase in compensation. Rising health insurance costs will put upward pressure on the share of fringe benefits.

The share of corporate profits was 12.9 percent of GDP in the third quarter of 2006 prior to the recession, which was near an all-time high. Since then profits have dropped sharply. They are forecast to be only 9.5 percent of GDP in 2009. As the economy recovers, the profit share is expected to rebound. In the forecast, the ratio of profits to GDP reaches 10-1/2 percent in 2011 and remains roughly stable at that level.

Comparison with CBO and Private-Sector Forecasts

Table 12–2 compares the economic assumptions for the 2010 Budget with projections by the Congressional Budget Office (CBO) and by the Blue Chip Consensus, an average of about 50 private-sector economic forecasts. These other economic projections differ in some respects from the Administration's projections, but the forecast differences are relatively small compared with the margin of error in all economic forecasts, and in broad outline, the three forecasts are similar. All three agree that the recession is likely to end in 2009 and that the economy will begin to recover showing positive growth in 2010

Table 12–2. COMPARISON OF ECONOMIC ASSUMPTIONS
(Calendar years)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Nominal GDP:												
2010 Budget	14,281	14,291	14,902	15,728	16,731	17,739	18,588	19,415	20,279	21,181	22,124	23,108
Congressional Budget Office (March 2009)	14,257	14,047	14,576	15,233	15,950	16,684	17,421	18,138	18,873	19,624	20,381	21,164
April Blue Chip Consensus[1]	14,263	14,080	14,524	15,304	16,172	17,024	17,903	18,779	19,672	20,607	21,587	22,613
Real GDP (year-over-year):												
2010 Budget	1.3	–1.2	3.2	4.0	4.6	4.2	2.9	2.6	2.6	2.6	2.6	2.6
Congressional Budget Office (March 2009)	1.1	–3.0	2.9	4.0	4.1	4.0	3.5	2.7	2.5	2.4	2.3	2.2
April Blue Chip Consensus[1]	1.1	–2.6	1.8	3.4	3.4	3.0	2.9	2.7	2.6	2.6	2.6	2.6
Real GDP (fourth-quarter-over-fourth-quarter):												
2010 Budget	–0.2	0.3	3.5	4.4	4.6	3.8	2.6	2.6	2.6	2.6	2.6	2.6
Congressional Budget Office (March 2009)	–0.9	–1.5	4.1	4.1	4.1	3.9	3.2	2.6	2.4	2.3	2.2	2.2
April Blue Chip Consensus[1]	–0.8	–1.3	2.7	3.6	3.3	2.9	2.9	2.6	2.6	2.6	2.6	2.6
GDP Price Index:[2]												
2010 Budget	2.2	1.2	1.1	1.5	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Congressional Budget Office (March 2009)	2.2	1.5	0.8	0.5	0.6	0.6	0.9	1.4	1.5	1.6	1.6	1.6
April Blue Chip Consensus[1]	2.2	1.4	1.3	1.7	1.9	2.2	2.2	2.3	2.3	2.3	2.3	2.3
Consumer Price Index (CPI-U):[2]												
2010 Budget	3.8	–0.6	1.6	1.8	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Congressional Budget Office (March 2009)	3.8	–0.7	1.4	1.2	1.0	1.0	1.2	1.6	1.9	1.9	1.9	1.9
April Blue Chip Consensus[1]	3.8	–0.8	1.7	2.1	2.3	2.4	2.5	2.5	2.5	2.5	2.5	2.5
Unemployment Rate:[3]												
2010 Budget	5.8	8.1	7.9	7.1	6.0	5.2	5.0	5.0	5.0	5.0	5.0	5.0
Congressional Budget Office (March 2009)	5.8	8.8	9.0	7.7	6.6	5.6	5.1	4.9	4.8	4.8	4.8	4.8
April Blue Chip Consensus[1]	5.8	8.9	9.5	8.1	7.1	6.4	5.9	5.7	5.6	5.5	5.5	5.5
Interest Rates:[3]												
91-Day Treasury Bills (discount basis):												
2010 Budget	1.4	0.2	1.6	3.4	3.9	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Congressional Budget Office (March 2009)	1.4	0.3	0.9	1.8	3.0	3.9	4.4	4.7	4.7	4.8	4.8	4.8
April Blue Chip Consensus[1]	1.4	0.3	0.9	2.8	3.6	4.0	4.2	4.3	4.2	4.2	4.2	4.2
10-Year Treasury Notes:												
2010 Budget	3.7	2.8	4.0	4.8	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Congressional Budget Office (March 2009)	3.7	2.9	3.4	4.0	4.6	5.0	5.3	5.4	5.5	5.6	5.6	5.6
April Blue Chip Consensus[1]	3.7	2.9	3.5	4.5	4.9	5.2	5.4	5.4	5.4	5.4	5.4	5.4

Sources: Administration; CBO, *A Preliminary Analysis of the President's Budget and an Update of CBO's Budget and Economic Outlook*, March 2009; April 2009 *Blue Chip Economic Indicators*, Aspen Publishers, Inc.

[1] The Blue Chip forecast was extended to 2011-2019 using the March long-run Blue Chip projections, quarterly growth rates for 2011-2019 were interpolated.

[2] Year-over-year percent change.

[3] Annual averages, percent.

and beyond. They are agreed that inflation will be at a low rate in 2009-2010, but outright deflation is avoided. They agree that after peaking at a relatively high rate, unemployment gradually declines and interest rates also return to more normal levels.

The three sets of economic assumptions are based on different underlying assumptions concerning economic policies. The Administration forecast assumes that the President's Budget proposals will be enacted and that the Financial Stability Plan and Homeowner Affordability and Stability Plan will be fully implemented. In contrast, the CBO baseline projection assumes that current law as of the time the estimates were made in March remains unchanged. The 50 or so private forecasters in the Blue Chip Consensus make differing policy assumptions, but none would necessarily assume that the Budget and financial rescue plans are adopted in full. Sometimes these policy differences have relatively little effect on the forecast outcomes, but that is not so in the current environment. The fiscal changes proposed in the budget and the related plans for financial stabilization are large enough to have a major effect on the macroeconomic outlook.

The forecasts also differ because they were made on different dates. Usually a several week difference in forecast dates has little impact on economic forecasts, but in the weeks since the Administration forecast was made, economic data have appeared showing that the economy was much weaker at the end of 2008 and beginning of 2009 than was apparent earlier. Because the CBO and Blue Chip Consensus forecasts were made several weeks later, they reflect the more recent data and consequently offer a somewhat more pessimistic economic outlook.

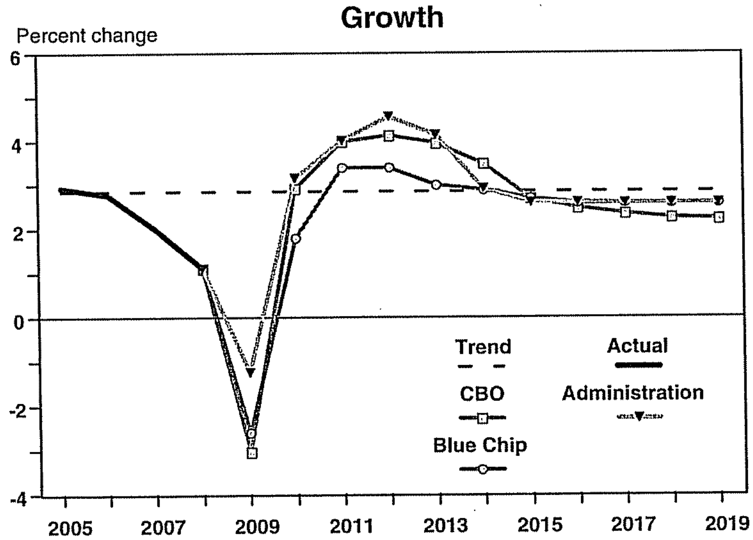
Real GDP Growth: In analyzing forecast differences with respect to real GDP growth, it is useful to consider two questions separately: how deep will the current recession be and what type of recovery is likely once the recession ends? The Administration's real GDP projections are more optimistic than CBO and the private consensus on both points, but the second is much more important for the budget outlook than the first.

Between the end of World War II and 2008, there were ten recessions in the United States. The average decline, from the peak quarter for real GDP to the trough, was 2.0 percent during those ten recessions. The Administration assumes that the current recession will be somewhat worse than this average experience. Meanwhile, CBO and the Blue Chip consensus both expect the recession to be much deeper than average. Nevertheless all three forecasts expect the recession to end in 2009. None anticipates a repeat of the four-year decline from 1929 to 1933, so the difference is mainly a question of when in 2009 the recession will end and how low real GDP will sink before reaching that point.

Naturally, there is great concern about these questions since they bear on how long the current period of mounting job losses will continue, but even were the recession to turn out deeper than the Administration originally forecast, it would not necessarily have a large permanent effect on the budget projections—provided the recovery from the recession adjusts in an offsetting way. The Administration's forecast assumption is that the depth of the recession does not affect the long-run level of real GDP, which is instead tied to potential output and is not affected by the business cycle. Unless a deeper recession affects the projection of the underlying trend for real GDP, it would have only a modest effect on the medium-term budget.

Differences in the potential rate of real GDP growth do have a profound effect on the budget projections, and these are the most important differences separating the Administration's forecast from those of CBO and the Blue Chip. As shown in the chart below, the Administration assumes that real GDP will grow rapidly in the years ahead as it recovers from the 2008-2009 recession. CBO and the Blue Chip are more pessimistic about the long-run outlook. CBO has relatively rapid growth beginning in 2011,

Chart 12-6. Alternative Projections of Real GDP Growth



but not rapid enough to offset the loss expected from the recession, and in the final years of the projection period, CBO has real growth sinking to 2.2 percent. Since 1947, U.S. real GDP has grown at an average rate of 3.3 percent, although the average growth rate over the last 35 years has averaged only 2.8 percent. The Blue Chip consensus is somewhat more optimistic than CBO about the final years of the forecast as its long-run growth rate is 2.6 percent, the same as the Administration assumes, but the Blue Chip has the smallest expected recovery from the current recession in 2010-2013.

A deep recession does not necessarily imply a slow recovery; if anything, it implies the opposite. The historical record points in the other direction with deeper recessions being followed by stronger recoveries. The strongest recovery since 1929 was during the five years following the Great Contraction of 1929-1933. Two important factors could contribute to a weaker than normal expansion: (1) a protracted credit crunch in which the problems in the financial markets are not resolved in 2009 and (2) a deeper world-wide slump that holds down U.S. exports and offsets the effects of fiscal stimulus on domestic demand. Both are possible, but the Administration believes that the credit market problems will be resolved in a timely fashion, and that the United States will once again lead the world out of recession as it has in the past.

It is worth remembering that all economic forecasts are subject to error, and the forecast errors are usually much larger than the forecast differences discussed above. Past forecast errors among the Administration, CBO, and the Blue Chip have been roughly similar.

Unemployment: The near-term differences in the unemployment rate forecasts track the differences in expected real GDP growth. Unemployment rises higher in the CBO and Blue Chip forecasts, because they both expect a deeper and somewhat longer recession than the Administration does. Unemployment peaks at 9.1 percent in 2010 according to the Consensus forecast, while it reaches 9.0 percent in the CBO forecast. In the long run, CBO expects unemployment to return to 4.8 percent, while the Blue Chip only sees it returning to 5.5 percent. The Administration's long-run projection for the unemployment rate is 5.0 percent.

Inflation: The three inflation forecasts are much closer. All three forecasts anticipate a slowdown in inflation in 2009–2010 followed by a gradual return of inflation to the range of 1.6 to 2.3 percent as measured by the GDP price index and between 1.9 and 2.5 percent as measured by the CPI. CBO has the lowest inflation forecast while the Consensus is the highest with the Administration in the middle. None of the forecasters expects the slowdown in inflation to turn into deflation although that risk would appear to be greater in the two forecasts with the slower real growth projections. The Blue Chip projection is somewhat puzzling in that its very weak recovery might have been expected to produce a larger permanent change in the inflation rate. CBO, by contrast, has five consecutive years of less than 1-percent inflation.

Interest Rates: The three forecasts are also similar in their projections for interest rates. They anticipate that interest rates will rise between 2009 and 2012 converging on stable higher levels in 2013 and beyond. CBO projects that the long-run yield on 10-year Treasury notes will be 5.6 percent and Blue Chip projects 5.4 percent. The Administration projects a long-run value of 5.2 percent. Short-term rates are expected to be near zero in 2009, but then to increase reaching a long-run rate of 4.0 percent in the Administration projections, 4.2 percent in the Blue Chip Consensus, and 4.8 percent in the CBO projections. The principal difference between CBO and the Administration projections is that the Administration anticipates a gradual restoration of a yield curve spread between long-term and short-term interest rates that is closer to the historical average.

Changes in Economic Assumptions

The economic assumptions underlying this Budget have changed compared with those used by the previous Administration for the 2009 Budget, although more in the short run than in the long run, as shown in Table 12–3. The previous Administration's final Budget did not anticipate the 2008-2009 recession. Consequently, the projected growth rates for 2008-2009 turned out to be far above those in the current Budget. For the same reason, the strong economic recovery projected for 2010-2013 was not anticipated in the previous Budget and real growth rates for those years are lower than in the current Budget. Finally, the long-run growth trend was pegged at 2.7 percent per year in the previous Budget and that has been revised down slightly to 2.6 percent per year in the current Budget.

The long-run unemployment rate projection is raised from 4.8 percent in the previous Budget to 5.0 percent in the current Budget, while near-term unemployment has been increased substantially as a result of the recession. Inflation was projected to be quite stable in the 2009 Budget at 2.0 percent for the GDP price index and 2.3 percent in most years for the CPI. In the current Budget, inflation is more subdued in 2009, but it rises subsequently reaching its long-run levels in 2013. These long-run stable values for inflation have been marked down by 0.2 percentage point for both the GDP price index and the CPI. Interest rates were much lower in 2008 than expected in the previous Budget and the current forecast has rates for several years that are below those projected in the 2009 Budget. The long-term values, however, for the 3-month Treasury bill rate and the 10-year Treasury note are close to those in the previous Budget.

Sensitivity of the Budget to Economic Assumptions

Both receipts and outlays are affected by changes in economic conditions. This sensitivity complicates budget planning because errors in economic assumptions lead to errors in the budget projections. It is therefore useful to examine the implications of possible changes in economic assumptions. Many of the budgetary effects of such changes are fairly predictable, and a set of rules of thumb

Table 12–3. COMPARISON OF ECONOMIC ASSUMPTIONS IN THE 2009 AND 2010 BUDGETS
(Calendar years; dollar amounts in billions)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nominal GDP:											
2009 Budget Assumptions [1]	14,456	15,190	15,961	16,754	17,574	18,432	19,320	20,241	21,206	22,220	23,288
2010 Budget Assumptions	14,281	14,291	14,902	15,728	16,731	17,739	18,588	19,415	20,279	21,181	22,124
Real GDP (2000 dollars):											
2009 Budget Assumptions [1]	11,846	12,203	12,572	12,938	13,305	13,681	14,059	14,440	14,831	15,236	15,653
2010 Budget Assumptions	11,671	11,527	11,893	12,372	12,937	13,474	13,870	14,231	14,601	14,981	15,371
Real GDP (percent change): [2]											
2009 Budget Assumptions	2.7	3.0	3.0	2.9	2.8	2.8	2.8	2.7	2.7	2.7	2.7
2010 Budget Assumptions	1.3	-1.2	3.2	4.0	4.6	4.2	2.9	2.6	2.6	2.6	2.6
GDP Price Index (percent change): [2]											
2009 Budget Assumptions	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
2010 Budget Assumptions	2.2	1.2	1.1	1.5	1.7	1.8	1.8	1.8	1.8	1.8	1.8
Consumer Price Index (all-urban; percent change): [2]											
2009 Budget Assumptions	2.1	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
2010 Budget Assumptions	1.5	0.8	1.6	1.8	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Civilian Unemployment Rate (percent): [3]											
2009 Budget Assumptions	4.9	4.9	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
2010 Budget Assumptions	5.8	8.1	7.9	7.1	6.0	5.2	5.0	5.0	5.0	5.0	5.0
91-day Treasury bill rate (percent): [3]											
2009 Budget Assumptions	3.7	3.8	4.0	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
2010 Budget Assumptions	1.4	0.2	1.6	3.4	3.9	4.0	4.0	4.0	4.0	4.0	4.0
10-year Treasury note rate (percent): [3]											
2009 Budget Assumptions	4.6	4.9	5.1	5.2	5.3	5.3	5.3	5.3	5.3	5.3	5.3
2010 Budget Assumptions	3.7	2.8	4.0	4.8	5.1	5.2	5.2	5.2	5.2	5.2	5.2

[1] Adjusted for July 2008 NIPA revisions.
[2] Year-over-year.
[3] Calendar year average.

embodying these relationships can aid in estimating how changes in the economic assumptions would alter outlays, receipts, and the surplus or deficit. These rules of thumb should be understood as suggesting orders of magnitude; they ignore a long list of secondary effects that are not captured in the estimates.

The rules of thumb show how the changes in economic variables affect Administration estimates for receipts and outlays; they are not a forecast of how receipts or outlays would actually change if there were a change in economic conditions. The rules of thumb are based on a fixed budget policy that is not always a good predictor of what might actually happen to the budget should the economic outlook change. This is especially true for inflation. Spending for indexed programs, like Social Security, does respond to changes in inflation, but only with a lag. Annually appropriated ("discretionary") spending is specified in nominal dollars, and therefore does not vary when there is a change in the projected rate of inflation. Congress would have to act to maintain unchanged purchasing power in discretionary appropriations. Also, the rules of thumb for receipts changes reported here reflect how Treasury's receipts estimates would shift with certain economic changes, but they do not capture associated "technical" changes that often accompany a shift in the economic outlook. There is, for example, no rule of thumb for the receipts effect of large changes in capital gains tax realizations that often occur when the economic outlook changes.

Economic variables that affect the budget do not usually change independently of one another. Output and employment tend to move together in the short run: a high rate of real GDP growth is generally associated with a declining rate of unemployment, while slow or negative growth is usually accompanied by rising unemployment. This is the Okun's Law relationship discussed above. In the long run, however, changes in the average rate of growth of real GDP are mainly due to changes in the rates of growth of productivity and the labor force, and are not necessarily associated with changes in the average rate of unemployment. Inflation and interest rates are also closely interrelated: a higher expected rate of inflation increases interest rates, while lower expected inflation reduces interest rates.

Changes in real GDP growth or inflation have a much greater cumulative effect on the budget if they are sustained for several years than if they last for only one year. However, even one-time changes can have permanent effects if they permanently raise the level of the tax base or the level of Government spending. Highlights of the budgetary effects of these rules of thumb are shown in Table 12–4.

For real growth and employment:

- The first block shows the effect of a temporary reduction in real GDP growth by one percentage point sustained for one year, followed by a recovery of GDP to the base-case level (the Budget assumptions) over the ensuing two years. In this case, the unemployment rate is assumed to rise by one-half percentage point relative to the Budget assumptions by the end of the first year, then return to the base case rate over the ensuing two years. After real GDP and the unemployment rate have returned to their base case levels, most budget effects vanish except for persistent out-year interest costs associated with larger near-term deficits.
- The second block shows the effect of a temporary reduction in real GDP growth by one percentage point sustained for one year along with a permanent increase in the unemployment rate of one-half percentage point relative to Budget assumptions. In this scenario, the level of GDP and taxable incomes are permanently lowered by the reduced growth rate in the first year. For that reason and because unemployment is permanently higher, the budget effects (including growing interest costs associated with larger deficits) continue to grow slightly in each successive year.
- The budgetary effects are much larger if the growth rate of real GDP is permanently reduced by one percentage point even leaving the unemployment rate unchanged as might result from a shock to productivity growth. These effects are shown in the third block. In this example, the cumulative increase in the budget deficit is many times larger than the effects in the first and second blocks.

For inflation and interest rates:

- The fourth block shows the effect of a one percentage point higher rate of inflation and one percentage point higher interest rates maintained for the first year only. In subsequent years, the price level and nominal GDP would both be one percentage point higher than in the base case, but interest rates and future inflation rates are assumed to return to their base levels. Receipts increase by about twice as much as outlays. This is partly due to the fact that outlays for annually appropriated spending are assumed to remain constant when projected inflation changes. Despite the apparent implication of these estimates, inflation cannot be relied upon to lower the budget deficit, mainly because Congress is not likely to allow inflation to erode the real value of spending permanently.
- In the fifth block, the rate of inflation and the level of interest rates are higher by one percentage point in all years. As a result, the price level and nominal GDP rise by a cumulatively growing percentage above their base levels. In this case, again the effect on receipts is about double the effect on outlays.
- The effects of a one percentage point increase in interest rates alone are shown in the sixth block. The outlay effect mainly reflects higher interest costs for Federal debt. The receipts portion of this rule-of-thumb is due to the Federal Reserve's deposit of earnings on its securities portfolio and the effect of interest rate changes on both individuals' income (and taxes) and financial corporations' profits (and taxes).
- The seventh block shows that a sustained one percentage point increase in the GDP price index and in CPI inflation decreases cumulative deficits substantially. The separate effects of higher inflation and higher interest rates do not sum to the effects for simultaneous changes in both. The gains in budget receipts due to higher inflation result in higher debt service savings when interest rates are also assumed to be higher (the combined case) than when interest rates are assumed to be unchanged (the separate case).
- The last entry in the table shows rules of thumb for the added interest cost associated with changes in the budget deficit, holding interest rates and other economic assumptions constant.

The effects of changes in economic assumptions in the opposite direction are approximately symmetric to those shown in the table. The impact of a one percentage point lower rate of inflation or higher real growth would have about the same magnitude as the effects shown in the table, but with the opposite sign.

Alternative Scenarios

The economic outlook is always uncertain, but it is especially uncertain at present. The rules-of-thumb described above can be used in combination to show the effect on the budget of alternative economic projections. Alternative scenarios can be used to gauge some of the risks to the current budget projections. For example, since the budget assumptions were formulated in late January, there has been further deterioration in economic conditions making a deeper recession a likely possibility. That possibility is explored in the two alternative scenarios presented in this section. Both alternatives allow for the same pattern of growth over the course of 2009-2010 as in the latest Blue Chip forecast (April). The only difference in these scenarios is how strong the recovery is.

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Table 12–4. SENSITIVITY OF THE BUDGET TO ECONOMIC ASSUMPTIONS
(In billions of dollars)

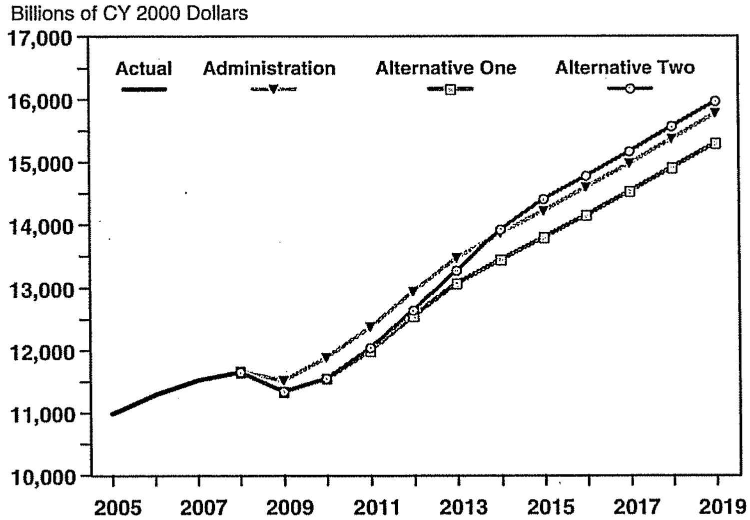
Budget effect	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total of Effects, 2009–2019
Real Growth and Employment												
Budgetary effects of 1 percent lower real GDP growth:												
(1) For calendar year 2009 only, with real GDP recovery in 2010–11:[1]												
Receipts	–14.1	–21.9	–10.3	–1.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	–45.8
Outlays	2.7	6.3	5.0	2.8	2.6	2.6	2.7	2.8	2.8	3.0	3.1	36.4
Increase in deficit (+)	16.7	28.2	15.3	4.0	2.4	2.4	2.5	2.5	2.6	2.7	2.8	82.2
(2) For calendar year 2009 only, with no subsequent recovery:[1]												
Receipts	–14.1	–29.3	–34.7	–37.8	–40.0	–41.9	–44.2	–46.5	–48.7	–51.0	–53.5	–441.6
Outlays	2.7	7.6	10.1	13.2	16.4	19.0	21.6	24.5	27.6	31.0	34.5	208.3
Increase in deficit (+)	16.8	36.9	44.8	50.9	56.4	60.9	65.8	71.0	76.3	82.0	88.0	649.9
(3) Sustained during 2009 - 2019, with no change in unemployment:												
Receipts	–14.2	–44.8	–84.8	–130.7	–180.4	–233.8	–291.9	–353.7	–418.4	–488.0	–562.6	–2,803.3
Outlays	–0.4	–0.8	1.9	6.5	12.8	20.6	30.4	42.5	57.0	74.3	94.4	339.2
Increase in deficit (+)	13.8	44.0	86.7	137.2	193.2	254.4	322.4	396.1	475.4	562.3	657.1	3,142.5
Inflation and Interest Rates												
Budgetary effects of 1 percentage point higher rate of:												
(4) Inflation and interest rates during calendar year 2009 only:												
Receipts	17.6	37.6	38.0	37.0	39.7	42.1	44.5	47.0	49.3	51.7	54.1	458.4
Outlays	13.1	26.7	16.0	19.8	20.2	20.4	18.5	18.2	16.2	15.6	15.2	199.8
Decrease in deficit (–)	–4.5	–10.9	–22.0	–17.2	–19.4	–21.7	–26.1	–28.8	–33.1	–36.1	–38.9	–258.6
(5) Inflation and interest rates, sustained during 2009 - 2019:												
Receipts	17.6	58.9	107.2	164.0	212.1	261.9	322.9	388.5	457.9	533.7	615.8	3,140.6
Outlays	13.5	54.1	78.4	111.1	137.3	162.0	185.0	210.0	232.9	254.9	283.1	1,722.2
Decrease in deficit (–)	–4.0	–4.9	–28.8	–53.0	–74.8	–99.9	–137.9	–178.4	–225.1	–278.8	–332.7	–1,418.3
(6) Interest rates only, sustained during 2009 - 2019:												
Receipts	3.9	15.3	24.7	37.1	36.3	33.1	35.6	37.9	40.2	42.4	44.6	351.2
Outlays	8.8	42.6	63.1	77.6	87.9	98.8	108.8	119.1	129.7	140.5	152.5	1,029.4
Increase in deficit (+)	4.9	27.4	38.3	40.5	51.5	65.7	73.2	81.1	89.5	98.0	107.9	678.2
(7) Inflation only, sustained during 2009 - 2019:												
Receipts	13.6	43.6	82.4	126.8	175.6	228.5	287.0	350.1	417.2	490.6	570.4	2,785.7
Outlays	4.7	11.7	16.3	35.3	52.6	67.9	83.2	100.7	116.3	131.8	152.9	773.4
Decrease in deficit (–)	–8.9	–31.9	–66.1	–91.5	–123.0	–160.6	–203.8	–249.4	–300.9	–358.8	–417.4	–2,012.3
Interest Cost of Higher Federal Borrowing												
(8) Outlay effect of $100 billion increase in borrowing in 2009	0.2	1.0	3.1	4.3	4.7	4.9	5.1	5.3	5.6	5.8	6.0	45.9

* $50 million or less.
[1] The unemployment rate is assumed to be 0.5 percentage point higher per 1.0 percent shortfall in the level of real GDP.

In the first scenario, growth in 2011-2014 is the same as in the current Administration forecast. In this case, there is a permanent loss of output from the recession that is never made up in the subsequent recovery. The loss is less than in the latest Blue Chip projections, which only show a modest and very partial recovery from the recession, but there is a substantial loss compared with the Budget as shown in Chart 12-7.

The second alternative scenario makes a different assumption about the recovery period. It assumes that over the five years from 2009 through 2014, growth is equal to the average growth rate achieved in the ex-

Chart 12-7. Alternative Scenarios for Real GDP



pansions that followed most of the recessions since the Great Depression as reflected in Chart 12-7. The average real growth rate following the trough of these recessions has been 4.2 percent. With that type of recovery, the level of real GDP would be higher in 2014 than in the Administration projections and budget deficits after 2014 would be lower than under the Administration's projections as shown in Table 12-5.

Many other scenarios are possible of course, but the point is that the most important influence on the budget projections beyond the next year or two is the rate of growth achieved once the recession has ended and the expansion has begun.

Structural and Cyclical Deficits

An alternative measure of the budget deficit is called the adjusted structural deficit. It provides a useful perspective on the stance of fiscal policy compared with the unadjusted unified budget deficit. The unadjusted deficit is affected by the business cycle. When the economy is operating below its potential and the unemployment rate exceeds the level consistent with price stability, receipts are lower, outlays for programs such as unemployment compensation are higher, and the deficit is larger (or the surplus smaller) than it would be otherwise.

The portion of the deficit (or surplus) traceable to the automatic effects of the business cycle is called the cyclical component. The remaining portion of the deficit is called the structural deficit (or structural surplus). Further adjustments are made to remove the effects of transitory financial transactions, such as outlays for bank closings under deposit insurance and the outlays made through the Troubled Asset Relief Program (TARP). Other financial stabilization outlays have also been removed from this adjusted structural deficit including GSE equity purchase programs. The adjusted structural deficit is a better gauge of the underlying stance of fiscal policy than the unadjusted unified deficit because it removes most of the effects of the business cycle and temporary financial transactions.

Estimates of the structural deficit are based on the historical relationship between changes in the unemployment rate and real GDP growth, known as "Okun's Law,"

Table 12–5. BUDGET EFFECTS OF ALTERNATIVE SCENARIOS
(In billions of dollars)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Alternative Budget Deficit Projections:											
Administration Economic Assumptions	1,841	1,258	929	557	512	536	528	645	675	688	779
Percent of GDP	12.9	8.9	6.5	3.7	3.2	3.1	2.9	3.5	3.5	3.4	3.7
Alternative Scenario 1	1,879	1,346	1,014	670	640	673	678	810	852	879	985
Percent of GDP	13.2	9.6	7.1	4.4	4.0	3.9	3.8	4.3	4.4	4.3	4.6
Alternative Scenario 2	1,879	1,346	1,006	651	593	542	470	574	597	605	689
Percent of GDP	13.2	9.6	7.0	4.3	3.7	3.1	2.5	2.9	2.9	2.8	3.1

which has been discussed above, as well as relationships of unemployment and real GDP growth with receipts and outlays. These estimated relationships take account of the major cyclical changes in the economy and their effects on the budget, but they do not reflect all the possible cyclical effects on the budget, because economists have not been able to identify the cyclical factor in some of these other effects. For example, the recent decline in the stock market will pull down capital gains-related receipts and increase the deficit. Some of this decline is cyclical in nature, but economists have not pinned down the cyclical component of the stock market exactly, and for that reason, all of the stock market's contribution to receipts is counted in the structural deficit.

Another factor that can affect the deficit and is related to the business cycle is labor force participation. Since the official unemployment rate does not include workers who have left the labor force, the conventional measures of potential GDP, incomes, and Government receipts understate the extent to which potential work hours are under-utilized because of a decline in labor force participation. The key unresolved question here is to what extent changes in labor force participation are cyclical and to what extent they are structural. By convention, in estimating the structural budget deficit, all changes in labor force participation are treated as structural.

There are also lags in the collection of tax revenue that can delay the impact of cyclical effects beyond the year in which they occur. The result is that even after the unemployment rate has fallen, receipts may remain cyclically depressed for some time until these lagged effects have dissipated. The current recession has added substantially to the cyclical component of the deficit, but for the reasons stated here, the cyclical component is probably understated. As the economy recovers, the cyclical deficit is projected to decline and when unemployment reaches 5 percent, the level assumed to be consistent with stable inflation, the cyclical component vanishes leaving only the structural deficit, although some cyclical effects would arguably still be present.

Despite these limitations, the distinction between cyclical and structural deficits is helpful in understanding the path of fiscal policy. The large increase in the deficit in 2009 and 2010 is due to combination of all three components of the deficit. There is a large increase in the cyclical component because of the rise in unemployment. That is what would be expected considering the severity of the current recession, but that is not the only reason for the increase in the deficit. There is also a large increase in the temporary financial component because of the financial stabilization measures undertaken by the Federal Government. Finally, there is a large increase in the adjusted structural deficit because of the policy measures taken to combat the recession. This reflects the Government's decision to make an active use of fiscal policy to hasten economic recovery. In 2011-2014, the cyclical component declines sharply as the economy recovers. The temporary financial measures lead to an expected inflow of funds and the adjusted structural deficit shrinks as the temporary spending and tax measures in the Recovery Act end.

Table 12–6. ADJUSTED STRUCTURAL BALANCE

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
In billions of dollars:												
Unadjusted deficit	377.6	412.7	318.3	248.2	162.0	458.6	1,841.2	1,258.4	929.4	557.4	512.3	535.9
Less cyclical component	106.4	61.8	14.7	–23.5	–10.5	49.2	297.8	350.9	300.8	185.5	57.9	1.7
Structural deficit	271.2	350.9	303.7	271.7	172.5	409.4	1,543.4	907.6	628.6	372.0	454.4	534.2
Less financial stabilization and deposit insurance	–1.4	–2.0	–1.4	–1.1	–1.5	18.7	727.0	68.9	9.6	–42.5	–53.1	–58.5
Adjusted structural deficit	272.6	352.9	305.0	272.8	174.0	390.7	816.4	838.7	619.0	414.4	507.6	592.7
As a percent of GDP:												
Unadjusted deficit	3.5	3.6	2.6	1.9	1.2	3.2	12.9	8.5	6.0	3.4	2.9	2.9
Less cyclical component	1.0	0.5	0.1	–0.2	–0.1	0.3	2.1	2.4	1.9	1.1	0.3	0.0
Structural deficit	2.5	3.1	2.5	2.1	1.3	2.9	10.8	6.2	4.1	2.3	2.6	2.9
Less financial stabilization and deposit insurance	–0.0	–0.0	–0.0	–0.0	–0.0	0.1	5.1	0.5	0.1	–0.3	–0.3	–0.3
Adjusted structural deficit	2.5	3.1	2.5	2.1	1.3	2.7	5.7	5.7	4.0	2.5	2.9	3.2

NOTE: The NAIRU is assumed to be 5.0%.

CASE: UE 210
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 805

Exhibits in Support
Of Opening Testimony

July 24, 2009

FRBSF ECONOMIC LETTER

Number 2005-25, October 3, 2005

Inflation Expectations: How the Market Speaks

The Federal Reserve wants to know what people think—specifically, the Fed wants to know what people think the future path of inflation is. One reason is that people's expectations about inflation influence their behavior in the marketplace, and that, in turn, has consequences for future inflation. Being able to forecast future inflation plays a critical role in the Fed's efforts to meet its mandate of promoting price stability in the U.S. economy.

Estimates of longer-term inflation expectations have been available from various surveys for quite some time. While useful, these survey estimates suffer a bit from the "talk is cheap" problem. What one would like, instead, is evidence that reflects people's "putting their money where their mouth is." And, indeed, in recent years, such a source of evidence has emerged, with the introduction of new financial instruments. These market-based estimates represent a bet by market participants on the future course of the economy, usually in terms of certain economic indicators or asset prices, and they have been shown to be better predictors than survey-based estimates.

One of these new financial instruments is the Treasury Inflation-Protected Security, or TIPS, which was introduced by the U.S. Department of Treasury in 1997 as a new class of government debt obligation. The key feature of TIPS is that the payments to investors adjust automatically to compensate for the actual change in the Consumer Price Index (CPI). Conventional Treasury securities, in contrast, do not provide such protection, so investors in those securities protect themselves by demanding nominal interest rates that compensate them for expected inflation as well as for bearing the risk that actual inflation could turn out to differ from their expectations. In principle, having information from both types of Treasury securities allows researchers to separate out the inflation compensation component embedded in nominal interest rates.

This *Economic Letter* discusses the structure of TIPS contracts, the development of the market in recent years, and the measure of inflation compensation derived from comparing TIPS yields to nominal yields.

How TIPS work

TIPS are one of two types of inflation-protected securities sold by the U.S. Treasury (the other type is Series I savings bonds for small investors). In 1997, the Treasury Department started issuing TIPS that are structured along the lines of the Real Return Bonds issued by the government of Canada. Like conventional Treasury notes and bonds, TIPS make interest payments every six months and a payment of principal when the securities mature. However, unlike conventional Treasury notes and bonds, both the semiannual interest payments and the final redemption payments of TIPS are tied to inflation.

All TIPS are issued by the Treasury using the single-price auction—the same auction used for all of Treasury's marketable securities. The interest rate on TIPS, which is set at auction, remains fixed throughout the term of the security. To protect against inflation, the Treasury adjusts the principal value of the TIPS using the CPI, published by the Bureau of Labor Statistics. Thus, TIPS are redeemed at maturity at their inflation-adjusted principal or their original par value, whichever is greater. While TIPS pay a fixed rate of interest that is determined at the initial auction, this rate is applied not to the par value of the security but to the inflation-adjusted principal. So, if inflation rises throughout the term of the security, every interest payment will be greater than the previous one. To the extent that both the semiannual interest payments and the final redemption value of TIPS rise and fall with the CPI, the nominal return on TIPS hedges perfectly against inflation.

The market for TIPS has grown steadily and now includes three terms to maturity: 5 years, 10 years, and 20 years. The Treasury auctions 5-year and 20-year TIPS semiannually and 10-year TIPS quarterly. As of 2005, there are about $200 billion TIPS outstanding, as part of the total $4 trillion Treasury marketable securities outstanding. The trading volume of TIPS also has increased gradually but still remains small compared to other Treasury securities; hence, TIPS generally are not as liquid as comparable Treasuries.

Extracting implied inflation expectations from TIPS

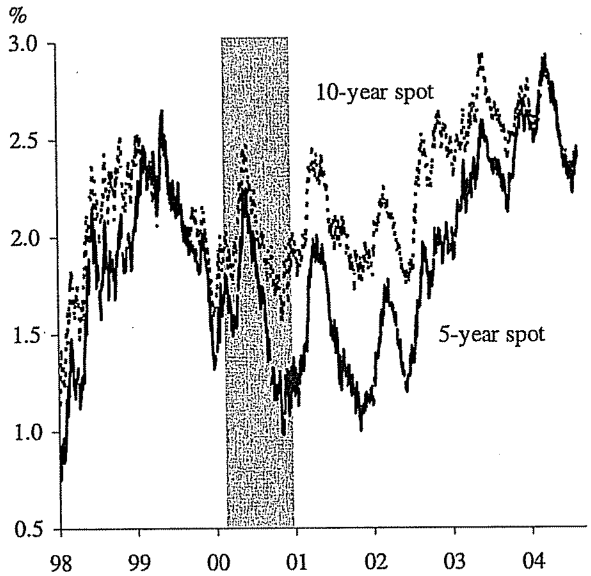
In principle, comparing the yields between conventional Treasury securities and TIPS can provide a useful measure of the market's expectation of future CPI inflation. At a basic level, the yield-to-maturity on a conventional Treasury bond that pays its holder a fixed nominal coupon and principal must compensate the investor for future inflation. Thus, this nominal yield includes two components: the real rate of interest and the inflation compensation over the maturity horizon of the bond. For TIPS, the coupons and principal rise and fall with the CPI, so the yield includes only the real rate of interest. Therefore, the difference, roughly speaking, between the two yields reflects the inflation compensation over that maturity horizon.

This inflation compensation is sometimes referred to as the breakeven inflation rate because, if future inflation were at this rate, the realized returns of holding a conventional Treasury bond and TIPS would be exactly the same. Figure 1 charts the breakeven inflation rate over the next five years by comparing the yield on the 5-year Treasury note to the yield on 5-year TIPS, and the breakeven inflation rate over the next ten years by using the 10-year Treasury note and 10-year TIPS, from 1998 to present.

There are two important caveats in using the breakeven inflation rate to measure inflation expectations. First, the breakeven inflation rate actually measures the compensation that conventional Treasury bondholders receive for expected inflation and for bearing the risk that realized inflation may deviate from expected inflation. The breakeven inflation rate hence has two components: expected inflation and the inflation risk premium. Ideally, one would like to subtract the inflation risk premium from the breakeven inflation rate to obtain a pure measure of inflation expectations. Nevertheless, assuming the inflation risk premium to be fairly stable over a short period of time, the changes in the breakeven inflation rate capture the changes in inflation expectations.

Second, TIPS yields contain a liquidity premium. While the market for TIPS is growing, it is still relatively small compared to the market for conventional Treasuries. Therefore, to the extent that TIPS are less liquid than Treasuries, investors would demand a liquidity premium for holding TIPS over conventional Treasuries. Because the breakeven inflation rate is obtained by comparing the yields on TIPS and similar maturity conventional Treasury bonds, the breakeven rate captures not only the inflation compensation but also the liquidity premium demanded by TIPS investors. In Figure 1, it is quite clear that the breakeven inflation rates exhibit an upward trend. This probably reflects artificially low breakeven rates when TIPS were introduced. At that time, the amount of TIPS outstanding was small and the investor base for TIPS was narrow, so TIPS were not very liquid and their yields likely contained a relatively large liquidity premium to compensate investors for holding TIPS in their portfolio. As the TIPS market has grown, the liquidity premium in TIPS has shrunk, resulting in higher breakeven inflation rates.

Figure 1
1998 to present: Breakeven inflation rates



Interpretations

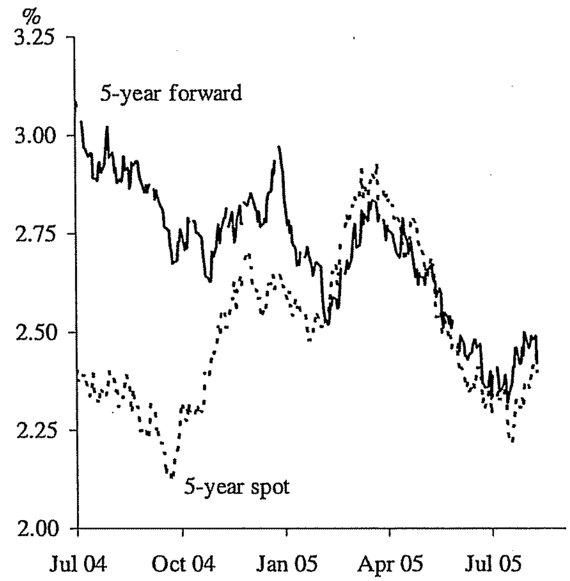
The breakeven inflation rate overstates inflation expectations because of the inflation risk premium in Treasury yields, but it understates inflation compensation because of the liquidity premium in TIPS yields. With a more mature TIPS market, and over relatively short time periods, both the inflation risk premium and the liquidity premium are likely to be fairly constant. Thus, the changes in breakeven inflation rates can be interpreted as the market measure of changes in inflation expectations. Estimates of intermediate-term inflation expectations can be extracted using 5-year TIPS and conventional Treasury securities. To focus on a relatively short recent time period, Figure 2 shows the 5-year breakeven inflation rate since July 2004. Note that this measure of inflation expectations over the next five years has fluctuated between 2% and 3% over the past 12 months. In part, the swings reflect temporary factors, such as movements in energy prices, cyclical factors, and the influences of monetary policy.

Estimates of longer-term inflation expectations can be derived using the forward nominal yields and forward real bond yields. For example, suppose one is interested in inflation expectations for the period from 2010–2015, that is a five-year period beginning five years from now. The forward nominal yield for that period is implied by the 5-year and 10-year nominal yield. The forward real yield is, likewise, implied by the 5-year and 10-year TIPS yield. And comparing the forward nominal yield to the forward TIPS yield implies a forward breakeven inflation rate.

Figure 2 plots the 5-year forward 5-year breakeven inflation rate. It suggests that longer-term inflation expectations have been trending down from about 3% to about 2.5% since the beginning of the current monetary policy tightening cycle. Compared to the spot 5-year forward breakeven rate, it is noteworthy that the forward breakeven inflation rate is more stable. This is because longer-term inflation expectations tend to be less affected by cyclical factors.

One interpretation of this measure of longer-term inflation expectations is that it captures the market's assessment of how well the Federal Reserve promotes price stability in the long run. From that perspective, the decline in this measure—by more than one-half a percentage point over the last 12 months, despite rapidly rising energy prices—suggests that the market views the run-up in energy prices as transitory and that it is confident in the Fed's commitment to promoting longer-term price stability.

Figure 2
July 2004 to present: Breakeven inflation rates



Conclusions

Given the Federal Reserve's dual mandates, promoting maximum sustainable output and employment and promoting price stability, having credibility in fighting inflation gives the central bank more room to promote economic growth. For example, with longer-term inflation expectations currently seemingly well anchored, the recent run-up in energy prices has not led to widespread fears about future inflation; therefore, the Fed has not had to tighten more aggressively. Nonetheless, the Fed cannot be complacent—the credibility of its commitment to price stability was earned through years of consistent performance, and to maintain that credibility, the Fed will need to continue to earn it. And to gauge its success, the Fed will also continue to pay close attention to longer-term inflation expectations.

Simon Kwan
Vice President

Empirical TIPS

Richard Roll

U.S. Treasury Inflation-Indexed Securities (commonly known as TIPS) were first issued in January 1997. Through the third quarter of 2003, 12 TIPS had been issued, with original maturities ranging from 5 to 30 years. One TIP bond has already matured. This study documents the correlations of TIPS returns with the returns on nominal bonds and with equity returns over the past seven years; TIPS real and effective nominal durations; and changes in the volatility of TIPS over time. TIPS are used here to estimate real yield curves, which are then compared against nominal yield curves to derive the term structure of anticipated inflation on a daily basis. An explanation offered for the dramatic decline in TIPS real yields since 1999 is supported by empirical tests. Finally, given plausible assumptions about future expected returns, the article shows that an investment portfolio diversified between U.S. equities and nominal bonds would be improved by the addition of TIPS.

In January 1997, the U.S. Treasury issued a unique new security—a bond with 10 years to maturity and with payments linked to the U.S. Consumer Price Index (CPI).[1] This bond is officially named a "marketable Treasury Inflation-Indexed Security," but it is commonly called TIPS, for Treasury inflation-protected security. Through September of 2003, 12 different TIPS had been issued, with maturity dates ranging from July 2002 through April 2032 (see **Table 1**).

The inflation linkage of U.S. TIPS adheres to the model for indexed bonds issued previously by the government of Canada. In this structure, the nominal principal is accreted daily on the basis of an extrapolation of inflation during the most recent reporting period for the price index. The bond's coupons are a fixed percentage of the accreted principal, so they also are effectively linked to the CPI. For U.S. TIPS, the Treasury has established a floor in the event of deflation (which no longer seems such an unlikely event). At maturity, TIPS will be redeemed at the greater of their inflation-adjusted principal or their par amount at original issue. During the lifetime of a TIP bond, its accreted principal could decline with deflation below the original par, so the coupons could decline below their originally stated dollar amounts, but the principal will eventually be redeemed at no less than the original face amount.

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In the secondary market, TIPS prices are quoted as percentages of par. Consequently, the settlement amount includes the trade price multiplied by an inflation accrual factor established officially by the Treasury for every day of the month and all outstanding TIPS. Accrued interest, which depends on the same accrual factor, is added in to obtain the total settlement payment. Details on nominal holding-period returns are given in Appendix A.

Almost seven years of daily TIPS trading experience have accumulated, so sample sizes are more than adequate to establish some empirical facts about TIPS behavior. This article's modest goal is to report those facts. TIPS share certain features with equities, in that they provide protection against inflation.[2] They also possess bondlike features, such as promised fixed payments. Now seems to be a good moment to undertake a systematic empirical study of these interesting new assets.[3] Consequently, I calculated and report here the available history of real yields and real durations of TIPS. The article presents empirical measures of the effective *nominal* durations of TIPS (i.e., the sensitivity of their returns to nominal yields and to changes in the shape of the nominal term structure of interest rates). It provides correlations of TIPS returns with nominal bonds and with equities. It provides empirical estimates of the entire term structure of anticipated inflation derived by combining TIPS and nominal bonds. The article also offers a tax-based conjecture to explain the dramatic recent decline in real yields and provides

Table 1. Assets and Sample Periods

Coupon	Issued	Maturity	Daily Returns Begin	End
A. TIPS				
3.625	Jul 1997	Jul 2002	16 Jul 1997	11 Jul 2002
3.375	Jan 1997	Jan 2007	22 Jan 1997	30 Sep 2003
3.625	Jan 1998	Jan 2008	15 Jan 1998	30 Sep 2003
3.875	Jan 1999	Jan 2009	15 Jan 1999	30 Sep 2003
4.250	Jan 2000	Jan 2010	19 Jan 2000	30 Sep 2003
3.500	Jan 2001	Jan 2011	17 Jan 2001	30 Sep 2003
3.375	Jan 2002	Jan 2012	15 Jan 2002	30 Sep 2003
3.000	Jul 2002	Jul 2012	15 Jul 2002	30 Sep 2003
1.875	Jul 2003	Jul 2013	10 Jul 2003	30 Sep 2003
3.625	Apr 1998	Apr 2028	15 Apr 1998	30 Sep 2003
3.875	Apr 1999	Apr 2029	16 Apr 1999	30 Sep 2003
3.375	Oct 2001	Apr 2032	15 Oct 2001	30 Sep 2003
B. U.S. Treasury Constant-Maturity Nominal Bonds				
3 Month			22 Jan 1997	30 Sep 2003
1 Year			22 Jan 1997	30 Sep 2003
5 Year			22 Jan 1997	30 Sep 2003
10 Year			22 Jan 1997	30 Sep 2003
30 Year			22 Jan 1997	15 Feb 2002
C. Equity Indexes				
vwretd			22 Jan 1997	30 Jun 2003
ewretd			22 Jan 1997	30 Jun 2003
sprtrn			22 Jan 1997	30 Jun 2003

Notes: In Panel C, "vwretd" is the CRSP NYSE + Amex + Nasdaq value-weighted index with dividends reinvested, "ewretd" is the CRSP equal-weighted index with dividends reinvested, and "sprtrn" is the S&P 500 Index with dividends included.

some supporting evidence. Finally, the article addresses the benefits of including TIPS in a balanced and diversified investment portfolio.

Data

Table 1 lists the 12 TIPS, 5 nominal bonds, and 3 equity indexes used in this study. The sample period begins with the first available TIPS return, on 22 July 1997, and it ends on 30 September 2003. All outstanding TIPS were included in the study, but only the issue with a January 2007 maturity has data covering the entire sample period. Barclays Capital kindly provided TIPS transaction prices.

To develop a sample of nominal bond returns, I downloaded constant-maturity yields from the U.S. Treasury website (www.ustreas.gov) for five different maturities. Approximate holding-period returns (in percentages per day) were computed from yields by the following formula:

$$R_t = \frac{Y_{t-j}}{252} + D_{t-j}(Y_{t-j} - Y_t), \qquad (1)$$

where R_t is return at time t, Y_t is the nominal yield on date t (in percentage per year), and D_{t-j} is the modified duration in years computed on day $t-j$.[4] The divisor is based on 252 trading days in a year. Most often, $j = 1$, so the yield change is from day $t-1$ to day t, but $j > 1$ when the yield change is across a holiday or weekend.

Equity returns were measured by three broad indexes—the value-weighted and equal-weighted CRSP (Center for Research in Securities Prices) indexes for all major U.S. exchanges and the S&P 500 Index. In each case, dividends were reinvested to obtain total index returns. Table 1 lists the data availability period for each of the 20 assets.

Asset Characteristics

The characteristics discussed in this section for TIPS, nominal bonds, and equities are daily nominal holding-period returns, correlations, real yields, real and effective nominal durations, and sensitivities to the nominal term structure's shape. The final subsection turns attention to the time-varying volatility of TIPS returns.

Daily Nominal Holding-Period Returns. Using all available observations, **Table 2** reports descriptive statistics for daily nominal returns. Means and standard deviations are given in percentage per year. Note that the number of observations used in computing each pairwise correlation differs among asset pairs because of the availability of joint observations. (A few assets had no joint observations.)

During the sample period, TIPS experienced exceptional average returns. The January 2007 issue, which has been around the longest, had a mean daily return of 6.86 percent per year for the entire sample period. The latter part of the sample period was particularly favorable for TIPS. For example, the January 2032 TIP bond, issued in October 2001, had an annualized mean return of more than 15 percent. Real yields on TIPS declined during the sample period from more than 3.5 percent to the neighborhood of 1.0–2.5 percent, depending on maturity.

Nominal bonds also did well in this period. The 30-year bond had an annualized average sample return of about 10 percent in the five years prior to its retirement in February 2002.

In comparison, equities fared rather poorly on average. The S&P 500 experienced an annualized average return of only 6.11 percent over the entire sample period, and of course, its return was strongly negative in 2001–2002. The equal-weighted return appears to be quite high, on average, but this sample mean is severely biased upward by bid–ask bounce and daily rebalancing (to equal weights).[5]

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Table 2. Daily Returns: Means and Standard Deviations

Asset	Return: Mean	Return: Standard Deviation	N
A. TIPS			
Jul 2002	5.93%	1.08%	1,262
Jan 2007	6.86	2.70	1,701
Jan 2008	7.89	2.95	1,453
Jan 2009	8.73	3.26	1,200
Jan 2010	10.90	3.86	944
Jan 2011	10.00	4.82	693
Jan 2012	11.80	5.70	442
Jul 2012	11.40	6.70	316
Jul 2013	3.88	10.10	58
Apr 2028	9.77	6.69	1,392
Apr 2029	11.40	7.16	1,138
Apr 2032	15.20	10.70	504
B. U.S. Treasuries			
3 Month	4.18%	0.22%	1,609
1 Year	4.97	0.74	1,609
5 Year	7.97	4.54	1,609
10 Year	9.49	7.58	1,609
30 Year	10.00	11.30	1,219
C. Equities			
vwretd	7.21%	20.80%	1,624
ewretd	22.30	15.20	1,624
sprtrn	6.11	21.20	1,624

Notes: The sample period varies by asset but begins at earliest in January 1997 and ends at latest in August 2002. *N* is the number of daily sample observations in the mean and standard deviation. The mean return and standard deviation were annualized by using 252 trading days a year.

As for volatility, TIPS returns exhibited lower volatility in the period than nominal bonds with similar maturities, as one would expect. For example, the January 2010 bond, whose maturity ranged from 10 to 7 years during the period, had an annualized daily standard deviation of 3.86 percent a year.[6] This percentage is half the volatility of the 10-year nominal bond and is substantially less than the volatility of the 5-year nominal bond. The 30-year nominal bond volatility was 11.3 percent a year (under the assumption of independent returns over time). In contrast, the two TIPS with original maturities of 30 years that have been outstanding the longest, the April 2028 and April 2029 issues, had annualized return standard deviations of, respectively, 6.69 percent and 7.16 percent. Changes in nominal yields are much more volatile than changes in real yields for the obvious reason that changes in nominal yields include shocks in expected inflation.

Table 3 shows that TIPS returns are strongly correlated with each other, particularly for adjacent maturities. Returns for the 30-year TIPS, with coefficients of 0.999, are almost perfectly correlated. The eight TIPS that had 10 years to maturity at issuance, those with maturities from January 2007 through July 2013, have correlations in the upper 90 percent range. Their correlations are somewhat lower with the longest-term TIPS (the three original 30-year issues) but are still in the upper 80 percent range. Only the single short-term TIP bond, which matured in July 2002, has somewhat lower correlation with other TIPS—and only when it was close to maturity.[7]

Long-term nominal bonds are positively correlated with long-term TIPS. These correlations, mainly in the range of 0.5–0.8, are not usually as large as those between adjacent TIPS. Shorter-term nominal bonds, such as the three-month and one-year bonds, are more weakly correlated both with TIPS and with longer-term nominal bonds. Interestingly, the shortest-term nominal bond and the shortest-term TIP bond (July 2002) are not highly correlated; the coefficient is only 0.229. This characteristic suggests that shocks in expected inflation were the predominant source of nominal interest rate volatility during the full sample period.

One of the most striking patterns in Table 3 involves the negative correlations between equities and bonds, both TIPS and nominal bonds. The evidence is that these correlations have become increasingly negative lately; that is, more recently issued TIPS display larger (in absolute value) correlations with equities. The correlations between nominal bonds and equities are similar to correlations between equities and TIPS that were outstanding during most of the sample. Over long historical periods, equities have been positively correlated with nominal bonds, so these sample period results are somewhat unusual.[8]

Daily TIPS returns have significant first-order serial correlation but, as **Table 4** shows, virtually no autocorrelation at longer lags. The same is true for nominal bonds with 1-, 5-, and 10-year maturities. The three-month nominal bond return has quite a bit of serial dependence, even for lags as long as five days. For TIPS and for longer-term nominal bonds, the serial dependence may be statistically significant but is probably not economically relevant. Notice that the total explanatory power (adjusted R_2) of the autocorrelation function is 1–2 percent in most cases. For the three-month nominal bond return, however, the explanatory power is more than 18 percent. The CRSP value-weighted equity and S&P 500 indexes are not greatly autocorrelated, but the equal-weighted equity return is, perhaps spuriously and attributable to daily rebalancing.

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Table 3. Daily Returns: Correlations

	TIPS												U.S. Treasuries					Equities		
	Jul 2002	Jan 2007	Jan 2008	Jan 2009	Jan 2010	Jan 2011	Jan 2012	Jul 2012	Jul 2013	Apr 2028	Apr 2029	Apr 2032	3 Month	1 Year	5 Year	10 Year	30 Year	vwretd	ewretd	sprtrn
TIPS																				
Jul 2002		0.757	0.722	0.626	0.604	0.543	0.183	NA	NA	0.486	0.392	0.277	0.229	0.426	0.414	0.387	0.344	−0.069	−0.127	−0.044
Jan 2007	1,262		0.980	0.972	0.959	0.950	0.954	0.950	0.962	0.777	0.781	0.814	0.148	0.496	0.634	0.620	0.457	−0.167	−0.187	−0.156
Jan 2008	1,135	1,453		0.987	0.979	0.974	0.968	0.963	0.973	0.815	0.817	0.842	0.164	0.532	0.688	0.674	0.494	−0.243	−0.241	−0.242
Jan 2009	882	1,200	1,200		0.991	0.987	0.980	0.977	0.982	0.840	0.840	0.861	0.156	0.521	0.710	0.703	0.502	−0.280	−0.282	−0.282
Jan 2010	626	944	944	944		0.996	0.991	0.988	0.991	0.860	0.861	0.877	0.179	0.551	0.762	0.771	0.584	−0.312	−0.299	−0.316
Jan 2011	375	693	693	693	693		0.996	0.994	0.994	0.875	0.874	0.887	0.236	0.568	0.793	0.812	0.641	−0.362	−0.348	−0.365
Jan 2012	124	442	442	442	442	442		0.999	0.997	0.920	0.921	0.919	0.333	0.621	0.840	0.866	0.756	−0.485	−0.468	−0.482
Jul 2012	0	316	316	316	316	316	316		0.998	0.926	0.926	0.925	0.347	0.632	0.862	0.890	NA	−0.533	−0.508	−0.529
Jul 2013	0	58	58	58	58	58	58	58		0.954	0.954	0.952	0.215	0.750	0.887	0.917	NA	NA	NA	NA
Apr 2028	1,074	1,392	1,392	1,200	944	693	442	316	58		0.999	0.998	0.085	0.399	0.610	0.644	0.554	−0.200	−0.184	−0.201
Apr 2029	820	1,138	1,138	1,138	944	693	442	316	58	1,138		0.999	0.097	0.408	0.635	0.675	0.589	−0.235	−0.222	−0.238
Apr 2032	186	504	504	504	504	504	442	316	58	504	504		0.251	0.498	0.736	0.798	0.829	−0.350	−0.348	−0.348
U.S. Treasuries																				
3 Month	1,194	1,605	1,369	1,130	888	648	412	292	56	1,311	1,070	469		0.527	0.285	0.230	0.195	−0.092	−0.112	−0.085
1 Year	1,194	1,605	1,369	1,130	888	648	412	292	56	1,311	1,070	469	1,609		0.779	0.699	0.572	−0.207	−0.238	−0.197
5 Year	1,194	1,605	1,369	1,130	888	648	412	292	56	1,311	1,070	469	1,609	1,609		0.945	0.829	−0.243	−0.274	−0.232
10 Year	1,194	1,605	1,369	1,130	888	648	412	292	56	1,311	1,070	469	1,609	1,609	1,609		0.906	−0.211	−0.241	−0.201
30 Year	1,098	1,215	979	740	498	258	22	0	0	921	680	79	1,219	1,219	1,219	1,219		−0.016	−0.061	0.005
Equities																				
vwretd	1,254	1,619	1,371	1,119	865	614	367	242	0	1,310	1,057	429	1,546	1,546	1,546	1,546	1,218		0.853	0.984
ewretd	1,254	1,619	1,371	1,119	865	614	367	242	0	1,310	1,057	429	1,546	1,546	1,546	1,546	1,218	1,624		0.784
sprtrn	1,254	1,619	1,371	1,119	865	614	367	242	0	1,310	1,057	429	1,546	1,546	1,546	1,546	1,218	1,624	1,624	

NA = not available.

Notes: The sample period varies by asset but begins at earliest in January 1997 and ends at latest in September 2003. Correlation coefficients computed from all available joint observations are reported in the shaded area, and the corresponding numbers of available observations are given in the unshaded area.

Table 4. Autocorrelations of Daily Asset Returns
(*t*-statistics in parentheses)

	Partial Autocorrelation Coefficient by Lag					
Asset	1 Day	2 Days	3 Days	4 Days	5 Days	Adjusted R^2
			A. TIPS			
Jul 2002	0.1214	–0.0110	–0.0136	0.0340	–0.0097	1.17%
$N = 1{,}257$	(4.30)	(–0.39)	(–0.48)	(1.20)	(–0.34)	
Jan 2007	0.1374	–0.0266	0.0043	0.0044	–0.0009	1.57
$N = 1{,}696$	(5.64)	(–1.08)	(0.18)	(0.18)	(–0.04)	
Jan 2008	0.1483	–0.0237	0.0449	–0.0172	0.0099	1.97
$N = 1{,}448$	(5.62)	(–0.89)	(1.68)	(–0.65)	(0.37)	
Jan 2009	0.1407	–0.0123	0.0501	–0.0228	0.0308	1.84
$N = 1{,}195$	(4.85)	(–0.42)	(1.71)	(–0.78)	(1.06)	
Jan 2010	0.1260	–0.0127	0.0569	–0.0261	0.0274	1.39
$N = 939$	(3.84)	(–0.38)	(1.72)	(–0.79)	(0.83)	
Jan 2011	0.1223	–0.0152	0.0552	–0.0375	0.0403	1.18
$N = 688$	(3.19)	(–0.39)	(1.43)	(–0.97)	(1.05)	
Jan 2012	0.0981	–0.0130	0.0832	–0.0462	0.0593	0.81
$N = 437$	(2.03)	(–0.27)	(1.72)	(–0.95)	(1.22)	
Jul 2012	0.0886	–0.0153	0.0895	–0.0545	0.0649	0.39
$N = 311$	(1.55)	(–0.27)	(1.56)	(–0.95)	(1.13)	
Jul 2013	–0.1674	–0.1094	0.1132	–0.0958	0.1480	–0.11
$N = 53$	(–1.14)	(–0.75)	(0.79)	(–0.67)	(1.02)	
Apr 2028	0.1350	–0.0201	0.0564	–0.0411	0.0650	2.08
$N = 1{,}387$	(5.02)	(–0.74)	(2.07)	(–1.51)	(2.40)	
Apr 2029	0.1227	–0.0151	0.0590	–0.0375	0.0753	1.87
$N = 1{,}133$	(4.12)	(–0.50)	(1.96)	(–1.25)	(2.51)	
Apr 2032	0.1241	–0.0193	0.0823	–0.0370	0.1020	2.06
$N = 499$	(2.76)	(–0.42)	(1.82)	(–0.81)	(2.25)	
			B. U.S. Treasuries			
3 Month	0.1893	0.0938	–0.0201	0.1826	0.1983	18.32%
$N = 1{,}604$	(7.72)	(3.82)	(–0.82)	(7.44)	(8.10)	
1 Year	0.0951	–0.0113	–0.0134	–0.0003	–0.0004	0.61
$N = 1{,}604$	(3.80)	(–0.45)	(–0.53)	(–0.01)	(–0.02)	
5 Year	0.0614	–0.0366	–0.0286	–0.0139	0.0035	0.31
$N = 1{,}604$	(2.45)	(–1.46)	(–1.14)	(–0.55)	(0.14)	
10 Year	0.0517	–0.0227	–0.0395	–0.0192	0.0158	0.24
$N = 1{,}604$	(2.07)	(–0.90)	(–1.57)	(–0.77)	(0.63)	
30 Year	0.0517	0.0008	–0.0306	–0.0163	0.0111	–0.01
$N = 1{,}214$	(1.80)	(0.03)	(–1.06)	(–0.57)	(0.39)	
			C. Equities			
vwretd	0.0207	–0.0377	–0.0174	0.0167	–0.0531	0.20%
$N = 1{,}619$	(0.83)	(–1.52)	(–0.70)	(0.67)	(–2.14)	
ewretd	0.2069	0.0046	0.0979	0.0701	–0.0079	6.44
$N = 1{,}619$	(8.31)	(0.18)	(3.88)	(2.76)	(–0.32)	
sprtrn	–0.0169	–0.0375	–0.0355	0.0106	–0.0488	0.21
$N = 1{,}619$	(–0.68)	(–1.51)	(–1.43)	(0.43)	(–1.96)	

Real Yields, Durations, and Sensitivities. This section reports real yields, real durations and effective nominal durations of TIPS, and the sensitivity of TIPS to changes in the shape of the nominal yield curve.

Real yields. Like nominal Treasury bonds, TIPS yields and durations can be computed directly from prices and promised cash payments. In calculating the real yield, inflation can be ignored because the transaction price and coupons are stated as percentages of the accrued face amount. Thus, the real yield is simply the internal rate of return that equates the current price plus accrued real interest to the discounted future real payments. Real duration can be calculated in the usual way, with inflation ignored.

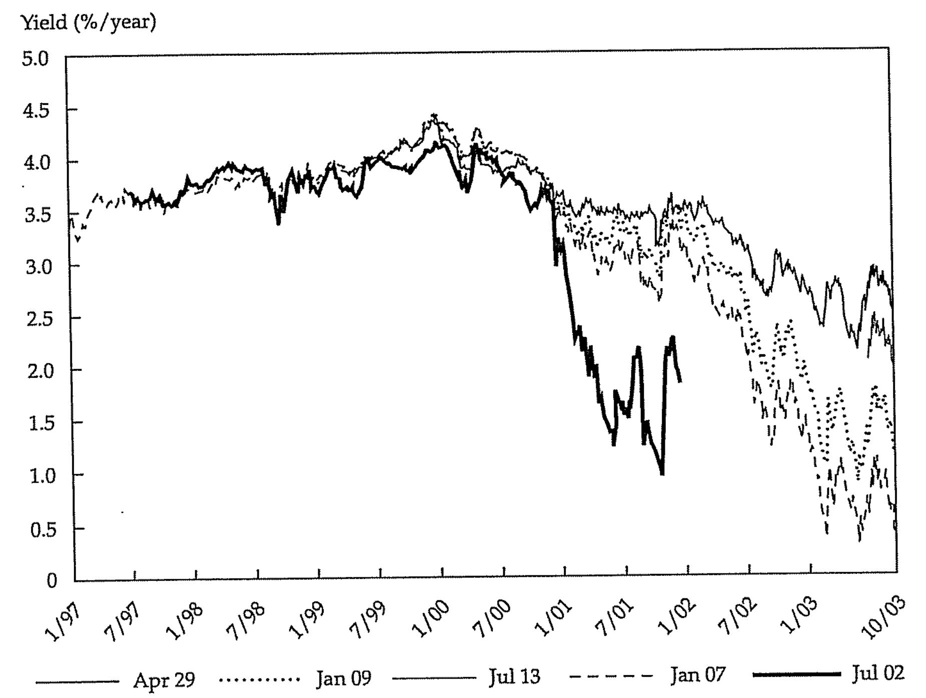
In a depiction of real yields for all 12 TIPS in the study, individual yields would be almost impossible to distinguish because they are so close together. So, **Figure 1** presents the July 2002 yield, which is clearly distinguished from the others, and the highest and lowest yields as of 30 September 2003 (respectively, the April 2029 and January 2007 TIPS).[9] The other yields lay in between at that date and were almost always ranked higher for successively longer maturities (two are included in Figure 1 to illustrate this pattern). Indeed, the April 2029 yield plots virtually on top of the April 2028 yield.

As Figure 1 clearly shows, TIPS yields of all maturities have declined dramatically since the beginning of 2000. From well over 4 percent a year, yields fell to less than 1 percent for the shorter-term issues and to less than 3 percent for the longest-term issue. Yields for maturities out to 2013 were below 2.5 percent at the end of the sample period.

Real and effective nominal durations. **Figure 2** shows real Macauley durations for all 12 TIPS in the study. Macauley duration is simply a weighted average of the calendar times until various payments, where each weight is proportional to the discounted (at the real yield) present value of the payment. Because Macauley duration is a real duration, the future payments are simply the TIPS stated coupon multiplied by the currently accrued principal plus the final (currently accrued) principal repayment.

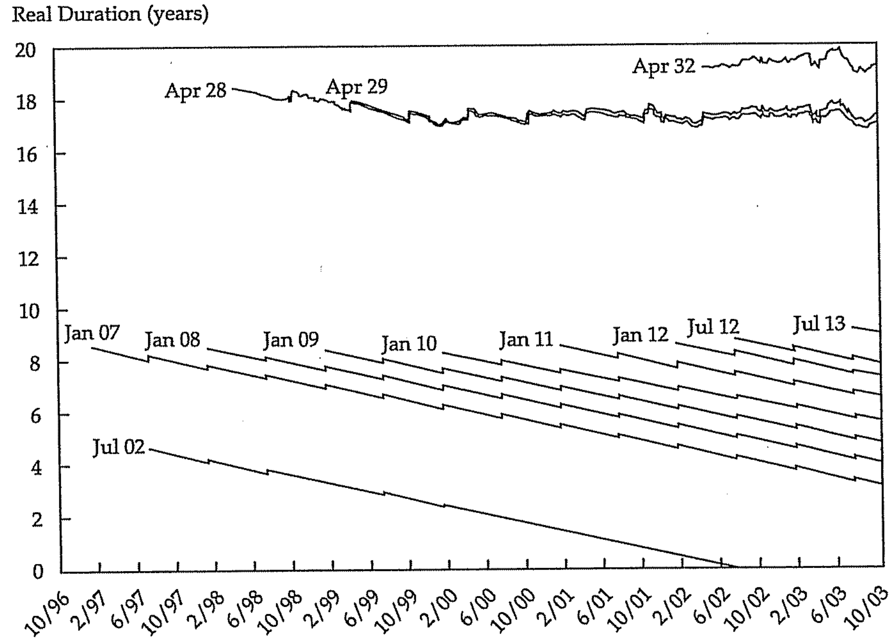
Individual cases are easily discernible in Figure 2 because, understandably, real durations rank monotonically from longest to shortest maturity. These durations are unremarkable except for the slight jump on each ex-coupon date. Only the three longest-term TIPS exhibit perceptible reactions to yield changes; otherwise, they are smoothly declining. The real durations of these issues have not declined at all during the past several years (because yields have fallen enough to more than offset aging).

Figure 1. Real Yields on TIPS, January 1997–September 2003



Note: Bond-equivalent yields—that is, semiannually compounded.

Figure 2. Real Durations of TIPS, January 1997–September 2003



The relatively low coupons of TIPS explain the smoothly declining durations for short-term issues. Low coupons imply that the final principal repayment represents the preponderance of present value and thus Macauley's duration is relatively insensitive to yield changes. (Recall that a zero-coupon bond, whose entire value depends on the single final payment, always has, entirely independent of yield, a Macauley duration equal to maturity.)

Real duration measures the response of TIPS' returns to infinitesimal changes in the real yield. Because real yields and coupons on TIPS are generally lower than nominal yields and coupons on otherwise similar nominal Treasury bonds, TIPS real durations are longer than nominal bond durations. But such comparisons mix apples and oranges because real and nominal yields do not have the same volatility. If nominal yields are essentially real yields plus expected inflation, nominal yields must have larger volatilities unless real yields and inflation are quite negatively correlated.[10]

Consequently, it is of considerable practical interest to estimate TIPS durations with respect to changes in nominal yields, thereby placing TIPS and nominal bonds on a comparable footing. This estimate cannot be made analytically because there is no obvious connection between nominal yields and TIPS prices. It can be accomplished empirically, however, by regressing TIPS returns on concurrent changes in nominal yields. The negative of the slope coefficient in such a regression is an estimate of modified duration.[11]

The second column of **Table 5** reports such empirical nominal durations for TIPS, where the regressor was a simple average of the constant-maturity 5- and 10-year nominal yield change. Of course, any nominal maturity could have been used and the resulting duration estimates would have differed. Those reported in Table 5 should be taken as indications of effective TIPS durations compared with the average duration of 5- and 10-year nominal Treasuries. At yields of 4 percent, 5 percent, and 6 percent, the nominal 5-year/10-year average modified duration for bonds selling at par would be, respectively, 6.40, 6.16, and 5.94 years. As shown in Table 5, TIPS durations are usually shorter than these bond durations, even when the TIPS maturities are much longer. For example, the April 2029 issue, whose maturity was at least 26 years throughout the sample, has an estimated duration of only 4.6 years in Table 5. Except for the aberrations because of the relatively short period of data availability for the January 2012, July 2012, and July 2013 TIPS, estimated durations increase monotonically with maturity.

Sensitivity to changes in the shape of the nominal yield curve. The second set of regressions in Table 5 (in the right-most three columns) report how TIPS respond to general changes in the shape of the nominal yield curve. Following Litterman and Scheinkman (1991), the shape of the nominal yield curve on each date was characterized by its level, slope, and curvature, as estimated by a simple model whose technical details are given in

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Table 5. TIPS Empirical Durations and Factor Sensitivities
(t-statistics in parentheses; adjusted R^2s in percents)

TIPS	Duration (effective years)	Factor Sensitivities Shift	Tilt	Flex
Jul 2002	0.585	–0.548	0.4664	–0.0061
N = 1,247	(18.34)	(–12.21)	(5.74)	(–0.06)
	21.2%	18.2%	*1.826*	*5.087*
Jan 2007	2.003	–2.048	–0.4081	0.8929
N = 1,674	(32.99)	(–23.95)	(–2.66)	(4.28)
	39.4%	37.8%	*1.842*	*8.204*
Jan 2008	2.288	–2.42	–0.7189	1.386
N = 1,428	(34.52)	(–25.73)	(–4.39)	(6.19)
	45.5%	44.5%	*1.771*	*6.443*
Jan 2009	2.552	–2.726	–1.174	1.937
N = 1,178	(32.40)	(–23.86)	(–6.23)	(7.26)
	47.1%	47.9%	*1.806*	*5.526*
Jan 2010	3.089	–3.509	–1.672	2.9
N = 926	(32.36)	(–25.52)	(–7.94)	(9.27)
	53.1%	57.0%	*1.851*	*7.382*
Jan 2011	3.725	–4.642	–2.449	5.055
N = 676	(29.30)	(–22.83)	(–8.73)	(10.63)
	56.0%	63.1%	*1.822*	*5.642*
Jan 2012	5.171	–5.302	–5.264	8.252
N = 429	(27.98)	(–13.28)	(–9.54)	(11.71)
	64.6%	71.9%	*1.896*	*2.389*
Jul 2012	6.154	–5.495	–4.751	5.105
N = 304	(25.94)	–(11.88)	(–7.44)	(5.27)
	68.9%	79.9%	*1.987*	*1.077*
Jul 2013	9.257	–8.985	–3.462	7.53
N = 57	(14.40)	(–3.21)	(–1.08)	(2.06)
	78.7%	84.2%	2.033	*0.837*
Apr 2028	4.227	–5.143	–5.955	6.336
N = 1,367	(24.68)	(–24.27)	(–16.23)	(12.60)
	30.8%	46.4%	*1.827*	*2.699*
Apr 2029	4.622	–5.677	–6.672	7.577
N = 1,116	(23.40)	(–23.01)	(–16.41)	(13.10)
	32.9%	50.9%	*1.892*	*2.359*
Apr 2032	7.836	–9.072	–10.91	15.67
N = 490	(20.82)	(–13.72)	(–12.41)	(12.65)
	46.9%	68.5%	*1.915*	*0.944*

Notes: For the second regression, two additional diagnostics are reported, in italics. The first is the Durbin–Watson statistic, and the second is excess kurtosis of the residuals. In the first regression, these diagnostics were similar to those of the regressions, so they were omitted to save space.

Appendix B. Changes in the general shape of the term structure from one day to another can be measured by simultaneous changes in the level, slope, and curvature—designated, respectively, as "shift," "tilt," and "flex" in Table 5. Such changes are illustrated in **Figure 3**.

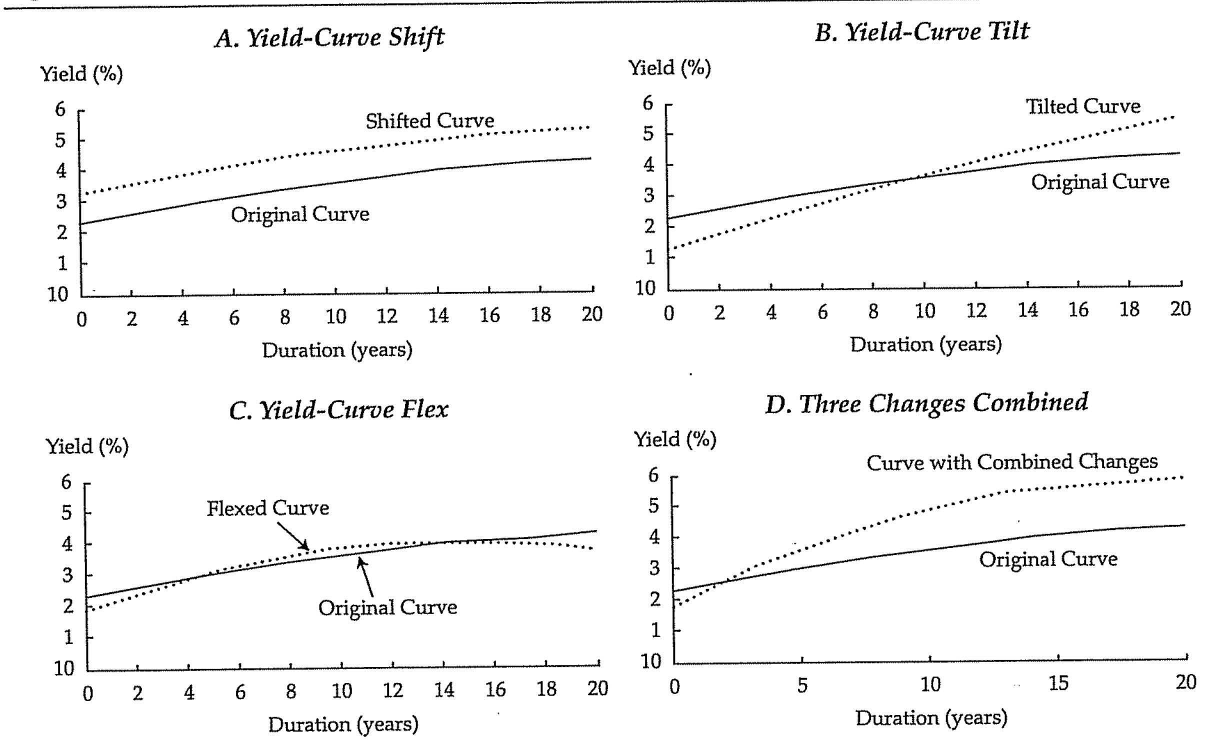
First, notice in Table 5 that the shift effect is similar in most cases to the negative of estimated duration reported in the second column. This similarity suggests that the 5-year/10-year nominal bond average is a reasonable indicator of term-structure level. Second, the longer-term TIPS are significantly and negatively related to the tilt factor, whereas the shortest-term TIP bond is significantly positively related to tilt. Thus, increases in the slope of the nominal term structure (tilting around an intermediate maturity) drive down (up) long-term (short-term) TIPS prices just as they do nominal bond prices. Finally, increases in curvature, or flex, affect positively all but the shortest-term bond (whose coefficient is insignificant), and the significance generally increases with maturity among bonds with long sample periods. Greater curvature of the underlying *real* term structure (i.e., more concavity from below) coincides with lower long-term real yields, all else being equal.

The explanatory power of the regressions in Table 5 is lower than would generally be found for nominal Treasury bonds. Typically, a three-factor model consisting of shift, tilt, and flex explains well over 90 percent of the returns on nominal bonds. But for the TIP bond with the longest sample period (the January 2007 issue), the explanatory power is only slightly more than 37 percent. Notice that the explanatory power seems to be quite a bit higher recently. For the July 2013 bond, whose sample includes only the most recent 57 trading days, the adjusted R^2 is 84 percent.

Although the results in Table 5 are interesting and provide some insight into the behavior of TIPS, the regression is undoubtedly misspecified. The most obvious reason is that each bond has aged during the sample period. Neither its actual duration nor its responses to the changes in the term-structure shape are constants. Of course, the materiality of this maturation is likely to be minor for the very long term TIPS because they have not aged much as a fraction of their original maturities. At the other extreme, however, the shortest-term issue has already matured, so its duration must have fallen to zero during the sample period.

A second problem is possible autocorrelation in the residuals. Table 4 showed that TIPS returns are significantly autocorrelated at the first daily lag. The Durbin–Watson statistics in the penultimate column of Table 5 similarly reveal a mild case of

Figure 3. Theoretical Yield-Curve Movements



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autocorrelation in the regression residuals. Finally, the residuals contain quite a bit of excess kurtosis (see the last column of Table 5). Excess kurtosis implies either thick tails or nonstationary probability distributions, which would, in turn, imply the econometric problem of heteroscedasticity.

An econometric correction for autocorrelation and heteroscedasticity in regression residuals is available. Newey and West (1987) derived an asymptotically consistent covariance matrix for the estimated coefficients that produces corrected standard errors and, hence, t-statistics. As a robustness check, I calculated the Newey–West estimator for the second regression of Table 5 involving the term-structure shape factors.[12] The results reveal that most t-statistics are somewhat smaller when Newey–West is used instead of ordinary least-squares (OLS) regression. Only a few were rendered insignificant, however, by the Newey–West correction. Consequently, I conclude that the mild degree of autocorrelation and the presence of heteroscedasticity have not produced seriously misleading OLS results.

To tackle the problem of bond maturation, I added supplementary time-dependent regressors to the models of Table 5 to capture declining TIPS sensitivity coefficients with decreasing bond maturity. The basic idea is that sensitivities should approximately satisfy a decreasing linear function of time. For example, duration at time t would be $D_t = D_0(1 - t/M)$, where M is the original maturity of the bond, t is an index of maturation that varies from $t = 0$ at issuance to $t = M$ at maturity, and D_0 is the bond's duration at issuance. The same function can be used for the shift, tilt, and flex factors. With the duration regression as an example, the model becomes

$$R_{i,t} = \alpha_i + \beta_{i,1}\Delta Y_t + \beta_{i,2}\left[\left(\frac{t}{M}\right)\Delta Y_t\right], \qquad (2)$$

where ΔY_t is the nominal yield change (on the average of the 5-year/10-year constant-maturity nominal Treasury bond). The first slope coefficient should be duration at issuance, and the second coefficient should be its negative. The results are in **Table 6.**

The first TIP bond, maturity July 2002, looks fairly sensible. Notice that the duration coefficient estimate is 0.816, which is larger than the duration from Table 5, 0.585. It should be larger because the duration coefficient in Table 6 pertains to the origination date, whereas the duration estimate in Table 5 is essentially an average over the entire life of the bond. The second coefficient (in the Table 6 column labeled "Duration*t") is negative (–0.409) and significant, as it should be, although it seems to be too small.[13] In the second Table 6 regression for this bond, we see similar plausible results. The significant origination date coefficients (shift and flex) have time-dependent coefficients with opposite signs, although only Flex*t is significant.

All the longer-term TIPS in Table 6 have completely unexpected and startling patterns of coefficients. Not one of the Duration*t coefficients is negative, and most are actually significantly positive.[14] Because maturities of these bonds became shorter by as much as seven years during the sample period, this outcome can only mean that *real-interest-rate* volatility increased dramatically in the latter part of the period. Additional supporting evidence for an increase in real rate volatility is provided by the time-varying coefficient Shift*t. These coefficients would all be positive if volatility were constant. Instead, most are negative, and many are significant. Notice that the most recently issued TIP bond, maturity July 2013, for which all the sample observations are in the last three months, has extremely large time-dependent coefficients. For this bond, the adjusted $\bar{R}^2$ is 85 percent, but many coefficients are insignificant. Consequently, one more item, multicollinearity, should probably be added to the list of econometric difficulties.

Time-Varying Volatility. A formal model of time-varying volatility for TIPS and other asset returns, the pleasant GARCH(1,1), is reported in **Table 7.**[15] Almost everything is significant for TIPS and, indeed, for all the assets. The evidence of persistence is strong because the lagged conditional variance has a coefficient in excess of 0.8 in most cases. This persistence seems to have been a bit higher in the latter part of the period (as revealed by slightly larger coefficients for the more recently issued TIPS).

Confirmatory visual evidence of nonconstant volatility is presented in **Figure 4** for the January 2007 issue, the bond outstanding for the longest time. Both rolling 21-day (21 trading days or approximately one month) volatility and the conditional volatility from GARCH(1,1) are plotted. The rolling volatility was positioned on the center date of each 21-day period, which explains why it appears to coincide without a lag with the GARCH conditional volatility.

Three features of the plots in Figure 4 stand out. First, a substantial decline in volatility occurred during the first 20 months of this TIP bond's existence. Because the January 2007 issue was the very first, one might reasonably surmise that some learning about TIPS trading characteristics was taking place in those early days. TIPS were

Table 6. Intertemporal Changes in TIPS Empirical Durations and Factor Sensitivities
(t-statistics in parenthesis; adjusted R^2s in percents)

TIPS	Duration	Duration*t	Shift	Tilt	Flex	Shift*t	Tilt*t	Flex*t
Jul 02	0.816	–0.409	–0.684	0.321	–0.590	0.217	0.328	0.951
N = 1,247	(11.75)	(–3.74)	(–7.37)	(1.60)	(–2.36)	(1.35)	(1.08)	(2.35)
	22.0%		21.4%		*1.837*		*4.563*	
Jan 07	0.877	2.976	–0.660	0.637	–1.563	–3.987	–2.111	7.021
N = 1,674	(6.44)	(9.18)	(–3.59)	(1.58)	(–3.14)	(–8.01)	(–2.23)	(5.56)
	42.3%		40.6%		*1.859*		*8.806*	
Jan 08	0.620	5.347	–0.474	1.644	–1.772	–6.316	–6.126	10.25
N = 1,428	(4.47)	(13.47)	(–2.54)	(4.32)	(–3.83)	(–10.27)	(–5.58)	(7.03)
	51.6%		51.1%		*1.814*		*9.181*	
Jan 09	–0.159	10.44	0.230	1.066	–1.880	–11.91	–6.372	15.51
N = 1,178	(–0.98)	(18.53)	(0.99)	(2.40)	(–3.64)	(–12.29)	(–3.89)	(7.52)
	59.0%		59.2%		*1.812*		*8.801*	
Jan 10	0.376	13.81	–0.765	1.189	–1.168	–13.78	–12.16	21.61
N = 926	(1.90)	(15.14)	(–2.76)	(2.89)	(–2.21)	(–8.74)	(–5.46)	(7.29)
	62.4%		65.0%		*1.812*		*7.272*	
Jan 11	1.164	20.57	–2.258	1.089	1.749	–14.95	–22.06	19.09
N = 676	(5.42)	(13.97)	(–6.67)	(2.29)	(2.12)	(–5.31)	(–5.70)	(3.06)
	65.8%		69.9%		*1.797*		*4.345*	
Jan 12	2.208	35.04	–3.021	–3.073	5.720	–25.20	–4.439	–5.480
N = 429	(6.63)	(10.26)	(–4.27)	(–3.08)	(5.13)	(–3.29)	(–0.44)	(–0.44)
	71.6%		78.9%		*1.829*		*1.421*	
Jul 12	3.944	39.90	–3.125	–4.506	2.635	–48.33	9.644	43.98
N = 304	(10.16)	(6.92)	(–4.01)	(–4.37)	(1.56)	(–3.80)	(0.61)	(1.78)
	73.1%		82.6%		*1.904*		*1.590*	
Jul 13	11.12	–204.1	–17.88	7.140	12.35	887.2	–1,022	–500.2
N = 57	(9.09)	(–1.77)	(–3.32)	(1.13)	(1.89)	(1.93)	(–1.91)	(–0.91)
	79.5%		85.0%		*2.105*		*0.911*	
Apr 28	–0.311	46.22	2.59E-02	3.321	–4.646	–51.72	–81.71	112.
N = 1,367	(–0.90)	(14.74)	(0.07)	(4.27)	(–4.97)	(–12.89)	(–11.46)	(11.88)
	40.3%		58.1%		*1.786*		*3.075*	
Apr 29	–1.151	71.55	–8.76E-02	2.119	–3.371	–69.53	–94.96	139.2
N = 1,116	(–2.81)	(15.67)	(–0.19)	(2.31)	(–3.13)	(–10.87)	(–8.65)	(10.07)
	45.0%		62.8%		*1.798*		*3.069*	
Apr 32	3.013	166.2	–6.783	–6.318	12.74	–69.950	–111.3	44.26
N = 490	(4.80)	(9.22)	(–6.50)	(–4.75)	(6.69)	(–2.12)	(–2.68)	(0.71)
	54.7%		72.0%		*1.784*		*1.441*	

Notes: For the second regression, two additional diagnostics are reported, in italics. The first is the Durbin–Watson statistic, and the second is excess kurtosis of the residuals. In the first regression, these diagnostics were similar to those of the regressions, so they were omitted to save space.

unfamiliar instruments in the U.S. fixed-income market at the time, so differences of opinion could have brought about volatility that slowly dissipated as traders learned more about these securities. Second, the late-1998 crisis dramatically increased volatility for roughly five months, September 1998 through January 1999. Then for two years, volatility was low, hovering around 0.10 percent a day. Finally, toward the end of 2000, volatility jumped dramatically and has fluctuated around 0.15–0.30 percent a day ever since.

Volatilities for the original 10-year issues, January 2007 through 2013, are generally ordered by remaining maturity.[16] The single short-term bond

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Table 7. Time Variation in Return Volatility Estimated by GARCH(1,1):
$h_t = \alpha_0 + \alpha_1\varepsilon^2_{t-1} + \rho h_{t-1}$
(t-statistics in parentheses)

Asset	Lagged Squared Innovation, α_1	Lagged Conditional Variance, ρ
	A. TIPS	
Jul 2002	0.105	0.878
	(6.51)	(53.2)
Jan 2007	0.132	0.865
	(8.04)	(59.0)
Jan 2008[a]	0.134	0.866
	(7.43)	(54.5)
Jan 2009	0.103	0.893
	(6.27)	(56.0)
Jan 2010	0.116	0.884
	(5.70)	(47.3)
Jan 2011	0.086	0.890
	(3.95)	(31.2)
Jan 2012	0.061	0.932
	(3.11)	(39.4)
Jul 2012	0.063	0.881
	(1.82)	(11.6)
Apr 2028	0.195	0.818
	(7.86)	(40.9)
Apr 2029[a]	0.048	0.953
	(6.07)	(120.0)
Apr 2032[a]	0.044	0.947
	(3.75)	(62.1)
	B. U.S. Treasuries	
3 Month	0.203	0.731
	(7.02)	(22.1)
1 Year	0.131	0.805
	(6.28)	(27.4)
5 Year	0.065	0.907
	(5.04)	(47.2)
10 Year	0.059	0.909
	(4.63)	(43.5)
30 Year	0.054	0.843
	(2.81)	(14.2)
	C. Equities	
vwretd	0.108	0.851
	(5.82)	(34.6)
ewretd	0.247	0.744
	(8.92)	(30.2)
sprtrn	0.096	0.854
	(5.26)	(31.4)

[a]Possible nonstationarity in the conditional volatility.

Notes: In the variance equation of GARCH(1,1), h is the conditional variance and ε is the innovation. GARCH(1,1) was estimated using daily returns on TIPS, identified by the security's maturity month, on U.S. Treasuries, and on equities. Sample sizes are the same as in Table 2 (less 1 for the single lag). The January 2013 TIP bond did not have enough observations for GARCH convergence.

of July 2002 is the only issue whose volatility appears to have declined from the beginning of 2001 through its maturity. All the others had considerably more volatility in 2001–2003 than in the two preceding calendar years, 1999–2000. Volatility was also relatively high around the Russian debt crisis in late 1998.

What is the source of the substantially higher volatility in the past two calendar years than in the previous two years? To deduce something about this question, **Figure 5** shows the ratio of volatilities for two consecutive two-year periods, 1999–2000 versus 2001–2002, not only for TIPS but also for the other assets. (TIPS issued after 2000 are not included.) Notice that all but the very shortest-term TIP bond had about 80 percent higher volatility in 2001–2002 than in 1999–2000. This pattern is matched neither by nominal bonds nor by equities. Volatility increased somewhat in both these asset classes, but it reached 40 percent only for the one-year nominal T-bond. Equities show increases of 10–20 percent. Curiously, although the volatility increase seems to grow with maturity for TIPS, it declines with maturities beyond one year for nominal bonds.

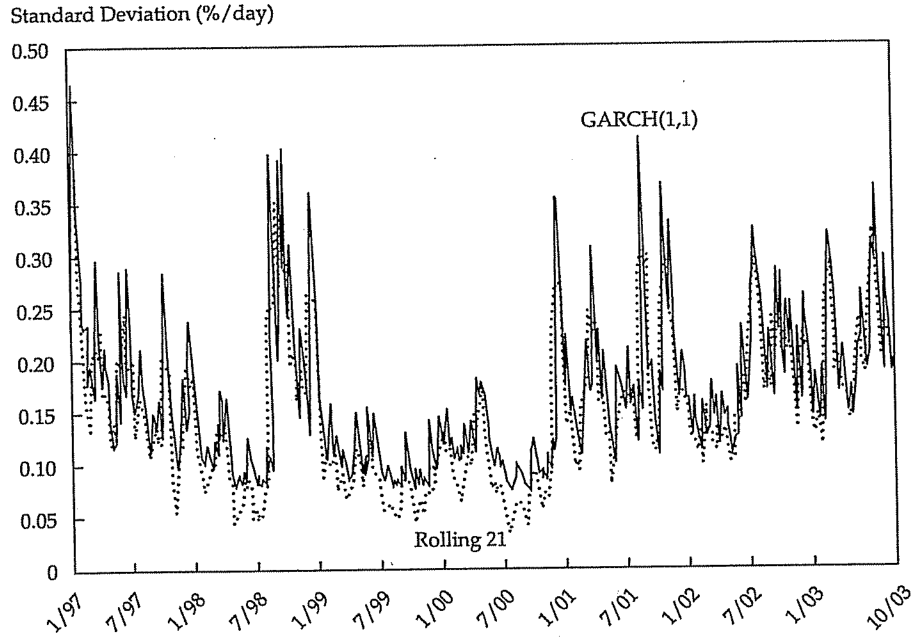
A story consistent with this pattern involves the relative volatilities of real interest rates and expected inflation. If real interest volatility increases while inflation volatility declines or does not increase very much, one would expect TIPS volatility to increase (and possibly increase more for longer maturities) more than nominal bond return volatility (which could even be negatively associated with maturity). Volatility of the real interest rate also affects equities, but because they are much more volatile in general and subject to other sources of risk, the relative impact of real-interest-rate volatility should be smaller for equities than for TIPS.

The Term Structures of Expected Inflation and Real Yields

This section discusses the term structures of nominal yields, real yields, and expected inflation.

Historical Patterns. Although only 12 TIPS have thus far been issued by the U.S. Treasury, when any 4 of them are outstanding, one can estimate the general shape of the term structure of real yields by exploiting the three-factor model used in the "Yields, Durations, and Sensitivities" section for nominal yields and explained in Appendix B. The method involves using real yields and real durations from TIPS to estimate the *real* yield curve's level, slope, and curvature on each trading date. The difference between the nominal and real yield curves is the yield curve of anticipated inflation (plus the inflation risk premium, if any). Hence, this difference also can be estimated for each date.

Figure 4. January 2007 TIPS Volatility: Comparison of GARCH(1,1) and Rolling 21-Day Results, January 1997–September 2003



Note: Standard deviations in percent per day.

Figure 5. Ratio of Return Standard Deviations, 2001–2002 vs. 1999–2000

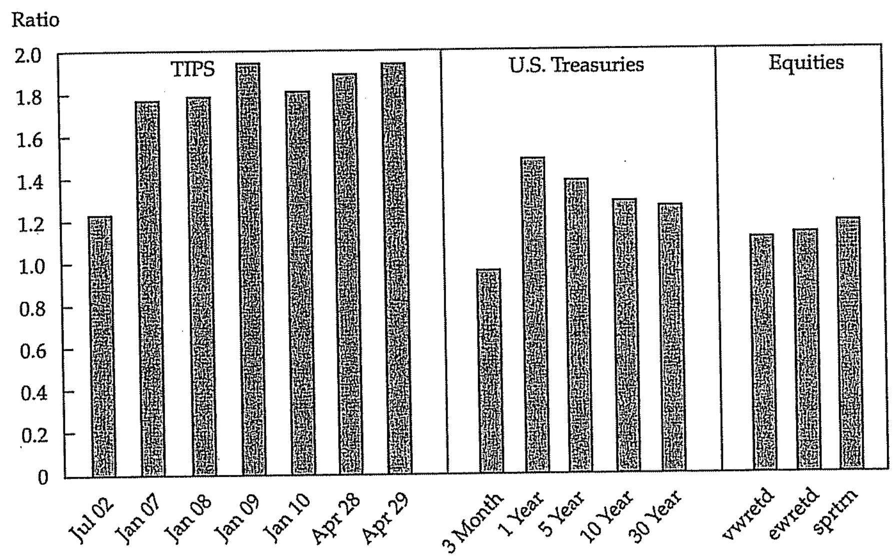


Figure 6, Figure 7, and **Figure 8** summarize the results by plotting, respectively, the level, slope, and curvature estimates for both the nominal and real term structures over time.[17] The vertical difference between the nominal and real term structures provides the corresponding term structure of anticipated inflation plus any inflation risk premium. For clarity, this structure is also plotted over time in **Figure 9**.

To obtain a visual image of the term structure on a given date, combine the level, tilt, and curvature estimates for that date. For example, the term structure of anticipated inflation around 15 January 2001 (see Figure 9) had an average level of about 1.5 percent, was tilted slightly upward from the short to the long end, and had convex downward curvature. For a later date—say, 15 January 2002—the inflation term structure had a lower average level

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Figure 6. Term-Structure Levels: Nominal and Real, January 1999–September 2003

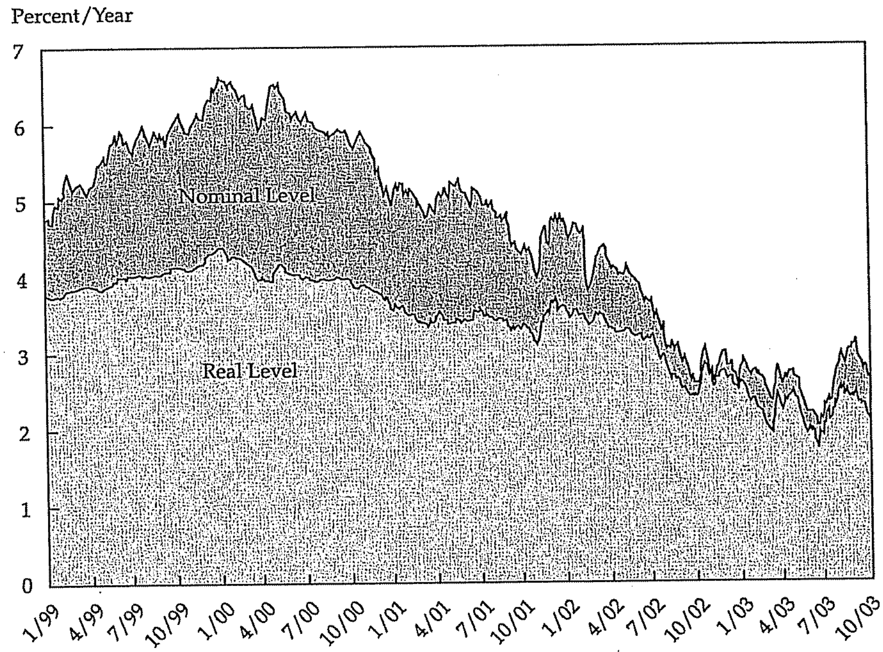


Figure 7. Term-Structure Slopes: Nominal and Real, January 1999–September 2003

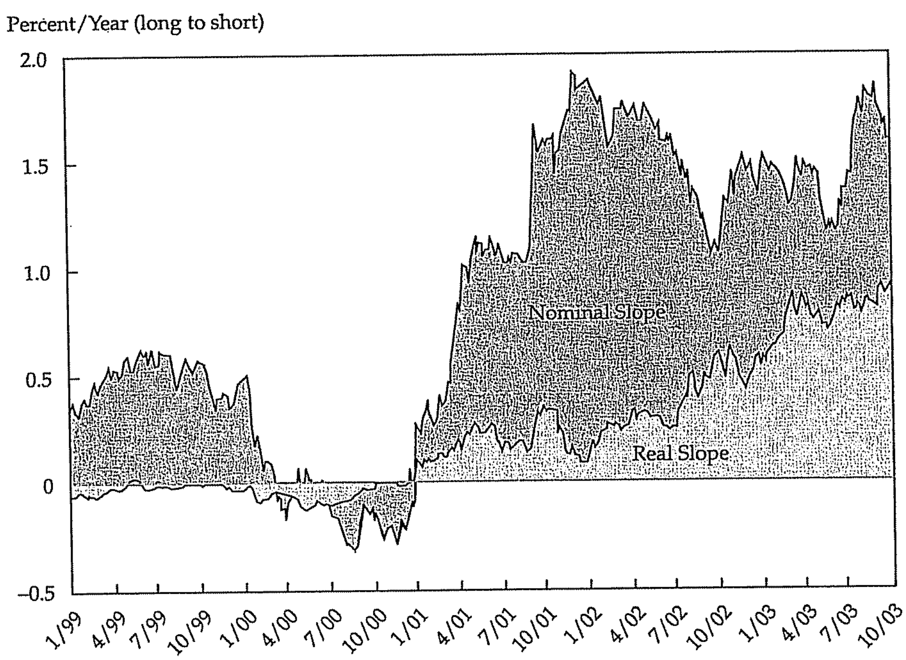


Figure 8. Term-Structure Curvatures: Nominal and Real, January 1999–September 2003

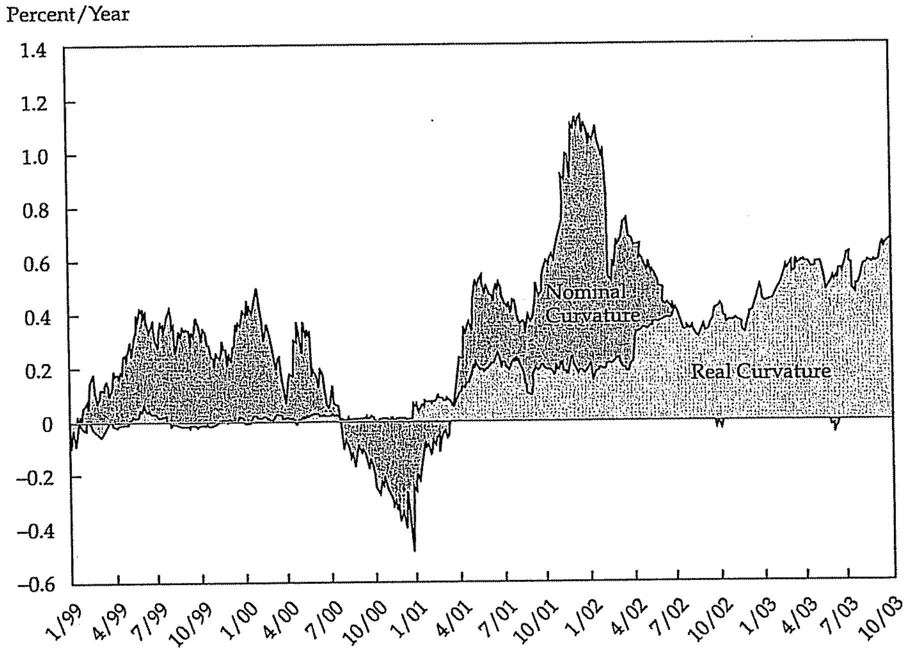
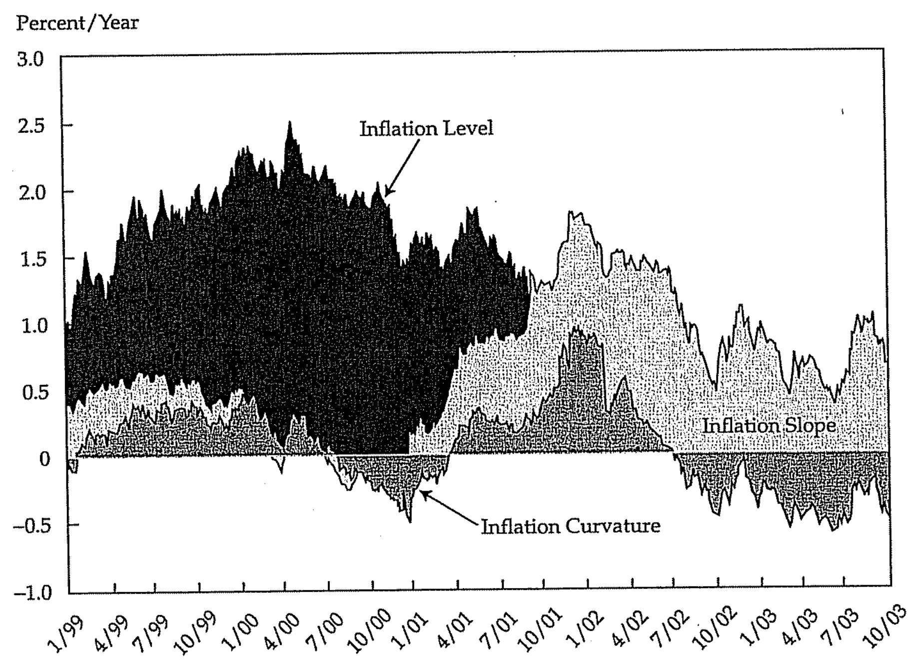


Figure 9. The Term-Structure of Anticipated Inflation, January 1999–September 2003



but was steeply upward sloping (about 1.5 percent from the short end to the long end) and had a pronounced *concave* downward curvature.

The term-structure levels in Figure 6 track *average* nominal- and real-interest-rate movements over time. A dramatic decrease has indeed occurred in both nominal and real interest rates since the beginning of calendar year 2000. The decline in nominal rates has been larger because anticipated inflation also has declined. The inflation level has recently been close to zero, as shown by the relatively small gap between the nominal- and real-yield-curve levels toward the right (latest) end of Figure 6.

As a rule, the nominal yield curve is more steeply sloped than the real yield curve (see Figure 7). This pattern is, of course, consistent with an inflation risk premium that increases with maturity. Notice in Figure 7 or Figure 9 that a sharply positive slope is presently a notable feature of the anticipated inflation term structure. This pattern is consistent with a market consensus belief that inflation will not remain for long at its current low level.

For a brief period during the last half of 2000, the nominal yield curve was less steeply sloped than the real yield curve. At the time, the market consensus must have been forecasting a decline in anticipated inflation, enough of a decline to outweigh any term-dependent risk premium. That forecast proved to be accurate; the estimated expected inflation level did decline.

Figure 8 shows that term-structure curvature was less in absolute value for the real yield curve than for the nominal yield curve until the middle of 2002, but the real curvature has been larger subsequently. The real curvature was mostly positive (concave downward) throughout the sample period and has been materially increasing lately. In term-structure theory, curvature is often associated with volatility, so the recent increase in TIPS return volatility is broadly consistent with the observed curvature trend. The nominal curvature was also mostly positive during the sample period except for the last quarter of 2000, when inflation was expected to decrease.

An obvious caveat applies to these results. Only sparse points along the real yield curve are available, so estimation error is a potentially significant problem. Caution is urged—particularly with respect to the term structure of anticipated inflation.

Possible Explanation for Real-Yield Decline. Real interest rates have fluctuated more in the past three years than in the prior two years. At the same time, inflation seems to have declined both in level and in volatility. TIPS returns have been extraordinarily high during this later period, and yields have declined precipitously. Evidently, TIPS returns can be high when inflation is low, even though real rates have increased in volatility. Is there a link between decreasing anticipated inflation and lower TIPS yields?

Because TIPS are well linked to official inflation, one might think there should be no connection between changes in their yields and changes in expected inflation. In an earlier paper (Roll 1996), however, I argued that inflation and TIPS yields might be coupled because of their tax treatment, which essentially stipulates full taxation of the real yield *and* the inflation accrual. For a taxable investor, the anticipated after-tax real yield on TIPS is

$$\gamma = r(1-\tau) - \frac{\tau I^e}{(1+I^e)}, \tag{3}$$

where τ is the effective tax rate, r is the pretax real yield on TIPS, and I^e is the rate of anticipated inflation.

When anticipated inflation changes, the pretax yield on TIPS must respond to maintain the same level of taxable demand. In other words, to maintain a constant after-tax real yield, the following must hold:

$$\partial\gamma = 0 \Rightarrow \frac{\partial r}{\partial I^e} = \frac{\tau}{\left[(1-\tau)(1+I^e)^2\right]}. \tag{4}$$

For example, if the effective tax rate is 30 percent and the expected inflation is 3 percent a year, $\partial r/\partial I^e \approx$ 0.396 (i.e., a decrease in anticipated inflation of 1 percent would induce a reduction in the pretax yield on TIPS of nearly 40 bps).

These results agree with prevailing market opinion that expected inflation has declined during the past two years. And plenty of tertiary evidence exists; for example, the Treasury auctioned three-month (nominal) bills on 23 December 2002 at an average yield of less than 1.2 percent a year. Even if the real interest rate were only 0.5 percent a year, this latest T-bill yield implies an anticipated inflation over the next quarter considerably below 1 percent (a year).

Falling inflation could explain why TIPS real yields have fallen (and why holding-period returns have been so high). Moreover, the magnitudes seem to be in the right ballpark; inflation fell from perhaps 3 percent during 1999–2000 to less than 1 percent at the end of 2002. At a marginal tax rate of 30 percent, a concurrent reduction should have occurred in TIPS real yields of roughly 80–100 bps, and indeed, this reduction is close to the observed decline.

This interpretation of recent TIPS history does, however, have a hole in it. It presumes that the marginal TIPS investor actually pays taxes. If TIPS are held mainly by tax-exempt organizations, such as pension funds and 401(k) plans, this tax-related explanation is less compelling. At the moment, however, there seem to be few alternative explanations for the dramatic recent holding-period returns of TIPS.

A tax-induced relationship between TIPS real yields and anticipated inflation implies more than simply a long-term trend. Even daily real yield fluctuations should be affected by concurrent changes in the market's consensus belief about future inflation. We have already constructed empirical estimates of the daily term structures of expected inflation reported in the previous section. These can be related to TIPS' real yields. As a first attempt at uncovering a possible tax effect, **Table 8** reports (in the "One Factor" columns) changes in the real yields of TIPS regressed on concurrent changes in the level of expected inflation (that is, the estimated level of the inflation yield curve from the previous section). The regression equation is

$$\Delta y_{j,t} = \alpha + \beta \Delta I^e{}_t + \varepsilon_{j,t}, \tag{5}$$

where $\Delta y_{j,t}$ is the real yield change for TIPS j from day $t-1$ to day t and $\Delta I^e{}_t$ is the contemporaneous change in the estimated level of anticipated inflation.

In every case, except the July 2013 issue (which has only a short period of data available), a strong positive relationship exists between changes in estimated anticipated inflation and changes in real yields. This finding is all the more impressive in that changes in real yields are themselves *negatively* related to estimated changes in anticipated inflation (because changes in anticipated inflation are the difference between the fitted levels of the nominal and real yield curves). If measurement error had been material, a spurious negative relationship might have been found between real yield changes and anticipated inflation changes, but as it turns out, there is no evidence of this at all. The slope coefficients from the one-factor model in Table 8 are estimates of $\tau/[(1-\tau)(1+I^e)^2]$, where τ is the effective tax rate and I^e is true expected inflation. Except for the July 2013 aberration mentioned previously, these coefficients are all positive (and significant), ranging from about 0.1 to more than 0.3. Assuming an expected inflation of 1 percent, the implied marginal tax rates range from about 10 percent for the longer TIPS to about 19 percent for the shortest.[18] This seems sensible, in that tax-exempt investors, such as pension funds, have long horizons and are likely to be attracted to the longer-term maturities.

The second regression reported in Table 8 reveals that a simple bivariate comparison of real yields and inflation is too simplistic. Obviously, tax-paying investors are concerned not only about current inflation but also, perhaps to a greater extent, about future inflation and implied future after-tax yields. Except for the shortest TIP bond, the slope and curvature of the inflation yield curve are probably more pertinent for after-tax yields. This seems to be particularly the case for the inflation term structure's slope. As the three-factor regressions of Table 8 reveal, the estimated inflation yield-curve slope has a positive and highly significant association with real yields for all TIPS beyond the shortest maturity. Evidently, increases in anticipated future inflation (as measured by the inflation term structure's slope) induce immediate and large increases in pretax real yields on TIPS. Inflation term-structure curvature also has an impact on current real yields, perhaps because it is associated with inflation volatility.

What explanations other than taxes could induce the strong empirical relations between real yields and anticipated inflation documented in Table 8? The joint response of real interest rates and inflation to business cycles might be a possibility. If, for example, inflation *and* real interest rates increase (decrease) during an expansion (recession), their mutual correlation would not necessarily imply causation. Future research may settle this important issue. At the present, simply remember that, whatever the cause, *a positive and strong relation definitely exists between real yields and anticipated inflation*. TIPS real yields are *not* independent of inflation.

TIPS in Investment Portfolios

Upon the appearance of any new asset, investors are anxious to know how it fits into well-diversified portfolios. In this section, I attempt a preliminary foray into this complicated terrain with the use of the three broad classes of assets discussed so far—TIPS, nominal T-bonds, and equities. Of course, any real-world investment portfolio would not restrict itself to such broad asset classes, but the exploration still might yield some insights into how TIPS fit into an overall investment strategy.

An optimized portfolio in the mean–variance sense depends on three inputs—expected returns, return volatilities, and correlations. Candidates for some of these ingredients have already been discussed—namely, the sample values given in Tables 2 and 3. A glance at these tables shows, however, that one should not blindly accept such historical estimates in a forward-looking portfolio allocation problem (as is always true of historical estimates).

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Table 8. Tests of the Tax Conjecture
(t-statistics in parentheses; R^2s in percents; Durbin–Watson statistics in italics)

	One Factor			Three Factor		
TIPS Statistic	Shift		Implied Tax Rate	Shift	Tilt	Flex
Jul 2002	0.234			0.136	0.027	0.192
$N = 74$	(5.22)		19%	(2.02)	(0.25)	(1.48)
	3.3%	*1.65*		3.6%		*1.66*
Jan 2007	0.212			–0.128	0.625	0.301
$N = 1{,}156$	(8.98)		18%	(–4.66)	(17.20)	(5.98)
	6.4%	*1.71*		42.7%		*1.64*
Jan 2008	0.195			–0.121	0.643	0.242
$N = 1{,}156$	(8.45)		17%	(–4.51)	(18.14)	(4.92)
	5.7%	*1.73*		42.4%		*1.67*
Jan 2009	0.178			–0.108	0.639	0.184
$N = 1{,}156$	(8.09)		15%	(–4.22)	(18.90)	(3.93)
	5.3%	*1.73*		42.2%		*1.68*
Jan 2010	0.213			–0.095	0.681	0.156
$N = 909$	(7.85)		18%	(–2.99)	(18.50)	(2.88)
	6.3%	*1.75*		45.9%		*1.70*
Jan 2011	0.221			–0.231	0.807	0.317
$N = 660$	(6.50)		18%	(–6.15)	(20.30)	(4.87)
	5.9%	*1.77*		59.1%		*1.82*
Jan 2012	0.187			–0.421	1.066	0.278
$N = 415$	(4.01)		16%	(–10.50)	(27.40)	(4.10)
	3.5%	*1.82*		78.7%		*2.02*
Jul 2012	0.344			–0.427	1.124	0.183
$N = 292$	(3.88)		26%	(–7.64)	(22.80)	(2.09)
	4.6%	*1.82*		80.7%		*2.09*
Jul 2013	–0.182			–0.807	1.219	0.316
$N = 53$	(–0.60)		–23%	(–7.65)	(14.40)	(2.15)
	–1.2%	*2.37*		91.7%		*2.53*
Apr 2028	0.103			–0.080	0.397	0.125
$N = 1{,}156$	(6.42)		10%	(–3.99)	(15.00)	(3.40)
	3.4%	*1.77*		31.5%		*1.75*
Apr 2029	0.107			–0.076	0.398	0.123
$N = 1{,}095$	(6.35)		10%	(–3.63)	(14.50)	(3.21)
	3.5%	*1.77*		31.6%		*1.75*
Apr 2032	0.159			–0.421	0.634	0.371
$N = 354$	(2.87)		14%	(–8.51)	(13.70)	(4.54)
	2.0%	*1.85*		61.6%		*1.97*

Notes: Daily changes in real yields on TIPS were regressed on concurrent daily changes in estimates of the inflation term structure. For the first regression, the implied estimated marginal tax rate was computed under the assumption of a 1 percent expected inflation rate.

For one thing, historical mean returns, particularly returns computed over such short sample periods as seven years, are completely unreliable as estimates of future *expected* returns. Indeed, they are almost nonsensical. Equities, for example, had mean returns lower than most TIPS for the five years ending in July 2003.[19] Probably few nonbehaviorists expect this pattern to continue.

Moreover, sample estimation errors are not confined to the historical means provided in Table 2. Correlations are a critical input for portfolio optimization, but the correlation matrix reported in Table 3 is not even positive definite, so it cannot be used directly; matrix inversion is required.[20] And practically, many of the TIPS are so highly correlated that including them all makes little sense.[21]

As a consequence, I decided (rather arbitrarily) to restrict this exploration to two individual TIPS that have long sample periods, the January 2007 and the April 2028 issues; two constant-maturity nominal bonds, the 1-year and the 10-year; and one equity index, the CRSP value-weighted index.

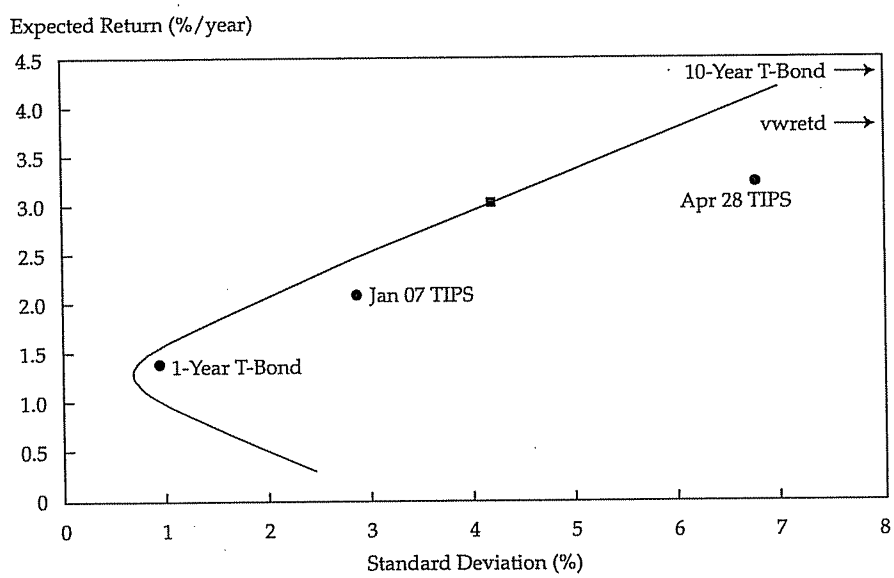
Finally, as the reader has already seen, the volatility of all asset classes fluctuated materially over the six+ years of TIPS history. So, to use all available sample observations in computing standard deviations and correlations would not be wise.

Because portfolio allocation is forward looking, one should use recent estimates of inputs rather than long-term historical values. Thus, I decided to compute the covariance matrix (i.e., standard deviations and correlations) from the beginning of January 2001 through the middle of 2002 and construct examples of "optimized" portfolios toward the end of 2002. I picked an arbitrary day, 13 December 2002, to calculate mean–variance-optimized portfolios.

For the expected returns on nominal bonds, I simply used their closing yields to maturity on the day of portfolio optimization, 13 December 2002. For TIPS, I used their real yields on the same day plus an assumed rate of expected inflation (which will be varied in some of the results to be reported shortly). For equities, I assumed an annual premium of 4 percent over the one-year nominal bond yield. This value could and should be debated. It is a bit high, in my opinion, but it enhances the desirability of equities relative to TIPS and is, therefore, conservative from the perspective of advocating TIPS for a diversified portfolio.

Under the assumption of an expected inflation of 0.4 percent a year, the efficient frontier resulting from this optimization is plotted in **Figure 10.** The 10-year nominal bond and the CRSP value-weighted equity index lie off the chart to the right because their volatilities are so high. Nonetheless, they are held in positive amounts in some of the portfolios along the efficient frontier. For example,

Figure 10. Efficient Frontier with Two TIPS, Two (Nominal) T-Bonds, and the CRSP Value-Weighted Index



Notes: Based on nominal yields for 13 December 2002 and 2001–02 data for daily returns. Expected returns and volatilities in percent per year. Assumptions: Expected inflation = 0.4 percent a year; equity premium = 4.0 percent a year.

the portfolio indicated by the square has an expected return equal to the yield on a five-year nominal bond, which on 13 December 2002 was very close to 3 percent a year. This portfolio is fairly evenly distributed among the five assets, although it has slightly more than 20 percent in each of the two TIPS and slightly less than 20 percent in equities. Its composition is plotted as the second pillar in **Figure 11**.

Figure 11 shows how the inflation assumption affects optimal portfolio composition. The impact is dramatic. Varying assumed inflation by only 10 bps significantly changes the relative allocation to TIPS and nominal bonds. If at the end of 2002 you had predicted inflation greater than 0.4 percent in 2003, you would have wanted to emphasize TIPS. Indeed, if your inflation expectation had been 0.9 percent (still less than 1 percent a year), you would have wanted to put nearly 90 percent of your assets in TIPS! Conversely, if you had thought inflation was going to be very low in 2003, say 0.3 percent or less, nominal bonds would have been your cup of tea.

The inflation-driven results in Figure 11 are not hard to understand: Current nominal bond yields already embed expected inflation, whereas TIPS yields do not. So, when inflation is added to TIPS real yields to obtain their nominal expected returns, the greater inflation is, the more favorable TIPS appear.

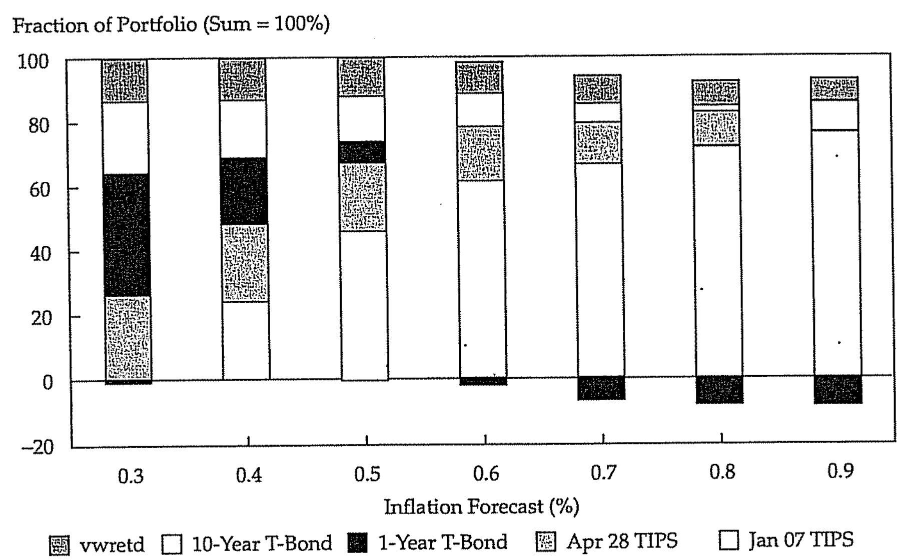
Several caveats are appropriate. First, I took no account of the possible tax–inflation interaction with respect to TIPS real returns. But I argued previously that if inflation increases, TIPS' real returns could decline because of these securities' tax treatment. Second, I did not consider any impact of inflation on the equity premium. Perhaps it should decrease with inflation, or perhaps it should increase. Who knows? Finally, and most importantly, the seeming knife-edged response of portfolio composition here is partly attributable to the small number of assets being considered. If I had used several hundred assets rather than five, the acute sensitivity would have been attenuated to some extent. Nonetheless, a large change in the total allocation to inflation-protected securities relative to nominal bonds would have taken place with a change in anticipated inflation.

The bottom line is: TIPS probably belong in many well-diversified portfolios, even when anticipated inflation is rather low, such as 0.4 percent. TIPS are not strongly correlated with other asset classes, and they have low volatility, much lower than that of nominal bonds with similar maturity. They seem to represent a new diversification opportunity to enhance returns and reduce risk.

Conclusions

TIPS have existed for almost seven years. At the point of this writing, 12 bonds had been issued and 1 had already matured. This article presents an empirical survey of their trading characteristics.

Figure 11. Composition of Optimal Portfolios to Match Five-Year Nominal Yield on 13 December 2002 for Various Inflation Forecasts



TIPS are well protected against inflation (at least as measured by the CPI). A daily *real* yield to maturity and a real duration can be computed in the usual way from the transaction price, real accrued interest, and future real payments, while always ignoring inflation.

Daily *nominal* holding-period returns can be calculated from the change in the trading prices, properly adjusted for the inflation accrual and the accrued interest. Such nominal returns can then be compared with other nominal returns.

Evidence presented here indicates the following about TIPS daily returns since their introduction in January 1997 through September 2003:

- First, TIPS nominal return volatility is less than the volatility of ordinary Treasuries of similar maturity.
- TIPS are highly correlated with each other, particularly for adjacent maturities.
- Over their period of availability, TIPS were negatively correlated with equities (as were nominal bonds) but the correlations were small in absolute magnitude.
- Nominal effective durations are much lower for TIPS than for nominal bonds.
- TIPS respond to changes in the shape of the nominal term structure. Their response to parallel shifts is congruent with their effective empirical durations. Longer (shorter) TIPS do poorly (well) when the term structure tilts upward. Increasing nominal term-structure curvature differentially affects long- and short-term TIPS (as with nominal bonds).
- There is strong evidence of time-varying volatility in TIPS returns.

Even though only a few TIPS issues are outstanding, one can use TIPS to estimate the term structure of real yields and, by comparing the real and nominal yield curves, can derive an estimate of the term structure of expected inflation.[22] The results reveal that short-term anticipated inflation is very low currently. Lower inflationary expectations may explain the recent decline in TIPS real yields. Although TIPS are well linked to the CPI, their tax treatment could render them indirectly subject to inflation because inflation accruals are fully taxed. Hence, a decline in anticipated inflation could induce a reduction in real yields.

Finally, TIPS probably belong in most well-diversified investment portfolios. Under plausible assumptions, TIPS enhance the risk–return characteristics available with other asset classes. Moreover, to the extent that inflation is expected to increase, they should be the dominant component of any portfolio intended to match the nominal return of a mid-maturity bond while minimizing risk.

I am indebted to Barclays Capital for making the TIPS data available, to Kevin Lee and Feifei Li for outstanding research assistance, and to seminar participants at the Harvard Business School, the Universität Konstanz, and the Universität Mannheim.

Appendix A. Calculation of Nominal Holding-Period Returns on TIPS

The explanation in this appendix uses the following definitions:

P_t = price on day t as a percentage of accrued face value
A_t = accrued interest on day t
F_t = face (accrued) value as of day t
C = stated annual coupon
k = number of coupon payments per year ($k = 2$ for TIPS)
CPI_m = CPI-U for calendar month m
CPI_B = CPI-U on the base (issue) date
A_t = accrual factor for day t within month m ($1 \le t \le 31$)
N_m = number of days within month m
G_m = growth factor for days within calendar month m

Accrual of Face Value. The growth factor is fixed so that the accrual factor on the first day of month m corresponds to the CPI reported for month $m - 3$. Thus, the accrual factor for the first day of month $m + 1$ corresponds to the CPI reported for month $m - 2$. For month m,

$$G_m = \sqrt[N_m]{CPI_{m-2}/CPI_{m-3}}. \tag{A1}$$

Then, for each day t within month m, the principal amount of the bond, together with the accrued interest and gross purchase cost, are adjusted by the inflation accrual factor:

$$F_t = \frac{CPI_{m-3}}{CPI_B} G_m^{t-1}. \tag{A2}$$

The seeming skip of one month is explained by the delay in publication of the CPI. For example, the CPI for May is revealed only sometime in early June, so the accrual factor has to depend on the latest available CPI, which, during the first days of June, is for April.

During the TIPS' first month, an analogous method is used to establish CPI_B corresponding to the issue date. If N_I is the number of days in the month of issue (month I) and t is the actual issue date within the month ($1 \le t \le N_I$), then G_I is calculated from Equation A1 and

$$CPI_B = CPI_{I-3}G_I^{t-1}. \qquad (A3)$$

Accrued Interest. The stated coupon is C/k paid k times each year on the accrued face value. Consequently, if F_p is the face value as of coupon payment date p, the actual amount paid is $(F_pC)/k$.

Accrued interest is calculated between coupon payment dates by using the accrued face amount on the settlement date. If n is the next coupon payment date and λ is the previous coupon date, then on settlement date t ($\lambda < t < n$), the accrued interest is

$$A_t = F_t \frac{(t-\lambda)}{(n-\lambda)} \frac{C}{k}. \qquad (A4)$$

Return. Settlement occurs within one business day. For a trade occurring on day t, the accrued interest and principal accrual are determined as of the next trading day. Hence, the one-day return for day t is

$$R_t = \frac{P_tF_{t+j} - P_{t-k}F_t + A_{t+j} - A_t}{P_{t-k}F_t + A_t}, \qquad (A5)$$

where j is the number of days between the trading day and the next business day and k is the number of days between the trading day and the previous business day. Abstracting from holidays, $j = 1$ when t = Monday, . . ., Thursday and $j = 3$ when t = Friday. Similarly, $k = 1$ when t = Tuesday, . . ., Friday and k = 3 when t = Monday. For returns across holidays, j and k could be 2 or 4.

Appendix B. Calculating Changes in the Shape of the Term Structure

A parsimonious (three-factor) model of the term structure's shape can be estimated on each observation date by a nonlinear regression of yield against functions of duration:

$$Y_{j,t} = Level_t + Slope_tX_{L,j} + Curvature_tX_{Q,j}, \qquad (B1)$$

where $Y_{j,t}$ is the yield for the jth bond on date t and where $X_{L,j,t} = a_t + b_tD_{j,t}$ and $X_{Q,j,t} = -(3X^2_{L,j,t} - 1)/2$ are, respectively, linear and quadratic Legendre transformations[23] of $D_{j,t}$, the estimated duration on day t of bond j.[24] The transformation coefficients are

$$b_t = \frac{2}{\max(D_t) - \min(D_t)} \qquad (B2)$$

and

$$a_t = 1 - b_t\max(D_t), \qquad (B3)$$

which assures that the transformed durations span the required range. The estimated regression coefficients, $Level_t$, $Slope_t$, and $Curvature_t$, jointly depict the general shape of the term structure on date t.

Changes in $Level_t$, $Slope_t$, and $Curvature_t$ from one day to the next provide a depiction of daily movements in the general shape of the term structure. Repeating the estimation over all sample days provides a time series of term-structure shape changes, or factors. The shift factor gives the change in term-structure level (i.e., $Shift_t = Level_t - Level_{t-1}$). Similarly, the tilt factor measures the change in term-structure slope: $Tilt_t = Slope_t - Slope_{t-1}$. And the change in curvature, the flex factor, is measured as $Flex_t = Curvature_t - Curvature_{t-1}$.

The shift factor is related to the usual notion of duration because it represents a parallel movement in the term structure. The tilt factor is related to "convexity." No common term is related to the flex factor, although bond market professionals sometimes refer to a similar construct as a "change in convexity."

Given a time series of shift, tilt, and flex factors, a bond's response to changes in term-structure shape can be estimated with a regression such as

$$R_{i,t} = \beta_0 + \beta_{Shift}(Shift_t) + \beta_{Tilt}(Tilt_t) + \beta_{Flex}(Flex_t) + \varepsilon_{i,t}, \qquad (B4)$$

where $R_{i,t}$ is the daily return on the ith bond and $\varepsilon_{i,t}$ is a residual.

The three regression coefficients can be interpreted as follows: β_{Shift} will generally be negative and should approximate the bond's duration in absolute value; β_{Tilt} will be positive for short-term bonds and negative for long-term bonds; β_{Flex} should usually be positive for very long term and very short term bonds and negative for bonds of intermediate maturities.

Notes

1. The index used for TIPS is, more specifically, the U.S. City Average All Items Consumer Price Index for All Urban Consumers (CPI-U), published monthly by the U.S. Bureau of Labor Statistics.
2. See, for example, Arnott (2003).
3. Recently, Jarrow and Yildirim (2003) derived and tested a theoretical pricing model for TIPS and provided analytic valuation formulas for TIPS derivatives.
4. To calculate the duration, I assumed that the constant-maturity yield prevailed for a par bond.

5. See Canina, Michaely, Thaler, and Womack (1998).
6. To approximate an annual rate, daily standard deviation was multiplied by $\sqrt{252}$. This approach assumes independence over time.
7. This statement can be deduced from the fact that the correlation between the July 2002 TIPS and the January 2007 TIPS is 0.757 (sample size 1,262), whereas the July 2002 and January 2012 correlation is only 0.183 (sample size 124). The January 2012 correlation was computed from observations close to the short-term TIPS' maturity date.
8. From January 1926 through December 1996, based on monthly returns, the S&P 500 had correlations of 0.180, 0.136, and 0.0847 with, respectively, long-term, intermediate-term, and one-year Treasury bonds (based on data from Ibbotson Associates).
9. A plot of all the TIPS is available upon request. The shortest-term TIPS exhibited rather bizarre price behavior as it neared maturity in July 2002. For many trading days, its real yield was even negative. The cause might have been measurement error in the recorded trade price; when a bond approaches maturity, even slight errors are magnified as the internal rate of return is annualized. Because of its odd behavior, I did not plot this particular TIPS' yields in Figure 1 for its final half-year of existence.
10. Specifically, unless $\rho < -\frac{1}{2}\sigma_I/\sigma_r$, where σ_I (σ_r) is the standard deviation of anticipated inflation (real yield) and ρ is correlation.
11. Modified duration is Macauley's duration divided by $(1 + Y/k)$, where Y is the yield and k is the compounding frequency. For discrete compounding, modified duration's units are not exactly years but they are close.
12. A table with these results will be provided to interested readers upon request.
13. The absolute value of Duration*t should be approximately the same as the coefficient labeled "Duration."
14. The single exception is the July 2013 TIPS, which provided only 57 observations.
15. GARCH stands for generalized autoregressive conditional heteroscedasticity.
16. To save space, the patterns described in this paragraph are not depicted, but a plot is available upon request.
17. These plots begin in January 1999 because this month is the first time that four different TIPS were outstanding.
18. Although I used 1 percent for expected inflation, this calculation is not sensitive to the inflation assumption.
19. The S&P 500 return averaged only 6.11 percent a year during the sample period. Most TIPS did better. Remember that the equal-weighted CRSP index, which appears to have done quite well in Table 2, has a mean return that is strongly upwardly biased.
20. A correlation matrix computed from simultaneous observations with no missing values will generally be positive definite, and thus invertible, unless there are more assets than sample periods or there is perfect linear dependence among some groups of variables. In the case of Table 3, however, there were large differences among assets in the number of available observations.
21. For example, the 0.999 correlation between the April 2028 and 2029 TIPS suggests that either could be included but not both are needed.
22. Technically, the estimate is the term structure of expected inflation plus the inflation risk premium, if any.
23. The Legendre transformations were used because they are approximately orthogonal over the range –1 to +1. They are exactly orthogonal if continuous from –1 to +1. Curvature is positive if the term structure is concave downward. See mathworld.wolfram.com/LegendreTransformation.html.
24. For constant-maturity nominal Treasury yields, the duration was estimated by assuming that the yield was valid for a bond selling at par.

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CASE: UE 210
WITNESS: Steve Storm

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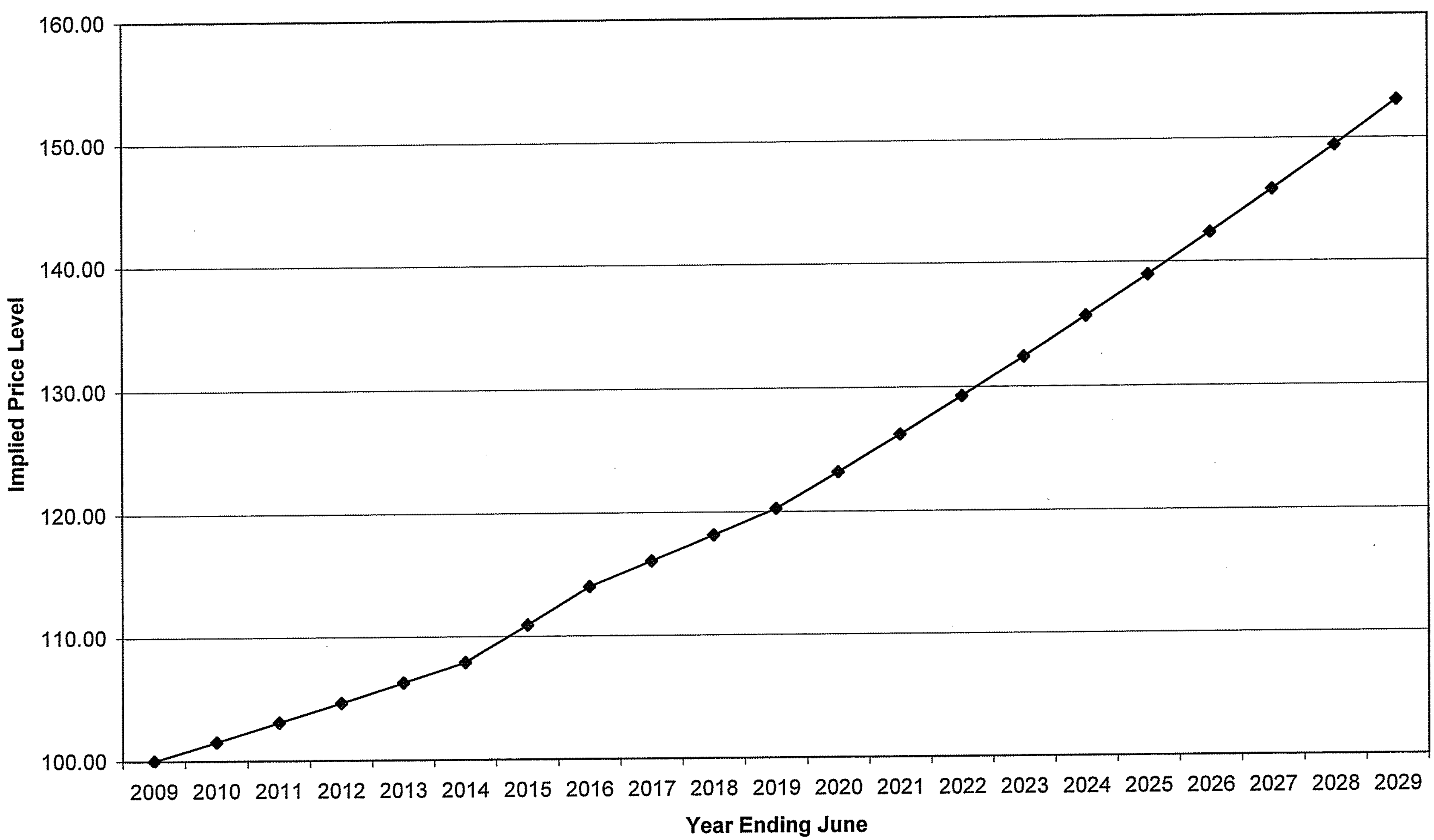
July 24, 2009

UE 210 PP&L

Market-based Inflationary Expectations
(based on June, 2009 Average Interest Rates)



File: Staff ROE
Worksheet: Inflation Chart

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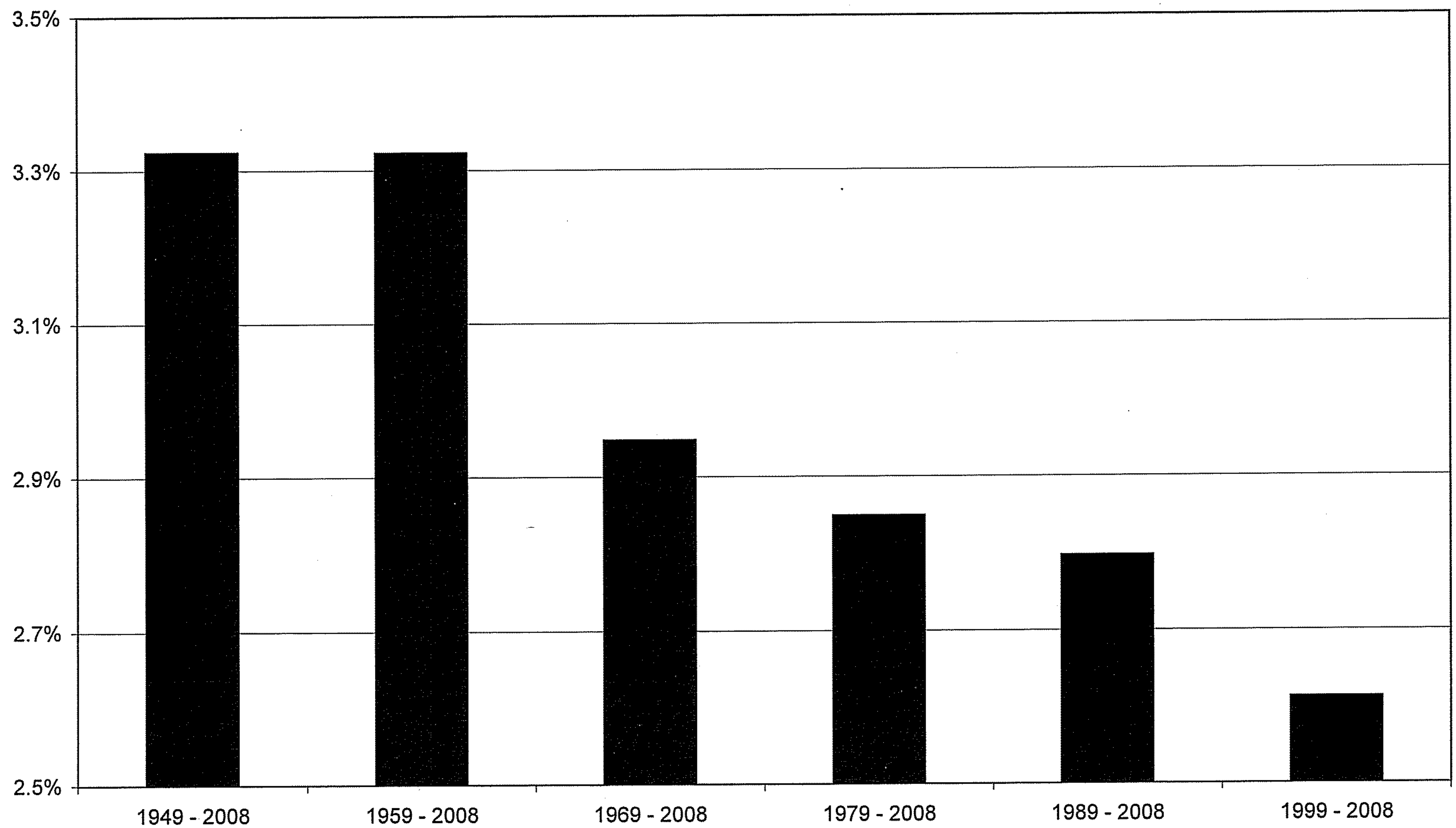
Real GDP Compound Annual Growth Rates for Historical Periods since 1948



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Worksheet: Real GDP Growth Chart

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July 24, 2009

Econometrica, Vol. 57, No. 6 (November, 1989), 1361–1401

THE GREAT CRASH, THE OIL PRICE SHOCK, AND THE UNIT ROOT HYPOTHESIS

BY PIERRE PERRON[1]

We consider the null hypothesis that a time series has a unit root with possibly nonzero drift against the alternative that the process is "trend-stationary." The interest is that we allow under both the null and alternative hypotheses for the presence of a one-time change in the level or in the slope of the trend function. We show how standard tests of the unit root hypothesis against trend stationary alternatives cannot reject the unit root hypothesis if the true data generating mechanism is that of stationary fluctuations around a trend function which contains a one-time break. This holds even asymptotically. We derive test statistics which allow us to distinguish the two hypotheses when a break is present. Their limiting distribution is established and selected percentage points are tabulated. We apply these tests to the Nelson-Plosser data set and to the postwar quarterly real GNP series. In the former, the break is due to the 1929 crash and takes the form of a sudden change in the level of the series. For 11 out of the 14 series analyzed by Nelson and Plosser we can reject at a high confidence level the unit root hypothesis. In the case of the postwar quarterly real GNP series, the break in the trend function occurs at the time of the oil price shock (1973) and takes the form of a change in the slope. Here again we can reject the null hypothesis of a unit root. If one is ready to postulate that the 1929 crash and the slowdown in growth after 1973 are not realizations of an underlying time-invariant stochastic process but can be modeled as exogenous, then the conclusion is that most macroeconomic time series are not characterized by the presence of a unit root. Fluctuations are indeed stationary around a deterministic trend function. The only "shocks" which have had persistent effects are the 1929 crash and the 1973 oil price shock.

KEYWORDS: Hypothesis testing, intervention analysis, structural change, stochastic trends, deterministic trends, functional weak convergence, Wiener process, macroeconomic time series.

1. INTRODUCTION

THE UNIT ROOT HYPOTHESIS has recently attracted a considerable amount of work in both the economics and statistics literature. Indeed, the view that most economic time series are characterized by a stochastic rather than deterministic nonstationarity has become prevalent. The seminal study of Nelson and Plosser (1982) which found that most macroeconomic variables have a univariate time series structure with a unit root has catalyzed a burgeoning research program with both empirical and theoretical dimensions.

Nelson and Plosser's study was followed by a series of empirical analyses which basically confirmed their findings. Some (Stulz and Wasserfallen (1985) and Wasserfallen (1986), among others) applied a similar Dickey–Fuller (1979) statistical methodology to other economic series. On the statistical front, there

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emerged an interest in developing alternative approaches to test the unit root hypothesis. Examples include: the class of tests proposed by Phillips and Perron (1988) and the methodology suggested by Campbell and Mankiw (1987, 1988) and Cochrane (1988) using an estimate of the spectral density at frequency zero. Empirical applications of these methodologies generally reaffirmed the conclusion that most macroeconomic time series have a unit root (e.g., Perron (1988)).

These studies had many effects on economic theorizing. They seem to confirm previous analyses which had advanced the unit root hypothesis for particular economic series, e.g., consumption (Hall (1978)), velocity of money (Gould and Nelson (1974)), and stock prices (Samuelson (1973)). They also launched a series of theoretical investigations with implications consistent with a unit root, e.g., Blanchard and Summers (1986) for employment. Furthermore, a considerable stock of statistical tools was developed for more general models with integrated variables; these include the cointegration framework (Engle and Granger (1987)) and multivariate systems (Stock and Watson (1988) and Phillips and Durlauf (1986)).

As far as macroeconomic theories are concerned, the most important implication of the unit root revolution, is that under this hypothesis random shocks have a permanent effect on the system. Fluctuations are not transitory. This implication, as forcefully argued by Nelson and Plosser, has profound consequences for business cycle theories. It runs counter to the prevailing view that business cycles are transitory fluctuations around a more or less stable trend path. It is therefore of importance to assess carefully the reliability of the unit root hypothesis as an empirical fact.

The aim of this paper appears startling, given the results in the above mentioned literature. Our conclusion is that most macroeconomic time series are not characterized by the presence of a unit root and that fluctuations are indeed transitory. Only two events (shocks) have had a permanent effect on the various macroeconomic variables: the Great Crash of 1929 and the oil price shock of 1973.

Of course, to reach such a conclusion, a particular postulate must be introduced which differentiates our approach from the previous ones. This postulate is that the Great Crash and the oil price shock were not a realization of the underlying data-generating mechanism of the various series. In this sense, we consider these shocks as exogenous. The exogeneity assumption is not a statement about a descriptive model for the time series representation of the variables. It is used here as a device to remove the influence of these shocks from the noise function. A more detailed discussion of these issues and their implications can be found in Section 6.

These two shocks are rather different in nature. On one hand, the Great Crash created a dramatic drop in the mean of most aggregate variables. On the other hand, the 1973 oil price shock was followed by a change in the slope of the trend for most aggregates, i.e., a slowdown in growth. In this light, our aim is to show that most macroeconomic variables are "trend-stationary" if one allows a single change in the intercept of the trend function after 1929 and a single change in the slope of the trend function after 1973.

Our approach is in the spirit of the "intervention analysis" suggested by Box and Tiao (1975). According to their methodology, "aberrant" or "outlying" events can be separated from the noise function and be modeled as changes or "interventions" in the deterministic part of the general time series model. Using such a strategy makes it "possible to distinguish between what can and what cannot be explained by the noise" (Box and Tiao (1975, p. 72)). These "interventions" are assumed to occur at a known date. The same strategy is used in the present analysis in that we consider the time of the changes in the trend function as fixed rather than as a random variable to be estimated.

To make our point as unambiguous as possible, we use the same data set as Nelson and Plosser, as well as the real GNP series analyzed by Campbell and Mankiw. The data set used by Nelson and Plosser contains fourteen macroeconomic variables sampled annually. All series end in 1970 and contain only one break, the 1929 Great Crash. We shall not analyze the unemployment rate series since there is a general agreement that it is stationary. The real GNP series is postwar quarterly from 1947:I to 1986:III and so contains only one break as well, the 1973 oil shock. Furthermore, to make our analysis as similar as possible to previous ones, the statistical methodology applied here is an extension of the Dickey–Fuller methodology (as used by Nelson and Plosser) to test for the presence of a single unit root in a univariate time series.

The plan of the paper is as follows. Section 2 motivates the ensuing analysis and presents the alternative models considered. Section 3 shows that usual tests will not be able to reject the unit root hypothesis if in fact the deterministic trend of the series has a single break (either in the intercept or the slope). In Section 4, we develop formal statistical tests of the null hypothesis of a unit root which can distinguish the unit root hypothesis from that of a stationary series around a trend which has a single break. The asymptotic distributions under the null hypothesis are derived and tabulated. Empirical results from applying these procedures are presented in Section 5. Section 6 contains a discussion of some issues raised by our analysis and suggestions for future research. All theorems are proved in Appendix A.

2. MOTIVATION

The null hypothesis considered is that a given series $\{y_t\}_0^T$ (of which a sample of size $T+1$ is available) is a realization of a time series process characterized by the presence of a unit root and possibly a nonzero drift. However, the approach is generalized to allow a one-time change in the structure occurring at a time T_B $(1 < T_B < T)$. Three different models are considered under the null hypothesis: one that permits an exogeneous change in the level of the series (a "crash"), one that permits an exogenous change in the rate of growth, and one that allows both change.⁷ These hypotheses are parameterized as follows:

Null hypotheses:

Model (A) $y_t = \mu + dD(TB)_t + y_{t-1} + e_t,$

Model (B) $y_t = \mu_1 + y_{t-1} + (\mu_2 - \mu_1) DU_t + e_t,$

Model (C) $y_t = \mu_1 + y_{t-1} + dD(TB)_t + (\mu_2 - \mu_1) DU_t + e_t,$ where

$$D(TB)_t = 1 \quad \text{if} \quad t = T_B + 1, \quad 0 \text{ otherwise;}$$
$$DU_t = 1 \quad \text{if} \quad t > T_B, \quad 0 \text{ otherwise; and}$$
$$A(L)e_t = B(L)v_t,$$

$v_t \sim$ i.i.d. $(0, \sigma^2)$, with $A(L)$ and $B(L)$ pth and qth order polynomials, respectively, in the lag operator L.

The innovation series $\{e_t\}$ is taken to be of the ARMA(p, q) type with the orders p and q possibly unknown. This postulate allows the series $\{y_t\}$ to represent quite general processes. More general conditions are possible and will be used in subsequent theoretical derivations.

Instead of considering the alternative hypothesis that y_t is a stationary series around a deterministic linear trend with time invariant parameters, we shall analyze the following three possible alternative models:

Alternative hypotheses:

Model (A) $y_t = \mu_1 + \beta t + (\mu_2 - \mu_1) DU_t + e_t,$

Model (B) $y_t = \mu + \beta_1 t + (\beta_2 - \beta_1) DT_t^* + e_t,$

Model (C) $y_t = \mu_1 + \beta_1 t + (\mu_2 - \mu_1) DU_t + (\beta_2 - \beta_1) DT_t + e_t$

where

$$DT_t^* = t - T_B, \quad \text{and} \quad DT_t = t \quad \text{if} \quad t > T_B \quad \text{and 0 otherwise.}$$

Here, T_B refers to the time of break, i.e., the period at which the change in the parameters of the trend function occurs. Model (A) describes what we shall refer to as the crash model. The null hypothesis of a unit root is characterized by a dummy variable which takes the value one at the time of break. Under the alternative hypothesis of a "trend-stationary" system, Model (A) allows for a one-time change in the intercept of the trend function. For the empirical cases we have in mind, T_B is the year 1929 and $\mu_2 < \mu_1$. Model (B) is referred to as the "changing growth" model. Under the alternative hypothesis, a change in the slope of the trend function without any sudden change in the level at the time of the break is allowed. Under the null hypothesis, the model specifies that the drift parameter μ changes from μ_1 to μ_2 at time T_B. In the empirical examples presented in Section 5, T_B is the first quarter of 1973 and $\beta_2 < \beta_1$, reflecting a slowdown in growth following the oil shock. Model (C) allows for both effects to take place simultaneously, i.e., a sudden change in the level followed by a different growth path.

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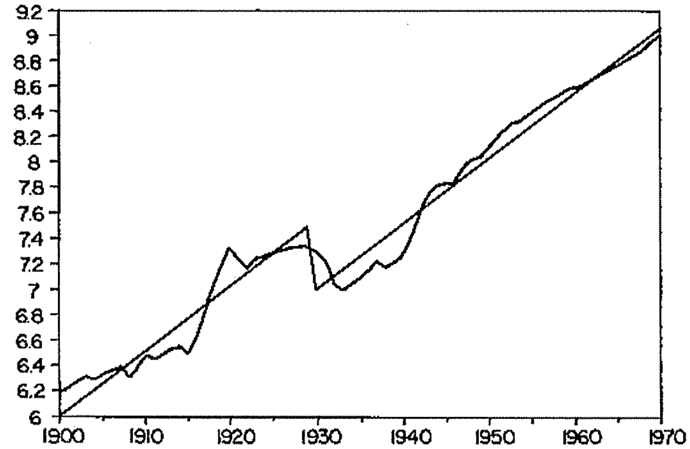


Note: The broken straight line is a fitted trend (by OLS) of the form $\tilde{y}_t = \tilde{\mu} + \tilde{\gamma} DU_t + \tilde{\beta} t$ where $DU_t = 0$ if $t \leqslant 1929$ and $DU_t = 1$ if $t > 1929$.

FIGURE 1.—Logarithm of "Nominal Wages."

To motivate the use of these three models as possible alternatives to the unit root with drift hypothesis, we present in this section some descriptive analyses for three series: "nominal wages" (1900–1970), "quarterly real GNP" (1947:I–1986:III) and "common stock prices" (1871–1970).

Figure 1 shows a plot of the logarithm of the nominal wage series. A feature of this graph is the marked decrease between 1929 and 1930. Apart from this change, the trend appears fairly stable (same slope) over the entire period. The solid line is the estimated trend line from a regression on a constant, a trend and a dummy variable taking a value of 0 prior and at 1929 and value 1 afterwards. Table I presents the results from estimating (by OLS) a regression of the Dickey-Fuller type, i.e.:

$$(1)\qquad y_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\alpha} y_{t-1} + \sum_{i=1}^{k} \tilde{c}_i \Delta y_{t-i} + \tilde{e}_t.$$

The first row presents the full sample regression. The coefficient on the lag dependent variable is 0.910 with a t statistic for the hypothesis that $\alpha = 1$ of -2.09. Using the critical values tabulated by Dickey and Fuller, we cannot reject the null hypothesis of a unit root. When the sample is split in two (pre-1929 and post-1929), the estimated value of α decreases dramatically: 0.304 for the pre-1929 sample and 0.735 for the post-1929 sample. However, due to the small samples available, the t statistics are not large enough (in absolute value) to reject the hypothesis that $\alpha = 1$, even at the 10 percent level.

Two features are worth emphasizing from this example: (a) the full sample estimate of α is markedly superior to any of the split sample estimates and relatively close to one. It appears that the 1929 crash is responsible for the near unit root value of α; and (b) the split sample regressions are not powerful enough

TABLE I

REGRESSION ANALYSIS FOR THE WAGES, QUARTERLY GNP, AND COMMON STOCK PRICE SERIES

Regression: $y_t = \tilde{\mu} + \tilde{\beta}t + \tilde{\alpha}y_{t-1} + \Sigma_{i=1}^{k}\tilde{c}_i \Delta y_{t-i} + \tilde{e}_t$

Series/Period	k	$\tilde{\mu}$	$t_{\tilde{\mu}}$	$\tilde{\beta}$	$t_{\tilde{\beta}}$	$\tilde{\alpha}$	$t_{\tilde{\alpha}}$	$S(\tilde{e})$
(a) Wages								
1900–1970[a]	2	0.566	2.30	0.004	2.30	0.910	−2.09	0.060
1900–1929	7	4.299	2.84	0.037	2.73	0.304	−2.82	0.0803
1930–1970	8	1.632	3.60	0.012	2.64	0.735	−3.19	0.0269
(b) Common stock prices								
1871–1970[a]	2	0.481	2.02	0.003	2.37	0.913	−2.05	0.158
1871–1929	3	0.3468	2.13	0.0063	2.70	0.732	−2.29	0.1209
1930–1970	4	−0.5312	−1.64	0.0166	1.96	0.788	−1.89	0.1376
(c) Quarterly real GNP								
1947:I–1986:III	2	0.386	2.90	0.0004	2.71	0.946	−2.85	0.010
1947:I–1973:I	2	0.637	3.04	0.0008	2.99	0.910	−3.02	0.0099
1973:II–1986:III	1	0.883	2.23	0.0008	2.27	0.878	−2.23	0.0102

[a] Results taken from Nelson and Plosser (1982, Table 5).

to reject the hypothesis that $\alpha = 1$ even though the estimates are well below one. It would be useful, in this light, to have a more powerful procedure based on the full sample that would allow the 1929 break to be exogenous.

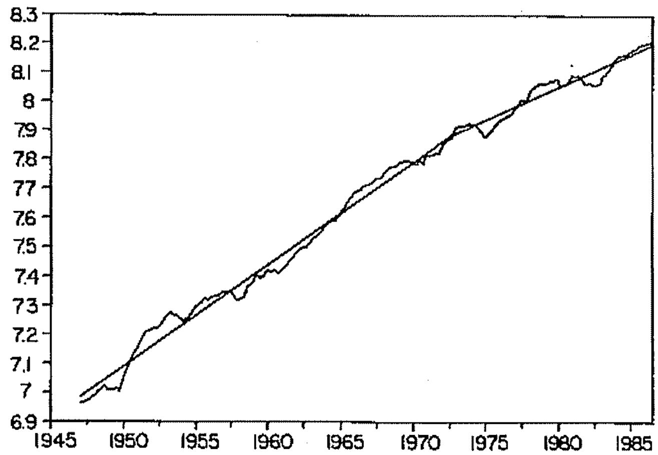
Figure 2 graphs the postwar quarterly real GNP series. Here, the series behave according to Model (B) where there is no sharp change in the level of the series at the 1973:I break point but rather a change in the slope. The solid line is a fitted trend where a dummy variable is included in the regression, taking the value 0 prior and at 1973:I and the value $(t - 105)$ after 1973:I (1973:I being the 105th observation in the sample). Table I compares regressions of the form (1) with full and split samples. Again, the estimate of α is lower in both subsamples than with

TABLE II

SAMPLE AUTOCORRELATIONS OF THE "DETRENDED" SERIES

Series		Period	T	Variance	r_1	r_2	r_3	r_4	r_5	r_6
Real GNP	A	1909–1970	62	0.010	0.77	0.45	0.23	0.11	0.05	0.04
Nominal GNP	A	1909–1970	62	0.023	0.68	0.31	0.12	0.08	0.11	0.12
Real per capita GNP	A	1909–1970	62	0.012	0.81	0.54	0.33	0.20	0.13	0.09
Industrial production	A	1860–1970	111	0.017	0.71	0.44	0.32	0.17	0.08	0.12
Employment	A	1890–1970	81	0.005	0.82	0.59	0.43	0.30	0.20	0.15
GNP deflator	A	1889–1970	82	0.015	0.82	0.63	0.45	0.31	0.17	0.06
Consumer prices	A	1860–1970	111	0.066	0.96	0.89	0.80	0.71	0.63	0.54
Wages	A	1900–1970	71	0.016	0.76	0.47	0.26	0.12	0.03	−0.03
Real wages	C	1900–1970	71	0.003	0.74	0.40	0.12	−0.12	−0.27	−0.33
Money stock	A	1889–1970	82	0.023	0.87	0.69	0.52	0.38	0.25	0.11
Velocity	A	1869–1970	102	0.036	0.90	0.79	0.70	0.62	0.57	0.52
Interest rate	A	1900–1970	71	0.587	0.77	0.58	0.38	0.25	0.15	0.11
Common stock prices	C	1871–1970	100	0.066	0.80	0.53	0.36	0.20	0.10	0.08
Quarterly GNP	B	47:I 86:III	159	0.001	0.94	0.83	0.70	0.57	0.45	0.35

Note: A, B, and C denote the detrending procedure corresponding to the given model under the alternative hypothesis.

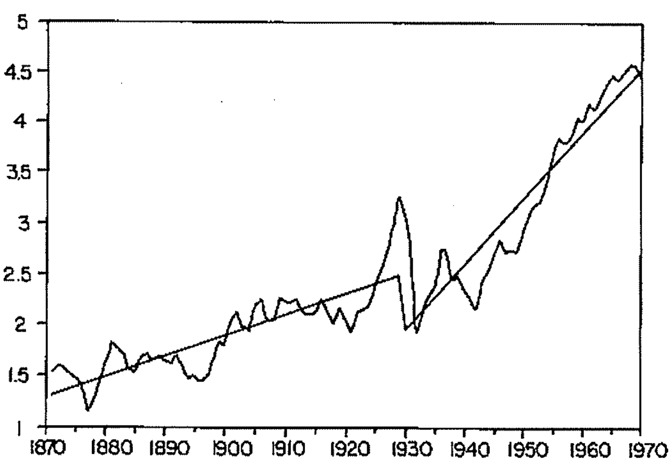


Note: The broken straight line is a fitted trend (by OLS) of the form: $\tilde{y}_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\gamma} DT_t^*$ where $DT_t^* = 0$ if $t \leqslant 1973{:}\mathrm{I}$ and $DT_t^* = t - T_B$ if $t > 1973{:}\mathrm{I} = T_B$.

FIGURE 2.—Logarithm of "Postwar Quarterly Real GNP."

the full sample (given the quarterly nature of the series, the difference is important). The same features discussed above appear to hold when there is a change in the slope of the trend function.

As a final example, consider the common stock price series graphed in Figure 3. The break point is again in 1929 but in this case there appears to be both a sudden change in the level of the series in 1929 and a higher growth rate after. The solid line is the estimated trend with two dummy variables added, an intercept dummy (0 prior and at 1929, 1 after 1929) and a slope dummy (0 prior



Note: The broken straight line is a fitted trend (by OLS) of the form $\tilde{y}_t = \tilde{\mu} + \tilde{\gamma}_1 DU_t + \tilde{\beta} t + \tilde{\gamma}_2 DT_t$ where $DU_t = DT_t = 0$ if $t \leqslant 1929$ and $DU_t = 1$, $DT_t = t$ if $t > 1929$.

FIGURE 3.—Logarithm of "Common Stock Prices."

and at 1929 and t after 1929). The estimated values of α (in regression (1)) with the full sample are 0.913 but are only 0.732 using the pre-1929 sample and 0.788 using the post-1929. Here again, the t statistics are not large enough, however, to reject the unit root hypothesis at even the 10 percent level using any of the subsamples.[2]

Table II presents the autocorellation function of the "detrended series" for the full set of variables analyzed by Nelson and Plosser, along with the postwar quarterly real GNP series. All series are detrended according to Model (A) (with a constant, a trend, and an intercept dummy) except for the postwar Quarterly Real GNP Series (with a slope dummy instead of the intercept dummy, Model (B)) and the real wage and common stock price series (with both a slope and intercept dummy, Model (C)). Unlike the "standard" detrended series (see Table 4 of Nelson-Plosser), the autocorrelations decay quite rapidly for all variables except for the consumer prices and velocity series. This behavior of the autocorrelation function is certainly not the one usually associated with either a random walk or a detrended random walk. Indeed, the "detrended" series appear stationary.

The results of this section motivate the analysis presented in the following sections. We first investigate the effects of the two types of changes in the trend function that we consider on the statistical properties of autoregressive estimates of the type found in regression (1) (both in finite samples and asymptotically). We find that such changes create a spurious unit root that may not vanish, even asymptotically. To overcome the problem of the low power associated with testing for a unit root using split samples, formal test statistics, which permit the presence of either or both an intercept and a slope shift, are developed in Section 4.

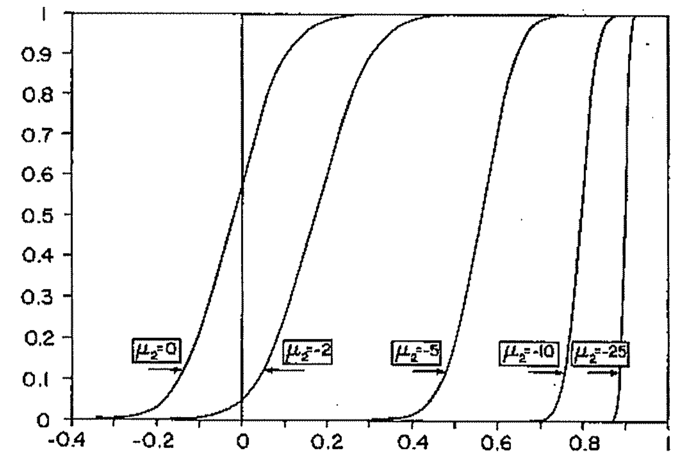
3. THE EFFECT OF A SHIFT IN THE TREND FUNCTION ON TESTS FOR A UNIT ROOT

To assess the effects of the presence of a shift in the level of the series or a shift in the slope (at a single point of time) on tests for the presence of a unit root, we first present a small Monte Carlo experiment. Consider first the "crash hypothesis" (Model (A)). We generated 10,000 replications of a series $\{y_t\}$ of length 100 defined by

$$y_t = \mu_1 + (\mu_2 - \mu_1) DU_t + \beta t + e_t \qquad (t = 1, \ldots, T), \tag{2}$$

where $DU_t = 1$ if $t > T_B$, and 0 otherwise.

[2]Dickey-Fuller tests for the presence of a unit root using split samples are presented in Appendix B for all the series considered. The results are presented for values of k ranging from 1 to 12. These results show that (i) the conclusions drawn are not sensitive to the value of k chosen; (ii) for some series it is possible to reject the unit root hypothesis, especially when considering the post-1929 subsample. Furthermore, the statistical significance of the lagged first-differences (not reported) suggest that a large value of k may be needed. For example, the t statistics on the eighth lagged first-difference is often statistically significant. A similar pattern will occur in the full sample tests reported in subsequent sections.



Note: $\tilde{\alpha}$ is the estimated autoregressive parameter in regression (4). The data-generating mechanism is given by equation (2) with $\mu_1 = 0$, $\beta = 1.0$ and $\{e_t\}$ i.i.d. $N(0,1)$, $T = 100$ and $T_B = 50$.

FIGURE 4.—C.D.F. of $\tilde{\alpha}$ under the "Crash" Model.

For simplicity, $\mu_1 = 0, \beta = 1, T_B = 50, T = 100$ and the innovations e_t are i.i.d. $N(0,1)$. For the "changing growth" hypothesis, a similar setup is considered except that y_t is generated by

$$(3) \qquad y_t = \mu + \beta_1 t + (\beta_2 - \beta_1) DT_t^* + e_t \qquad (t = 1, \ldots, T),$$

where $DT_t^* = t - T_B$ if $t > T_B$, and 0 otherwise.

Again, $\mu = 0, \beta_1 = 1, T_B = 50, T = 100$, and $e_t \sim$ i.i.d. $N(0,1)$. For each replication, we computed the autoregressive coefficient $\tilde{\alpha}$ in the following regression, using ordinary least squares:

$$(4) \qquad y_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\alpha} y_{t-1} + \tilde{e}_t.$$

Figure 4 graphs the cumulative distribution function of $\tilde{\alpha}$ when the data generating process (D.G.P.) is given by (2) for various values of μ_2. This experiment reveals that as the magnitude of the crash increases (μ_2 decreases), the c.d.f of $\tilde{\alpha}$ becomes more concentrated at a value ever closer to 1. The corresponding mean and variance of the sample of $\tilde{\alpha}$ generated are shown in Table III. Figure 5 graphs the c.d.f. of $\tilde{\alpha}$ when the D.G.P. is given by (3) for various values of β_2. As β_2 diverges from β_1, again, the c.d.f. becomes more concentrated and closer to one. The computed mean and variance of $\tilde{\alpha}$ presented in Table III confirms this behavior.[3]

[3]Note that when the error structure is i.i.d., $\tilde{\alpha}$ is free of nuisance parameters and hence can be used as a formal test statistic on the same ground as the t statistic. However, we also performed a similar experiment with the t statistic on $\tilde{\alpha}$ ($\alpha = 1$) in regression (4) as well as in a regression with additional lags of first-differences as regressors. The results obtained show the same behavior. If anything, the t statistic with extra lags of first-differences as regressors shows a still greater bias toward nonrejection of the null hypothesis of a unit root. These results are available upon request. We prefer to report our result in terms of the behavior of the estimator $\tilde{\alpha}$ instead of its t statistic because it makes clear that what causes the nonrejection is not due solely to the behavior of the variance estimator. What is of importance is that $\tilde{\alpha}$ is biased towards unity.

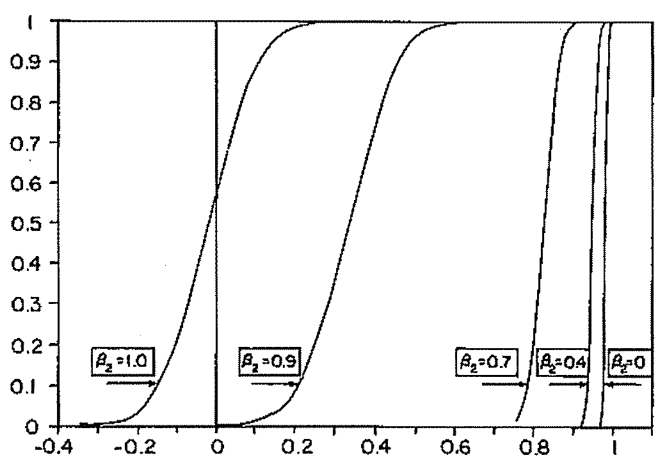
TABLE III
MEAN AND VARIANCE OF $\tilde{\alpha}$

	(a) Crash Simulations, $\mu_1 = 0$, $\beta = 1$				
	$\mu_2 = 0$	$\mu_2 = -2$	$\mu_2 = -5$	$\mu_2 = -10$	$\mu_2 = -25$
Mean	−0.019	0.172	0.558	0.795	0.899
Variance	0.00986	0.01090	0.00471	0.00089	0.00009
	(b) Breaking Trend Simulations, $\beta_1 = 1$, $\mu = 0$				
	$\beta_2 = 1.0$	$\beta_2 = 0.9$	$\beta_2 = 0.7$	$\beta_2 = 0.4$	$\beta_2 = 0.0$
Mean	−0.019	0.334	0.825	0.949	0.981
Variance	0.00986	0.00938	0.00094	0.00009	0.00001

See notes to Figure 4 for case (a) and Figure 5 for case (b).

What emerges from this experiment is that if the magnitude of the shift is significant, one could hardly reject the unit root hypothesis even if the series is that of a trend (albeit with a break) with i.i.d. disturbances. In particular, one would conclude that the shocks have permanent effects. Here, the shocks clearly have no permanent effects, only the one-time shift in the trend function is permanent.

To analyze the effect of an increase in the sample size on the distribution of $\tilde{\alpha}$ with a shift of a given magnitude, we derive the asymptotic limit of $\tilde{\alpha}$. To this end, we again consider processes generated by Models (A), (B), or (C) under the alternative hypotheses, but we enlarge the framework by allowing general conditions on the error structure $\{e_t\}$. Many such sets of conditions are possible and would allow us to carry out the asymptotic theory. For simplicity, we use the



Note: $\tilde{\alpha}$ is the estimated autoregressive parameter in regression (4). The data-generating mechanism is given by equation (3) with $\mu = 0$, $\beta_1 = 1.0$, $\{e_t\}$ i.i.d. $N(0,1)$, $T = 100$, $T_B = 50$.

FIGURE 5.—C.D.F. of $\tilde{\alpha}$ under the "Breaking Trend" Model.

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"mixing-type" conditions of Phillips (1987) and Phillips and Perron (1988). These are stated in Assumption 1.

ASSUMPTION 1: *(a)* $E(e_t)=0$ *all* t; *(b)* $\sup_t E|e_t|^{\beta+\varepsilon}<\infty$ *for some* $\beta>2$ *and* $\varepsilon>0$; *(c)* $\sigma^2=\lim_{T\to\infty}T^{-1}E(S_T^2)$ *exists and* $\sigma^2>0$, *where* $S_T=\sum_1^T e_t$; *(d)* $\{e_t\}_1^\infty$ *is strong mixing with mixing numbers* α_m *that satisfy*: $\sum_1^\infty \alpha_m^{1-2/\beta}<\infty$.

These conditions are general enough to permit the series $\{e_t\}$ to be generated by a finite order ARMA(p,q) process with Gaussian innovations. To carry out the asymptotic analysis, we shall require that both the pre-break and post-break samples increase at the same rate as the total number of observations, T, increases. To this effect, we assume, for simplicity, that $T_B=\lambda T$ for all T. We refer to λ as the "break fraction." The asymptotic limits are taken as T increases to infinity in a sequence that ensures an integer value of T_B for a given λ. This type of increasing sequence is assumed throughout the paper. The results proved in Appendix A are presented in the following theorem.

THEOREM 1: *Let* $\{y_t\}_0^T$ *be a sample of size* $T+1$ *generated under one of the alternative hypotheses with the innovations* $\{e_t\}$ *satisfying Assumption* 1. *Let* '$\to$' *denote convergence in probability. Furthermore, let* $T_B=\lambda T$, *for all* T *and* $0<\lambda<1$; *then as* $T\to\infty$:

(a) *The "crash hypothesis": Under Model* (A)

$$\tilde{\alpha}\to\left\{[\mu_1-\mu_2]^2A+\gamma_1\right\}\left\{[\mu_1-\mu_2]^2A+\sigma_e^2\right\}^{-1}$$

where

$$A=[\lambda-4\lambda^2+6\lambda^3-3\lambda^4],\quad \gamma_1=\lim_{T\to\infty}T^{-1}\sum_1^T E(e_te_{t-1}),$$

and

$$\sigma_e^2=\lim_{T\to\infty}T^{-1}\sum_1^T E\left(e_t^2\right).$$

(b) *The "breaking trend hypothesis": Under either Model* (B) *or* (C)

(i) $\tilde{\alpha}\to 1$,

(ii) $$T(\tilde{\alpha}-1)\to\left\{3(-1+4\lambda-5\lambda^2+2\lambda^3)\right\}\cdot\left\{2(-3+4\lambda-3\lambda^2+3\lambda^3-\lambda^4)\right\}^{-1}.$$

Part (a) of Theorem 1 shows that under the crash hypothesis, the limit of $\tilde{\alpha}$ depends on the relative magnitude of $[\mu_1-\mu_2]^2\ A$ and σ_e^2. In particular, this limit gets closer to one as $[\mu_1-\mu_2]^2$ increases. Another feature is that the limit of $\tilde{\alpha}$ is always greater than the true first-order autoregressive coefficient of the stationary part of the series, γ_1/σ_e^2. However, since $\tilde{\alpha}$ does not converge to 1, the usual statistics for testing that $\alpha = 1$, such as $T(\tilde{\alpha} - 1)$ or the t statistic on $\tilde{\alpha}$, would eventually reject the null hypothesis of a unit root. Nevertheless, added to the generally poor power properties of tests for a unit root is the consideration that the limit of $\tilde{\alpha}$ is inflated above its true value. These conditions are such that it could be difficult to reject the unit root hypothesis in finite samples.

There is another interpretation to the results under the crash hypothesis. As stated in model (A), the change in the intercept of the trend function is given by $(\mu_2 - \mu_1)$, a fixed value. This implies that in the asymptotic derivations we are considering a shift which decreases relative to the level of the series as the sample size increases. It may be more appropriate to specify the change in the intercept as a magnitude relative to the level of the series at the time of the break. Since at this period the level of the series is proportional to T_B, we can specify $(\mu_2 - \mu_1)$ as a proportion of T_B, say, $(\mu_2 - \mu_1) = \gamma T_B$. In this case the "crash" is proportional to the level of the series. Since $T_B \to \infty$ as $T \to \infty$, it is clear, from part (a), that under this interpretation, $\tilde{\alpha} \to 1$.

Such ambiguity does not occur under the "breaking trend hypothesis" (Models (B) or (C)) as is shown by part (b) of Theorem 1. Here, the limit of $\tilde{\alpha}$ is 1 irrespective of the behavior of the intercept and the limit of $T(\tilde{\alpha} - 1)$ is invariant to the relative magnitude of the shift (β_2 versus β_1). The expression in part (b, ii) is a function of λ. However, it varies from 0 to 1/2 for values of λ in the range (0, 1). Since the one-sided 5 percent asymptotic critical value of $T(\tilde{\alpha} - 1)$ is -21.8 under the null hypothesis of a unit root (Fuller (1976)), Theorem 2 implies that the unit root hypothesis could not be rejected, even asymptotically.[4]

These results could be extended to more general test statistics, such as the t statistics. Nevertheless, the picture is clear. Tests of the unit root hypothesis are not consistent against "trend stationary" alternatives when the trend function contains a shift in the slope. Although they are not inconsistent against a shift in the intercept of the trend function (if the change is fixed as T increases), their power is likely to be substantially reduced due to the fact that the limit of the autoregressive coefficient is inflated above its true value. When interpreting the "crash" as proportional to the level of the series as T increases, $\tilde{\alpha}$ unambiguously converges to one and implies a considerable loss in power. There is therefore a need to develop alternative statistical procedures that could distinguish a process with a unit root from a process stationary around a breaking trend function.

4. ALTERNATIVE STATISTICAL PROCEDURES

In this section, we extend the Dickey-Fuller testing strategy to ensure a consistent testing procedure against shifting trend functions. We shall present several ways to do so, all of which are asymptotically equivalent, and discuss the main differences between each.

[4] After the first draft of this paper was written, we became aware of a result similar to part (b, i) of Theorem 1 proved by Rappoport and Reichlin (1987). In fact, in the case of deterministic trends with multiple shifts in slope, they prove the following more general result: "If the true model contains $K+1$ segments, then any fitted model involving K or less segments will, asymptotically, yield a larger sum of squared residuals than [a difference stationary] model" (p.9).

Consider first detrending the raw series $\{y_t\}$ according to either model (A), (B), or (C). Let $\{\tilde{y}_t^i\}$, $i = A, B, C$ be the residuals from a regression of y_t on (1) $i = A$: a constant, a time trend, and DU_t; (2) $i = B$: a constant, a time trend, and DT_t^*; (3) $i = C$: a constant, a time trend, DU_t, and DT_t. Furthermore, let $\tilde{\alpha}^i$ be the least squares estimator of α in the following regression:

$$\tilde{y}_t^i = \tilde{\alpha}^i \tilde{y}_{t-1}^i + \tilde{e}_t \qquad (i = A, B, C;\ t = 1, 2, \ldots, T). \tag{5}$$

Up to this point the extensions from the no break model are straightforward enough. However, matters are not so simple concerning the distribution of the statistics of interest, namely the normalized bias, $T(\tilde{\alpha}^i - 1)$, and the t statistic on $\tilde{\alpha}^i$, $t_{\tilde{\alpha}^i}$ $(i = A, B, C)$. Needless to say, the only manageable analytical distribution theory is asymptotic in nature. But two additional features are also present over the usual procedure: (a) extra regressors and (b) the split sample nature of these extra regressors. To this effect, we derive the asymptotic distribution of $T(\tilde{\alpha}^i - 1)$ and $t_{\tilde{\alpha}^i}$ under the null hypothesis of a unit root. As in Section 3, we require that the break point T_B increases at the same rate as the total sample size T. Again, for simplicity, it is assumed that $T_B = \lambda T$ with both T and T_B integer valued.

The method of proof is similar to that of Phillips (1987) and Phillips and Perron (1988). We use weak convergence results that hold for normalized functions of the sum of the innovations when the latter are assumed to satisfy Assumption 1. The limiting distributions obtained under this general setting are then specialized to the i.i.d. case. The asymptotic distributions in the i.i.d. case are evaluated using simulations, and critical values are tabulated. We then show how the results can be extended to innovations $\{e_t\}$ that follow the general ARMA(p, q) process in the same way that the Dickey-Fuller regressions are modified by adding extra lags of first-differences of the data as regressors.

The main results concerning the asymptotic distributions of the normalized bias estimators and the t statistics of the autoregressive coefficient under the null hypothesis of a unit root are presented in the next theorem.

THEOREM 2: *Let $\{y_t\}$ be generated under the null hypothesis of model i $(i = A, B, C)$ with the innovation sequence $\{e_t\}$ satisfying Assumption* 1. *Let $\Rightarrow$ denote weak convergence in distribution and $\lambda = T_B/T$ for all T. Then, as $T \to \infty$:*

(a) $\quad T(\tilde{\alpha}^i - 1) \Rightarrow H_i/K_i,$

(b) $\quad t_{\tilde{\alpha}^i} \Rightarrow (\sigma/\sigma_e) H_i/(g_i K_i)^{1/2},$

where

$$H_A = g_A D_1 - D_5\psi_1 - D_6\psi_2; \qquad K_A = g_A D_2 - D_4\psi_2 - D_3\psi_1;$$

$$H_B = g_B D_1 + D_5\psi_3 + D_8\psi_4; \qquad K_B = g_B D_2 + D_7\psi_4 + D_3\psi_3;$$

$$H_C = g_C D_9 + D_{13}\psi_5 - D_{14}\psi_6; \qquad K_C = g_C D_{10} - D_{12}\psi_6 + D_{11}\psi_5;$$

with

$$\psi_1 = 6D_4 + 12D_3; \qquad \psi_2 = 6D_3 + (1-\lambda)^{-1}\lambda^{-1}D_4;$$
$$\psi_3 = (1+2\lambda)(1-\lambda)^{-1}D_7 - (1+3\lambda)D_3;$$
$$\psi_4 = (1+2\lambda)(1-\lambda)^{-1}D_3 - (1-\lambda)^{-3}D_7;$$
$$\psi_5 = D_{12} - D_{11}; \qquad \psi_6 = \psi_5 + (1-\lambda)^2 D_{12}/\lambda^3;$$

and

$$D_1 = \left(\tfrac{1}{2}\right)\left(w(1)^2 - \sigma_e^2/\sigma^2\right) - w(1)\int_0^1 w(r)\,dr;$$
$$D_2 = \int_0^1 w(r)^2\,dr - \left[\int_0^1 w(r)\,dr\right]^2;$$
$$D_3 = \int_0^1 rw(r)\,dr - \left(\tfrac{1}{2}\right)\int_0^1 w(r)\,dr; \qquad D_4 = \int_0^\lambda w(r)\,dr - \lambda\int_0^1 w(r)\,dr;$$
$$D_5 = w(1)/2 - \int_0^1 w(r)\,dr; \qquad D_6 = w(\lambda) - \lambda w(1);$$
$$D_7 = \int_\lambda^1 rw(r)\,dr - \lambda\int_\lambda^1 w(r)\,dr - \left((1-\lambda)^2/2\right)\int_0^1 w(r)\,dr;$$
$$D_8 = \left((1-\lambda^2)/2\right)w(1) - \int_\lambda^1 w(r)\,dr;$$
$$D_9 = \int_0^1 w(r)^2\,dr - \lambda^{-1}\left(\int_0^\lambda w(r)\,dr\right)^2 - (1-\lambda)^{-1}\left(\int_\lambda^1 w(r)\,dr\right)^2;$$
$$D_{10} = \left(w(1)^2 - \sigma_e^2/\sigma^2\right)/2 - \lambda^{-1}w(\lambda)\int_0^\lambda w(r)\,dr$$
$$\qquad - (w(1) - w(\lambda))(1-\lambda)^{-1}\int_\lambda^1 w(r)\,dr;$$
$$D_{11} = \int_0^1 rw(r)\,dr - \left(\tfrac{1}{2}\right)(1+\lambda)\int_0^1 w(r)\,dr + \left(\tfrac{1}{2}\right)\int_0^\lambda w(r)\,dr;$$
$$D_{12} = \int_0^\lambda rw(r)\,dr - (\lambda/2)\int_0^\lambda w(r)\,dr;$$
$$D_{13} = (1-\lambda)w(1)/2 + w(\lambda)/2 - \int_0^1 w(r)\,dr;$$
$$D_{14} = \lambda w(\lambda)/2 - \int_0^\lambda w(r)\,dr;$$
$$g_A = 1 - 3(1-\lambda)\lambda; \qquad g_B = 3\lambda^3; \qquad g_C = 12(1-\lambda)^2;$$

and where $w(r)$ *is the unit Wiener process defined on* $C[0,1]$, $\sigma^2 = \lim_{T\to\infty} E[T^{-1} S_T^2]$, $S_T = \Sigma_1^T e_t$, *and* $\sigma_e^2 = \lim_{T\to\infty} E[T^{-1}\Sigma_1^T e_t^2]$.

Theorem 2 provides a representation for the limiting distribution of the normalized least squares estimators and their t statistics in terms of functionals of Wiener processes. These limiting distributions are functions of the parameter λ, the ratio of the pre-break sample size to total sample size. It is easy to verify that when λ is either 0 or 1, the limiting distributions are identical over all models and are given by:

$$T(\tilde{\alpha}-1) \Rightarrow H/K \quad \text{and} \quad t_{\tilde{\alpha}} \Rightarrow (\sigma/\sigma_e)H/K^{1/2}$$

where

$$H = \left(\tfrac{1}{2}\right)\left(w(1)^2 - \sigma_e^2/\sigma^2\right) + 12\left[\int_0^1 rw(r)\,dr - \left(\tfrac{1}{2}\right)\int_0^1 w(r)\,dr\right] \cdot \left[\int_0^1 w(r)\,dr - \left(\tfrac{1}{2}\right)w(1)\right] - w(1)\int_0^1 w(r)\,dr,$$

$$K = \int_0^1 w(r)^2\,dr - 12\left(\int_0^1 rw(r)\,dr\right)^2 + 12\int_0^1 w(r)\,dr\int_0^1 rw(r)\,dr - 4\left(\int_0^1 w(r)\,dr\right)^2.$$

These latter asymptotic distributions correspond to those derived by Phillips and Perron (1988) in the case where no dummy variables are included.

The expressions for the limiting distributions in Theorem 2 depend on additional nuisance parameters, apart from λ, namely σ^2 and σ_e^2. As in Phillips (1987) and Phillips and Perron (1988), σ_e^2 is the variance of the innovations and σ^2 is, in the case of weakly stationary innovations, equal to $2\pi f(0)$ where $f(0)$ is the spectral density of $\{e_t\}$ evaluated at frequency zero. When the innovation sequence $\{e_t\}$ is independent and identically distributed, $\sigma^2 = \sigma_e^2$ and, in that case, the limiting distributions are invariant with respect to nuisance parameters, except λ.

Therefore, when $\sigma^2 = \sigma_e^2$, percentage points of the limiting distributions can be tabulated for given values of λ. Tables IV, V, and VI present selected percentage points that will allow us to carry hypothesis testing. The critical values are obtained via simulation methods. We briefly describe the steps involved. First, we generate a sample of size 1,000 of i.i.d. $N(0,1)$ random deviates, $\{e_t\}$. We then construct sample moments of the data which converge weakly to the various functionals of the Wiener process involved in the representation of the asymptotic distributions. For example, as $T\to\infty$, $T^{-1/2}\,\Sigma_1^T e_t \Rightarrow w(1)$, $T^{-1/2}\Sigma_1^{T_B} e_t \Rightarrow w(\lambda)$, $T^{-3/2}\Sigma_1^T\Sigma_{j=1}^t e_j \Rightarrow \int_0^1 w(r)\,dr$, $\Sigma_{t=1}^T(\Sigma_{j=1}^{t-1} e_j)e_t \Rightarrow (\tfrac{1}{2})(w(1)^2-1)$, etc. With a sample size of 1,000 and i.i.d. $N(0,1)$ variates, we can expect the approximation to be quite accurate. Once the various functionals are evaluated, we construct the expressions in Theorem 2 and obtain one realization of the limiting distributions

TABLE IV.A

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $T(\tilde{\alpha}-1)$ IN MODEL A
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−34.17	−35.85	−35.07	−34.44	−34.07	−35.83	−35.59	−34.86	−34.65
2.5%	−28.93	−30.35	−29.92	−29.26	−29.00	−29.80	−29.61	−29.40	−29.35
5%	−25.04	−26.00	−25.90	−25.40	−25.25	−25.56	−25.99	−25.82	−25.40
10%	−21.45	−22.16	−21.93	−21.61	−21.55	−21.79	−22.33	−22.10	−21.48
90%	−4.57	−5.19	−5.13	−4.28	−3.85	−4.36	−5.15	−5.32	−4.62
95%	−3.40	−3.90	−3.80	−2.83	−2.38	−2.92	−3.86	−3.87	−3.27
97.5%	−2.35	−2.92	−2.85	−1.69	−1.42	−1.89	−2.78	−2.84	−2.13
99%	−1.28	−1.70	−1.60	−0.61	−0.40	−0.78	−1.58	−1.78	−1.39

TABLE IV.B

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $t_{\tilde{\alpha}}$ IN MODEL A
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−4.30	−4.39	−4.39	−4.34	−4.32	−4.45	−4.42	−4.33	−4.27
2.5%	−3.93	−4.08	−4.03	−4.01	−4.01	−4.09	−4.07	−3.99	−3.97
5%	−3.68	−3.77	−3.76	−3.72	−3.76	−3.76	−3.80	−3.75	−3.69
10%	−3.40	−3.47	−3.46	−3.44	−3.46	−3.47	−3.51	−3.46	−3.38
90%	−1.38	−1.45	−1.43	−1.26	−1.17	−1.28	−1.42	−1.46	−1.37
95%	−1.09	−1.14	−1.13	−0.88	−0.79	−0.92	−1.10	−1.13	−1.04
97.5%	−0.78	−0.90	−0.83	−0.55	−0.49	−0.60	−0.82	−0.89	−0.74
99%	−0.46	−0.54	−0.51	−0.21	−0.15	−0.26	−0.50	−0.57	−0.47

TABLE V.A

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $T(\tilde{\alpha}-1)$ IN MODEL B
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−34.34	−37.16	−38.07	−39.21	−39.77	−40.08	−38.70	−36.18	−34.69
2.5%	−28.74	−31.97	−32.78	−33.42	−33.60	−33.21	−32.31	−31.45	−29.42
5%	−25.00	−27.16	−28.61	−29.23	−29.65	−29.51	−28.68	−27.24	−25.25
10%	−21.26	−23.10	−24.20	−25.04	−25.40	−25.15	−24.30	−23.01	−21.24
90%	−4.27	−5.09	−5.92	−6.62	−6.96	−6.71	−6.08	−5.26	−4.45
95%	−3.12	−3.85	−4.50	−5.06	−5.31	−5.15	−4.59	−3.82	−3.16
97.5%	−2.20	−2.69	−3.30	−3.90	−4.14	−3.94	−3.36	−2.72	−2.21
99%	−1.11	−1.58	−2.19	−2.50	−3.01	−2.54	−2.20	−1.50	−1.24

of the statistics $T(\tilde{\alpha}^i-1)$, $t_{\tilde{\alpha}^i}$ $(i=A,B,C)$. We replicate this procedure 5,000 times and obtain the critical values from the sorted vector of replicated statistics. This procedure is performed for each statistic with nine values of the parameter λ, the ratio of pre-break sample size to total sample size.[5]

Several features are worth mentioning with respect to these critical values. First, as expected, for a given size of the test, the critical values are larger (in

[5]For some evidence on the adequacy of this method to obtain critical values for limiting distributions involving functions of Wiener processes, see Chan (1988).

TABLE V.B

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $t_{\hat{\alpha}}$ IN MODEL B
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−4.27	−4.41	−4.51	−4.55	−4.56	−4.57	−4.51	−4.38	−4.26
2.5%	−3.94	−4.08	−4.17	−4.20	−4.26	−4.20	−4.13	−4.07	−3.96
5%	−3.65	−3.80	−3.87	−3.94	−3.96	−3.95	−3.85	−3.82	−3.68
10%	−3.36	−3.49	−3.58	−3.66	−3.68	−3.66	−3.57	−3.50	−3.35
90%	−1.35	−1.48	−1.59	−1.69	−1.74	−1.71	−1.61	−1.49	−1.34
95%	−1.04	−1.18	−1.27	−1.37	−1.40	−1.36	−1.28	−1.16	−1.04
97.5%	−0.78	−0.87	−0.97	−1.11	−1.18	−1.11	−0.97	−0.87	−0.77
99%	−0.40	−0.52	−0.69	−0.75	−0.82	−0.78	−0.67	−0.54	−0.43

TABLE VI.A

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $T(\hat{\alpha} - 1)$ IN MODEL C
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−36.17	−39.97	−42.98	−45.52	−44.07	−44.75	−43.02	−41.48	−36.58
2.5%	−30.65	−34.92	−36.48	−37.12	−37.56	−37.72	−37.50	−35.16	−31.82
5%	−26.63	−29.95	−32.47	−33.22	−33.79	−33.19	−33.11	−30.70	−27.16
10%	−22.68	−25.50	−27.90	−29.39	−29.41	−29.04	−28.14	−25.79	−22.62
90%	−4.74	−5.85	−7.35	−8.43	−8.84	−8.55	−7.41	−6.17	−4.89
95%	−3.41	−4.34	−5.50	−6.67	−7.19	−6.79	−5.66	−4.52	−3.52
97.5%	−2.51	−3.19	−4.14	−5.37	−5.82	−5.47	−4.33	−3.35	−2.49
99%	−1.31	−2.14	−2.82	−3.96	−4.39	−4.24	−2.80	−2.02	−1.28

TABLE VI.B

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $t_{\hat{\alpha}}$ IN MODEL C
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−4.38	−4.65	−4.78	−4.81	−4.90	−4.88	−4.75	−4.70	−4.41
2.5%	−4.01	−4.32	−4.46	−4.48	−4.53	−4.49	−4.44	−4.31	−4.10
5%	−3.75	−3.99	−4.17	−4.22	−4.24	−4.24	−4.18	−4.04	−3.80
10%	−3.45	−3.66	−3.87	−3.95	−3.96	−3.95	−3.86	−3.69	−3.46
90%	−1.44	−1.60	−1.78	−1.91	−1.96	−1.93	−1.81	−1.63	−1.44
95%	−1.11	−1.27	−1.46	−1.62	−1.69	−1.63	−1.47	−1.29	−1.12
97.5%	−0.82	−0.98	−1.15	−1.35	−1.43	−1.37	−1.17	−1.04	−0.80
99%	−0.45	−0.67	−0.81	−1.04	−1.07	−1.08	−0.79	−0.64	−0.50

absolute value) for each model than the standard Dickey-Fuller critical values when considering the left tail. One would therefore expect a loss in power. Secondly, although the critical values are not significantly influenced by the value of the parameter λ, the maximum (in absolute value) occurs around the value $\lambda = 0.5$, i.e., for a break at mid-sample.[6] In the left tail, critical values of the statistics are smallest (in absolute value) when λ is close to 0 or 1. This is to be

[6]The simulated critical values suggest that the limiting distributions are symmetric around $\lambda = 0.5$. This feature seems intuitively plausible. We have not, however, proved that such is the case.

expected since, as previously mentioned, the critical values are identical to those of Dickey and Fuller when $\lambda = 0, 1$.

Some critical values are worth noticing. Consider the t statistics. Under Model (A), the "crash hypothesis", the 5 percent critical value has a minimum (over values of λ) of -3.80. Under Models (B) and (C), the corresponding figures are -3.96 and -4.24 respectively. The critical values under the various models are therefore noticeably smaller than the standard Dickey-Fuller critical value of -3.41 (see Dickey (1976) and Fuller (1976)).

These sets of results can be used to perform hypothesis testing. One simply picks the critical value corresponding to the sample value of λ at the chosen significance level. Since we only provide critical values for a selected grid of λ's, the procedure suggested is to choose the critical value corresponding to the value of λ nearest to its sample value, i.e., T_B/T. Given that the differences in the critical values over adjacent values for λ in the tables are not substantially different, this procedure should not cause misleading inferences.

4.1. *Extensions to More General Error Processes*: *Case* (1)

Using regressions (5) ($i = A, B, C$) and the critical values in Tables IV, V, and VI is valid only in the case where the innovation sequence $\{e_t\}$ is uncorrelated. When there is additional correlation, as one would expect, an extension is necessary. Two approaches are possible. One is to follow the approach suggested by Phillips (1987) and Phillips and Perron (1988). This involves finding a set of transformed statistics that would converge weakly to the limiting distributions expressed in Theorem 2 with $\sigma^2 = \sigma_e^2$. The other approach is that suggested by Dickey and Fuller (1979) and Said and Dickey (1984).

Consider first the extension to Phillips' (1987) procedure. It is useful first to write the limiting distributions of Theorem 2 in a different, more compact form. To do so, we adopt the framework suggested by Ouliaris, Park, and Phillips (1988). Define $w_i(r)$ ($i = A, B, C$) to be the stochastic process on $[0,1]$ such that $w_i(r)$ is the projection residual of a Wiener process $w(r)$ on the subspace generated by the following set of functions: (1) $i = A$: $1, r, du(r)$, where $du(r) = 0$ if $r \leqslant \lambda$ and $du(r) = 1$ if $r > \lambda$; (2) $i = B$: $1, r, dt^*(r)$, where $dt^*(r) = 0$ if $r \leqslant \lambda$ and $dt^*(r) = r - \lambda$ if $r > \lambda$; (3) $i = C$: $1, r, du(r), dt(r)$, where $dt(r) = 0$ if $r \leqslant \lambda$ and $dt(r) = r$ if $r > \lambda$. Adopting this notation, an alternative representation of the limiting distributions in Theorem 2 is given by:

$$T(\tilde{\alpha}^i - 1) \Rightarrow \left(\int_0^1 w_i(r)\,dw(r) + \delta\right)\left(\int_0^1 w_i(r)^2\,dr\right)^{-1} \qquad (i = A, B, C)$$

and

$$t_{\tilde{\alpha}^i} \Rightarrow (\sigma/\sigma_e)\left(\int_0^1 w_i(r)\,dw(r) + \delta\right)\left(\int_0^1 w_i(r)^2\,dr\right)^{-1/2} \qquad (i = A, B, C)$$

where $\delta = (\sigma^2 - \sigma_e^2)/(2\sigma^2)$.

Now, define $\tilde{\sigma}_i^2$ and $\tilde{\sigma}_{ei}^2$ to be, respectively, any consistent estimator of σ^2 and σ_e^2 based on the estimated residuals from regression (5)($i = A, B, C$).[7] Also define S_i^2 ($i = A, B, C$) to be the residual sum of squares from the regression y_{t-1} on (1) $i = A$: $1, t, DU_t$; (2) $i = B$: $1, t, DT_t^*$; and (3) $i = C$: $1, t, DU_t, DT_t$. We then define the transformed statistics as:

(6) $$Z(\tilde{\alpha}^i) = T(\tilde{\alpha}^i - 1) - T^2(\tilde{\sigma}_i^2 - \tilde{\sigma}_{ei}^2)/2S_i^2 \qquad (i = A, B, C),$$

(7) $$Z(t_{\tilde{\alpha}^i}) = (\tilde{\sigma}_{ei}/\tilde{\sigma}_i)t_{\tilde{\alpha}^i} - T(\tilde{\sigma}_i^2 - \tilde{\sigma}_{ei}^2)/2\tilde{\sigma}_i S_i \qquad (i = A, B, C).$$

Following Ouliaris, Park, and Phillips (1988), it is straightforward to show that:

(8) $$Z(\tilde{\alpha}^i) \Rightarrow \left(\int_0^1 w_i(r)\,dw(r)\right)\left(\int_0^1 w_i(r)^2\,dr\right)^{-1} \qquad (i = A, B, C)$$

and

(9) $$Z(t_{\tilde{\alpha}^i}) \Rightarrow \left(\int_0^1 w_i(r)\,dw(r)\right)\left(\int_0^1 w_i(r)^2\,dr\right)^{-1/2} \qquad (i = A, B, C).$$

The limiting distributions in (8) and (9) are those whose critical values are presented in Tables IV, V, and VI derived using the representation given by Theorem 2.

The other approach adopts the procedures suggested by Dickey and Fuller (1979, 1981) and Said and Dickey (1984) which add extra lags of the first differences of the data as regressors in equation (5). This extended framework is characterized by the following regression (again estimated by OLS):

(10) $$\tilde{y}_t^i = \tilde{\alpha}^i \tilde{y}_{t-1}^i + \sum_{j=1}^{k} \tilde{c}_j \Delta \tilde{y}_{t-j}^i + \tilde{e}_t \qquad (i = A, B, C)$$

where

$$\Delta \tilde{y}_t^i = \tilde{y}_t^i - \tilde{y}_{t-1}^i.$$

In the above representation, $\tilde{\alpha}$ is the OLS estimator of α, the sum of the autoregressive coefficients and the test is again that $\alpha = 1$. The parameter k specifies the number of extra regressors added. In a simple AR(p) process, $k = p$. In a more general ARMA(p, q) process with p and q unknown, k must increase at a controlled rate with the sample size. Arguments similar to those developed by Said and Dickey can be used to show that the limiting distributions of the statistics $t_{\tilde{\alpha}^i}$ ($i = A, B, C$) are the same when the innovation sequence is an ARMA(p, q) process and regression (10) is used, as they are when the errors are i.i.d. and regression (5) is used. However, slightly more restrictive assumptions are needed with respect to the innovation sequence $\{e_t\}$ and the truncation parameter k for this asymptotic equivalence to hold. They are detailed in the following Assumption (see Said and Dickey (1984)).

[7] See Phillips (1987), Phillips and Perron (1988), and Perron (1988) for details.

ASSUMPTION 2: *(a) $A(L)e_t = B(L)v_t$; (b) v_t is a sequence of i.i.d. $(0, \sigma^2)$ random variables with finite $(4+\delta)$th moment for some $\delta > 0$; (c) $k \to \infty$ and $T^{-1}k^3 \to 0$ as $T \to \infty$.*

4.2. *Extensions to More General Error Processes: Case* (2)

A possible drawback of the methods suggested above is that they imply that the change in the trend function occurs instantaneously. Given, for instance, that the Great Depression was not an instantaneous event but lasted several years, one may wish to allow for such a transition period during changes in the trend function. One way to model this is to suppose that the economy reacts gradually to a shock to the trend function.[8] Consider, for instance, Model (A) where a crash occurs. A plausible specification of the trend function, say η_t^A, is given by:

$$\eta_t^A = \mu_1 + \beta t + \gamma\psi(L)\, DU_t \tag{11}$$

where $\psi(L)$ is a stationary and invertible polynomial in L with $\psi(0) = 1$ and $\gamma = \mu_2 - \mu_1$. The long run change in the trend function is given by $\gamma\psi(1)$ while the immediate impact is simply γ. A similar framework holds for models (B) and (C).

One way to incorporate such a gradual change in the trend function is to suppose that the economy responds to a shock to the trend function the same way as it reacts to any other shock, i.e. to impose $\psi(L) = B(L)^{-1}A(L)$ (see Section 2). In the literature on outliers specification the framework suggested here is analogous to the so-called "innovational outlier" model whereas the framework considered in Section 4.1 is analogous to the "additive outlier" model (see, e.g., Tsay (1986)). We can then implement tests for the presence of a unit root in a framework that directly extends the Dickey-Fuller strategy by adding dummy variables in regression (1). The following regressions, corresponding to Models (A), (B), and (C) are constructed by nesting the corresponding models under the null and alternative hypotheses:

$$y_t = \hat{\mu}^A + \hat{\theta}^A DU_t + \hat{\beta}^A t + \hat{d}^A D(TB)_t + \hat{\alpha}^A y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t, \tag{12}$$

$$y_t = \hat{\mu}^B + \hat{\theta}^B DU_t + \hat{\beta}^B t + \hat{\gamma}^B DT_t^* + \hat{\alpha}^B y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t, \tag{13}$$

$$y_t = \hat{\mu}^C + \hat{\theta}^C DU_t + \hat{\beta}^C t + \hat{\gamma}^C DT_t + \hat{d}^C D(TB)_t + \hat{\alpha}^C y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t. \tag{14}$$

The null hypothesis of a unit root imposes the following restrictions on the true parameters of each model: Model (A), the "crash hypothesis": $\alpha^A = 1$, $\beta^A = 0$,

[8] Again, this treatment is analogous to the methodology proposed by Box and Tiao (1975) concerning intervention analyses.

$\theta^A = 0$; Model (B), the "breaking slope with no crash": $\alpha^B = 1$, $\gamma^B = 0$, $\beta^B = 0$; and Model (C), where both effects are allowed: $\alpha^C = 1$, $\gamma^C = 0$, $\beta^C = 0$. Under the alternative hypothesis of a "trend stationary" process, we expect $\alpha^A, \alpha^B, \alpha^C < 1$; $\beta^A, \beta^B, \beta^C \neq 0$; $\theta^A, \theta^C, \gamma^B, \gamma^C \neq 0$. Finally, under the alternative hypothesis, d^A, d^C, and θ^B should be close to zero while under the null hypothesis they are expected to be significantly different from zero.

The asymptotic distribution of the t statistics $t_{\hat{\alpha}}A$ and $t_{\hat{\alpha}}C$ in (12) and (14) are the same, respectively, as the asymptotic distribution of $t_{\hat{\alpha}}A$ and $t_{\hat{\alpha}}C$ in (10). However such a correspondence does not hold for the t statistic $t_{\hat{\alpha}}B$ in (13). Apart from the one-time dummy variable $d(TB)_t$, regressions (13) and (14) are equivalent; hence the asymptotic distribution of $t_{\hat{\alpha}}B$ is identical to the asymptotic distribution of $t_{\hat{\alpha}}C$. This implies that in the above framework, it is not possible to test for a unit root under the maintained hypothesis that the trend function has a change in slope with the two segments joined at the time of the change. Consequently, tests for the presence of a unit root in Model (B) will have less power using regression (13) than using (10) where the asymptotic critical values of the t statistic on α are smaller (in absolute value). However, it is still possible to test for a unit root with constant drift against a trend stationary process as in Model (B) and use the critical values of Table V. One simply runs the regression:

$$(15) \qquad y_t = \hat{\mu}^B + \hat{\beta}^B t + \hat{\gamma}^B DT_t^* + \hat{\alpha}^B y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t.$$

The asymptotic distribution of the t statistic $t_{\hat{\alpha}}B$ in (15) is the same as the asymptotic distribution of the t statistic $t_{\hat{\alpha}}B$ in (10). Given that the regressor DU_t is absent from (15), this case, however, implies that the change in drift is not permitted under the null hypothesis.

Finally, note that it is possible to apply Phillips' nonparametric procedure using regressions (12) through (14) without the lagged first-differenced regressors and applying the corrections given by (6) and (7). However, such a procedure has the unattractive feature of imposing only a one-period adjustment to the change in the trend function. In the notation of (11), it imposes $\psi(L) = 1 - \psi_1 L$ where ψ_1 is the coefficient on the first lag in the polynomial $B(L)^{-1}A(L)$.

The procedures outlined in this section permit testing for the presence of a unit root in a quite general time series process which allows a one-time break in the mean of the series or its rate of growth (or both). In the next section, we apply these procedures in the specific context of breaks at the time of the 1929 crash and the 1973 oil shock.

5. EMPIRICAL APPLICATIONS

We apply the test statistics derived in the previous section to the data set used by Nelson and Plosser and to the postwar quarterly real GNP series. The data set considered by Nelson and Plosser consists of fourteen major macroeconomic series sampled at an annual frequency. We omit the analysis of the unemployment rate series given that it is generally perceived as being stationary. The sample varies for each series with a starting date between 1869 and 1909. However, each series ends in 1970. Given that we entertain the hypothesis that only the 1929 Great Crash and the 1973 oil price shock caused a major change in trend function, each series in this data set contains only one break. It is therefore possible to apply the tests described in the previous section. Similarly, the quarterly postwar real GNP series contains a single break as the sample goes from 1947:I to 1986:III. Following Nelson and Plosser, we consider the logarithm of each series except for the interest rate for which we use the level.

Of the thirteen series in the Nelson-Plosser data set that we analyze, preliminary investigations showed that eleven were potentially well-characterized by a trend function with a constant slope but with a major change in their level occurring right after the year 1929. For these series, the maintained hypothesis is, therefore, that of Model (A) and given that the Great Crash did not occur instantaneously but lasted several years, we apply regression (12) to carry out our testing procedure. The two series that were not modeled as such are the "real wages" and "common stock price" series. For these series, it appeared that not only a change in the level occurred after 1929 but there was also an increase in the slope of the trend function after this date. For these reasons, the maintained hypothesis is that of Model (C), and we use regression (14) to implement our tests.

The postwar quarterly real GNP series offers yet a different picture. The 1973 oil price shock did not cause a significant drop in the level of the series. However, after that date, the slope of the trend function has sensibly decreased. This phenomenon is consistent with the much discussed slowdown in the growth rate of real GNP since the mid-seventies; see, for example, the recent symposium in the *Journal of Economic Perspectives* (1988). For these reasons, the maintained hypothesis is that of Model (B). Given the inherent difficulty in testing for a unit root allowing lagged effects for the change in the trend function, we apply regression (10) ($i = B$) to carry the testing procedure. Modeling the change in the trend function following the 1973 oil price shock as instantaneous, at least appears more plausible than the change that occurred during the Great Depression.

Table VII presents the corresponding estimated regressions for each series along with the t statistic on the parameters for the following respective hypotheses: $\mu = 0$, $\beta = 0$, $\theta = 0$, $\gamma = 0$, $d = 0$, and $\alpha = 1$. Recall that under the hypothesis of a unit root process $\mu \neq 0$ (in general), $\beta = 0$, $\theta = 0$ (except in regression Models (C)), $\gamma = 0$, $d \neq 0$, and $\alpha = 1$. Under the alternative hypothesis of stationary fluctuations around a deterministic breaking trend function: $\mu \neq 0$, $\theta \neq 0$, $\beta \neq 0$, $\gamma \neq 0$ (in general), $d = 0$, and $\alpha < 1$.

The value of k chosen is determined by a test on the significance of the estimated coefficients $\hat{c}_i$. We actually used a fairly liberal procedure choosing a value of k equal to say k^* if the t statistic on $\hat{c}_i$ was greater than 1.60 in absolute value and the t statistic on $\hat{c}_l$ for $l > k^*$ was less than 1.60 (with a maximum value for k of 8, except for the postwar quarterly real GNP series

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TABLE VII

TESTS FOR A UNIT ROOT

(a) Regression (12), Model A; $y_t = \hat{\mu} + \hat{\theta}DU_t + \hat{\beta}t + \hat{d}D(TB)_t + \hat{\alpha}y_{t-1} + \sum_{i=1}^{k}\hat{c}_i \Delta y_{t-i} + \hat{e}_t$

$T_B = 1929$	T	λ	k	$\hat{\mu}$	$t_{\hat{\mu}}$	$\hat{\theta}$	$t_{\hat{\theta}}$	$\hat{\beta}$	$t_{\hat{\beta}}$	$\hat{d}$	$t_{\hat{d}}$	$\hat{\alpha}$	$t_{\hat{\alpha}}$	$S(\hat{e})$
Real GNP	62	0.33	8	3.441	5.07	−0.189	−4.28	0.0267	5.05	−0.018	−0.30	0.282	−5.03[a]	0.0509
Nominal GNP	62	0.33	8	5.692	5.44	−0.360	−4.77	0.0359	5.44	0.100	1.09	0.471	−5.42[a]	0.0694
Real per capita GNP	62	0.33	7	3.325	4.11	−0.102	−2.76	0.0111	4.00	−0.070	−1.09	0.531	−4.09[b]	0.0555
Industrial production	111	0.63	8	0.120	4.37	−0.298	−4.58	0.0323	5.42	−0.095	−0.99	0.322	−5.47[a]	0.0875
Employment	81	0.49	7	3.402	4.54	−0.046	−2.65	0.0057	4.26	−0.025	−0.77	0.667	−4.51[a]	0.0295
GNP deflator	82	0.49	5	0.669	4.09	−0.098	−3.16	0.0070	4.01	0.026	0.53	0.776	−4.04[b]	0.0438
Consumer prices	111	0.63	2	0.065	1.12	−0.004	−0.21	0.0005	1.75	−0.036	−0.79	0.978	−1.28	0.0445
Wages	71	0.41	7	2.38	5.45	−0.190	−4.32	0.0197	5.37	0.085	1.36	0.619	−5.41[a]	0.0532
Money stock	82	0.49	6	0.301	4.72	−0.071	−2.59	0.0121	4.18	0.033	0.68	0.812	−4.29[b]	0.0440
Velocity	102	0.59	0	0.050	0.932	−0.005	−0.20	−0.0002	−0.35	−0.136	−2.01	0.941	−1.66	0.0663
Interest rate	71	0.41	2	−0.018	−0.088	−0.343	−2.06	0.0105	2.64	0.197	0.64	0.976	−0.45	0.2787

(b) Regression (14), Model C; $y_t = \hat{\mu} + \hat{\theta}DU_t + \hat{\beta}t + \hat{\gamma}DT_t + \hat{d}D(TB)_t + \hat{\alpha}y_{t-1} + \sum_{i=1}^{k}\hat{c}_i \Delta y_{t-i} + \hat{e}_t$

$T_B = 1929$	T	λ	k	$\hat{\mu}$	$t_{\hat{\mu}}$	$\hat{\theta}$	$t_{\hat{\theta}}$	$\hat{\beta}$	$t_{\hat{\beta}}$	$\hat{\gamma}$	$t_{\hat{\gamma}}$	$\hat{d}$	$t_{\hat{d}}$	$\hat{\alpha}$	$t_{\hat{\alpha}}$	$S(\hat{e})$
Common stock prices	100	0.59	1	0.353	4.09	−1.051	−4.29	0.0070	4.43	0.0139	3.98	0.128	0.76	0.718	−4.87[b]	0.1402
Real wages	71	0.41	8	2.115	4.33	−0.190	−3.71	0.0107	3.79	0.0066	3.33	0.031	0.78	0.298	−4.28[c]	0.0330

(c) Regression (10), Model B; $y_t = \tilde{\mu} + \tilde{\beta}t + \tilde{\gamma}DT_t^* + \tilde{y}_t$; $\tilde{y}_t = \tilde{\alpha}\tilde{y}_{t-1} + \sum_{i=1}^{k}\tilde{c}_i \Delta \tilde{y}_{t-i} + \tilde{e}_t$

$T_B = 1973{:}1$	T	λ	k	$\tilde{\mu}$	$t_{\tilde{\mu}}$	$\tilde{\beta}$	$t_{\tilde{\beta}}$	$\tilde{\gamma}$	$t_{\tilde{\gamma}}$	$\tilde{\alpha}$	$t_{\tilde{\alpha}}$	$S(\tilde{e})$
Quarterly real GNP	159	0.66	10	6.977	1160.51	0.0087	97.73	−0.0031	−12.06	0.86	−3.98[c]	0.0097

NOTE: a, b, and c denote statistical significance at the 1%, 2.5%, and 5% level respectively.

where we used a maximum of 12). This liberal procedure is justified in the sense that including too many extra regressors of lagged first-differences does not affect the size of the test but only decreases its power. Including too few lags may have a substantial effect on the size of the test.

Consider first the series for which we applied Model (A). To evaluate the significance of the t statistic on $\hat{\alpha}$, we use the critical value presented in Table IV.B with a value of λ closest to the ratio of pre-break sample size to total sample size. Of the eleven series in that group, the unit root hypothesis cannot be rejected even at the 10 percent level for three of them: "consumer prices," "interest rate" and "velocity." However, we can reject the null hypothesis of a unit root at that 2.5 percent level or better for all other eight series. We can reject it at the 1 percent level for the following series: "real GNP," "nominal GNP," "industrial production," "employment," and "wages," and at the 2.5 percent level for the series "real per capita GNP," "GNP deflator," and "money stock." In some cases the coefficient $\hat{\alpha}$, which is an estimate of the sum of the autoregressive coefficients, is dramatically different from one. For example, it is 0.282 for "real GNP" and 0.322 for "industrial production."

Given that the unit root hypothesis can be rejected for the eight series mentioned above, we can assess the significance of the other coefficients using the fact that the asymptotic distribution of their t statistic is standardized normal. In all cases, the estimated coefficients on the constant ($\hat{\mu}$), the post-break dummy ($\hat{\theta}$), and the trend ($\hat{\beta}$) are significant at least at the 5 percent level. All series showed a trend function with a positive slope and a significant decrease in level just after 1929. For these eight series the coefficient on the break dummy ($\hat{d}$) is not significant. These results strongly suggest that, except for the "consumer price," "velocity," and "interest rate" series, the underlying process is one of stationary fluctuations around a deterministic trend function.

Consider now panel (b) of Table VII which presents the results for the "common stock price," and "real wages" series estimated under Model (C). We can reject the null hypothesis of a unit root at the 2.5 percent level for "common stock prices" and at the 5 percent level for the "real wages" series. In both cases, the constant ($\hat{\mu}$), the post-break constant dummy ($\hat{\theta}$), the trend ($\hat{\beta}$), and the post-break slope dummy ($\hat{\gamma}$) are highly significant, while the break dummy ($\hat{d}$) is not. The coefficients $\hat{\alpha}$ for the "real wages" series is very low at 0.298 while for the "common stock price" it is at 0.718 showing substantial mean reversion effects. This finding about the "common stock price" series is particularly striking given the vast amount of theoretical and empirical studies supporting the random walk hypothesis in this situation.

Finally, panel (c) of Table VII presents the results for the postwar quarterly real GNP series using regression (10) corresponding to Model (B). In this case, the null hypothesis that $\alpha = 1$ can be rejected at the 5 percent level with an estimated coefficient $\tilde{\alpha}$ equal to 0.86. This result is especially significant given the usual poor power properties of tests for a unit root against stationary alternatives when using a data set with a small span sampled frequently (see, e.g., Perron (1987) and Shiller and Perron (1985)). The other estimated coefficients in panel (c) confirm the relevance of the "trend stationary" model versus the "unit root" model. The coefficient on the post-break slope dummy coefficient ($\tilde{\gamma}$) is highly significant. The estimated regression is therefore consistent with an underlying process characterized by stationary fluctuations around a deterministic trend function with a decrease in the slope after 1973.[9]

Table A3 in Appendix B presents the estimated value for the sum of the autoregressive coefficient, α, and its t statistic for the null hypothesis $\alpha = 1$, for all values of the truncation lag parameter k between 1 and 12. In general, the results are quite robust to which value of k is selected.[10]

The results presented in this section are quite striking. The unit root hypothesis can be rejected for all but three series. To obtain these results, only a rather weak postulate needed to be imposed, namely the presence of a one-time change in the trend function. We claim that this is a weak postulate for the following reasons. As shown by Nelson and Plosser and Campbell and Mankiw, all the series analyzed have a unit root if the trend function is not allowed to change. This view implies that the 1929 crash is simply one big outlier in the innovation sequence. On the other hand, it also implies that the post-1973 growth slowdown is a succession of smaller innovations and that the mean of the innovations is different for the pre-1973 and the post-1973 period. These alternative interpretations are, we think, less appealing than the hypothesis of a break in the trend function, especially given that we allow such a break under both the null and alternative hypotheses.

Given that the "consumer price," "velocity," and "interest rate" series appear to be characterized by the presence of a unit root, it seems worthwhile to see if this feature is stable in the pre and post 1929 samples. The subsample Dickey-Fuller type regressions are presented in Appendix B for values of k between 1 and 12. Consider first the "consumer price index." With $k = 2$, the estimated value of the sum of the autoregressive coefficients, $\tilde{\alpha}$ is 0.965 for the pre-1929 sample with a t statistic of -1.28. We therefore cannot reject the null hypothesis of a unit root for this subperiod. However, for the post-1929 sample, the picture is rather different; when $k = 7$, $\tilde{\alpha}$ has a value of 0.704 with a t statistic of -4.56 significant at the 1 percent level. The nonrejection of the unit root hypothesis using the full sample is due to the pre-1929 sample. After 1929, the unit root is no longer present.

The case for the "velocity" series has a special feature. It has been well documented that the U.S. velocity series declined steadily until 1946, remained at a fairly constant level until 1970, before increasing (see, for example, Poole (1988) and Gould and Nelson (1974)). For this reason, we discuss applications of the standard Dickey-Fuller procedure for the following three samples: 1869–1929, 1930–1945, 1946–1970. We cannot reject the unit root hypothesis with the pre-1929 sample even though $\tilde{\alpha}$ is only 0.865 ($k = 0$). However, the picture is

[9] Basically, the same estimates of the sum of the autoregressive coefficient α and its t statistic were obtained using regressions (13) and (14), for all values of k, showing some robustness for the results presented. We also applied Phillips' nonparametric procedure to the detrended series (equations (6) and (7), $i = B$). These test statistics did not allow the rejection of the null hypothesis of a unit root.

[10] One notable exception is the quarterly real GNP series where the t statistic is significant at the 5 percent level with $k = 2$ or $k = 10$. It is significant at the 2.5 percent level with $k = 11$, with a value of -4.32. We choose to report the result of $k = 10$ because the 10th lagged first-difference was highly significant (t statistic of 2.29) while the 11th and 12th lags were not.

dramatically different using post-1929 samples. For the period 1930–1945, with $k=1$, $\tilde{\alpha}$ is estimated at -0.011 with a t statistic (for testing $\alpha=1$) of -3.44 which is significant at the 5 percent level. Though this result should be taken with caution due to the small number of observations, it is suggestive of a quite different behavior. The period 1946–1970 affords a modest amount of additional information and yields still more dramatic results: with $k=4$, $\tilde{\alpha}$ is equal to 0.00 with a t statistic (for $\alpha=1$) of -5.86, significant at the 1 percent level using the Dickey-Fuller critical values. It therefore appears that the "velocity" and "consumer price" series yield similar results: the presence of a unit root before 1929 but not after.

The results for the interest rate series indicate that, in this case, the unit root hypothesis cannot be rejected at usual significance levels for both subsamples (even though α is estimated at 0.540 ($k=3$) with the pre-1929 sample). Indeed, given our previous results, we can conclude that only the "interest rate" series is characterized by the presence of a unit root after 1929. All the other series are better construed as stationary fluctuations around a deterministic trend function for this period.

6. DISCUSSION AND CONCLUDING COMMENTS

When testing for the presence of a unit root in a time series of data against the hypothesis of stationary fluctuations around a deterministic trend function, the use of a long span of data has definite advantages. It allows tests with larger power compared to using a smaller span, in most cases even if the latter allows more observations (see Shiller and Perron (1985) and Perron (1987)). The drawback, however, is that a data set with a large span has more chance to include a major event which one would rather consider as an outlier or as exogenous given its relative importance. The arguments in this paper rest on the postulate that two such events have occurred in the 20th century: the 1929 Great Crash and the slowdown in growth after the oil shock of 1973. We therefore considered, as a relevant alternative, a trend function with a change in the intercept in 1929 and a change in the slope after 1973.

Let us discuss, in more detail, what are the relevant issues in drawing particular conclusions about the nature of economic fluctuations from our results. It is particularly important to put our results into perspective and also highlight what has not been shown.

The first important issue to point out is that we have not provided a formal unconditional statistical model of the time series properties of the various aggregates. A rejection of the null hypothesis of a unit root conditional on the possibility of shifts in the underlying trend function at known dates does not imply that the various series can be modeled as stationary fluctuations around a completely deterministic breaking trend function. As a matter of general principle, a rejection of the null hypothesis does not imply acceptance of a particular alternative hypothesis. However, since the tests were designed to have power against a specific class of alternative hypotheses, it is useful to look among close members of that class to propose an interesting statistical model for the various aggregates. Only with such a model is it possible to provide forecasts with appropriate standard errors.

We certainly do not entertain the view that the trend function including its changes are deterministic. This would imply that one would be able to forecast with certainty future changes. This is indeed quite unappealing. What we have in mind in specifying our class of maintained hypotheses can be parameterized as follows:

$$y_t = \eta_t + Z_t, \qquad \eta_t = \mu_t + \beta_t t, \tag{16}$$

where $A(L)Z_t = B(L)e_t$; $e_t \sim$ i.i.d.$(0, \sigma^2)$; $\mu_t = \mu_{t-1} + V(L)v_t$, and $\beta_t = \beta_{t-1} + W(L)w_t$. Here, the Z_t's are (not necessarily stationary) deviations from the trend function η_t. The intercept and the slope of the trend functions, μ_t and β_t, are themselves random variables modeled as integrated processes with $W(L)$, $V(L)$ stationary and invertible polynomials. However, the important distinction is that the timing of the occurrence of the shocks v_t and w_t are rare relative to the sequence of innovations $\{e_t\}$, for example, poisson processes with arrival rates specified such that their occurrences are rare relative to the frequency of the realizations in the sequence $\{e_t\}$. The intuitive idea behind this type of modeling is that the coefficients of the trend function are determined by long-term economic fundamentals (e.g., the structure of the economic organization, population growth, etc.) and that these fundamentals are rarely changed. In our examples, v_t is nonzero in 1929 (the great depression) and w_t is nonzero in 1973 (the oil price shock).

In this sense, our exogeneity assumption about the changes in the trend function is a device that allows taking these shocks out of the noise function into the trend function without specific modeling of the stochastic nature of the behavior of μ_t and β_t. It is in this sense that our approach does not provide an unconditional representation of the time series properties of the various variables.

Estimation of models of the form (16) by specifying a probability distribution for the error sequences $\{e_t, w_t, v_t\}$ is clearly an important avenue of future research. Interesting recent advances on this topic have been provided by Hamilton (1987) and Lam (1988) where the slope of the trend function is allowed to take two different values and the changes are modeled as a binomial process. However, no methods are currently available to test whether Z_t is integrated or not in this framework.[11] Problems in estimation of models of the form (16) are further compounded by the fact that, according to our view, only one nonzero realization of both v_t and w_t would be present in the data set typically available for the series of interest.

In the above framework, the purpose of this paper is to test whether Z_t is an integrated process or not, i.e. to test whether the shocks $\{e_t\}$ have persistent effects that do not vanish over a long horizon. Our approach is to remove from the noise function two events that occurred at two dates where we believe positive occurrences of the shocks $\{v_t, w_t\}$ happened and to model them as part

[11] Both authors studied the behavior of the postwar quarterly real GNP with possible shifts in the slope of the trend function. Hamilton (1987) imposes Z_t to be an integrated process while Lam (1988) leaves Z_t unconstrained.

of the trend function. The fact that we model these changes as exogenous implies that our results are conditional. That is, conditional upon the presence of a change in the trend function in 1929 and 1973, the fluctuations are transitory (i.e., Z_t is stationary).

An important direction for future research is to make this conditional result into an unconditional statement. This could, in principle, be achieved by a direct test for structural change in the trend function. In a sense, our procedure allows such a test, but conditional on a change occurring at a fixed known date. Hence, problems of pre-testing and "data mining" could be raised regarding the role of looking, ex-post, at the data on the choice of the date.[12] Accordingly, what is needed is a test for structural changes in the trend function occurring at unknown dates. The problem, however, is that care must be applied to ensure that the test has an adequate size under both the unit root and trend-stationary hypotheses. No such test is currently available in the literature. We hope to report, in the near future, developments in this area and applications in this context.

However, an important issue of observational equivalence could not even be settled by such a formal test for structural change. Consider, for instance, the following limiting case in the crash model.[13] A trend-stationary model with a break and where the errors have zero variance is observationally equivalent to a unit root model with drift where the errors have a high probability of being zero but are occasionally nonzero and finite. In general, when the variance of the errors is nonzero, the two models will be nearly observationally equivalent with the disturbances in the unit root model having fat tails. We are able to make a distinction in our empirical result through the mixing conditions (see Assumptions 1 and 2) which prohibit fat tailed disturbances. Any formal test for structural change would, presumably, also have to impose some mixing condition prohibiting fat-tailed disturbances, thereby not resolving this issue of near-observational equivalence.

In fact, any test for the presence of a unit root against trend-stationary alternatives is subject to another type of observational equivalence, as recently argued by Cochrane (1987) and Blough (1988). Indeed, in finite samples, any trend-stationary process is nearly observationally equivalent to a unit root process with a strong mean-reversion component, i.e. where the errors have a moving-average component with a root near minus one.[14] The fact that we reject the unit root hypothesis excluding the event of 1929 suggests that if there is a unit root at all the correlation structure of the innovation sequence must exhibit substantial mean reversion.

[12] See, for example, Christiano (1988).

[13] This issue and its following illustration were raised by a referee.

[14] This observational equivalence problem only disappears asymptotically. In other words, in finite samples, any test for a unit root with ARMA errors should have zero power. Formally, the critical values should be determined such that the test has a given fixed size over all possible values of the nuisance parameters (here, the additional correlation in the errors). Given the near observational equivalence, any such test would have zero power by definition. The unit root tests can be rationalized by arguing that we are willing to have the wrong size over some of the parameter space exactly because for all practical purposes it does not matter whether we label a series as trend stationary or difference stationary with a strong mean-reversion component.

To sum up: trend stationary processes with a break are nearly observationally equivalent to unit root processes with strong mean-reversion and a fat-tailed distribution for the error sequence. Whichever view one adopts cannot be decided by data alone. Nevertheless, the picture under any of these views is basically the same: shocks had little, if any, persistence effect over a long horizon. Only those associated with the Great Depression and the oil price shock significantly altered the long run behavior of the series.

While choosing one view over the other is a matter of convenience for interpreting the data, it has profound implications for a multitude of statistical procedures. Indeed, under the unit root view one must ensure the validity of the procedures under fat-tailed disturbances, and at the moment very few are appropriate in a time series context. Hence for all practical purposes, it may be more advantageous to adopt the trend-stationary view with breaks and detrend our series accordingly prior to analyzing the remaining noise.

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APPENDIX A

The conditions imposed by Assumption 1 permit us to use a functional weak convergence result due to Herrndorf (1984). Let $S_t = \Sigma_{j=1}^{t} e_j (S_0 = 0)$ and define the following variable lying in the space $D[0,1]$:

$$X_T(r) = \sigma^{-1}T^{-1/2}S_{[Tr]} = \sigma^{-1}T^{-1/2}S_{j-1}, \quad (j-1)/T \leqslant r < j/T \qquad (j = 1, \ldots, T)$$

$$X_T(1) = \sigma^{-1}T^{-1/2}S_T.$$

Herrndorf's theorem states that under the conditions of Assumption 1, $X_T(r) \Rightarrow w(r)$ where $\Rightarrow$ denotes weak convergence to the associated probability measure and $w(r)$ is the unit Wiener process defined on $C[0,1]$, the space of all continuous functions on the interval $[0,1]$. Following Phillips (1987) and Phillips and Perron (1988), it is easy to derive the following lemma related to functions of S_t. These results will be used in proving both Theorems 1 and 2.

LEMMA A.1: *Let $S_t = \Sigma_{j=1}^{t} e_j (S_0 = 0)$ and assume that the innovation sequence $\{e_t\}$ satisfies the conditions of Assumption* 1. *Furthermore, let $T_B = \lambda T$ for all T; then as $T \to \infty$:*

(a) $$T^{-3/2}\sum_{1}^{T_B} S_j \Rightarrow \sigma \int_0^{\lambda} w(r)\,dr;$$

(b) $$T^{-2}\sum_{1}^{T_B} S_j^2 \Rightarrow \sigma^2 \int_0^{\lambda} w(r)^2\,dr;$$

(c) $$T^{-5/2}\sum_{1}^{T_B} jS_j \Rightarrow \sigma \int_0^{\lambda} rw(r)\,dr;$$

(d) $$T^{-3/2}\sum_{1}^{T_B} je_j \Rightarrow \sigma\left(\lambda w(\lambda) - \int_0^{\lambda} w(r)\,dr\right);$$

(e) $$T^{-1}\sum_{1}^{T} S_{j-1}e_j \Rightarrow (\sigma^2/2)\left(w(1)^2 - \sigma_e^2/\sigma^2\right).$$

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The results in (a) through (d) are simple extensions of those in Phillips (1987) and Phillips and Perron (1988); part (e) is proved in Phillips (1987). The previous results can be recovered by simply letting $\lambda = 1$ in which case $T_B = T$. For example, to prove part (a):

$$T^{-3/2}\sum_1^{T_B} S_j = \sigma \sum_1^{T_B}\int_{i-1/T}^{i/T} T^{-1/2}\sigma^{-1}S_{[Tr]}\,dr = \sigma\int_0^\lambda X_T(r)\,dr \Rightarrow \sigma\int_0^\lambda w(r)\,dr$$

using Herrndorf's weak convergence result and the continuous mapping theorem (see, e.g., Billingsley (1968)). The proofs of (b), (c), and (d) are entirely analogous.

Proof of Theorem 1: We consider first the most general model (C) in which both β (the slope) and μ (the intercept) are allowed to change, i.e.:

$$\text{(A.1)}\qquad \begin{aligned} y_t &= \mu_1 + \beta_1 t + e_t && (0 \leq t \leq T_B).\\ y_t &= \mu_2 + (\beta_2 - \beta_1)T_B + \beta_2 t + e_t && (T_B < t \leq T). \end{aligned}$$

The following lemma provides a convenient representation of the sample moments of $\{y_t\}$.

Lemma A.2: *Assume that* $\{y_t\}_0^T$ *is generated according to* (A.1) *with the innovation sequence* $\{e_t\}$ *satisfying Assumption* 1; *then,*

(a)
$$\begin{aligned}\sum_1^T t y_{t-1} &= (1/6)\left[\beta_1(3\lambda - \lambda^3) + \beta_2(2 - 3\lambda + \lambda^3)\right]T^3\\ &+ (\tfrac{1}{2})\left[\mu_1\lambda^2 + \mu_2(1-\lambda^2) + \lambda(1-\lambda)(\beta_1 - \beta_2)\right]T^2\\ &+ \left[(3/2)\mu_1\lambda + (3/2)(1-\lambda)\mu_2 - \mu_2 - (1/3)\beta_1\lambda - (1/3)\beta_2(1-\lambda)\right]T\\ &+ \left[T^{-3/2}\sum_1^T t e_{t-1}\right]T^{3/2} + o_p(T),\end{aligned}$$

(b)
$$\begin{aligned}\sum_1^T y_{t-1} &= (\tfrac{1}{2})\left[\beta_1(\lambda^2 - 2\lambda) + \beta_2(1 + 2\lambda - 3\lambda^2)\right]T^2\\ &+ \left[\lambda\mu_1 + (1-\lambda)\mu_2 + (3/2)\beta_1\lambda - (\tfrac{1}{2})\beta_2(1+3\lambda)\right]T\\ &+ \left[T^{-1/2}\sum_1^T e_{t-1}\right]T^{1/2} - (\mu_2 - \mu_1),\end{aligned}$$

(c)
$$\begin{aligned}\sum_1^T y_{t-1}^2 &= (1/3)\left[\beta_1^2\lambda^2(3-2\lambda) + \beta_2^2(1-\lambda)^3 + 3\beta_1\beta_2\lambda(1-\lambda)^2\right]T^3\\ &+ \left[\mu_1\beta_1\lambda^2 + \mu_2\beta_2(1-\lambda^2) - (\tfrac{1}{2})\left(\beta_1\lambda + \beta_2(1-\lambda)^2\right)\right]T^2\\ &+ 2\left[\lambda(\beta_1 - \beta_2)T^{-1/2}\sum_{T_B+1}^T e_t + \beta_1 T^{-3/2}\sum_1^{T_B} t e_t - \beta_2 T^{-3/2}\sum_{T_B+1}^T t e_t\right]T^{3/2}\\ &+ \left[\lambda\mu_1^2 + (1/6)\beta_1^2\lambda^2 + \mu_1\beta_1\lambda + (1-\lambda)\mu_2^2 + (1/6)\beta_2^2(1-\lambda)\right.\\ &\qquad \left. + \mu_2\beta_2(1-\lambda) - 2\mu_2\beta_2 + T^{-1}\sum_1^T e_{t-1}^2\right]T + o_p(T),\end{aligned}$$

(d)
$$\sum_1^T y_t y_{t-1} = (1/3)\left[\beta_1^2\lambda^2(3-2\lambda)+\beta_2^2(1-\lambda)^3+3\beta_1\beta_2\lambda(1-\lambda)^2\right]T^3$$
$$+\left[\mu_1\beta_1\lambda^2+\mu_2\beta_2(1-\lambda^2)\right]T^2$$
$$+2\left[\beta_1 T^{-3/2}\sum_1^{T_B} te_{t-1}+\beta_2 T^{-3/2}\sum_{T_B+1}^{T} te_{t-1}+\lambda(\beta_1-\beta_2)T^{-1/2}\sum_{T_B+1}^{T} e_t\right]T^{3/2}$$
$$+\left[\mu_1^2\lambda+\mu_2^2(1-\lambda)-(1/3)(\lambda\beta_1^2+(1-\lambda)\beta_2^2)\right.$$
$$\left.+\lambda(\beta_2^2-\beta_1\beta_2)+\lambda\beta_1(\mu_2+\mu_1)-2\lambda\mu_2\beta_2\right]T+o_p(T).$$

It is straightforward but tedious to show that $\tilde{\alpha}$ is given by $\tilde{\alpha}=A/D$ where

(A.2)
$$A=(T^2/2+T/2)\sum ty_{t-1}\sum y_t$$
$$-(T^3/3+T^2/2+T/6)\sum y_{t-1}\sum y_t - T\sum ty_{t-1}\sum ty_t$$
$$+(T^2/2+T/2)\sum y_{t-1}\sum ty_t+(T^4/12-T^2/12)\sum y_t y_{t-1}$$

and

(A.3)
$$D=(T^4/12-T^2/12)\sum y_{t-1}^2 - T\left(\sum ty_{t-1}\right)^2$$
$$+(T^2+T)\sum ty_{t-1}\sum y_{t-1}-(T^3/3+T^2/2+T/6)\left(\sum y_{t-1}\right)^2$$

where all summations run from 1 to T. To prove part (b) we derive the limits of $T^{-7}A$ and $T^{-7}D$ using Lemma A.2:

$$T^{-7}D=(1/12)T^{-3}\sum y_{t-1}^2 - T^{-6}\left(\sum ty_{t-1}\right)^2$$
$$+T^{-3}\sum ty_{t-1}\cdot T^{-2}\sum y_{t-1}-(1/3)T^{-4}\left(\sum y_{t-1}\right)^2+o_p(1)$$
$$=(1/36)\left[\beta_1^2\lambda^3+\beta_2^2(1-3\lambda+2\lambda^3)+3\beta_2\beta_1\lambda(1-\lambda^2)\right]$$
$$-(1/36)\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]^2$$
$$+(1/12)\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]$$
$$-(1/12)\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]^2+o_p(1).$$

Simple algebra yields:

(A.4)
$$T^{-7}D\to(1/36)(-3\lambda^2+4\lambda^3-3\lambda^4+3\lambda^5-\lambda^6)(\beta_1-\beta_2)^2.$$

Similarly,

$$T^{-7}A=T^{-3}\sum ty_{t-1}\cdot T^{-2}\sum y_{t-1}-(1/3)T^{-4}\left(\sum y_{t-1}\right)^2-T^{-6}\left(\sum ty_{t-1}\right)^2$$
$$+(1/12)T^{-3}\sum y_t y_{t-1}+o_p(1)$$
$$=(1/12)\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]\cdot\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]$$
$$-(1/12)\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]^2$$
$$-(1/36)\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]^2$$
$$+(1/36)\left[\beta_1^2\lambda^3+\beta_2^2(1-3\lambda+2\lambda^3)+3\beta_2\beta_1\lambda(1-\lambda^2)\right]+o_p(1)$$

and

$$T^{-7}A \to (1/36)(-3\lambda^2+4\lambda^3-3\lambda^4+3\lambda^5-\lambda^6)(\beta_1-\beta_2)^2.$$

Therefore, $\tilde{\alpha}=T^{-7}A/T^{-7}D \to 1$ proving part (b, i). To prove part (b, ii), note that $T(\tilde{\alpha}-1)=T^{-6}(A-D)/T^{-7}D$. Simple manipulation yields:

$$\begin{aligned}
T^{-6}(A-D) &= (1/12)T^{-2}\sum y_t y_{t-1} - (1/12)T^{-2}\sum y_{t-1}^2 + T^{-5}\sum t y_{t-1}\sum y_{t-1} \\
&\quad + (1/6)T^{-3}y_T\sum y_{t-1} - (\tfrac{1}{2})T^{-4}y_T\sum t y_{t-1} - (1/12)T^{-4}\Big(\sum y_{t-1}\Big)^2 \\
&\quad + o_p(1) \\
&= (1/24)\big[\beta_1^2\lambda^2+\beta_2^2(1-\lambda)^2+2\beta_1\beta_2\lambda(1-\lambda)\big] \\
&\quad + (1/12)\big[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\big]\big[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\big] \\
&\quad + (1/12)[(\beta_1-\beta_2)\lambda+\beta_2]\cdot\big[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\big] \\
&\quad - (1/12)[(\beta_1-\beta_2)\lambda+\beta_2]\big[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\big] \\
&\quad - (1/12)\big[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\big]^2 + o_p(1)
\end{aligned}$$

and

$$T^{-6}(A-D) \to (1/24)(\beta_1-\beta_2)^2[-\lambda^2+4\lambda^3-5\lambda^4+2\lambda^5].$$

Therefore,

$$T(\tilde{\alpha}-1) \to (3/2)[-1+4\lambda-5\lambda^2+2\lambda^3]\cdot[-3+4\lambda-3\lambda^2+3\lambda^3-\lambda^4]^{-1}$$

proving part (b, ii).

PROOF OF PART (a): The proof of part (a) is straightforward but tedious. The following arguments present the main steps. First, the expressions for the moments of $\{y_t\}$ in Lemma A.2 can be written as follows:

$$\sum_1^T t y_{t-1} = a_1T^3+b_1T^2+c_1T^{3/2}+d_1T+o_p(T),$$

$$\sum_1^T y_{t-1} = a_2T^2+b_2T+c_2T^{1/2}+d_2,$$

$$\sum_1^T y_{t-1}^2 = a_3T^3+b_3T^2+c_3T^{3/2}+d_3T+o_p(T),$$

$$\sum_1^T y_t y_{t-1} = a_4T^3+b_4T^2+c_4T^{3/2}+d_4T+o_p(T).$$

The coefficients a_i, b_i, c_i and d_i $(i=1,\dots,4)$ are given by the corresponding expressions in Lemma A.2 where the condition $\beta_1=\beta_2=\beta$ is imposed. From (A.3), the denominator of $\hat{\alpha}$ is given by:

$$\begin{aligned}
T^{-5}D &= \big[a_3/12 - a_1^2 + a_1a_2 - a_2^2/3\big]T^2 \\
&\quad + \big[b_3/12 - 2a_1b_1 + a_1b_2 + b_1a_2 + a_1a_2 - (2/3)a_2b_2 - a_2^2/2\big]T \\
&\quad + \big[c_3/12 - 2a_1c_1 + a_1c_2 + c_1a_2 - (2/3)a_2c_2\big]T^{1/2} \\
&\quad + \big[d_3/12 - a_3/12 - b_1^2 - 2a_1d_1 + a_1d_2 + b_1b_2 \\
&\qquad + d_1a_2 + a_1b_2 + b_1a_2 - b_2^2/3 - (2/3)a_2d_2 - a_2b_2 - a_2^2/6\big] + o_p(1).
\end{aligned}$$

Now, tedious algebra shows that the $0(T^2)$, $0(T)$, and $0(T^{1/2})$ coefficients all cancel out and the sum of the 0(1) coefficients yields the following result:

$$T^{-5}D \to (1/12)\sigma_e^2 + (1/12)[\mu_1 - \mu_2]^2[\lambda - 4\lambda^2 + 6\lambda^3 - 3\lambda^4].$$

To analyze the limit of $T^{-5}A$, the numerator of $\tilde{\alpha}$, we need the expansions for Σy_t and $\Sigma t y_t$. These are given by:

$$\sum_1^T t y_t = a_1 T^3 + (b_1 + \beta/2)T^2 + c_1 T^{3/2} + (1/3)(d_1 + (5/6)\beta + \mu_2)T + o_p(T),$$

$$\sum_1^T y_t = a_2 T^2 + (b_2 + \beta)T + c_2 T^{1/2} + d_2.$$

Then we can write, using (A.2):

$$\begin{aligned} T^{-5}A = {} & \left[a_1 a_2 - a_2^2/3 - a_1^2 + a_4/12\right]T^2 \\ & + \big[a_1 a_2 + (b_2 + \beta)(a_1/2 - a_2/3) + (b_1 + \beta/2)(a_2/2 - a_1) - a_2^2/2 + b_4/12 \\ & \qquad + a_1 b_2/2 - a_1 b_1 - a_2 b_2/3 + b_1 a_2/2\big]T \\ & + \left[a_1 c_2 + c_1 a_2 - (2/3)a_2 c_2 - 2a_1 c_1 + c_4/12\right]T^{1/2} \\ & + \big[(b_2 + \beta)(b_1/2 + a_1/2 - b_2/3 - a_2/2) \\ & + (1/3)(d_1 + (5/6)\beta + \mu_2)(a_2/2 - a_1) \\ & + (b_1 + \beta/2)(b_2/2 + a_2/2 - b_1) + d_1 a_2/2 + b_1 a_2/2 - a_2 d_2/3 - a_2 b_2/2 \\ & - a_2^2/6 - d_1 a_1 + a_1 d_2/2 + d_4/12 + a_4/12\big]. \end{aligned}$$

Again, tedious algebra shows that the $0(T^2)$, $0(T)$, and $0(T^{1/2})$ terms all cancel out and that the sum of the coefficients remaining yields the following result:

$$T^{-5}A \to (1/12)\gamma_1 + (1/12)[\mu_1 - \mu_2]^2[\lambda - 4\lambda^2 + 6\lambda^3 - 3\lambda^4].$$

This proves part (a).

PROOF OF THEOREM 2: We first note some invariance properties of the estimators $\tilde{\alpha}^i$ $(i = A, B, C)$: $\tilde{\alpha}^A$ is invariant with respect to μ and d; $\tilde{\alpha}^B$ is invariant to μ_1 and μ_2; and $\tilde{\alpha}^C$ is invariant to d, μ_1 and μ_2. Hence, without loss of generality, we can study the limiting distribution of $T(\tilde{\alpha}^i - 1)$ and $t_{\tilde{\alpha}^i}$ under the null hypothesis that the sequence $\{y_t\}$ is generated according to:

$$\text{(A.5)} \qquad y_t = y_{t-1} + e_t \qquad (t = 1, \ldots, T)$$

with the innovation sequence satisfying Assumption 1. It is also straightforward to show that under (A.5), $\tilde{\alpha}^i$ $(i = A, B, C)$ are asymptotically equivalent to the least-squares estimators $\hat{\alpha}^i$ $(i = A, B, C)$ in the following regressions:

$$\text{(A.6)} \qquad y_t = \hat{\mu}^A + \hat{\theta}^A DU_t + \hat{\beta}^A t + \hat{\alpha}^A y_{t-1} + \hat{e}_t^A,$$

$$\text{(A.7)} \qquad y_t = \hat{\mu}^B + \hat{\beta}^B t + \hat{\gamma}^B DT_t^* + \hat{\alpha}^B y_{t-1} + \hat{e}_t^B,$$

$$\text{(A.8)} \qquad y_t = \hat{\mu}^C + \hat{\theta}^C DU_t + \hat{\beta}^C t + \hat{\gamma}^C DT_t + \hat{\alpha}^C y_{t-1} + \hat{e}_t^C,$$

where $DU_t = 1$ and $DT_t = DT_t^* = 0$ if $t \leq T_B$ and $DU_t = 0$, $DT_t^* = t - T_B$, $DT_t = t$ if $t > T_B$. Since we are also concerned with regressions of the type (A.6)–(A.8) later in the text, we shall derive the limiting distributions concerning $\tilde{\alpha}^i$ $(i = A, B, C)$ using the representation of $\hat{\alpha}^i$ $(i = A, B, C)$. Note, however, that $\hat{\alpha}^A$ in (A.6) and $\hat{\alpha}^C$ in (A.9) are not invariant to the value of the parameter d under the null hypothesis. To achieve invariance, one must introduce a dummy variable $D(TB)$, taking value 1 at $t = T_B + 1$ and 0 elsewhere, as is done in regressions (12) and (14). Under the null hypothesis, $\hat{\alpha}^B$ is not invariant to a drift taking two distinct values: μ_1 and μ_2. To achieve invariance, the variable DU_t must be introduced in (A.7). However, this affects the limiting distribution of $\hat{\alpha}^B$ which becomes equivalent to that of $\hat{\alpha}^C$. Hence, one cannot analyze directly the case of a joint segmented trend function in a one-step type regression. We now turn to the proof of the theorem deriving the limiting distribution of $T(\hat{\alpha}^i - 1)$ and $t_{\hat{\alpha}^i}$ $(i = A, B, C)$ in (A.6) through (A.8).

The following Lemma provides weak convergence results for the sample moments of the data and will be used extensively. Its proof is a simple extension of Lemma A.1 and follows the methods of Phillips (1987) and Phillips and Perron (1988).

LEMMA A.3: *Let* $\{y_t\}_0^T$ *be a stochastic process generated according to (A.5) with the innovation sequence satisfying Assumption* 1. *Furthermore, let* $T_B = \lambda T$; *then as* $T \to \infty$:

(a) $$T^{-3/2}\sum_1^{T_B} y_t \Rightarrow \sigma\int_0^\lambda w(r)\,dr,$$

(b) $$T^{-5/2}\sum_1^{T_B} t y_t \Rightarrow \sigma\int_0^\lambda r w(r)\,dr,$$

(c) $$T^{-2}\sum_1^{T_B} y_t^2 \Rightarrow \sigma^2\int_0^\lambda w(r)^2\,dr,$$

(d) $$T^{-1}\sum_1^{T} y_{t-1}e_t \Rightarrow (\sigma^2/2)\left(w(1)^2 - \sigma_e^2/\sigma^2\right).$$

Parts (a), (b), and (c) are simple generalizations of results in Phillips (1987) and Phillips and Perron (1988) where $T_B = T$ and hence $\lambda = 1$; part (d) is proved in Phillips (1987).

Using the property that a regression of the form $y = X_1\hat\beta_1 + X_2\hat\beta_2 + \hat e$ yields a numerically identical estimator $\hat\beta_2$ as obtained in a regression of the form $y^* = X_2^*\hat\beta_2 + \hat e$ where y^* and X_2^* are projections of y and X_2, respectively, on the space spanned by the vectors in X_1, (A.6), (A.7), and (A.8), can be written as:

$$Y_{it} = \hat\beta^i X_{1it} + \hat\psi_i X_{2it} + \hat\alpha^i y_{it-1}^* + \hat e_{it} \qquad (t = 1,\dots,T;\ i = A, B, C), \tag{A.9}$$

where

$$\hat\psi_A = \hat\theta^A;\quad \hat\psi_B = \hat\gamma^B;\quad \hat\psi_C = \hat\gamma^C,$$
$$Y_{At} = Y_{Bt} = y_t - \bar Y,$$
$$y_{At-1}^* = y_{Bt-1}^* = y_{t-1} - \bar Y_{-1},$$
$$X_{1At} = X_{1Bt} = t - \bar t,$$
$$X_{1Ct} = t - c_1 \ \text{ if }\ t \le T_B \ \text{ and }\ = t - c_2 \text{ otherwise},$$
$$X_{2At} = DU_t - \lambda,$$
$$X_{2Bt} = -\bar t^* \ \text{ if }\ t \le T_B \ \text{ and }\ = t - T_B - \bar t^* \ \text{ otherwise},$$
$$X_{2Ct} = t - c_1 \ \text{ if }\ t \le T_B \ \text{ and }\ = 0 \ \text{ otherwise},$$
$$Y_{Ct} = y_t - A \ \text{ if }\ t \le T_B \ \text{ and }\ = y_t - B \ \text{ otherwise},$$
$$y_{Ct-1}^* = y_{t-1} - A' \ \text{ if }\ t \le T_B \ \text{ and }\ = y_{t-1} - B' \text{ otherwise},$$

and

$$\bar t = T^{-1}\sum_1^T t = (T+1)/2,\quad \bar t^* = T^{-1}\sum_1^{T-T_B} t = T(1-\lambda)^2/2 + (1-\lambda)/2,$$
$$c_1 = \bar t - T(1-\lambda)/2,\quad c_2 = \bar t + T\lambda/2,$$
$$A = \bar Y + \lambda^{-1}T^{-1}\sum_1^{T_B}(y_t - \bar Y),\quad B = \bar Y - (1-\lambda)^{-1}T^{-1}\sum_1^{T_B}(y_t - \bar Y),$$
$$A' = \bar Y_{-1} + \lambda^{-1}T^{-1}\sum_1^{T_B}(y_{t-1} - \bar Y_{-1}),\quad B' = \bar Y_{-1} - (1-\lambda)^{-1}T^{-1}\sum_1^{T_B}(y_{t-1} - \bar Y_{-1}),$$
$$\bar Y = T^{-1}\sum_1^T y_t,\quad \bar Y_{-1} = T^{-1}\sum_1^T y_{t-1}.$$

Now, let $Y_i' = (y_{i,0}^*, \dots, y_{i,T-1}^*)$, $E' = (e_1, \dots, e_T)$, $Z_i' = [X_{1i}, X_{2i}]$, $X_{1i} = (X_{1i,1}, \dots, X_{1i,T})$, $X_{2i} = (X_{2i,1}, \dots, X_{2i,T})$; then, under the null hypothesis,

(A.10) $$\hat{\alpha}^i - 1 = (Y_i'Y_i)^{-1}Y_i'E - (Y_i'Y_i)^{-1}Y_i'Z_i\left[Z_i'(I - P_{Y_i})Z_i\right]^{-1}Z_i'\left[I - P_{Y_i}\right]E$$

where $P_{Y_i} = Y_i(Y_i'Y_i)^{-1}Y_i'$. Furthermore, define the following terms:

$$Z_i'Z_i = \begin{bmatrix} a_i & b_i \\ b_i & c_i \end{bmatrix}, \quad Z_i'Y_i = \begin{bmatrix} H_i \\ J_i \end{bmatrix}, \quad Z_i'E = \begin{bmatrix} K_i \\ L_i \end{bmatrix}.$$

Straightforward manipulation yields the following representation for $\hat{\alpha}^i - 1$:

(A.11) $$\begin{aligned}\hat{\alpha}^i - 1 &= \left[(a_ic_i - b_i^2)Y_i'E - c_iH_iK_i + b_iJ_iK_i - a_iJ_iL_i + b_iH_iL_i\right] / \\ &\quad \left[(a_ic_i - b_i^2)Y_i'Y_i - a_iJ_i^2 - c_iH_i^2 + 2b_iH_iJ_i\right] \\ &\equiv E_i/F_i.\end{aligned}$$

The quantities involved are defined as follows with their respective limits as $T \to \infty$, obtained using Lemma A.3:

$$a_A = a_B = T^3/12 - T/12, \quad T^{-3}a_A = T^{-3}a_B \to 1/12,$$

$$b_A = -(1-\lambda)\lambda T^2/2, \quad T^{-2}b_A \to -(1-\lambda)\lambda/2,$$

$$c_A = (1-\lambda)\lambda T, \quad T^{-1}c_A \to (1-\lambda)\lambda,$$

$$Y_A'Y_A = Y_B'Y_B = \sum_1^T (y_{t-1} - \bar{Y}_{-1})^2,$$

$$T^{-2}Y_A'Y_A = T^{-2}Y_B'Y_B \Rightarrow \sigma^2\left[\int_0^1 w(r)^2\,dr - \left(\int_0^1 w(r)\,dr\right)^2\right],$$

$$Y_A'E = Y_B'E = \sum_1^T (y_{t-1} - \bar{Y}_{-1})e_t,$$

$$T^{-1}Y_A'E = T^{-1}Y_B'E \Rightarrow (\sigma^2/2)\left(w(1)^2 - \sigma_e^2/\sigma^2\right) - \sigma^2 w(1)\int_0^1 w(r)\,dr,$$

$$H_A = H_B = \sum_1^T t(y_{t-1} - \bar{Y}_{-1}),$$

$$T^{-5/2}H_A = T^{-5/2}H_B \Rightarrow \sigma\int_0^1 rw(r)\,dr - (\sigma/2)\int_0^1 w(r)\,dr,$$

$$J_A = \sum_1^{T_B}(y_{t-1} - \bar{Y}_{-1}), \quad T^{-3/2}J_A \Rightarrow \sigma\int_0^\lambda w(r)\,dr - \sigma\lambda\int_0^1 w(r)\,dr,$$

$$K_A = K_B = \sum_1^T tu_t - \bar{t}\sum_1^T u_t, \quad T^{-3/2}K_A = T^{-3/2}K_B \Rightarrow (\sigma/2)w(1) - \sigma\int_0^1 w(r)\,dr,$$

$$L_A = \sum_1^{T_B}(e_t - \bar{E}), \quad T^{-1/2}L_A \Rightarrow \sigma w(\lambda) - \sigma\lambda w(1),$$

$$b_B = \sum_{T_B+1}^{T}(t - \bar{t})(t - T_B), \quad T^{-3}b_B \to (1-\lambda)^2(1+2\lambda)/12,$$

$$c_B = T_B\bar{t}^{*2} + \sum_1^{T-T_B}(t - \bar{t}^*)^2, \quad T^{-3}c_B \to (1-\lambda)^3(1+3\lambda)/12,$$

$$J_B = \sum_{T_B+1}^{T}(t - T_B)(y_{t-1} - \bar{Y}_{-1}),$$

$$T^{-5/2}J_B \Rightarrow \sigma\int_\lambda^1 rw(r)\,dr - \lambda\sigma\int_\lambda^1 w(r)\,dr - \left((1-\lambda)^2/2\right)\sigma\int_0^1 w(r)\,dr,$$

$$L_B = \sum_{T_B+1}^{T} (t - T_B)(e_t - \bar{E}), \quad T^{-3/2} L_B \Rightarrow ((1-\lambda^2)/2)\sigma w(1) - \sigma \int_\lambda^1 w(r)\, dr,$$

$$a_C = \sum_{1}^{T_B} (t - c_1)^2 + \sum_{T_B+1}^{T} (t - c_2)^2, \quad T^{-3} a_C \to (1-\lambda)^2/12 + \lambda^3/12,$$

$$b_C = \sum_{1}^{T_B} (t - c_1)^2, \quad T^{-3} b_C \to \lambda^3/12,$$

$$c_C = \sum_{1}^{T_B} (t - c_1)^2, \quad T^{-3} c_C \to \lambda^3/12,$$

$$Y_C' Y_C = \sum_{1}^{T_B} (y_{t-1} - A')^2 + \sum_{T_B+1}^{T} (y_{t-1} - B')^2,$$

$$T^{-2} Y_C' Y_C \Rightarrow \sigma^2 \left[\int_0^1 w(r)^2\, dr - \lambda^{-1} \left(\int_0^\lambda w(r)\, dr \right)^2 - (1-\lambda)^{-1} \left(\int_\lambda^1 w(r)\, dr \right)^2 \right],$$

$$Y_C' E = \sum_{1}^{T_B} (y_{t-1} - A') e_t + \sum_{T_B+1}^{T} (y_{t-1} - B') e_t,$$

$$T^{-1} Y_C' E \Rightarrow (\sigma^2/2)\left(w(1)^2 - \sigma_e^2/\sigma^2 \right) - \lambda^{-1} \sigma^2 w(\lambda) \int_0^\lambda w(r)\, dr$$
$$- \sigma^2 (w(1) - w(\lambda))(1-\lambda)^{-1} \int_\lambda^1 w(r)\, dr,$$

$$H_C = \sum_{1}^{T_B} (t - c_1)(y_{t-1} - A') + \sum_{T_B+1}^{T} (t - c_2)(y_{t-1} - B'),$$

$$T^{-5/2} H_C \Rightarrow \sigma \left[\int_0^1 r w(r)\, dr - (\tfrac{1}{2})(1+\lambda) \int_0^1 w(r)\, dr + (\tfrac{1}{2}) \int_0^\lambda w(r)\, dr \right],$$

$$J_C = \sum_{1}^{T_B} (t - c_1)(y_{t-1} - A'), \quad T^{-5/2} J_C \Rightarrow \sigma \left[\int_0^\lambda r w(r)\, dr - (\lambda/2) \int_0^\lambda w(r)\, dr \right],$$

$$K_C = \sum_{1}^{T_B} (t - c_1) e_t + \sum_{T_B+1}^{T} (t - c_2) e_t,$$

$$T^{-3/2} K_C \Rightarrow \sigma \left[(\tfrac{1}{2})(1-\lambda) w(1) + (\tfrac{1}{2}) w(\lambda) - \int_0^1 w(r)\, dr \right],$$

$$L_C = \sum_{1}^{T_B} (t - c_1) e_t, \quad T^{-3/2} L_C \Rightarrow \sigma \left[(\lambda/2) w(\lambda) - \int_0^\lambda w(r)\, dr \right].$$

Now, using (A.11), we can write the statistics as follows:

(A.12) $\quad T(\hat{\alpha}^A - 1) = T^{-5} E_A / T^{-6} F_A,$

(A.13) $\quad t_{\hat{\alpha}} A = T^{-5} E_A / \left[\hat{S}_A^2 \cdot T^{-6} F_A \cdot T^{-4} \left(a_A c_A - b_A^2 \right) \right]^{1/2},$

(A.14) $\quad T(\hat{\alpha}^i - 1) = T^{-7} E_i / T^{-8} F_i, \quad i = B, C,$

(A.15) $\quad t_{\hat{\alpha}} i = T^{-7} E_i / \left[\hat{S}_i^2 \cdot T^{-8} F_i \cdot T^{-6} \left(a_i c_i - b_i^2 \right) \right]^{1/2}, \quad i = B, C,$

where $\hat{S}_i^2 = T^{-1} \Sigma_1^T \hat{e}_t^i$.

The results of Theorem 2 follow taking the limits of the expressions in (A.12) through (A.15) as $T \to \infty$, using the weak convergence results of the relevant moments (given above) and the fact that $\hat{S}_i^2 (i = A, B, C)$ converges in probability to σ_e^2 as $T \to \infty$.

APPENDIX B

Extended Set of Results for Tests of a Unit Root using Split and Full Samples

TABLE A1

Tests for a Unit Root on Pre-1929 Samples

Regression: $y_t = \tilde{\mu} + \tilde{\beta}t + \tilde{\alpha}y_{t-1} + \Sigma_{i=1}^{k}\tilde{d}_i \Delta y_{t-i} + \tilde{e}_t$

		$k=1$	$k=2$	$k=3$	$k=4$	$k=5$	$k=6$	$k=7$	$k=8$	$k=9$	$k=10$	$k=11$	$k=12$
Real GNP	$\tilde{\alpha}$	0.44	0.42	0.43	0.32								
	$t_{\tilde{\alpha}}$	−2.33	−1.83	−1.43	−1.27								
Nominal GNP	$\tilde{\alpha}$	0.60	0.52	0.45	0.44	0.57							
	$t_{\tilde{\alpha}}$	−2.14	−2.04	−1.80	−1.12	−0.89							
Real per capita GNP	$\tilde{\alpha}$	0.39	0.37	0.37	0.23								
	$t_{\tilde{\alpha}}$	−2.44	−1.91	−1.51	−1.36								
Industrial production	$\tilde{\alpha}$	0.69	0.72	0.65	0.64	0.69	0.73	0.68	0.71				
	$t_{\tilde{\alpha}}$	−3.14	−2.57	−3.00	−2.83	−2.18	−1.78	−1.93	−1.43				
Employment	$\tilde{\alpha}$	0.76	0.80	0.80	0.78	0.82	0.74	0.61	0.56				
	$t_{\tilde{\alpha}}$	−2.16	−1.65	−1.72	−1.91	−1.43	−2.05	−2.85	−2.63				
GNP deflator	$\tilde{\alpha}$	0.84	0.80	0.78	0.77	0.79	0.75	0.74	0.71				
	$t_{\tilde{\alpha}}$	−2.44	−2.79	−2.66	−2.54	−2.10	−2.19	−2.05	−2.05				
Consumer prices	$\tilde{\alpha}$	0.95	0.97	0.96	0.96	0.96	0.97	0.96	0.96				
	$t_{\tilde{\alpha}}$	−1.89	−1.28	−1.37	−1.50	−1.47	−1.29	−1.37	−1.41				
Wages	$\tilde{\alpha}$	0.76	0.73	0.68	0.66	0.63	0.54	0.30	0.43				
	$t_{\tilde{\alpha}}$	−2.32	−2.22	−2.35	−2.09	−1.90	−2.08	−2.82	−1.67				
Real wages	$\tilde{\alpha}$	0.44	0.50	0.49	0.43	0.24	0.28	0.09	0.68				
	$t_{\tilde{\alpha}}$	−2.83	−2.23	−2.05	−1.89	−2.21	−1.71	−1.84	−0.63				
Money stock	$\tilde{\alpha}$	0.75	0.71	0.55	0.61	0.55	0.46	0.25	−0.04				
	$t_{\tilde{\alpha}}$	−2.88	−2.89	−4.20	−2.71	−2.53	−2.54	−3.01	−3.37				
Velocity	$\tilde{\alpha}$	0.89	0.90	0.91	0.90	0.93	0.91	0.89	0.90				
	$t_{\tilde{\alpha}}$	−1.52	−1.33	−1.22	−1.17	−0.82	−0.93	−1.12	−1.08				
Interest rate	$\tilde{\alpha}$	0.73	0.71	0.54	0.54								
	$t_{\tilde{\alpha}}$	−1.73	−1.53	−2.06	−1.59								
Common stock prices	$\tilde{\alpha}$	0.81	0.86	0.73	0.75	0.76	0.75	0.64	0.68	0.61			
	$t_{\tilde{\alpha}}$	−1.95	−1.27	−2.29	−1.83	−1.60	−1.55	−2.09	−1.75	−2.06			
Quarterly real GNP[a]	$\tilde{\alpha}$	0.93	0.91	0.92	0.93	0.93	0.92	0.91	0.90	0.90	0.88	0.86	0.89
	$t_{\tilde{\alpha}}$	−2.51	−3.02	−2.52	−2.23	−2.18	−2.41	−2.60	−2.83	−2.68	−3.04	−3.40	−2.62

[a] The sample for Quarterly Real GNP is 47:1–73:I.

TABLE A2

TESTS FOR A UNIT ROOT ON POST-1929 SAMPLES

Regression: $y_t = \tilde{\mu} + \tilde{\beta}t + \tilde{\alpha}y_{t-1} + \sum_{i=1}^{k}\tilde{d}_i \Delta y_{t-i} + \tilde{e}_t$

		$k=1$	$k=2$	$k=3$	$k=4$	$k=5$	$k=6$	$k=7$	$k=8$	$k=9$	$k=10$	$k=11$	$k=12$
Real GNP	$\tilde{\alpha}$	0.72	0.75	0.75	0.78	0.74	0.66	0.56	0.33	0.22	0.18	0.30	0.09
	$t_{\tilde{\alpha}}$	−3.48	−3.00	−2.57	−1.96	−2.16	−2.65	−3.03	−5.32	−3.97	−3.19	−2.05	−2.34
Nominal GNP	$\tilde{\alpha}$	0.76	0.87	0.87	0.89	0.86	0.79	0.72	0.63	0.56	0.51	0.41	0.40
	$t_{\tilde{\alpha}}$	−3.37	−1.87	−1.60	−1.35	−1.66	−2.40	−2.93	−4.10	−3.39	−3.20	−2.91	−2.24
Real per capita GNP	$\tilde{\alpha}$	0.78	0.79	0.79	0.82	0.78	0.71	0.63	0.43	0.34	0.32	0.46	0.30
	$t_{\tilde{\alpha}}$	−3.05	−2.91	−2.55	−1.96	−2.19	−2.64	−3.03	−5.36	−3.91	−3.08	−1.89	−2.13
Industrial production	$\tilde{\alpha}$	0.68	0.69	0.66	0.63	0.71	0.64	0.53	0.23	0.03	−0.11	−0.03	−0.24
	$t_{\tilde{\alpha}}$	−2.84	−2.75	−2.65	−2.52	−1.76	−2.13	−2.55	−5.75	−4.38	−3.61	−2.40	−2.33
Employment	$\tilde{\alpha}$	0.78	0.80	0.80	0.83	0.80	0.72	0.67	0.47	0.55	0.42	0.24	0.10
	$t_{\tilde{\alpha}}$	−3.14	−2.66	−2.34	−1.80	−2.02	−2.64	−2.70	−5.61	−2.94	−3.24	−3.30	−2.79
GNP deflator	$\tilde{\alpha}$	0.85	0.92	0.91	0.87	0.87	0.83	0.72	0.76	0.75	0.81	0.75	0.68
	$t_{\tilde{\alpha}}$	−2.60	−1.32	−1.68	−2.29	−2.25	−2.64	−4.47	−3.08	−2.57	−1.73	−2.14	−2.48
Consumer prices	$\tilde{\alpha}$	0.84	0.91	0.90	0.88	0.85	0.81	0.70	0.68	0.62	0.72	0.67	0.58
	$t_{\tilde{\alpha}}$	−2.92	−1.64	−1.76	−2.10	−2.50	−2.72	−4.55	−3.45	−3.21	−1.98	−2.04	−2.39
Wages	$\tilde{\alpha}$	0.78	0.88	0.89	0.88	0.85	0.81	0.77	0.76	0.78	0.75	0.66	0.60
	$t_{\tilde{\alpha}}$	−3.37	−1.69	−1.41	−1.46	−1.77	−2.12	−2.27	−3.19	−2.02	−2.48	−3.06	−2.81
Real wages	$\tilde{\alpha}$	0.72	0.71	0.70	0.75	0.68	0.54	0.58	0.36	0.40	0.23	0.14	−0.35
	$t_{\tilde{\alpha}}$	−3.33	−3.10	−2.55	−1.84	−2.14	−2.79	−2.05	−3.31	−2.14	−2.34	−1.89	−2.11
Money stock	$\tilde{\alpha}$	0.89	0.93	0.92	0.91	0.89	0.87	0.86	0.79	0.67	0.63	0.59	0.39
	$t_{\tilde{\alpha}}$	−3.01	−1.85	−2.03	−2.55	−2.50	−2.59	−2.57	−4.57	−5.93	−3.61	−2.83	−4.05
Velocity	$\tilde{\alpha}$	0.61	0.67	0.63	0.71	0.69	0.66	0.60	0.52	0.49	0.63	0.50	0.36
	$t_{\tilde{\alpha}}$	−3.82	−2.70	−2.80	−1.97	−1.95	−1.91	−2.11	−2.33	−2.16	−1.43	−1.82	−2.54
Interest rate	$\tilde{\alpha}$	1.07	0.98	1.01	1.03	1.04	1.06	0.97					
	$t_{\tilde{\alpha}}$	1.11	−0.28	0.14	0.37	0.51	0.60	−0.25					
Common stock prices	$\tilde{\alpha}$	0.65	0.84	0.79	0.79	0.75	0.64	0.58	0.64	0.62	0.66	0.58	0.52
	$t_{\tilde{\alpha}}$	−3.48	−1.58	−1.99	−1.89	−2.13	−3.07	−2.96	−1.99	−2.00	−1.63	−1.64	−1.56
Quarterly real GNP[a]	$\tilde{\alpha}$	0.88	0.84	0.85	0.84	0.82	0.80	0.77	0.80	0.73	0.65	0.52	0.52
	$t_{\tilde{\alpha}}$	−2.23	−2.74	−2.39	−2.44	−2.48	−2.63	−2.80	−2.19	−2.78	−3.30	−4.03	−3.17

[a] The sample for Quarterly Real GNP is 73:II–86:III.

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TABLE A3

TESTS FOR A UNIT ROOT ON THE FULL SAMPLES

	(1)[a]		$k=1$	$k=2$	$k=3$	$k=4$	$k=5$	$k=6$	$k=7$	$k=8$	$k=9$	$k=10$	$k=11$	$k=12$
Real GNP	(12)	$\tilde{\alpha}$	0.71	0.68	0.66	0.63	0.62	0.55	0.43	0.28	0.19	0.19	0.15	0.13
		$t_{\tilde{\alpha}}$	−4.04	−4.06	−3.86	−3.73	−3.48	−3.87	−4.81	−5.03	−4.89	−4.14	−4.16	−4.20
Nominal GNP	(12)	$\tilde{\alpha}$	0.70	0.69	0.69	0.70	0.66	0.60	0.56	0.47	0.46	0.41	0.23	0.34
		$t_{\tilde{\alpha}}$	−4.43	−4.17	−3.87	−3.58	−4.01	−4.70	−4.88	−5.42	−5.18	−5.38	−7.86	−5.98
Real per capita GNP	(12)	$\tilde{\alpha}$	0.76	0.73	0.72	0.70	0.70	0.64	0.53	0.43	0.39	0.42	0.37	0.34
		$t_{\tilde{\alpha}}$	−3.62	−3.58	−3.37	−3.21	−2.94	−3.27	−4.09	−4.08	−3.89	−3.14	−3.23	−3.17
Industrial production	(12)	$\tilde{\alpha}$	0.67	0.65	0.59	0.56	0.61	0.57	0.48	0.32	0.40	−0.37	−0.29	−0.32
		$t_{\tilde{\alpha}}$	−4.63	−4.46	−4.84	−4.69	−3.83	−3.98	−4.65	−5.47	−4.15	−4.05	−4.45	−4.08
Employment	(12)	$\tilde{\alpha}$	0.78	0.80	0.77	0.76	0.78	0.73	0.67	0.60	0.64	0.62	0.59	0.58
		$t_{\tilde{\alpha}}$	−3.77	−3.29	−3.72	−3.78	−3.12	−3.94	−4.51	−4.76	−3.59	−3.58	−3.59	−3.49
GNP deflator	(12)	$\tilde{\alpha}$	0.84	0.82	0.81	0.78	0.78	0.75	0.74	0.71	0.70	0.69	0.67	0.68
		$t_{\tilde{\alpha}}$	−3.79	−3.99	−3.89	−4.16	−4.04	−4.20	−4.10	−4.32	−4.28	−4.34	−4.35	−4.00
Consumer prices	(12)	$\tilde{\alpha}$	0.97	0.98	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.97	0.97
		$t_{\tilde{\alpha}}$	−1.87	−1.28	−1.68	−2.19	−2.06	−1.89	−2.01	−2.01	−1.90	−1.93	−1.49	−1.44
Wages	(12)	$\tilde{\alpha}$	0.77	0.76	0.74	0.73	0.71	0.68	0.62	0.62	0.64	0.63	0.60	0.67
		$t_{\tilde{\alpha}}$	−4.31	−4.15	−4.25	−4.05	−4.21	−4.73	−5.41	−4.91	−4.62	−4.63	−4.69	−3.64
Real wages	(14)	$\tilde{\alpha}$	0.68	0.63	0.57	0.52	0.49	0.47	0.38	0.30	0.29	0.28	0.27	0.29
		$t_{\tilde{\alpha}}$	−3.87	−3.97	−4.11	−4.06	−3.89	−3.62	−4.02	−4.28	−4.11	−3.82	−3.64	−3.37
Money stock	(12)	$\tilde{\alpha}$	0.87	0.87	0.85	0.86	0.84	0.81	0.78	0.76	0.74	0.74	0.72	0.77
		$t_{\tilde{\alpha}}$	−3.94	−3.61	−3.86	−3.66	−3.82	−4.29	−4.69	−4.56	−4.36	−4.29	−4.32	−3.18
Velocity	(12)	$\tilde{\alpha}$	0.93	0.94	0.95	0.96	0.97	0.97	0.96	0.95	0.96	0.96	0.94	0.98
		$t_{\tilde{\alpha}}$	−1.82	−1.53	−1.41	−1.11	−0.74	−0.79	−0.94	−1.09	−0.91	−0.89	−1.22	−0.49
Interest rate	(12)	$\tilde{\alpha}$	1.01	0.98	0.97	0.98	0.98	0.99	1.004	1.01	1.01	1.03	0.99	0.97
		$t_{\tilde{\alpha}}$	0.12	−0.45	−0.53	−0.34	−0.31	−0.24	0.07	0.22	0.12	0.46	−0.08	-0.40
Common stock prices	(14)	$\tilde{\alpha}$	0.72	0.73	0.72	0.74	0.76	0.76	0.75	0.75	0.73	0.67	0.62	0.60
		$t_{\tilde{\alpha}}$	−4.87	−4.39	−4.43	−3.91	−3.53	−3.52	−3.51	−3.41	−3.52	−4.19	−4.50	−4.35
Quarterly real GNP	(10)	$\tilde{\alpha}$	0.92	0.90	0.91	0.90	0.90	0.90	0.89	0.89	0.88	0.86	0.84	0.87
	$i = B$	$t_{\tilde{\alpha}}$	−3.33	−3.97	−3.47	−3.18	−3.16	−3.39	−3.51	−3.42	−3.55	−3.98	−4.32	−3.28

[a]The number in column (1) refers to the regression model used to test for a unit root using the full samples. See the discussion in the text.

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THE GREAT CRASH, THE OIL PRICE SHOCK, AND THE UNIT ROOT HYPOTHESIS

BY PIERRE PERRON[1]

We consider the null hypothesis that a time series has a unit root with possibly nonzero drift against the alternative that the process is "trend-stationary." The interest is that we allow under both the null and alternative hypotheses for the presence of a one-time change in the level or in the slope of the trend function. We show how standard tests of the unit root hypothesis against trend stationary alternatives cannot reject the unit root hypothesis if the true data generating mechanism is that of stationary fluctuations around a trend function which contains a one-time break. This holds even asymptotically. We derive test statistics which allow us to distinguish the two hypotheses when a break is present. Their limiting distribution is established and selected percentage points are tabulated. We apply these tests to the Nelson-Plosser data set and to the postwar quarterly real GNP series. In the former, the break is due to the 1929 crash and takes the form of a sudden change in the level of the series. For 11 out of the 14 series analyzed by Nelson and Plosser we can reject at a high confidence level the unit root hypothesis. In the case of the postwar quarterly real GNP series, the break in the trend function occurs at the time of the oil price shock (1973) and takes the form of a change in the slope. Here again we can reject the null hypothesis of a unit root. If one is ready to postulate that the 1929 crash and the slowdown in growth after 1973 are not realizations of an underlying time-invariant stochastic process but can be modeled as exogenous, then the conclusion is that most macroeconomic time series are not characterized by the presence of a unit root. Fluctuations are indeed stationary around a deterministic trend function. The only "shocks" which have had persistent effects are the 1929 crash and the 1973 oil price shock.

KEYWORDS: Hypothesis testing, intervention analysis, structural change, stochastic trends, deterministic trends, functional weak convergence, Wiener process, macroeconomic time series.

1. INTRODUCTION

THE UNIT ROOT HYPOTHESIS has recently attracted a considerable amount of work in both the economics and statistics literature. Indeed, the view that most economic time series are characterized by a stochastic rather than deterministic nonstationarity has become prevalent. The seminal study of Nelson and Plosser (1982) which found that most macroeconomic variables have a univariate time series structure with a unit root has catalyzed a burgeoning research program with both empirical and theoretical dimensions.

Nelson and Plosser's study was followed by a series of empirical analyses which basically confirmed their findings. Some (Stulz and Wasserfallen (1985) and Wasserfallen (1986), among others) applied a similar Dickey–Fuller (1979) statistical methodology to other economic series. On the statistical front, there

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emerged an interest in developing alternative approaches to test the unit root hypothesis. Examples include: the class of tests proposed by Phillips and Perron (1988) and the methodology suggested by Campbell and Mankiw (1987, 1988) and Cochrane (1988) using an estimate of the spectral density at frequency zero. Empirical applications of these methodologies generally reaffirmed the conclusion that most macroeconomic time series have a unit root (e.g., Perron (1988)).

These studies had many effects on economic theorizing. They seem to confirm previous analyses which had advanced the unit root hypothesis for particular economic series, e.g., consumption (Hall (1978)), velocity of money (Gould and Nelson (1974)), and stock prices (Samuelson (1973)). They also launched a series of theoretical investigations with implications consistent with a unit root, e.g., Blanchard and Summers (1986) for employment. Furthermore, a considerable stock of statistical tools was developed for more general models with integrated variables; these include the cointegration framework (Engle and Granger (1987)) and multivariate systems (Stock and Watson (1988) and Phillips and Durlauf (1986)).

As far as macroeconomic theories are concerned, the most important implication of the unit root revolution, is that under this hypothesis random shocks have a permanent effect on the system. Fluctuations are not transitory. This implication, as forcefully argued by Nelson and Plosser, has profound consequences for business cycle theories. It runs counter to the prevailing view that business cycles are transitory fluctuations around a more or less stable trend path. It is therefore of importance to assess carefully the reliability of the unit root hypothesis as an empirical fact.

The aim of this paper appears startling, given the results in the above mentioned literature. Our conclusion is that most macroeconomic time series are not characterized by the presence of a unit root and that fluctuations are indeed transitory. Only two events (shocks) have had a permanent effect on the various macroeconomic variables: the Great Crash of 1929 and the oil price shock of 1973.

Of course, to reach such a conclusion, a particular postulate must be introduced which differentiates our approach from the previous ones. This postulate is that the Great Crash and the oil price shock were not a realization of the underlying data-generating mechanism of the various series. In this sense, we consider these shocks as exogenous. The exogeneity assumption is not a statement about a descriptive model for the time series representation of the variables. It is used here as a device to remove the influence of these shocks from the noise function. A more detailed discussion of these issues and their implications can be found in Section 6.

These two shocks are rather different in nature. On one hand, the Great Crash created a dramatic drop in the mean of most aggregate variables. On the other hand, the 1973 oil price shock was followed by a change in the slope of the trend for most aggregates, i.e., a slowdown in growth. In this light, our aim is to show that most macroeconomic variables are "trend-stationary" if one allows a single change in the intercept of the trend function after 1929 and a single change in the slope of the trend function after 1973.

Our approach is in the spirit of the "intervention analysis" suggested by Box and Tiao (1975). According to their methodology, "aberrant" or "outlying" events can be separated from the noise function and be modeled as changes or "interventions" in the deterministic part of the general time series model. Using such a strategy makes it "possible to distinguish between what can and what cannot be explained by the noise" (Box and Tiao (1975, p. 72)). These "interventions" are assumed to occur at a known date. The same strategy is used in the present analysis in that we consider the time of the changes in the trend function as fixed rather than as a random variable to be estimated.

To make our point as unambiguous as possible, we use the same data set as Nelson and Plosser, as well as the real GNP series analyzed by Campbell and Mankiw. The data set used by Nelson and Plosser contains fourteen macroeconomic variables sampled annually. All series end in 1970 and contain only one break, the 1929 Great Crash. We shall not analyze the unemployment rate series since there is a general agreement that it is stationary. The real GNP series is postwar quarterly from 1947:I to 1986:III and so contains only one break as well, the 1973 oil shock. Furthermore, to make our analysis as similar as possible to previous ones, the statistical methodology applied here is an extension of the Dickey–Fuller methodology (as used by Nelson and Plosser) to test for the presence of a single unit root in a univariate time series.

The plan of the paper is as follows. Section 2 motivates the ensuing analysis and presents the alternative models considered. Section 3 shows that usual tests will not be able to reject the unit root hypothesis if in fact the deterministic trend of the series has a single break (either in the intercept or the slope). In Section 4, we develop formal statistical tests of the null hypothesis of a unit root which can distinguish the unit root hypothesis from that of a stationary series around a trend which has a single break. The asymptotic distributions under the null hypothesis are derived and tabulated. Empirical results from applying these procedures are presented in Section 5. Section 6 contains a discussion of some issues raised by our analysis and suggestions for future research. All theorems are proved in Appendix A.

2. MOTIVATION

The null hypothesis considered is that a given series $\{y_t\}_0^T$ (of which a sample of size $T+1$ is available) is a realization of a time series process characterized by the presence of a unit root and possibly a nonzero drift. However, the approach is generalized to allow a one-time change in the structure occurring at a time T_B $(1 < T_B < T)$. Three different models are considered under the null hypothesis: one that permits an exogeneous change in the level of the series (a "crash"), one that permits an exogenous change in the rate of growth, and one that allows both change. These hypotheses are parameterized as follows:

Null hypotheses:

$$\text{Model (A)} \quad y_t = \mu + dD(TB)_t + y_{t-1} + e_t,$$

$$\text{Model (B)} \quad y_t = \mu_1 + y_{t-1} + (\mu_2 - \mu_1)DU_t + e_t,$$

$$\text{Model (C)} \quad y_t = \mu_1 + y_{t-1} + dD(TB)_t + (\mu_2 - \mu_1)DU_t + e_t, \quad \text{where}$$

$$D(TB)_t = 1 \quad \text{if} \quad t = T_B + 1, \quad 0 \text{ otherwise;}$$
$$DU_t = 1 \quad \text{if} \quad t > T_B, \quad 0 \text{ otherwise; and}$$

$$A(L)e_t = B(L)v_t,$$

$v_t \sim$ i.i.d. $(0, \sigma^2)$, with $A(L)$ and $B(L)$ pth and qth order polynomials, respectively, in the lag operator L.

The innovation series $\{e_t\}$ is taken to be of the ARMA(p, q) type with the orders p and q possibly unknown. This postulate allows the series $\{y_t\}$ to represent quite general processes. More general conditions are possible and will be used in subsequent theoretical derivations.

Instead of considering the alternative hypothesis that y_t is a stationary series around a deterministic linear trend with time invariant parameters, we shall analyze the following three possible alternative models:

Alternative hypotheses:

$$\text{Model (A)} \quad y_t = \mu_1 + \beta t + (\mu_2 - \mu_1)DU_t + e_t,$$

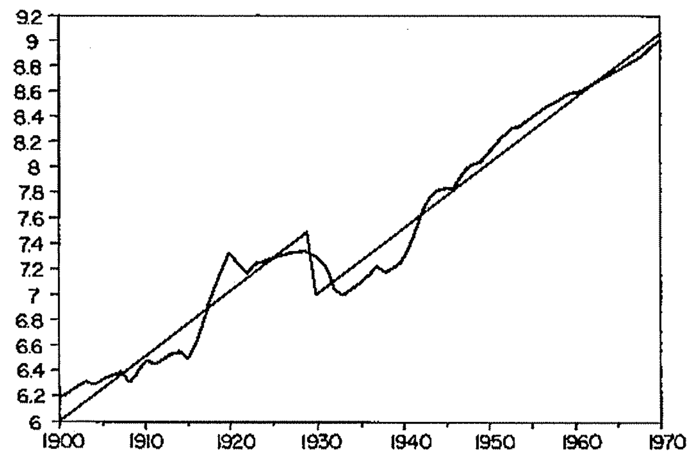
$$\text{Model (B)} \quad y_t = \mu + \beta_1 t + (\beta_2 - \beta_1)DT_t^* + e_t,$$

$$\text{Model (C)} \quad y_t = \mu_1 + \beta_1 t + (\mu_2 - \mu_1)DU_t + (\beta_2 - \beta_1)DT_t + e_t$$

where

$$DT_t^* = t - T_B, \quad \text{and} \quad DT_t = t \quad \text{if} \quad t > T_B \quad \text{and 0 otherwise.}$$

Here, T_B refers to the time of break, i.e., the period at which the change in the parameters of the trend function occurs. Model (A) describes what we shall refer to as the crash model. The null hypothesis of a unit root is characterized by a dummy variable which takes the value one at the time of break. Under the alternative hypothesis of a "trend-stationary" system, Model (A) allows for a one-time change in the intercept of the trend function. For the empirical cases we have in mind, T_B is the year 1929 and $\mu_2 < \mu_1$. Model (B) is referred to as the "changing growth" model. Under the alternative hypothesis, a change in the slope of the trend function without any sudden change in the level at the time of the break is allowed. Under the null hypothesis, the model specifies that the drift parameter μ changes from μ_1 to μ_2 at time T_B. In the empirical examples presented in Section 5, T_B is the first quarter of 1973 and $\beta_2 < \beta_1$, reflecting a slowdown in growth following the oil shock. Model (C) allows for both effects to take place simultaneously, i.e., a sudden change in the level followed by a different growth path.



Note: The broken straight line is a fitted trend (by OLS) of the form $\tilde{y}_t = \tilde{\mu} + \tilde{\gamma} DU_t + \tilde{\beta} t$ where $DU_t = 0$ if $t \leq 1929$ and $DU_t = 1$ if $t > 1929$.

FIGURE 1.—Logarithm of "Nominal Wages."

To motivate the use of these three models as possible alternatives to the unit root with drift hypothesis, we present in this section some descriptive analyses for three series: "nominal wages" (1900–1970), "quarterly real GNP" (1947:I–1986:III) and "common stock prices" (1871–1970).

Figure 1 shows a plot of the logarithm of the nominal wage series. A feature of this graph is the marked decrease between 1929 and 1930. Apart from this change, the trend appears fairly stable (same slope) over the entire period. The solid line is the estimated trend line from a regression on a constant, a trend and a dummy variable taking a value of 0 prior and at 1929 and value 1 afterwards. Table I presents the results from estimating (by OLS) a regression of the Dickey-Fuller type, i.e.:

$$y_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\alpha} y_{t-1} + \sum_{i=1}^{k} \tilde{c}_i \Delta y_{t-i} + \tilde{e}_t. \tag{1}$$

The first row presents the full sample regression. The coefficient on the lag dependent variable is 0.910 with a t statistic for the hypothesis that $\alpha = 1$ of -2.09. Using the critical values tabulated by Dickey and Fuller, we cannot reject the null hypothesis of a unit root. When the sample is split in two (pre-1929 and post-1929), the estimated value of α decreases dramatically: 0.304 for the pre-1929 sample and 0.735 for the post-1929 sample. However, due to the small samples available, the t statistics are not large enough (in absolute value) to reject the hypothesis that $\alpha = 1$, even at the 10 percent level.

Two features are worth emphasizing from this example: (a) the full sample estimate of α is markedly superior to any of the split sample estimates and relatively close to one. It appears that the 1929 crash is responsible for the near unit root value of α; and (b) the split sample regressions are not powerful enough

TABLE I

REGRESSION ANALYSIS FOR THE WAGES, QUARTERLY GNP, AND COMMON STOCK PRICE SERIES

Regression: $y_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\alpha} y_{t-1} + \sum_{i=1}^{k} \tilde{c}_i \Delta y_{t-i} + \tilde{e}_t$

Series/Period	k	$\tilde{\mu}$	$t_{\tilde{\mu}}$	$\tilde{\beta}$	$t_{\tilde{\beta}}$	$\tilde{\alpha}$	$t_{\tilde{\alpha}}$	$S(\tilde{e})$
(a) Wages								
1900–1970[a]	2	0.566	2.30	0.004	2.30	0.910	−2.09	0.060
1900–1929	7	4.299	2.84	0.037	2.73	0.304	−2.82	0.0803
1930–1970	8	1.632	3.60	0.012	2.64	0.735	−3.19	0.0269
(b) Common stock prices								
1871–1970[a]	2	0.481	2.02	0.003	2.37	0.913	−2.05	0.158
1871–1929	3	0.3468	2.13	0.0063	2.70	0.732	−2.29	0.1209
1930–1970	4	−0.5312	−1.64	0.0166	1.96	0.788	−1.89	0.1376
(c) Quarterly real GNP								
1947:I–1986:III	2	0.386	2.90	0.0004	2.71	0.946	−2.85	0.010
1947:I–1973:I	2	0.637	3.04	0.0008	2.99	0.910	−3.02	0.0099
1973:II–1986:III	1	0.883	2.23	0.0008	2.27	0.878	−2.23	0.0102

[a] Results taken from Nelson and Plosser (1982, Table 5).

to reject the hypothesis that $\alpha = 1$ even though the estimates are well below one. It would be useful, in this light, to have a more powerful procedure based on the full sample that would allow the 1929 break to be exogenous.

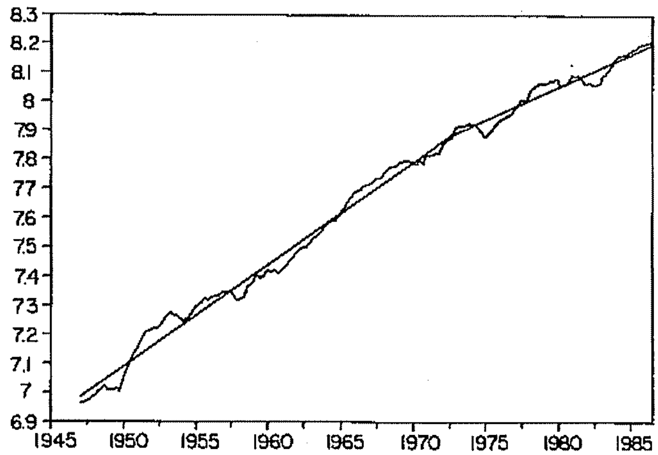
Figure 2 graphs the postwar quarterly real GNP series. Here, the series behave according to Model (B) where there is no sharp change in the level of the series at the 1973:I break point but rather a change in the slope. The solid line is a fitted trend where a dummy variable is included in the regression, taking the value 0 prior and at 1973:I and the value $(t - 105)$ after 1973:I (1973:I being the 105th observation in the sample). Table I compares regressions of the form (1) with full and split samples. Again, the estimate of α is lower in both subsamples than with

TABLE II

SAMPLE AUTOCORRELATIONS OF THE "DETRENDED" SERIES

Series		Period	T	Variance	r_1	r_2	r_3	r_4	r_5	r_6
Real GNP	A	1909–1970	62	0.010	0.77	0.45	0.23	0.11	0.05	0.04
Nominal GNP	A	1909–1970	62	0.023	0.68	0.31	0.12	0.08	0.11	0.12
Real per capita GNP	A	1909–1970	62	0.012	0.81	0.54	0.33	0.20	0.13	0.09
Industrial production	A	1860–1970	111	0.017	0.71	0.44	0.32	0.17	0.08	0.12
Employment	A	1890–1970	81	0.005	0.82	0.59	0.43	0.30	0.20	0.15
GNP deflator	A	1889–1970	82	0.015	0.82	0.63	0.45	0.31	0.17	0.06
Consumer prices	A	1860–1970	111	0.066	0.96	0.89	0.80	0.71	0.63	0.54
Wages	A	1900–1970	71	0.016	0.76	0.47	0.26	0.12	0.03	−0.03
Real wages	C	1900–1970	71	0.003	0.74	0.40	0.12	−0.12	−0.27	−0.33
Money stock	A	1889–1970	82	0.023	0.87	0.69	0.52	0.38	0.25	0.11
Velocity	A	1869–1970	102	0.036	0.90	0.79	0.70	0.62	0.57	0.52
Interest rate	A	1900–1970	71	0.587	0.77	0.58	0.38	0.25	0.15	0.11
Common stock prices	C	1871–1970	100	0.066	0.80	0.53	0.36	0.20	0.10	0.08
Quarterly GNP	B	47:I 86:III	159	0.001	0.94	0.83	0.70	0.57	0.45	0.35

Note: A, B, and C denote the detrending procedure corresponding to the given model under the alternative hypothesis.

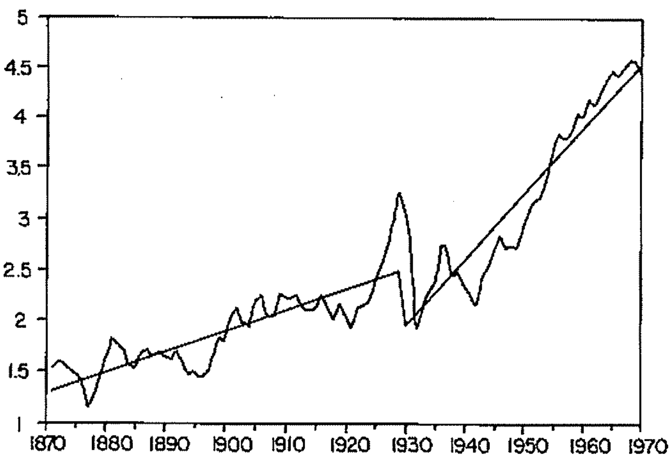


Note: The broken straight line is a fitted trend (by OLS) of the form: $\tilde{y}_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\gamma} DT_t^*$ where $DT_t^* = 0$ if $t \leqslant 1973$:I and $DT_t^* = t - T_B$ if $t > 1973\text{:I} = T_B$.

FIGURE 2.—Logarithm of "Postwar Quarterly Real GNP."

the full sample (given the quarterly nature of the series, the difference is important). The same features discussed above appear to hold when there is a change in the slope of the trend function.

As a final example, consider the common stock price series graphed in Figure 3. The break point is again in 1929 but in this case there appears to be both a sudden change in the level of the series in 1929 and a higher growth rate after. The solid line is the estimated trend with two dummy variables added, an intercept dummy (0 prior and at 1929, 1 after 1929) and a slope dummy (0 prior



Note: The broken straight line is a fitted trend (by OLS) of the form $\tilde{y}_t = \tilde{\mu} + \tilde{\gamma}_1 DU_t + \tilde{\beta} t + \tilde{\gamma}_2 DT_t$ where $DU_t = DT_t = 0$ if $t \leqslant 1929$ and $DU_t = 1$, $DT_t = t$ if $t > 1929$.

FIGURE 3.—Logarithm of "Common Stock Prices."

and at 1929 and t after 1929). The estimated values of α (in regression (1)) with the full sample are 0.913 but are only 0.732 using the pre-1929 sample and 0.788 using the post-1929. Here again, the t statistics are not large enough, however, to reject the unit root hypothesis at even the 10 percent level using any of the subsamples.[2]

Table II presents the autocorellation function of the "detrended series" for the full set of variables analyzed by Nelson and Plosser, along with the postwar quarterly real GNP series. All series are detrended according to Model (A) (with a constant, a trend, and an intercept dummy) except for the postwar Quarterly Real GNP Series (with a slope dummy instead of the intercept dummy, Model (B)) and the real wage and common stock price series (with both a slope and intercept dummy, Model (C)). Unlike the "standard" detrended series (see Table 4 of Nelson-Plosser), the autocorrelations decay quite rapidly for all variables except for the consumer prices and velocity series. This behavior of the autocorrelation function is certainly not the one usually associated with either a random walk or a detrended random walk. Indeed, the "detrended" series appear stationary.

The results of this section motivate the analysis presented in the following sections. We first investigate the effects of the two types of changes in the trend function that we consider on the statistical properties of autoregressive estimates of the type found in regression (1) (both in finite samples and asymptotically). We find that such changes create a spurious unit root that may not vanish, even asymptotically. To overcome the problem of the low power associated with testing for a unit root using split samples, formal test statistics, which permit the presence of either or both an intercept and a slope shift, are developed in Section 4.

3. THE EFFECT OF A SHIFT IN THE TREND FUNCTION ON TESTS FOR A UNIT ROOT

To assess the effects of the presence of a shift in the level of the series or a shift in the slope (at a single point of time) on tests for the presence of a unit root, we first present a small Monte Carlo experiment. Consider first the "crash hypothesis" (Model (A)). We generated 10,000 replications of a series $\{y_t\}$ of length 100 defined by

$$y_t = \mu_1 + (\mu_2 - \mu_1) DU_t + \beta t + e_t \qquad (t = 1, \ldots, T), \tag{2}$$

where $DU_t = 1$ if $t > T_B$, and 0 otherwise.

[2]Dickey-Fuller tests for the presence of a unit root using split samples are presented in Appendix B for all the series considered. The results are presented for values of k ranging from 1 to 12. These results show that (i) the conclusions drawn are not sensitive to the value of k chosen; (ii) for some series it is possible to reject the unit root hypothesis, especially when considering the post-1929 subsample. Furthermore, the statistical significance of the lagged first-differences (not reported) suggest that a large value of k may be needed. For example, the t statistics on the eighth lagged first-difference is often statistically significant. A similar pattern will occur in the full sample tests reported in subsequent sections.

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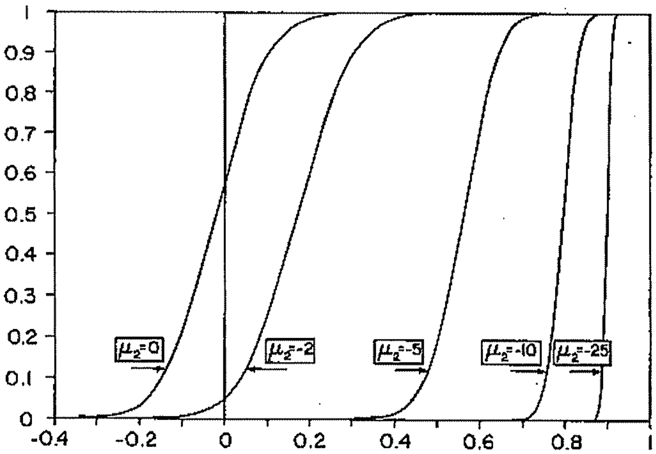


Note: $\tilde{\alpha}$ is the estimated autoregressive parameter in regression (4). The data-generating mechanism is given by equation (2) with $\mu_1 = 0$, $\beta = 1.0$ and $\{e_t\}$ i.i.d. $N(0,1)$, $T = 100$ and $T_B = 50$.

FIGURE 4.—C.D.F. of $\tilde{\alpha}$ under the "Crash" Model.

For simplicity, $\mu_1 = 0, \beta = 1, T_B = 50, T = 100$ and the innovations e_t are i.i.d. $N(0,1)$. For the "changing growth" hypothesis, a similar setup is considered except that y_t is generated by

(3) $$y_t = \mu + \beta_1 t + (\beta_2 - \beta_1) DT_t^* + e_t \qquad (t = 1, \ldots, T),$$

where $DT_t^* = t - T_B$ if $t > T_B$, and 0 otherwise.

Again, $\mu = 0, \beta_1 = 1, T_B = 50, T = 100$, and $e_t \sim$ i.i.d. $N(0,1)$. For each replication, we computed the autoregressive coefficient $\tilde{\alpha}$ in the following regression, using ordinary least squares:

(4) $$y_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\alpha} y_{t-1} + \tilde{e}_t.$$

Figure 4 graphs the cumulative distribution function of $\tilde{\alpha}$ when the data generating process (D.G.P.) is given by (2) for various values of μ_2. This experiment reveals that as the magnitude of the crash increases (μ_2 decreases), the c.d.f of $\tilde{\alpha}$ becomes more concentrated at a value ever closer to 1. The corresponding mean and variance of the sample of $\tilde{\alpha}$ generated are shown in Table III. Figure 5 graphs the c.d.f. of $\tilde{\alpha}$ when the D.G.P. is given by (3) for various values of β_2. As β_2 diverges from β_1, again, the c.d.f. becomes more concentrated and closer to one. The computed mean and variance of $\tilde{\alpha}$ presented in Table III confirms this behavior.[3]

[3] Note that when the error structure is i.i.d., $\tilde{\alpha}$ is free of nuisance parameters and hence can be used as a formal test statistic on the same ground as the t statistic. However, we also performed a similar experiment with the t statistic on $\tilde{\alpha}$ ($\alpha = 1$) in regression (4) as well as in a regression with additional lags of first-differences as regressors. The results obtained show the same behavior. If anything, the t statistic with extra lags of first-differences as regressors shows a still greater bias toward nonrejection of the null hypothesis of a unit root. These results are available upon request. We prefer to report our result in terms of the behavior of the estimator $\tilde{\alpha}$ instead of its t statistic because it makes clear that what causes the nonrejection is not due solely to the behavior of the variance estimator. What is of importance is that $\tilde{\alpha}$ is biased towards unity.

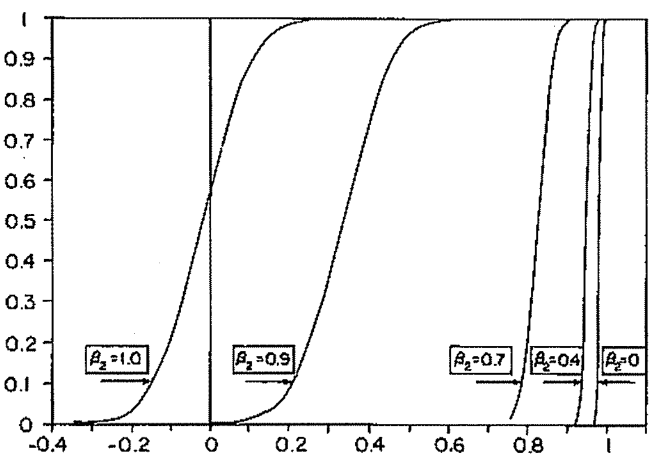
TABLE III
MEAN AND VARIANCE OF $\tilde{\alpha}$

	(a) Crash Simulations, $\mu_1 = 0$, $\beta = 1$				
	$\mu_2 = 0$	$\mu_2 = -2$	$\mu_2 = -5$	$\mu_2 = -10$	$\mu_2 = -25$
Mean	−0.019	0.172	0.558	0.795	0.899
Variance	0.00986	0.01090	0.00471	0.00089	0.00009
	(b) Breaking Trend Simulations, $\beta_1 = 1$, $\mu = 0$				
	$\beta_2 = 1.0$	$\beta_2 = 0.9$	$\beta_2 = 0.7$	$\beta_2 = 0.4$	$\beta_2 = 0.0$
Mean	−0.019	0.334	0.825	0.949	0.981
Variance	0.00986	0.00938	0.00094	0.00009	0.00001

See notes to Figure 4 for case (a) and Figure 5 for case (b).

What emerges from this experiment is that if the magnitude of the shift is significant, one could hardly reject the unit root hypothesis even if the series is that of a trend (albeit with a break) with i.i.d. disturbances. In particular, one would conclude that the shocks have permanent effects. Here, the shocks clearly have no permanent effects, only the one-time shift in the trend function is permanent.

To analyze the effect of an increase in the sample size on the distribution of $\tilde{\alpha}$ with a shift of a given magnitude, we derive the asymptotic limit of $\tilde{\alpha}$. To this end, we again consider processes generated by Models (A), (B), or (C) under the alternative hypotheses, but we enlarge the framework by allowing general conditions on the error structure $\{e_t\}$. Many such sets of conditions are possible and would allow us to carry out the asymptotic theory. For simplicity, we use the



Note: $\tilde{\alpha}$ is the estimated autoregressive parameter in regression (4). The data-generating mechanism is given by equation (3) with $\mu = 0$, $\beta_1 = 1.0$, $\{e_t\}$ i.i.d. $N(0,1)$, $T = 100$, $T_B = 50$.

FIGURE 5.—C.D.F. of $\tilde{\alpha}$ under the "Breaking Trend" Model.

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"mixing-type" conditions of Phillips (1987) and Phillips and Perron (1988). These are stated in Assumption 1.

ASSUMPTION 1: *(a)* $E(e_t)=0$ *all t; (b)* $\sup_t E|e_t|^{\beta+\varepsilon}<\infty$ *for some* $\beta>2$ *and* $\varepsilon>0$; *(c)* $\sigma^2=\lim_{T\to\infty} T^{-1}E(S_T^2)$ *exists and* $\sigma^2>0$, *where* $S_T=\sum_1^T e_t$; *(d)* $\{e_t\}_1^\infty$ *is strong mixing with mixing numbers* α_m *that satisfy*: $\sum_1^\infty \alpha_m^{1-2/\beta}<\infty$.

These conditions are general enough to permit the series $\{e_t\}$ to be generated by a finite order ARMA(p,q) process with Gaussian innovations. To carry out the asymptotic analysis, we shall require that both the pre-break and post-break samples increase at the same rate as the total number of observations, T, increases. To this effect, we assume, for simplicity, that $T_B=\lambda T$ for all T. We refer to λ as the "break fraction." The asymptotic limits are taken as T increases to infinity in a sequence that ensures an integer value of T_B for a given λ. This type of increasing sequence is assumed throughout the paper. The results proved in Appendix A are presented in the following theorem.

THEOREM 1: *Let* $\{y_t\}_0^T$ *be a sample of size* $T+1$ *generated under one of the alternative hypotheses with the innovations* $\{e_t\}$ *satisfying Assumption* 1. *Let* '$\to$' *denote convergence in probability. Furthermore, let* $T_B=\lambda T$, *for all T and* $0<\lambda<1$; *then as* $T\to\infty$:

(a) *The "crash hypothesis": Under Model* (A)

$$\tilde{\alpha}\to\left\{[\mu_1-\mu_2]^2A+\gamma_1\right\}\left\{[\mu_1-\mu_2]^2A+\sigma_e^2\right\}^{-1}$$

where

$$A=[\lambda-4\lambda^2+6\lambda^3-3\lambda^4],\quad \gamma_1=\lim_{T\to\infty}T^{-1}\sum_1^T E(e_te_{t-1}),$$

and

$$\sigma_e^2=\lim_{T\to\infty}T^{-1}\sum_1^T E\left(e_t^2\right).$$

(b) *The "breaking trend hypothesis": Under either Model* (B) *or* (C)

(i) $\tilde{\alpha}\to 1$,

(ii) $$T(\tilde{\alpha}-1)\to\left\{3(-1+4\lambda-5\lambda^2+2\lambda^3)\right\}\cdot\left\{2(-3+4\lambda-3\lambda^2+3\lambda^3-\lambda^4)\right\}^{-1}.$$

Part (a) of Theorem 1 shows that under the crash hypothesis, the limit of $\tilde{\alpha}$ depends on the relative magnitude of $[\mu_1-\mu_2]^2\ A$ and σ_e^2. In particular, this limit gets closer to one as $[\mu_1-\mu_2]^2$ increases. Another feature is that the limit of $\tilde{\alpha}$ is always greater than the true first-order autoregressive coefficient of the stationary part of the series, γ_1/σ_e^2. However, since $\tilde{\alpha}$ does not converge to 1, the usual statistics for testing that $\alpha = 1$, such as $T(\tilde{\alpha} - 1)$ or the t statistic on $\tilde{\alpha}$, would eventually reject the null hypothesis of a unit root. Nevertheless, added to the generally poor power properties of tests for a unit root is the consideration that the limit of $\tilde{\alpha}$ is inflated above its true value. These conditions are such that it could be difficult to reject the unit root hypothesis in finite samples.

There is another interpretation to the results under the crash hypothesis. As stated in model (A), the change in the intercept of the trend function is given by $(\mu_2 - \mu_1)$, a fixed value. This implies that in the asymptotic derivations we are considering a shift which decreases relative to the level of the series as the sample size increases. It may be more appropriate to specify the change in the intercept as a magnitude relative to the level of the series at the time of the break. Since at this period the level of the series is proportional to T_B, we can specify $(\mu_2 - \mu_1)$ as a proportion of T_B, say, $(\mu_2 - \mu_1) = \gamma T_B$. In this case the "crash" is proportional to the level of the series. Since $T_B \to \infty$ as $T \to \infty$, it is clear, from part (a), that under this interpretation, $\tilde{\alpha} \to 1$.

Such ambiguity does not occur under the "breaking trend hypothesis" (Models (B) or (C)) as is shown by part (b) of Theorem 1. Here, the limit of $\tilde{\alpha}$ is 1 irrespective of the behavior of the intercept and the limit of $T(\tilde{\alpha} - 1)$ is invariant to the relative magnitude of the shift (β_2 versus β_1). The expression in part (b, ii) is a function of λ. However, it varies from 0 to $1/2$ for values of λ in the range $(0, 1)$. Since the one-sided 5 percent asymptotic critical value of $T(\tilde{\alpha} - 1)$ is -21.8 under the null hypothesis of a unit root (Fuller (1976)), Theorem 2 implies that the unit root hypothesis could not be rejected, even asymptotically.[4]

These results could be extended to more general test statistics, such as the t statistics. Nevertheless, the picture is clear. Tests of the unit root hypothesis are not consistent against "trend stationary" alternatives when the trend function contains a shift in the slope. Although they are not inconsistent against a shift in the intercept of the trend function (if the change is fixed as T increases), their power is likely to be substantially reduced due to the fact that the limit of the autoregressive coefficient is inflated above its true value. When interpreting the "crash" as proportional to the level of the series as T increases, $\tilde{\alpha}$ unambiguously converges to one and implies a considerable loss in power. There is therefore a need to develop alternative statistical procedures that could distinguish a process with a unit root from a process stationary around a breaking trend function.

4. ALTERNATIVE STATISTICAL PROCEDURES

In this section, we extend the Dickey-Fuller testing strategy to ensure a consistent testing procedure against shifting trend functions. We shall present several ways to do so, all of which are asymptotically equivalent, and discuss the main differences between each.

[4]After the first draft of this paper was written, we became aware of a result similar to part (b, i) of Theorem 1 proved by Rappoport and Reichlin (1987). In fact, in the case of deterministic trends with multiple shifts in slope, they prove the following more general result: "If the true model contains $K+1$ segments, then any fitted model involving K or less segments will, asymptotically, yield a larger sum of squared residuals than [a difference stationary] model" (p.9).

Consider first detrending the raw series $\{y_t\}$ according to either model (A), (B), or (C). Let $\{\tilde{y}_t^i\}$, $i = A, B, C$ be the residuals from a regression of y_t on (1) $i = A$: a constant, a time trend, and DU_t; (2) $i = B$: a constant, a time trend, and DT_t^*; (3) $i = C$: a constant, a time trend, DU_t, and DT_t. Furthermore, let $\tilde{\alpha}^i$ be the least squares estimator of α in the following regression:

$$\tilde{y}_t^i = \tilde{\alpha}^i \tilde{y}_{t-1}^i + \tilde{e}_t \qquad (i = A, B, C;\ t = 1, 2, \ldots, T). \tag{5}$$

Up to this point the extensions from the no break model are straightforward enough. However, matters are not so simple concerning the distribution of the statistics of interest, namely the normalized bias, $T(\tilde{\alpha}^i - 1)$, and the t statistic on $\tilde{\alpha}^i$, $t_{\tilde{\alpha}^i}$ $(i = A, B, C)$. Needless to say, the only manageable analytical distribution theory is asymptotic in nature. But two additional features are also present over the usual procedure: (a) extra regressors and (b) the split sample nature of these extra regressors. To this effect, we derive the asymptotic distribution of $T(\tilde{\alpha}^i - 1)$ and $t_{\tilde{\alpha}^i}$ under the null hypothesis of a unit root. As in Section 3, we require that the break point T_B increases at the same rate as the total sample size T. Again, for simplicity, it is assumed that $T_B = \lambda T$ with both T and T_B integer valued.

The method of proof is similar to that of Phillips (1987) and Phillips and Perron (1988). We use weak convergence results that hold for normalized functions of the sum of the innovations when the latter are assumed to satisfy Assumption 1. The limiting distributions obtained under this general setting are then specialized to the i.i.d. case. The asymptotic distributions in the i.i.d. case are evaluated using simulations, and critical values are tabulated. We then show how the results can be extended to innovations $\{e_t\}$ that follow the general ARMA(p, q) process in the same way that the Dickey-Fuller regressions are modified by adding extra lags of first-differences of the data as regressors.

The main results concerning the asymptotic distributions of the normalized bias estimators and the t statistics of the autoregressive coefficient under the null hypothesis of a unit root are presented in the next theorem.

THEOREM 2: *Let $\{y_t\}$ be generated under the null hypothesis of model i $(i = A, B, C)$ with the innovation sequence $\{e_t\}$ satisfying Assumption* 1. *Let $\Rightarrow$ denote weak convergence in distribution and $\lambda = T_B/T$ for all T. Then, as $T \to \infty$:*

(a) $\quad T(\tilde{\alpha}^i - 1) \Rightarrow H_i/K_i$,

(b) $\quad t_{\tilde{\alpha}^i} \Rightarrow (\sigma/\sigma_e) H_i/(g_i K_i)^{1/2}$,

where

$$H_A = g_A D_1 - D_5\psi_1 - D_6\psi_2; \qquad K_A = g_A D_2 - D_4\psi_2 - D_3\psi_1;$$

$$H_B = g_B D_1 + D_5\psi_3 + D_8\psi_4; \qquad K_B = g_B D_2 + D_7\psi_4 + D_3\psi_3;$$

$$H_C = g_C D_9 + D_{13}\psi_5 - D_{14}\psi_6; \qquad K_C = g_C D_{10} - D_{12}\psi_6 + D_{11}\psi_5;$$

with

$$\psi_1 = 6D_4 + 12D_3; \qquad \psi_2 = 6D_3 + (1-\lambda)^{-1}\lambda^{-1}D_4;$$

$$\psi_3 = (1+2\lambda)(1-\lambda)^{-1}D_7 - (1+3\lambda)D_3;$$

$$\psi_4 = (1+2\lambda)(1-\lambda)^{-1}D_3 - (1-\lambda)^{-3}D_7;$$

$$\psi_5 = D_{12} - D_{11}; \qquad \psi_6 = \psi_5 + (1-\lambda)^2 D_{12}/\lambda^3;$$

and

$$D_1 = \left(\tfrac{1}{2}\right)\left(w(1)^2 - \sigma_e^2/\sigma^2\right) - w(1)\int_0^1 w(r)\,dr;$$

$$D_2 = \int_0^1 w(r)^2\,dr - \left[\int_0^1 w(r)\,dr\right]^2;$$

$$D_3 = \int_0^1 rw(r)\,dr - \left(\tfrac{1}{2}\right)\int_0^1 w(r)\,dr; \qquad D_4 = \int_0^\lambda w(r)\,dr - \lambda\int_0^1 w(r)\,dr;$$

$$D_5 = w(1)/2 - \int_0^1 w(r)\,dr; \qquad D_6 = w(\lambda) - \lambda w(1);$$

$$D_7 = \int_\lambda^1 rw(r)\,dr - \lambda\int_\lambda^1 w(r)\,dr - \left((1-\lambda)^2/2\right)\int_0^1 w(r)\,dr;$$

$$D_8 = \left((1-\lambda^2)/2\right)w(1) - \int_\lambda^1 w(r)\,dr;$$

$$D_9 = \int_0^1 w(r)^2\,dr - \lambda^{-1}\left(\int_0^\lambda w(r)\,dr\right)^2 - (1-\lambda)^{-1}\left(\int_\lambda^1 w(r)\,dr\right)^2;$$

$$D_{10} = \left(w(1)^2 - \sigma_e^2/\sigma^2\right)/2 - \lambda^{-1}w(\lambda)\int_0^\lambda w(r)\,dr$$
$$- (w(1) - w(\lambda))(1-\lambda)^{-1}\int_\lambda^1 w(r)\,dr;$$

$$D_{11} = \int_0^1 rw(r)\,dr - \left(\tfrac{1}{2}\right)(1+\lambda)\int_0^1 w(r)\,dr + \left(\tfrac{1}{2}\right)\int_0^\lambda w(r)\,dr;$$

$$D_{12} = \int_0^\lambda rw(r)\,dr - (\lambda/2)\int_0^\lambda w(r)\,dr;$$

$$D_{13} = (1-\lambda)w(1)/2 + w(\lambda)/2 - \int_0^1 w(r)\,dr;$$

$$D_{14} = \lambda w(\lambda)/2 - \int_0^\lambda w(r)\,dr;$$

$$g_A = 1 - 3(1-\lambda)\lambda; \qquad g_B = 3\lambda^3; \qquad g_C = 12(1-\lambda)^2;$$

and where $w(r)$ *is the unit Wiener process defined on* $C[0,1]$, $\sigma^2 = \lim_{T\to\infty} E[T^{-1} S_T^2]$, $S_T = \Sigma_1^T e_t$, *and* $\sigma_e^2 = \lim_{T\to\infty} E[T^{-1}\Sigma_1^T e_t^2]$.

Theorem 2 provides a representation for the limiting distribution of the normalized least squares estimators and their t statistics in terms of functionals of Wiener processes. These limiting distributions are functions of the parameter λ, the ratio of the pre-break sample size to total sample size. It is easy to verify that when λ is either 0 or 1, the limiting distributions are identical over all models and are given by:

$$T(\tilde{\alpha}-1) \Rightarrow H/K \quad \text{and} \quad t_{\tilde{\alpha}} \Rightarrow (\sigma/\sigma_e)H/K^{1/2}$$

where

$$H = \left(\tfrac{1}{2}\right)\left(w(1)^2 - \sigma_e^2/\sigma^2\right) + 12\left[\int_0^1 rw(r)\,dr - \left(\tfrac{1}{2}\right)\int_0^1 w(r)\,dr\right]$$
$$\cdot\left[\int_0^1 w(r)\,dr - \left(\tfrac{1}{2}\right)w(1)\right] - w(1)\int_0^1 w(r)\,dr,$$
$$K = \int_0^1 w(r)^2\,dr - 12\left(\int_0^1 rw(r)\,dr\right)^2$$
$$+ 12\int_0^1 w(r)\,dr\int_0^1 rw(r)\,dr - 4\left(\int_0^1 w(r)\,dr\right)^2.$$

These latter asymptotic distributions correspond to those derived by Phillips and Perron (1988) in the case where no dummy variables are included.

The expressions for the limiting distributions in Theorem 2 depend on additional nuisance parameters, apart from λ, namely σ^2 and σ_e^2. As in Phillips (1987) and Phillips and Perron (1988), σ_e^2 is the variance of the innovations and σ^2 is, in the case of weakly stationary innovations, equal to $2\pi f(0)$ where $f(0)$ is the spectral density of $\{e_t\}$ evaluated at frequency zero. When the innovation sequence $\{e_t\}$ is independent and identically distributed, $\sigma^2 = \sigma_e^2$ and, in that case, the limiting distributions are invariant with respect to nuisance parameters, except λ.

Therefore, when $\sigma^2 = \sigma_e^2$, percentage points of the limiting distributions can be tabulated for given values of λ. Tables IV, V, and VI present selected percentage points that will allow us to carry hypothesis testing. The critical values are obtained via simulation methods. We briefly describe the steps involved. First, we generate a sample of size 1,000 of i.i.d. $N(0,1)$ random deviates, $\{e_t\}$. We then construct sample moments of the data which converge weakly to the various functionals of the Wiener process involved in the representation of the asymptotic distributions. For example, as $T \to \infty$, $T^{-1/2}\,\Sigma_1^T e_t \Rightarrow w(1)$, $T^{-1/2}\Sigma_1^{T_B} e_t \Rightarrow w(\lambda)$, $T^{-3/2}\Sigma_1^T\Sigma_{j=1}^t e_j \Rightarrow \int_0^1 w(r)\,dr$, $\Sigma_{t=1}^T(\Sigma_{j=1}^{t-1}e_j)e_t \Rightarrow (\frac{1}{2})(w(1)^2-1)$, etc. With a sample size of 1,000 and i.i.d. $N(0,1)$ variates, we can expect the approximation to be quite accurate. Once the various functionals are evaluated, we construct the expressions in Theorem 2 and obtain one realization of the limiting distributions

TABLE IV.A

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $T(\tilde{\alpha}-1)$ IN MODEL A
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−34.17	−35.85	−35.07	−34.44	−34.07	−35.83	−35.59	−34.86	−34.65
2.5%	−28.93	−30.35	−29.92	−29.26	−29.00	−29.80	−29.61	−29.40	−29.35
5%	−25.04	−26.00	−25.90	−25.40	−25.25	−25.56	−25.99	−25.82	−25.40
10%	−21.45	−22.16	−21.93	−21.61	−21.55	−21.79	−22.33	−22.10	−21.48
90%	−4.57	−5.19	−5.13	−4.28	−3.85	−4.36	−5.15	−5.32	−4.62
95%	−3.40	−3.90	−3.80	−2.83	−2.38	−2.92	−3.86	−3.87	−3.27
97.5%	−2.35	−2.92	−2.85	−1.69	−1.42	−1.89	−2.78	−2.84	−2.13
99%	−1.28	−1.70	−1.60	−0.61	−0.40	−0.78	−1.58	−1.78	−1.39

TABLE IV.B

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $t_{\tilde{\alpha}}$ IN MODEL A
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−4.30	−4.39	−4.39	−4.34	−4.32	−4.45	−4.42	−4.33	−4.27
2.5%	−3.93	−4.08	−4.03	−4.01	−4.01	−4.09	−4.07	−3.99	−3.97
5%	−3.68	−3.77	−3.76	−3.72	−3.76	−3.76	−3.80	−3.75	−3.69
10%	−3.40	−3.47	−3.46	−3.44	−3.46	−3.47	−3.51	−3.46	−3.38
90%	−1.38	−1.45	−1.43	−1.26	−1.17	−1.28	−1.42	−1.46	−1.37
95%	−1.09	−1.14	−1.13	−0.88	−0.79	−0.92	−1.10	−1.13	−1.04
97.5%	−0.78	−0.90	−0.83	−0.55	−0.49	−0.60	−0.82	−0.89	−0.74
99%	−0.46	−0.54	−0.51	−0.21	−0.15	−0.26	−0.50	−0.57	−0.47

TABLE V.A

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $T(\tilde{\alpha}-1)$ IN MODEL B
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−34.34	−37.16	−38.07	−39.21	−39.77	−40.08	−38.70	−36.18	−34.69
2.5%	−28.74	−31.97	−32.78	−33.42	−33.60	−33.21	−32.31	−31.45	−29.42
5%	−25.00	−27.16	−28.61	−29.23	−29.65	−29.51	−28.68	−27.24	−25.25
10%	−21.26	−23.10	−24.20	−25.04	−25.40	−25.15	−24.30	−23.01	−21.24
90%	−4.27	−5.09	−5.92	−6.62	−6.96	−6.71	−6.08	−5.26	−4.45
95%	−3.12	−3.85	−4.50	−5.06	−5.31	−5.15	−4.59	−3.82	−3.16
97.5%	−2.20	−2.69	−3.30	−3.90	−4.14	−3.94	−3.36	−2.72	−2.21
99%	−1.11	−1.58	−2.19	−2.50	−3.01	−2.54	−2.20	−1.50	−1.24

of the statistics $T(\tilde{\alpha}^i-1)$, $t_{\tilde{\alpha}^i}$ $(i=A,B,C)$. We replicate this procedure 5,000 times and obtain the critical values from the sorted vector of replicated statistics. This procedure is performed for each statistic with nine values of the parameter λ, the ratio of pre-break sample size to total sample size.[5]

Several features are worth mentioning with respect to these critical values. First, as expected, for a given size of the test, the critical values are larger (in

[5]For some evidence on the adequacy of this method to obtain critical values for limiting distributions involving functions of Wiener processes, see Chan (1988).

TABLE V.B

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $t_{\hat{\alpha}}$ IN MODEL B
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−4.27	−4.41	−4.51	−4.55	−4.56	−4.57	−4.51	−4.38	−4.26
2.5%	−3.94	−4.08	−4.17	−4.20	−4.26	−4.20	−4.13	−4.07	−3.96
5%	−3.65	−3.80	−3.87	−3.94	−3.96	−3.95	−3.85	−3.82	−3.68
10%	−3.36	−3.49	−3.58	−3.66	−3.68	−3.66	−3.57	−3.50	−3.35
90%	−1.35	−1.48	−1.59	−1.69	−1.74	−1.71	−1.61	−1.49	−1.34
95%	−1.04	−1.18	−1.27	−1.37	−1.40	−1.36	−1.28	−1.16	−1.04
97.5%	−0.78	−0.87	−0.97	−1.11	−1.18	−1.11	−0.97	−0.87	−0.77
99%	−0.40	−0.52	−0.69	−0.75	−0.82	−0.78	−0.67	−0.54	−0.43

TABLE VI.A

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $T(\hat{\alpha}-1)$ IN MODEL C
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−36.17	−39.97	−42.98	−45.52	−44.07	−44.75	−43.02	−41.48	−36.58
2.5%	−30.65	−34.92	−36.48	−37.12	−37.56	−37.72	−37.50	−35.16	−31.82
5%	−26.63	−29.95	−32.47	−33.22	−33.79	−33.19	−33.11	−30.70	−27.16
10%	−22.68	−25.50	−27.90	−29.39	−29.41	−29.04	−28.14	−25.79	−22.62
90%	−4.74	−5.85	−7.35	−8.43	−8.84	−8.55	−7.41	−6.17	−4.89
95%	−3.41	−4.34	−5.50	−6.67	−7.19	−6.79	−5.66	−4.52	−3.52
97.5%	−2.51	−3.19	−4.14	−5.37	−5.82	−5.47	−4.33	−3.35	−2.49
99%	−1.31	−2.14	−2.82	−3.96	−4.39	−4.24	−2.80	−2.02	−1.28

TABLE VI.B

PERCENTAGE POINTS OF THE ASYMPTOTIC DISTRIBUTION OF $t_{\hat{\alpha}}$ IN MODEL C
Time of Break Relative to Total Sample Size: λ

$\lambda =$	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
1%	−4.38	−4.65	−4.78	−4.81	−4.90	−4.88	−4.75	−4.70	−4.41
2.5%	−4.01	−4.32	−4.46	−4.48	−4.53	−4.49	−4.44	−4.31	−4.10
5%	−3.75	−3.99	−4.17	−4.22	−4.24	−4.24	−4.18	−4.04	−3.80
10%	−3.45	−3.66	−3.87	−3.95	−3.96	−3.95	−3.86	−3.69	−3.46
90%	−1.44	−1.60	−1.78	−1.91	−1.96	−1.93	−1.81	−1.63	−1.44
95%	−1.11	−1.27	−1.46	−1.62	−1.69	−1.63	−1.47	−1.29	−1.12
97.5%	−0.82	−0.98	−1.15	−1.35	−1.43	−1.37	−1.17	−1.04	−0.80
99%	−0.45	−0.67	−0.81	−1.04	−1.07	−1.08	−0.79	−0.64	−0.50

absolute value) for each model than the standard Dickey-Fuller critical values when considering the left tail. One would therefore expect a loss in power. Secondly, although the critical values are not significantly influenced by the value of the parameter λ, the maximum (in absolute value) occurs around the value $\lambda = 0.5$, i.e., for a break at mid-sample.[6] In the left tail, critical values of the statistics are smallest (in absolute value) when λ is close to 0 or 1. This is to be

[6] The simulated critical values suggest that the limiting distributions are symmetric around $\lambda = 0.5$. This feature seems intuitively plausible. We have not, however, proved that such is the case.

expected since, as previously mentioned, the critical values are identical to those of Dickey and Fuller when $\lambda = 0, 1$.

Some critical values are worth noticing. Consider the t statistics. Under Model (A), the "crash hypothesis", the 5 percent critical value has a minimum (over values of λ) of -3.80. Under Models (B) and (C), the corresponding figures are -3.96 and -4.24 respectively. The critical values under the various models are therefore noticeably smaller than the standard Dickey-Fuller critical value of -3.41 (see Dickey (1976) and Fuller (1976)).

These sets of results can be used to perform hypothesis testing. One simply picks the critical value corresponding to the sample value of λ at the chosen significance level. Since we only provide critical values for a selected grid of λ's, the procedure suggested is to choose the critical value corresponding to the value of λ nearest to its sample value, i.e., T_B/T. Given that the differences in the critical values over adjacent values for λ in the tables are not substantially different, this procedure should not cause misleading inferences.

4.1. *Extensions to More General Error Processes*: *Case* (1)

Using regressions (5) ($i = A, B, C$) and the critical values in Tables IV, V, and VI is valid only in the case where the innovation sequence $\{e_t\}$ is uncorrelated. When there is additional correlation, as one would expect, an extension is necessary. Two approaches are possible. One is to follow the approach suggested by Phillips (1987) and Phillips and Perron (1988). This involves finding a set of transformed statistics that would converge weakly to the limiting distributions expressed in Theorem 2 with $\sigma^2 = \sigma_e^2$. The other approach is that suggested by Dickey and Fuller (1979) and Said and Dickey (1984).

Consider first the extension to Phillips' (1987) procedure. It is useful first to write the limiting distributions of Theorem 2 in a different, more compact form. To do so, we adopt the framework suggested by Ouliaris, Park, and Phillips (1988). Define $w_i(r)$ ($i = A, B, C$) to be the stochastic process on $[0,1]$ such that $w_i(r)$ is the projection residual of a Wiener process $w(r)$ on the subspace generated by the following set of functions: (1) $i = A$: $1, r, du(r)$, where $du(r) = 0$ if $r \leqslant \lambda$ and $du(r) = 1$ if $r > \lambda$; (2) $i = B$: $1, r, dt^*(r)$, where $dt^*(r) = 0$ if $r \leqslant \lambda$ and $dt^*(r) = r - \lambda$ if $r > \lambda$; (3) $i = C$: $1, r, du(r), dt(r)$, where $dt(r) = 0$ if $r \leqslant \lambda$ and $dt(r) = r$ if $r > \lambda$. Adopting this notation, an alternative representation of the limiting distributions in Theorem 2 is given by:

$$T(\tilde{\alpha}^i - 1) \Rightarrow \left(\int_0^1 w_i(r)\, dw(r) + \delta\right)\left(\int_0^1 w_i(r)^2\, dr\right)^{-1} \qquad (i = A, B, C)$$

and

$$t_{\tilde{\alpha}^i} \Rightarrow (\sigma/\sigma_e)\left(\int_0^1 w_i(r)\, dw(r) + \delta\right)\left(\int_0^1 w_i(r)^2\, dr\right)^{-1/2} \qquad (i = A, B, C)$$

where $\delta = (\sigma^2 - \sigma_e^2)/(2\sigma^2)$.

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Now, define $\tilde{\sigma}_i^2$ and $\tilde{\sigma}_{ei}^2$ to be, respectively, any consistent estimator of σ^2 and σ_e^2 based on the estimated residuals from regression (5)($i = A, B, C$).[7] Also define S_i^2 ($i = A, B, C$) to be the residual sum of squares from the regression y_{t-1} on (1) $i = A$: $1, t, DU_t$; (2) $i = B$: $1, t, DT_t^*$; and (3) $i = C$: $1, t, DU_t, DT_t$. We then define the transformed statistics as:

$$Z(\tilde{\alpha}^i) = T(\tilde{\alpha}^i - 1) - T^2(\tilde{\sigma}_i^2 - \tilde{\sigma}_{ei}^2)/2S_i^2 \qquad (i = A, B, C), \tag{6}$$

$$Z(t_{\tilde{\alpha}^i}) = (\tilde{\sigma}_{ei}/\tilde{\sigma}_i)t_{\tilde{\alpha}^i} - T(\tilde{\sigma}_i^2 - \tilde{\sigma}_{ei}^2)/2\tilde{\sigma}_i S_i \qquad (i = A, B, C). \tag{7}$$

Following Ouliaris, Park, and Phillips (1988), it is straightforward to show that:

$$Z(\tilde{\alpha}^i) \Rightarrow \left(\int_0^1 w_i(r)\,dw(r)\right)\left(\int_0^1 w_i(r)^2\,dr\right)^{-1} \qquad (i = A, B, C) \tag{8}$$

and

$$Z(t_{\tilde{\alpha}^i}) \Rightarrow \left(\int_0^1 w_i(r)\,dw(r)\right)\left(\int_0^1 w_i(r)^2\,dr\right)^{-1/2} \qquad (i = A, B, C). \tag{9}$$

The limiting distributions in (8) and (9) are those whose critical values are presented in Tables IV, V, and VI derived using the representation given by Theorem 2.

The other approach adopts the procedures suggested by Dickey and Fuller (1979, 1981) and Said and Dickey (1984) which add extra lags of the first differences of the data as regressors in equation (5). This extended framework is characterized by the following regression (again estimated by OLS):

$$\tilde{y}_t^i = \tilde{\alpha}^i \tilde{y}_{t-1}^i + \sum_{j=1}^{k} \tilde{c}_j \Delta \tilde{y}_{t-j}^i + \tilde{e}_t \qquad (i = A, B, C) \tag{10}$$

where

$$\Delta \tilde{y}_t^i = \tilde{y}_t^i - \tilde{y}_{t-1}^i.$$

In the above representation, $\tilde{\alpha}$ is the OLS estimator of α, the sum of the autoregressive coefficients and the test is again that $\alpha = 1$. The parameter k specifies the number of extra regressors added. In a simple AR(p) process, $k = p$. In a more general ARMA(p, q) process with p and q unknown, k must increase at a controlled rate with the sample size. Arguments similar to those developed by Said and Dickey can be used to show that the limiting distributions of the statistics $t_{\tilde{\alpha}^i}$ ($i = A, B, C$) are the same when the innovation sequence is an ARMA(p, q) process and regression (10) is used, as they are when the errors are i.i.d. and regression (5) is used. However, slightly more restrictive assumptions are needed with respect to the innovation sequence $\{e_t\}$ and the truncation parameter k for this asymptotic equivalence to hold. They are detailed in the following Assumption (see Said and Dickey (1984)).

[7] See Phillips (1987), Phillips and Perron (1988), and Perron (1988) for details.

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ASSUMPTION 2: *(a)* $A(L)e_t = B(L)v_t$; *(b)* v_t *is a sequence of i.i.d.* $(0, \sigma^2)$ *random variables with finite* $(4+\delta)$*th moment for some* $\delta > 0$; *(c)* $k \to \infty$ *and* $T^{-1}k^3 \to 0$ *as* $T \to \infty$.

4.2. *Extensions to More General Error Processes: Case* (2)

A possible drawback of the methods suggested above is that they imply that the change in the trend function occurs instantaneously. Given, for instance, that the Great Depression was not an instantaneous event but lasted several years, one may wish to allow for such a transition period during changes in the trend function. One way to model this is to suppose that the economy reacts gradually to a shock to the trend function.[8] Consider, for instance, Model (A) where a crash occurs. A plausible specification of the trend function, say η_t^A, is given by:

$$(11) \qquad \eta_t^A = \mu_1 + \beta t + \gamma\psi(L)\, DU_t$$

where $\psi(L)$ is a stationary and invertible polynomial in L with $\psi(0) = 1$ and $\gamma = \mu_2 - \mu_1$. The long run change in the trend function is given by $\gamma\psi(1)$ while the immediate impact is simply γ. A similar framework holds for models (B) and (C).

One way to incorporate such a gradual change in the trend function is to suppose that the economy responds to a shock to the trend function the same way as it reacts to any other shock, i.e. to impose $\psi(L) = B(L)^{-1}A(L)$ (see Section 2). In the literature on outliers specification the framework suggested here is analogous to the so-called "innovational outlier" model whereas the framework considered in Section 4.1 is analogous to the "additive outlier" model (see, e.g., Tsay (1986)). We can then implement tests for the presence of a unit root in a framework that directly extends the Dickey-Fuller strategy by adding dummy variables in regression (1). The following regressions, corresponding to Models (A), (B), and (C) are constructed by nesting the corresponding models under the null and alternative hypotheses:

$$(12) \qquad y_t = \hat{\mu}^A + \hat{\theta}^A DU_t + \hat{\beta}^A t + \hat{d}^A D(TB)_t + \hat{\alpha}^A y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t,$$

$$(13) \qquad y_t = \hat{\mu}^B + \hat{\theta}^B DU_t + \hat{\beta}^B t + \hat{\gamma}^B DT_t^* + \hat{\alpha}^B y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t,$$

$$(14) \qquad y_t = \hat{\mu}^C + \hat{\theta}^C DU_t + \hat{\beta}^C t + \hat{\gamma}^C DT_t + \hat{d}^C D(TB)_t + \hat{\alpha}^C y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t.$$

The null hypothesis of a unit root imposes the following restrictions on the true parameters of each model: Model (A), the "crash hypothesis": $\alpha^A = 1$, $\beta^A = 0$,

[8] Again, this treatment is analogous to the methodology proposed by Box and Tiao (1975) concerning intervention analyses.

$\theta^A = 0$; Model (B), the "breaking slope with no crash": $\alpha^B = 1$, $\gamma^B = 0$, $\beta^B = 0$; and Model (C), where both effects are allowed: $\alpha^C = 1$, $\gamma^C = 0$, $\beta^C = 0$. Under the alternative hypothesis of a "trend stationary" process, we expect $\alpha^A, \alpha^B, \alpha^C < 1$; $\beta^A, \beta^B, \beta^C \neq 0$; $\theta^A, \theta^C, \gamma^B, \gamma^C \neq 0$. Finally, under the alternative hypothesis, d^A, d^C, and θ^B should be close to zero while under the null hypothesis they are expected to be significantly different from zero.

The asymptotic distribution of the t statistics $t_{\hat{\alpha}}A$ and $t_{\hat{\alpha}}C$ in (12) and (14) are the same, respectively, as the asymptotic distribution of $t_{\hat{\alpha}}A$ and $t_{\hat{\alpha}}C$ in (10). However such a correspondence does not hold for the t statistic $t_{\hat{\alpha}}B$ in (13). Apart from the one-time dummy variable $d(TB)_t$, regressions (13) and (14) are equivalent; hence the asymptotic distribution of $t_{\hat{\alpha}}B$ is identical to the asymptotic distribution of $t_{\hat{\alpha}}C$. This implies that in the above framework, it is not possible to test for a unit root under the maintained hypothesis that the trend function has a change in slope with the two segments joined at the time of the change. Consequently, tests for the presence of a unit root in Model (B) will have less power using regression (13) than using (10) where the asymptotic critical values of the t statistic on α are smaller (in absolute value). However, it is still possible to test for a unit root with constant drift against a trend stationary process as in Model (B) and use the critical values of Table V. One simply runs the regression:

$$(15) \qquad y_t = \hat{\mu}^B + \hat{\beta}^B t + \hat{\gamma}^B DT_t^* + \hat{\alpha}^B y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t.$$

The asymptotic distribution of the t statistic $t_{\hat{\alpha}}B$ in (15) is the same as the asymptotic distribution of the t statistic $t_{\hat{\alpha}}B$ in (10). Given that the regressor DU_t is absent from (15), this case, however, implies that the change in drift is not permitted under the null hypothesis.

Finally, note that it is possible to apply Phillips' nonparametric procedure using regressions (12) through (14) without the lagged first-differenced regressors and applying the corrections given by (6) and (7). However, such a procedure has the unattractive feature of imposing only a one-period adjustment to the change in the trend function. In the notation of (11), it imposes $\psi(L) = 1 - \psi_1 L$ where ψ_1 is the coefficient on the first lag in the polynomial $B(L)^{-1}A(L)$.

The procedures outlined in this section permit testing for the presence of a unit root in a quite general time series process which allows a one-time break in the mean of the series or its rate of growth (or both). In the next section, we apply these procedures in the specific context of breaks at the time of the 1929 crash and the 1973 oil shock.

5. EMPIRICAL APPLICATIONS

We apply the test statistics derived in the previous section to the data set used by Nelson and Plosser and to the postwar quarterly real GNP series. The data set considered by Nelson and Plosser consists of fourteen major macroeconomic series sampled at an annual frequency. We omit the analysis of the unemployment rate series given that it is generally perceived as being stationary. The sample varies for each series with a starting date between 1869 and 1909. However, each series ends in 1970. Given that we entertain the hypothesis that only the 1929 Great Crash and the 1973 oil price shock caused a major change in trend function, each series in this data set contains only one break. It is therefore possible to apply the tests described in the previous section. Similarly, the quarterly postwar real GNP series contains a single break as the sample goes from 1947:I to 1986:III. Following Nelson and Plosser, we consider the logarithm of each series except for the interest rate for which we use the level.

Of the thirteen series in the Nelson-Plosser data set that we analyze, preliminary investigations showed that eleven were potentially well-characterized by a trend function with a constant slope but with a major change in their level occurring right after the year 1929. For these series, the maintained hypothesis is, therefore, that of Model (A) and given that the Great Crash did not occur instantaneously but lasted several years, we apply regression (12) to carry out our testing procedure. The two series that were not modeled as such are the "real wages" and "common stock price" series. For these series, it appeared that not only a change in the level occurred after 1929 but there was also an increase in the slope of the trend function after this date. For these reasons, the maintained hypothesis is that of Model (C), and we use regression (14) to implement our tests.

The postwar quarterly real GNP series offers yet a different picture. The 1973 oil price shock did not cause a significant drop in the level of the series. However, after that date, the slope of the trend function has sensibly decreased. This phenomenon is consistent with the much discussed slowdown in the growth rate of real GNP since the mid-seventies; see, for example, the recent symposium in the *Journal of Economic Perspectives* (1988). For these reasons, the maintained hypothesis is that of Model (B). Given the inherent difficulty in testing for a unit root allowing lagged effects for the change in the trend function, we apply regression (10) ($i = B$) to carry the testing procedure. Modeling the change in the trend function following the 1973 oil price shock as instantaneous, at least appears more plausible than the change that occurred during the Great Depression.

Table VII presents the corresponding estimated regressions for each series along with the t statistic on the parameters for the following respective hypotheses: $\mu = 0$, $\beta = 0$, $\theta = 0$, $\gamma = 0$, $d = 0$, and $\alpha = 1$. Recall that under the hypothesis of a unit root process $\mu \neq 0$ (in general), $\beta = 0$, $\theta = 0$ (except in regression Models (C)), $\gamma = 0$, $d \neq 0$, and $\alpha = 1$. Under the alternative hypothesis of stationary fluctuations around a deterministic breaking trend function: $\mu \neq 0$, $\theta \neq 0$, $\beta \neq 0$, $\gamma \neq 0$ (in general), $d = 0$, and $\alpha < 1$.

The value of k chosen is determined by a test on the significance of the estimated coefficients $\hat{c}_i$. We actually used a fairly liberal procedure choosing a value of k equal to say k^* if the t statistic on $\hat{c}_i$ was greater than 1.60 in absolute value and the t statistic on $\hat{c}_l$ for $l > k^*$ was less than 1.60 (with a maximum value for k of 8, except for the postwar quarterly real GNP series

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TABLE VII

TESTS FOR A UNIT ROOT

(a) Regression (12), Model A; $y_t = \hat{\mu} + \hat{\theta} DU_t + \hat{\beta} t + \hat{d} D(TB)_t + \hat{\alpha} y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t$

$T_B = 1929$	T	λ	k	$\hat{\mu}$	$t_{\hat{\mu}}$	$\hat{\theta}$	$t_{\hat{\theta}}$	$\hat{\beta}$	$t_{\hat{\beta}}$	$\hat{d}$	$t_{\hat{d}}$	$\hat{\alpha}$	$t_{\hat{\alpha}}$	$S(\hat{e})$
Real GNP	62	0.33	8	3.441	5.07	−0.189	−4.28	0.0267	5.05	−0.018	−0.30	0.282	−5.03[a]	0.0509
Nominal GNP	62	0.33	8	5.692	5.44	−0.360	−4.77	0.0359	5.44	0.100	1.09	0.471	−5.42[a]	0.0694
Real per capita GNP	62	0.33	7	3.325	4.11	−0.102	−2.76	0.0111	4.00	−0.070	−1.09	0.531	−4.09[b]	0.0555
Industrial production	111	0.63	8	0.120	4.37	−0.298	−4.58	0.0323	5.42	−0.095	−0.99	0.322	−5.47[a]	0.0875
Employment	81	0.49	7	3.402	4.54	−0.046	−2.65	0.0057	4.26	−0.025	−0.77	0.667	−4.51[a]	0.0295
GNP deflator	82	0.49	5	0.669	4.09	−0.098	−3.16	0.0070	4.01	0.026	0.53	0.776	−4.04[b]	0.0438
Consumer prices	111	0.63	2	0.065	1.12	−0.004	−0.21	0.0005	1.75	−0.036	−0.79	0.978	−1.28	0.0445
Wages	71	0.41	7	2.38	5.45	−0.190	−4.32	0.0197	5.37	0.085	1.36	0.619	−5.41[a]	0.0532
Money stock	82	0.49	6	0.301	4.72	−0.071	−2.59	0.0121	4.18	0.033	0.68	0.812	−4.29[b]	0.0440
Velocity	102	0.59	0	0.050	0.932	−0.005	−0.20	−0.0002	−0.35	−0.136	−2.01	0.941	−1.66	0.0663
Interest rate	71	0.41	2	−0.018	−0.088	−0.343	−2.06	0.0105	2.64	0.197	0.64	0.976	−0.45	0.2787

(b) Regression (14), Model C; $y_t = \hat{\mu} + \hat{\theta} DU_t + \hat{\beta} t + \hat{\gamma} DT_t + \hat{d} D(TB)_t + \hat{\alpha} y_{t-1} + \sum_{i=1}^{k} \hat{c}_i \Delta y_{t-i} + \hat{e}_t$

$T_B = 1929$	T	λ	k	$\hat{\mu}$	$t_{\hat{\mu}}$	$\hat{\theta}$	$t_{\hat{\theta}}$	$\hat{\beta}$	$t_{\hat{\beta}}$	$\hat{\gamma}$	$t_{\hat{\gamma}}$	$\hat{d}$	$t_{\hat{d}}$	$\hat{\alpha}$	$t_{\hat{\alpha}}$	$S(\hat{e})$
Common stock prices	100	0.59	1	0.353	4.09	−1.051	−4.29	0.0070	4.43	0.0139	3.98	0.128	0.76	0.718	−4.87[b]	0.1402
Real wages	71	0.41	8	2.115	4.33	−0.190	−3.71	0.0107	3.79	0.0066	3.33	0.031	0.78	0.298	−4.28[c]	0.0330

(c) Regression (10), Model B; $y_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\gamma} DT_t^* + \tilde{y}_t$; $\tilde{y}_t = \tilde{\alpha} \tilde{y}_{t-1} + \sum_{i=1}^{k} \tilde{c}_i \Delta \tilde{y}_{t-i} + \tilde{e}_t$

$T_B = 1973{:}1$	T	λ	k	$\tilde{\mu}$	$t_{\tilde{\mu}}$	$\tilde{\beta}$	$t_{\tilde{\beta}}$	$\tilde{\gamma}$	$t_{\tilde{\gamma}}$	$\tilde{\alpha}$	$t_{\tilde{\alpha}}$	$S(\tilde{e})$
Quarterly real GNP	159	0.66	10	6.977	1160.51	0.0087	97.73	−0.0031	−12.06	0.86	−3.98[c]	0.0097

NOTE: a, b, and c denote statistical significance at the 1%, 2.5%, and 5% level respectively.

where we used a maximum of 12). This liberal procedure is justified in the sense that including too many extra regressors of lagged first-differences does not affect the size of the test but only decreases its power. Including too few lags may have a substantial effect on the size of the test.

Consider first the series for which we applied Model (A). To evaluate the significance of the t statistic on $\hat{\alpha}$, we use the critical value presented in Table IV.B with a value of λ closest to the ratio of pre-break sample size to total sample size. Of the eleven series in that group, the unit root hypothesis cannot be rejected even at the 10 percent level for three of them: "consumer prices," "interest rate" and "velocity." However, we can reject the null hypothesis of a unit root at that 2.5 percent level or better for all other eight series. We can reject it at the 1 percent level for the following series: "real GNP," "nominal GNP," "industrial production," "employment," and "wages," and at the 2.5 percent level for the series "real per capita GNP," "GNP deflator," and "money stock." In some cases the coefficient $\hat{\alpha}$, which is an estimate of the sum of the autoregressive coefficients, is dramatically different from one. For example, it is 0.282 for "real GNP" and 0.322 for "industrial production."

Given that the unit root hypothesis can be rejected for the eight series mentioned above, we can assess the significance of the other coefficients using the fact that the asymptotic distribution of their t statistic is standardized normal. In all cases, the estimated coefficients on the constant ($\hat{\mu}$), the post-break dummy ($\hat{\theta}$), and the trend ($\hat{\beta}$) are significant at least at the 5 percent level. All series showed a trend function with a positive slope and a significant decrease in level just after 1929. For these eight series the coefficient on the break dummy ($\hat{d}$) is not significant. These results strongly suggest that, except for the "consumer price," "velocity," and "interest rate" series, the underlying process is one of stationary fluctuations around a deterministic trend function.

Consider now panel (b) of Table VII which presents the results for the "common stock price," and "real wages" series estimated under Model (C). We can reject the null hypothesis of a unit root at the 2.5 percent level for "common stock prices" and at the 5 percent level for the "real wages" series. In both cases, the constant ($\hat{\mu}$), the post-break constant dummy ($\hat{\theta}$), the trend ($\hat{\beta}$), and the post-break slope dummy ($\hat{\gamma}$) are highly significant, while the break dummy ($\hat{d}$) is not. The coefficients $\hat{\alpha}$ for the "real wages" series is very low at 0.298 while for the "common stock price" it is at 0.718 showing substantial mean reversion effects. This finding about the "common stock price" series is particularly striking given the vast amount of theoretical and empirical studies supporting the random walk hypothesis in this situation.

Finally, panel (c) of Table VII presents the results for the postwar quarterly real GNP series using regression (10) corresponding to Model (B). In this case, the null hypothesis that $\alpha = 1$ can be rejected at the 5 percent level with an estimated coefficient $\tilde{\alpha}$ equal to 0.86. This result is especially significant given the usual poor power properties of tests for a unit root against stationary alternatives when using a data set with a small span sampled frequently (see, e.g., Perron (1987) and Shiller and Perron (1985)). The other estimated coefficients in panel (c) confirm the relevance of the "trend stationary" model versus the "unit root" model. The coefficient on the post-break slope dummy coefficient ($\tilde{\gamma}$) is highly significant. The estimated regression is therefore consistent with an underlying process characterized by stationary fluctuations around a deterministic trend function with a decrease in the slope after 1973.[9]

Table A3 in Appendix B presents the estimated value for the sum of the autoregressive coefficient, α, and its t statistic for the null hypothesis $\alpha = 1$, for all values of the truncation lag parameter k between 1 and 12. In general, the results are quite robust to which value of k is selected.[10]

The results presented in this section are quite striking. The unit root hypothesis can be rejected for all but three series. To obtain these results, only a rather weak postulate needed to be imposed, namely the presence of a one-time change in the trend function. We claim that this is a weak postulate for the following reasons. As shown by Nelson and Plosser and Campbell and Mankiw, all the series analyzed have a unit root if the trend function is not allowed to change. This view implies that the 1929 crash is simply one big outlier in the innovation sequence. On the other hand, it also implies that the post-1973 growth slowdown is a succession of smaller innovations and that the mean of the innovations is different for the pre-1973 and the post-1973 period. These alternative interpretations are, we think, less appealing than the hypothesis of a break in the trend function, especially given that we allow such a break under both the null and alternative hypotheses.

Given that the "consumer price," "velocity," and "interest rate" series appear to be characterized by the presence of a unit root, it seems worthwhile to see if this feature is stable in the pre and post 1929 samples. The subsample Dickey-Fuller type regressions are presented in Appendix B for values of k between 1 and 12. Consider first the "consumer price index." With $k = 2$, the estimated value of the sum of the autoregressive coefficients, $\tilde{\alpha}$ is 0.965 for the pre-1929 sample with a t statistic of -1.28. We therefore cannot reject the null hypothesis of a unit root for this subperiod. However, for the post-1929 sample, the picture is rather different; when $k = 7$, $\tilde{\alpha}$ has a value of 0.704 with a t statistic of -4.56 significant at the 1 percent level. The nonrejection of the unit root hypothesis using the full sample is due to the pre-1929 sample. After 1929, the unit root is no longer present.

The case for the "velocity" series has a special feature. It has been well documented that the U.S. velocity series declined steadily until 1946, remained at a fairly constant level until 1970, before increasing (see, for example, Poole (1988) and Gould and Nelson (1974)). For this reason, we discuss applications of the standard Dickey-Fuller procedure for the following three samples: 1869–1929, 1930–1945, 1946–1970. We cannot reject the unit root hypothesis with the pre-1929 sample even though $\tilde{\alpha}$ is only 0.865 ($k = 0$). However, the picture is

[9] Basically, the same estimates of the sum of the autoregressive coefficient α and its t statistic were obtained using regressions (13) and (14), for all values of k, showing some robustness for the results presented. We also applied Phillips' nonparametric procedure to the detrended series (equations (6) and (7), $i = B$). These test statistics did not allow the rejection of the null hypothesis of a unit root.

[10] One notable exception is the quarterly real GNP series where the t statistic is significant at the 5 percent level with $k = 2$ or $k = 10$. It is significant at the 2.5 percent level with $k = 11$, with a value of -4.32. We choose to report the result of $k = 10$ because the 10th lagged first-difference was highly significant (t statistic of 2.29) while the 11th and 12th lags were not.

dramatically different using post-1929 samples. For the period 1930–1945, with $k=1$, $\tilde{\alpha}$ is estimated at -0.011 with a t statistic (for testing $\alpha=1$) of -3.44 which is significant at the 5 percent level. Though this result should be taken with caution due to the small number of observations, it is suggestive of a quite different behavior. The period 1946–1970 affords a modest amount of additional information and yields still more dramatic results: with $k=4$, $\tilde{\alpha}$ is equal to 0.00 with a t statistic (for $\alpha=1$) of -5.86, significant at the 1 percent level using the Dickey-Fuller critical values. It therefore appears that the "velocity" and "consumer price" series yield similar results: the presence of a unit root before 1929 but not after.

The results for the interest rate series indicate that, in this case, the unit root hypothesis cannot be rejected at usual significance levels for both subsamples (even though α is estimated at 0.540 ($k=3$) with the pre-1929 sample). Indeed, given our previous results, we can conclude that only the "interest rate" series is characterized by the presence of a unit root after 1929. All the other series are better construed as stationary fluctuations around a deterministic trend function for this period.

6. DISCUSSION AND CONCLUDING COMMENTS

When testing for the presence of a unit root in a time series of data against the hypothesis of stationary fluctuations around a deterministic trend function, the use of a long span of data has definite advantages. It allows tests with larger power compared to using a smaller span, in most cases even if the latter allows more observations (see Shiller and Perron (1985) and Perron (1987)). The drawback, however, is that a data set with a large span has more chance to include a major event which one would rather consider as an outlier or as exogenous given its relative importance. The arguments in this paper rest on the postulate that two such events have occurred in the 20th century: the 1929 Great Crash and the slowdown in growth after the oil shock of 1973. We therefore considered, as a relevant alternative, a trend function with a change in the intercept in 1929 and a change in the slope after 1973.

Let us discuss, in more detail, what are the relevant issues in drawing particular conclusions about the nature of economic fluctuations from our results. It is particularly important to put our results into perspective and also highlight what has not been shown.

The first important issue to point out is that we have not provided a formal unconditional statistical model of the time series properties of the various aggregates. A rejection of the null hypothesis of a unit root conditional on the possibility of shifts in the underlying trend function at known dates does not imply that the various series can be modeled as stationary fluctuations around a completely deterministic breaking trend function. As a matter of general principle, a rejection of the null hypothesis does not imply acceptance of a particular alternative hypothesis. However, since the tests were designed to have power against a specific class of alternative hypotheses, it is useful to look among close members of that class to propose an interesting statistical model for the various aggregates. Only with such a model is it possible to provide forecasts with appropriate standard errors.

We certainly do not entertain the view that the trend function including its changes are deterministic. This would imply that one would be able to forecast with certainty future changes. This is indeed quite unappealing. What we have in mind in specifying our class of maintained hypotheses can be parameterized as follows:

$$y_t = \eta_t + Z_t, \qquad \eta_t = \mu_t + \beta_t t, \tag{16}$$

where $A(L)Z_t = B(L)e_t$; $e_t \sim$ i.i.d.$(0, \sigma^2)$; $\mu_t = \mu_{t-1} + V(L)v_t$, and $\beta_t = \beta_{t-1} + W(L)w_t$. Here, the Z_t's are (not necessarily stationary) deviations from the trend function η_t. The intercept and the slope of the trend functions, μ_t and β_t, are themselves random variables modeled as integrated processes with $W(L)$, $V(L)$ stationary and invertible polynomials. However, the important distinction is that the timing of the occurrence of the shocks v_t and w_t are rare relative to the sequence of innovations $\{e_t\}$, for example, poisson processes with arrival rates specified such that their occurrences are rare relative to the frequency of the realizations in the sequence $\{e_t\}$. The intuitive idea behind this type of modeling is that the coefficients of the trend function are determined by long-term economic fundamentals (e.g., the structure of the economic organization, population growth, etc.) and that these fundamentals are rarely changed. In our examples, v_t is nonzero in 1929 (the great depression) and w_t is nonzero in 1973 (the oil price shock).

In this sense, our exogeneity assumption about the changes in the trend function is a device that allows taking these shocks out of the noise function into the trend function without specific modeling of the stochastic nature of the behavior of μ_t and β_t. It is in this sense that our approach does not provide an unconditional representation of the time series properties of the various variables.

Estimation of models of the form (16) by specifying a probability distribution for the error sequences $\{e_t, w_t, v_t\}$ is clearly an important avenue of future research. Interesting recent advances on this topic have been provided by Hamilton (1987) and Lam (1988) where the slope of the trend function is allowed to take two different values and the changes are modeled as a binomial process. However, no methods are currently available to test whether Z_t is integrated or not in this framework.[11] Problems in estimation of models of the form (16) are further compounded by the fact that, according to our view, only one nonzero realization of both v_t and w_t would be present in the data set typically available for the series of interest.

In the above framework, the purpose of this paper is to test whether Z_t is an integrated process or not, i.e. to test whether the shocks $\{e_t\}$ have persistent effects that do not vanish over a long horizon. Our approach is to remove from the noise function two events that occurred at two dates where we believe positive occurrences of the shocks $\{v_t, w_t\}$ happened and to model them as part

[11] Both authors studied the behavior of the postwar quarterly real GNP with possible shifts in the slope of the trend function. Hamilton (1987) imposes Z_t to be an integrated process while Lam (1988) leaves Z_t unconstrained.

of the trend function. The fact that we model these changes as exogenous implies that our results are conditional. That is, conditional upon the presence of a change in the trend function in 1929 and 1973, the fluctuations are transitory (i.e., Z_t is stationary).

An important direction for future research is to make this conditional result into an unconditional statement. This could, in principle, be achieved by a direct test for structural change in the trend function. In a sense, our procedure allows such a test, but conditional on a change occurring at a fixed known date. Hence, problems of pre-testing and "data mining" could be raised regarding the role of looking, ex-post, at the data on the choice of the date.[12] Accordingly, what is needed is a test for structural changes in the trend function occurring at unknown dates. The problem, however, is that care must be applied to ensure that the test has an adequate size under both the unit root and trend-stationary hypotheses. No such test is currently available in the literature. We hope to report, in the near future, developments in this area and applications in this context.

However, an important issue of observational equivalence could not even be settled by such a formal test for structural change. Consider, for instance, the following limiting case in the crash model.[13] A trend-stationary model with a break and where the errors have zero variance is observationally equivalent to a unit root model with drift where the errors have a high probability of being zero but are occasionally nonzero and finite. In general, when the variance of the errors is nonzero, the two models will be nearly observationally equivalent with the disturbances in the unit root model having fat tails. We are able to make a distinction in our empirical result through the mixing conditions (see Assumptions 1 and 2) which prohibit fat tailed disturbances. Any formal test for structural change would, presumably, also have to impose some mixing condition prohibiting fat-tailed disturbances, thereby not resolving this issue of near-observational equivalence.

In fact, any test for the presence of a unit root against trend-stationary alternatives is subject to another type of observational equivalence, as recently argued by Cochrane (1987) and Blough (1988). Indeed, in finite samples, any trend-stationary process is nearly observationally equivalent to a unit root process with a strong mean-reversion component, i.e. where the errors have a moving-average component with a root near minus one.[14] The fact that we reject the unit root hypothesis excluding the event of 1929 suggests that if there is a unit root at all the correlation structure of the innovation sequence must exhibit substantial mean reversion.

[12] See, for example, Christiano (1988).

[13] This issue and its following illustration were raised by a referee.

[14] This observational equivalence problem only disappears asymptotically. In other words, in finite samples, any test for a unit root with ARMA errors should have zero power. Formally, the critical values should be determined such that the test has a given fixed size over all possible values of the nuisance parameters (here, the additional correlation in the errors). Given the near observational equivalence, any such test would have zero power by definition. The unit root tests can be rationalized by arguing that we are willing to have the wrong size over some of the parameter space exactly because for all practical purposes it does not matter whether we label a series as trend stationary or difference stationary with a strong mean-reversion component.

To sum up: trend stationary processes with a break are nearly observationally equivalent to unit root processes with strong mean-reversion and a fat-tailed distribution for the error sequence. Whichever view one adopts cannot be decided by data alone. Nevertheless, the picture under any of these views is basically the same: shocks had little, if any, persistence effect over a long horizon. Only those associated with the Great Depression and the oil price shock significantly altered the long run behavior of the series.

While choosing one view over the other is a matter of convenience for interpreting the data, it has profound implications for a multitude of statistical procedures. Indeed, under the unit root view one must ensure the validity of the procedures under fat-tailed disturbances, and at the moment very few are appropriate in a time series context. Hence for all practical purposes, it may be more advantageous to adopt the trend-stationary view with breaks and detrend our series accordingly prior to analyzing the remaining noise.

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APPENDIX A

The conditions imposed by Assumption 1 permit us to use a functional weak convergence result due to Herrndorf (1984). Let $S_t = \Sigma_{j=1}^{t} e_j (S_0 = 0)$ and define the following variable lying in the space $D[0,1]$:

$$X_T(r) = \sigma^{-1}T^{-1/2}S_{[Tr]} = \sigma^{-1}T^{-1/2}S_{j-1}, \quad (j-1)/T \leqslant r < j/T \qquad (j = 1, \dots, T)$$

$$X_T(1) = \sigma^{-1}T^{-1/2}S_T.$$

Herrndorf's theorem states that under the conditions of Assumption 1, $X_T(r) \Rightarrow w(r)$ where $\Rightarrow$ denotes weak convergence to the associated probability measure and $w(r)$ is the unit Wiener process defined on $C[0,1]$, the space of all continuous functions on the interval $[0,1]$. Following Phillips (1987) and Phillips and Perron (1988), it is easy to derive the following lemma related to functions of S_t. These results will be used in proving both Theorems 1 and 2.

LEMMA A.1: *Let $S_t = \Sigma_{j=1}^{t} e_j (S_0 = 0)$ and assume that the innovation sequence $\{e_t\}$ satisfies the conditions of Assumption* 1. *Furthermore, let $T_B = \lambda T$ for all T; then as $T \to \infty$:*

(a) $$T^{-3/2}\sum_1^{T_B} S_j \Rightarrow \sigma\int_0^{\lambda} w(r)\,dr;$$

(b) $$T^{-2}\sum_1^{T_B} S_j^2 \Rightarrow \sigma^2\int_0^{\lambda} w(r)^2\,dr;$$

(c) $$T^{-5/2}\sum_1^{T_B} jS_j \Rightarrow \sigma\int_0^{\lambda} rw(r)\,dr;$$

(d) $$T^{-3/2}\sum_1^{T_B} je_j \Rightarrow \sigma\left(\lambda w(\lambda) - \int_0^{\lambda} w(r)\,dr\right);$$

(e) $$T^{-1}\sum_1^{T} S_{j-1}e_j \Rightarrow (\sigma^2/2)\left(w(1)^2 - \sigma_e^2/\sigma^2\right).$$

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The results in (a) through (d) are simple extensions of those in Phillips (1987) and Phillips and Perron (1988); part (e) is proved in Phillips (1987). The previous results can be recovered by simply letting $\lambda = 1$ in which case $T_B = T$. For example, to prove part (a):

$$T^{-3/2}\sum_1^{T_B} S_j = \sigma \sum_1^{T_B} \int_{i-1/T}^{i/T} T^{-1/2}\sigma^{-1} S_{[Tr]}\,dr = \sigma\int_0^{\lambda} X_T(r)\,dr \Rightarrow \sigma\int_0^{\lambda} w(r)\,dr$$

using Herrndorf's weak convergence result and the continuous mapping theorem (see, e.g., Billingsley (1968)). The proofs of (b), (c), and (d) are entirely analogous.

PROOF OF THEOREM 1: We consider first the most general model (C) in which both β (the slope) and μ (the intercept) are allowed to change, i.e.:

$$\text{(A.1)} \qquad \begin{aligned} y_t &= \mu_1 + \beta_1 t + e_t && (0 \leqslant t \leqslant T_B). \\ y_t &= \mu_2 + (\beta_2 - \beta_1) T_B + \beta_2 t + e_t && (T_B < t \leqslant T). \end{aligned}$$

The following lemma provides a convenient representation of the sample moments of $\{y_t\}$.

LEMMA A.2: *Assume that $\{y_t\}_0^T$ is generated according to (A.1) with the innovation sequence $\{e_t\}$ satisfying Assumption 1; then,*

(a)
$$\begin{aligned}\sum_1^T t y_{t-1} = {} & (1/6)\left[\beta_1(3\lambda - \lambda^3) + \beta_2(2 - 3\lambda + \lambda^3)\right]T^3 \\ & + \left(\tfrac{1}{2}\right)\left[\mu_1\lambda^2 + \mu_2(1-\lambda^2) + \lambda(1-\lambda)(\beta_1 - \beta_2)\right]T^2 \\ & + \left[(3/2)\mu_1\lambda + (3/2)(1-\lambda)\mu_2 - \mu_2 - (1/3)\beta_1\lambda - (1/3)\beta_2(1-\lambda)\right]T \\ & + \left[T^{-3/2}\sum_1^T t e_{t-1}\right]T^{3/2} + o_p(T),\end{aligned}$$

(b)
$$\begin{aligned}\sum_1^T y_{t-1} = {} & \left(\tfrac{1}{2}\right)\left[\beta_1(\lambda^2 - 2\lambda) + \beta_2(1 + 2\lambda - 3\lambda^2)\right]T^2 \\ & + \left[\lambda\mu_1 + (1-\lambda)\mu_2 + (3/2)\beta_1\lambda - \left(\tfrac{1}{2}\right)\beta_2(1+3\lambda)\right]T \\ & + \left[T^{-1/2}\sum_1^T e_{t-1}\right]T^{1/2} - (\mu_2 - \mu_1),\end{aligned}$$

(c)
$$\begin{aligned}\sum_1^T y_{t-1}^2 = {} & (1/3)\left[\beta_1^2\lambda^2(3 - 2\lambda) + \beta_2^2(1-\lambda)^3 + 3\beta_1\beta_2\lambda(1-\lambda)^2\right]T^3 \\ & + \left[\mu_1\beta_1\lambda^2 + \mu_2\beta_2(1-\lambda^2) - \left(\tfrac{1}{2}\right)\left(\beta_1\lambda + \beta_2(1-\lambda)^2\right)\right]T^2 \\ & + 2\left[\lambda(\beta_1 - \beta_2)T^{-1/2}\sum_{T_B+1}^T e_t + \beta_1 T^{-3/2}\sum_1^{T_B} t e_t - \beta_2 T^{-3/2}\sum_{T_B+1}^T t e_t\right]T^{3/2} \\ & + \Bigg[\lambda\mu_1^2 + (1/6)\beta_1^2\lambda^2 + \mu_1\beta_1\lambda + (1-\lambda)\mu_2^2 + (1/6)\beta_2^2(1-\lambda) \\ & \qquad + \mu_2\beta_2(1-\lambda) - 2\mu_2\beta_2 + T^{-1}\sum_1^T e_{t-1}^2\Bigg]T + o_p(T),\end{aligned}$$

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(d)
$$\sum_1^T y_t y_{t-1} = (1/3)\left[\beta_1^2\lambda^2(3-2\lambda)+\beta_2^2(1-\lambda)^3+3\beta_1\beta_2\lambda(1-\lambda)^2\right]T^3$$
$$+\left[\mu_1\beta_1\lambda^2+\mu_2\beta_2(1-\lambda^2)\right]T^2$$
$$+2\left[\beta_1 T^{-3/2}\sum_1^{T_B} te_{t-1}+\beta_2 T^{-3/2}\sum_{T_B+1}^{T} te_{t-1}+\lambda(\beta_1-\beta_2)T^{-1/2}\sum_{T_B+1}^{T} e_t\right]T^{3/2}$$
$$+\left[\mu_1^2\lambda+\mu_2^2(1-\lambda)-(1/3)(\lambda\beta_1^2+(1-\lambda)\beta_2^2)\right.$$
$$\left.+\lambda(\beta_2^2-\beta_1\beta_2)+\lambda\beta_1(\mu_2+\mu_1)-2\lambda\mu_2\beta_2\right]T+o_p(T).$$

It is straightforward but tedious to show that $\tilde{\alpha}$ is given by $\tilde{\alpha}=A/D$ where

(A.2)
$$A=(T^2/2+T/2)\sum ty_{t-1}\sum y_t$$
$$-(T^3/3+T^2/2+T/6)\sum y_{t-1}\sum y_t-T\sum ty_{t-1}\sum ty_t$$
$$+(T^2/2+T/2)\sum y_{t-1}\sum ty_t+(T^4/12-T^2/12)\sum y_t y_{t-1}$$

and

(A.3)
$$D=(T^4/12-T^2/12)\sum y_{t-1}^2-T\left(\sum ty_{t-1}\right)^2$$
$$+(T^2+T)\sum ty_{t-1}\sum y_{t-1}-(T^3/3+T^2/2+T/6)\left(\sum y_{t-1}\right)^2$$

where all summations run from 1 to T. To prove part (b) we derive the limits of $T^{-7}A$ and $T^{-7}D$ using Lemma A.2:

$$T^{-7}D=(1/12)T^{-3}\sum y_{t-1}^2-T^{-6}\left(\sum ty_{t-1}\right)^2$$
$$+T^{-3}\sum ty_{t-1}\cdot T^{-2}\sum y_{t-1}-(1/3)T^{-4}\left(\sum y_{t-1}\right)^2+o_p(1)$$
$$=(1/36)\left[\beta_1^2\lambda^3+\beta_2^2(1-3\lambda+2\lambda^3)+3\beta_2\beta_1\lambda(1-\lambda^2)\right]$$
$$-(1/36)\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]^2$$
$$+(1/12)\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]$$
$$-(1/12)\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]^2+o_p(1).$$

Simple algebra yields:

(A.4)
$$T^{-7}D\to(1/36)(-3\lambda^2+4\lambda^3-3\lambda^4+3\lambda^5-\lambda^6)(\beta_1-\beta_2)^2.$$

Similarly,

$$T^{-7}A=T^{-3}\sum ty_{t-1}\cdot T^{-2}\sum y_{t-1}-(1/3)T^{-4}\left(\sum y_{t-1}\right)^2-T^{-6}\left(\sum ty_{t-1}\right)^2$$
$$+(1/12)T^{-3}\sum y_t y_{t-1}+o_p(1)$$
$$=(1/12)\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]\cdot\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]$$
$$-(1/12)\left[\beta_1\lambda(2-\lambda)+\beta_2(1-\lambda)^2\right]^2$$
$$-(1/36)\left[\beta_1\lambda(3-\lambda^2)+\beta_2(2-3\lambda+\lambda^3)\right]^2$$
$$+(1/36)\left[\beta_1^2\lambda^3+\beta_2^2(1-3\lambda+2\lambda^3)+3\beta_2\beta_1\lambda(1-\lambda^2)\right]+o_p(1)$$

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and

$$T^{-7}A \to (1/36)(-3\lambda^2 + 4\lambda^3 - 3\lambda^4 + 3\lambda^5 - \lambda^6)(\beta_1 - \beta_2)^2.$$

Therefore, $\tilde{\alpha} = T^{-7}A/T^{-7}D \to 1$ proving part (b, i). To prove part (b, ii), note that $T(\tilde{\alpha} - 1) = T^{-6}(A - D)/T^{-7}D$. Simple manipulation yields:

$$\begin{aligned} T^{-6}(A-D) &= (1/12)T^{-2}\sum y_t y_{t-1} - (1/12)T^{-2}\sum y_{t-1}^2 + T^{-5}\sum t y_{t-1}\sum y_{t-1} \\ &\quad + (1/6)T^{-3}y_T\sum y_{t-1} - (\tfrac{1}{2})T^{-4}y_T\sum t y_{t-1} - (1/12)T^{-4}\left(\sum y_{t-1}\right)^2 \\ &\quad + o_p(1) \\ &= (1/24)\left[\beta_1^2\lambda^2 + \beta_2^2(1-\lambda)^2 + 2\beta_1\beta_2\lambda(1-\lambda)\right] \\ &\quad + (1/12)\left[\beta_1\lambda(3-\lambda^2) + \beta_2(2 - 3\lambda + \lambda^3)\right]\left[\beta_1\lambda(2-\lambda) + \beta_2(1-\lambda)^2\right] \\ &\quad + (1/12)[(\beta_1 - \beta_2)\lambda + \beta_2]\cdot\left[\beta_1\lambda(2-\lambda) + \beta_2(1-\lambda)^2\right] \\ &\quad - (1/12)[(\beta_1-\beta_2)\lambda + \beta_2]\left[\beta_1\lambda(3-\lambda^2) + \beta_2(2-3\lambda+\lambda^3)\right] \\ &\quad - (1/12)\left[\beta_1\lambda(2-\lambda) + \beta_2(1-\lambda)^2\right]^2 + o_p(1) \end{aligned}$$

and

$$T^{-6}(A-D) \to (1/24)(\beta_1 - \beta_2)^2[-\lambda^2 + 4\lambda^3 - 5\lambda^4 + 2\lambda^5].$$

Therefore,

$$T(\tilde{\alpha} - 1) \to (3/2)[-1 + 4\lambda - 5\lambda^2 + 2\lambda^3]\cdot[-3 + 4\lambda - 3\lambda^2 + 3\lambda^3 - \lambda^4]^{-1}$$

proving part (b, ii).

PROOF OF PART (a): The proof of part (a) is straightforward but tedious. The following arguments present the main steps. First, the expressions for the moments of $\{y_t\}$ in Lemma A.2 can be written as follows:

$$\begin{aligned} &\sum_1^T t y_{t-1} = a_1T^3 + b_1T^2 + c_1T^{3/2} + d_1T + o_p(T), \\ &\sum_1^T y_{t-1} = a_2T^2 + b_2T + c_2T^{1/2} + d_2, \\ &\sum_1^T y_{t-1}^2 = a_3T^3 + b_3T^2 + c_3T^{3/2} + d_3T + o_p(T), \\ &\sum_1^T y_t y_{t-1} = a_4T^3 + b_4T^2 + c_4T^{3/2} + d_4T + o_p(T). \end{aligned}$$

The coefficients a_i, b_i, c_i and d_i $(i = 1, \ldots, 4)$ are given by the corresponding expressions in Lemma A.2 where the condition $\beta_1 = \beta_2 = \beta$ is imposed. From (A.3), the denominator of $\hat{\alpha}$ is given by:

$$\begin{aligned} T^{-5}D &= \left[a_3/12 - a_1^2 + a_1a_2 - a_2^2/3\right]T^2 \\ &\quad + \left[b_3/12 - 2a_1b_1 + a_1b_2 + b_1a_2 + a_1a_2 - (2/3)a_2b_2 - a_2^2/2\right]T \\ &\quad + \left[c_3/12 - 2a_1c_1 + a_1c_2 + c_1a_2 - (2/3)a_2c_2\right]T^{1/2} \\ &\quad + \left[d_3/12 - a_3/12 - b_1^2 - 2a_1d_1 + a_1d_2 + b_1b_2\right. \\ &\qquad \left. + d_1a_2 + a_1b_2 + b_1a_2 - b_2^2/3 - (2/3)a_2d_2 - a_2b_2 - a_2^2/6\right] + o_p(1). \end{aligned}$$

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Now, tedious algebra shows that the $0(T^2)$, $0(T)$, and $0(T^{1/2})$ coefficients all cancel out and the sum of the $0(1)$ coefficients yields the following result:

$$T^{-5}D \to (1/12)\sigma_e^2 + (1/12)[\mu_1 - \mu_2]^2[\lambda - 4\lambda^2 + 6\lambda^3 - 3\lambda^4].$$

To analyze the limit of $T^{-5}A$, the numerator of $\tilde{\alpha}$, we need the expansions for Σy_t and Σty_t. These are given by:

$$\sum_1^T ty_t = a_1T^3 + (b_1 + \beta/2)T^2 + c_1T^{3/2} + (1/3)(d_1 + (5/6)\beta + \mu_2)T + o_p(T),$$

$$\sum_1^T y_t = a_2T^2 + (b_2 + \beta)T + c_2T^{1/2} + d_2.$$

Then we can write, using (A.2):

$$\begin{aligned}T^{-5}A = {}&\left[a_1a_2 - a_2^2/3 - a_1^2 + a_4/12\right]T^2\\ &+\left[a_1a_2 + (b_2+\beta)(a_1/2 - a_2/3) + (b_1 + \beta/2)(a_2/2 - a_1) - a_2^2/2 + b_4/12\right.\\ &\qquad\left. + a_1b_2/2 - a_1b_1 - a_2b_2/3 + b_1a_2/2\right]T\\ &+\left[a_1c_2 + c_1a_2 - (2/3)a_2c_2 - 2a_1c_1 + c_4/12\right]T^{1/2}\\ &+\left[(b_2+\beta)(b_1/2 + a_1/2 - b_2/3 - a_2/2)\right.\\ &+ (1/3)(d_1 + (5/6)\beta + \mu_2)(a_2/2 - a_1)\\ &+ (b_1 + \beta/2)(b_2/2 + a_2/2 - b_1) + d_1a_2/2 + b_1a_2/2 - a_2d_2/3 - a_2b_2/2\\ &\left. - a_2^2/6 - d_1a_1 + a_1d_2/2 + d_4/12 + a_4/12\right].\end{aligned}$$

Again, tedious algebra shows that the $0(T^2)$, $0(T)$, and $0(T^{1/2})$ terms all cancel out and that the sum of the coefficients remaining yields the following result:

$$T^{-5}A \to (1/12)\gamma_1 + (1/12)[\mu_1 - \mu_2]^2[\lambda - 4\lambda^2 + 6\lambda^3 - 3\lambda^4].$$

This proves part (a).

PROOF OF THEOREM 2: We first note some invariance properties of the estimators $\tilde{\alpha}^i$ ($i = A, B, C$): $\tilde{\alpha}^A$ is invariant with respect to μ and d; $\tilde{\alpha}^B$ is invariant to μ_1 and μ_2; and $\tilde{\alpha}^C$ is invariant to d, μ_1 and μ_2. Hence, without loss of generality, we can study the limiting distribution of $T(\tilde{\alpha}^i - 1)$ and $t_{\tilde{\alpha}^i}$ under the null hypothesis that the sequence $\{y_t\}$ is generated according to:

$$\text{(A.5)} \qquad y_t = y_{t-1} + e_t \qquad (t = 1,\ldots,T)$$

with the innovation sequence satisfying Assumption 1. It is also straightforward to show that under (A.5), $\tilde{\alpha}^i$ ($i = A, B, C$) are asymptotically equivalent to the least-squares estimators $\hat{\alpha}^i$ ($i = A, B, C$) in the following regressions:

$$\text{(A.6)} \qquad y_t = \hat{\mu}^A + \hat{\theta}^A DU_t + \hat{\beta}^A t + \hat{\alpha}^A y_{t-1} + \hat{e}_t^A,$$

$$\text{(A.7)} \qquad y_t = \hat{\mu}^B + \hat{\beta}^B t + \hat{\gamma}^B DT_t^* + \hat{\alpha}^B y_{t-1} + \hat{e}_t^B,$$

$$\text{(A.8)} \qquad y_t = \hat{\mu}^C + \hat{\theta}^C DU_t + \hat{\beta}^C t + \hat{\gamma}^C DT_t + \hat{\alpha}^C y_{t-1} + \hat{e}_t^C,$$

where $DU_t = 1$ and $DT_t = DT_t^* = 0$ if $t \leq T_B$ and $DU_t = 0$, $DT_t^* = t - T_B$, $DT_t = t$ if $t > T_B$. Since we are also concerned with regressions of the type (A.6)–(A.8) later in the text, we shall derive the limiting distributions concerning $\tilde{\alpha}^i$ ($i = A, B, C$) using the representation of $\hat{\alpha}^i$ ($i = A, B, C$). Note, however, that $\hat{\alpha}^A$ in (A.6) and $\hat{\alpha}^C$ in (A.9) are not invariant to the value of the parameter d under the null hypothesis. To achieve invariance, one must introduce a dummy variable $D(TB)$, taking value 1 at $t = T_B + 1$ and 0 elsewhere, as is done in regressions (12) and (14). Under the null hypothesis, $\hat{\alpha}^B$ is not invariant to a drift taking two distinct values: μ_1 and μ_2. To achieve invariance, the variable DU_t must be introduced in (A.7). However, this affects the limiting distribution of $\hat{\alpha}^B$ which becomes equivalent to that of $\hat{\alpha}^C$. Hence, one cannot analyze directly the case of a joint segmented trend function in a one-step type regression. We now turn to the proof of the theorem deriving the limiting distribution of $T(\hat{\alpha}^i - 1)$ and $t_{\hat{\alpha}^i}$ ($i = A, B, C$) in (A.6) through (A.8).

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The following Lemma provides weak convergence results for the sample moments of the data and will be used extensively. Its proof is a simple extension of Lemma A.1 and follows the methods of Phillips (1987) and Phillips and Perron (1988).

LEMMA A.3: *Let $\{y_t\}_0^T$ be a stochastic process generated according to (A.5) with the innovation sequence satisfying Assumption 1. Furthermore, let $T_B = \lambda T$; then as $T \to \infty$:*

(a) $$T^{-3/2}\sum_1^{T_B} y_t \Rightarrow \sigma\int_0^\lambda w(r)\,dr,$$

(b) $$T^{-5/2}\sum_1^{T_B} ty_t \Rightarrow \sigma\int_0^\lambda rw(r)\,dr,$$

(c) $$T^{-2}\sum_1^{T_B} y_t^2 \Rightarrow \sigma^2\int_0^\lambda w(r)^2\,dr,$$

(d) $$T^{-1}\sum_1^{T} y_{t-1}e_t \Rightarrow (\sigma^2/2)\left(w(1)^2 - \sigma_e^2/\sigma^2\right).$$

Parts (a), (b), and (c) are simple generalizations of results in Phillips (1987) and Phillips and Perron (1988) where $T_B = T$ and hence $\lambda = 1$; part (d) is proved in Phillips (1987).

Using the property that a regression of the form $y = X_1\hat{\beta}_1 + X_2\hat{\beta}_2 + \hat{e}$ yields a numerically identical estimator $\hat{\beta}_2$ as obtained in a regression of the form $y^* = X_2^*\hat{\beta}_2 + \hat{e}$ where y^* and X_2^* are projections of y and X_2, respectively, on the space spanned by the vectors in X_1, (A.6), (A.7), and (A.8), can be written as:

(A.9) $$Y_{it} = \hat{\beta}^i X_{1it} + \hat{\psi}_i X_{2it} + \hat{\alpha}^i y^*_{it-1} + \hat{e}_{it} \qquad (t = 1,\ldots,T;\ i = A, B, C),$$

where

$$\hat{\psi}_A = \hat{\theta}^A;\quad \hat{\psi}_B = \hat{\gamma}^B;\quad \hat{\psi}_C = \hat{\gamma}^C,$$
$$Y_{At} = Y_{Bt} = y_t - \overline{Y},$$
$$y^*_{At-1} = y^*_{Bt-1} = y_{t-1} - \overline{Y}_{-1},$$
$$X_{1At} = X_{1Bt} = t - \bar{t},$$
$$X_{1Ct} = t - c_1 \text{ if } t \leq T_B \text{ and } = t - c_2 \text{ otherwise},$$
$$X_{2At} = DU_t - \lambda,$$
$$X_{2Bt} = -\bar{t}^* \text{ if } t \leq T_B \text{ and } = t - T_B - \bar{t}^* \text{ otherwise},$$
$$X_{2Ct} = t - c_1 \text{ if } t \leq T_B \text{ and } = 0 \text{ otherwise},$$
$$Y_{Ct} = y_t - A \text{ if } t \leq T_B \text{ and } = y_t - B \text{ otherwise},$$
$$y^*_{Ct-1} = y_{t-1} - A' \text{ if } t \leq T_B \text{ and } = y_{t-1} - B' \text{ otherwise},$$

and

$$\bar{t} = T^{-1}\sum_1^T t = (T+1)/2,\quad \bar{t}^* = T^{-1}\sum_1^{T-T_B} t = T(1-\lambda)^2/2 + (1-\lambda)/2,$$
$$c_1 = \bar{t} - T(1-\lambda)/2,\quad c_2 = \bar{t} + T\lambda/2,$$
$$A = \overline{Y} + \lambda^{-1}T^{-1}\sum_1^{T_B}(y_t - \overline{Y}),\quad B = \overline{Y} - (1-\lambda)^{-1}T^{-1}\sum_1^{T_B}(y_t - \overline{Y}),$$
$$A' = \overline{Y}_{-1} + \lambda^{-1}T^{-1}\sum_1^{T_B}(y_{t-1} - \overline{Y}_{-1}),\quad B' = \overline{Y}_{-1} - (1-\lambda)^{-1}T^{-1}\sum_1^{T_B}(y_{t-1} - \overline{Y}_{-1}),$$
$$\overline{Y} = T^{-1}\sum_1^T y_t,\quad \overline{Y}_{-1} = T^{-1}\sum_1^T y_{t-1}.$$

Now, let $Y_i' = (y_{i,0}^*, \ldots, y_{i,T-1}^*)$, $E' = (e_1, \ldots, e_T)$, $Z_i' = [X_{1i}, X_{2i}]$, $X_{1i} = (X_{1i,1}, \ldots, X_{1i,T})$, $X_{2i} = (X_{2i,1}, \ldots, X_{2i,T})$; then, under the null hypothesis,

(A.10) $$\hat{\alpha}^i - 1 = (Y_i'Y_i)^{-1}Y_i'E - (Y_i'Y_i)^{-1}Y_i'Z_i\left[Z_i'(I - P_{Y_i})Z_i\right]^{-1}Z_i'\left[I - P_{Y_i}\right]E$$

where $P_{Y_i} = Y_i(Y_i'Y_i)^{-1}Y_i'$. Furthermore, define the following terms:

$$Z_i'Z_i = \begin{bmatrix} a_i & b_i \\ b_i & c_i \end{bmatrix}, \quad Z_i'Y_i = \begin{bmatrix} H_i \\ J_i \end{bmatrix}, \quad Z_i'E = \begin{bmatrix} K_i \\ L_i \end{bmatrix}.$$

Straightforward manipulation yields the following representation for $\hat{\alpha}^i - 1$:

(A.11) $$\begin{aligned} \hat{\alpha}^i - 1 &= \left[\left(a_ic_i - b_i^2\right)Y_i'E - c_iH_iK_i + b_iJ_iK_i - a_iJ_iL_i + b_iH_iL_i\right] / \\ &\quad \left[\left(a_ic_i - b_i^2\right)Y_i'Y_i - a_iJ_i^2 - c_iH_i^2 + 2b_iH_iJ_i\right] \\ &\equiv E_i/F_i. \end{aligned}$$

The quantities involved are defined as follows with their respective limits as $T \to \infty$, obtained using Lemma A.3:

$$a_A = a_B = T^3/12 - T/12, \quad T^{-3}a_A = T^{-3}a_B \to 1/12,$$

$$b_A = -(1-\lambda)\lambda T^2/2, \quad T^{-2}b_A \to -(1-\lambda)\lambda/2,$$

$$c_A = (1-\lambda)\lambda T, \quad T^{-1}c_A \to (1-\lambda)\lambda,$$

$$Y_A'Y_A = Y_B'Y_B = \sum_1^T\left(y_{t-1} - \overline{Y}_{-1}\right)^2,$$

$$T^{-2}Y_A'Y_A = T^{-2}Y_B'Y_B \Rightarrow \sigma^2\left[\int_0^1 w(r)^2\,dr - \left(\int_0^1 w(r)\,dr\right)^2\right],$$

$$Y_A'E = Y_B'E = \sum_1^T\left(y_{t-1} - \overline{Y}_{-1}\right)e_t,$$

$$T^{-1}Y_A'E = T^{-1}Y_B'E \Rightarrow \left(\sigma^2/2\right)\left(w(1)^2 - \sigma_e^2/\sigma^2\right) - \sigma^2 w(1)\int_0^1 w(r)\,dr,$$

$$H_A = H_B = \sum_1^T t\left(y_{t-1} - \overline{Y}_{-1}\right),$$

$$T^{-5/2}H_A = T^{-5/2}H_B \Rightarrow \sigma\int_0^1 rw(r)\,dr - (\sigma/2)\int_0^1 w(r)\,dr,$$

$$J_A = \sum_1^{T_B}\left(y_{t-1} - \overline{Y}_{-1}\right), \quad T^{-3/2}J_A \Rightarrow \sigma\int_0^\lambda w(r)\,dr - \sigma\lambda\int_0^1 w(r)\,dr,$$

$$K_A = K_B = \sum_1^T tu_t - \bar{t}\sum_1^T u_t, \quad T^{-3/2}K_A = T^{-3/2}K_B \Rightarrow (\sigma/2)w(1) - \sigma\int_0^1 w(r)\,dr,$$

$$L_A = \sum_1^{T_B}\left(e_t - \overline{E}\right), \quad T^{-1/2}L_A \Rightarrow \sigma w(\lambda) - \sigma\lambda w(1),$$

$$b_B = \sum_{T_B+1}^{T}(t - \bar{t})(t - T_B), \quad T^{-3}b_B \to (1-\lambda)^2(1+2\lambda)/12,$$

$$c_B = T_B\bar{t}^{*2} + \sum_1^{T-T_B}(t - \bar{t}^*)^2, \quad T^{-3}c_B \to (1-\lambda)^3(1+3\lambda)/12,$$

$$J_B = \sum_{T_B+1}^{T}(t - T_B)\left(y_{t-1} - \overline{Y}_{-1}\right),$$

$$T^{-5/2}J_B \Rightarrow \sigma\int_\lambda^1 rw(r)\,dr - \lambda\sigma\int_\lambda^1 w(r)\,dr - \left((1-\lambda)^2/2\right)\sigma\int_0^1 w(r)\,dr,$$

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$$L_B=\sum_{T_B+1}^{T}(t-T_B)(e_t-\bar{E}),\quad T^{-3/2}L_B\Rightarrow((1-\lambda^2)/2)\sigma w(1)-\sigma\int_\lambda^1 w(r)\,dr,$$

$$a_C=\sum_{1}^{T_B}(t-c_1)^2+\sum_{T_B+1}^{T}(t-c_2)^2,\quad T^{-3}a_C\to(1-\lambda)^2/12+\lambda^3/12,$$

$$b_C=\sum_{1}^{T_B}(t-c_1)^2,\quad T^{-3}b_C\to\lambda^3/12,$$

$$c_C=\sum_{1}^{T_B}(t-c_1)^2,\quad T^{-3}c_C\to\lambda^3/12,$$

$$Y_C'Y_C=\sum_{1}^{T_B}(y_{t-1}-A')^2+\sum_{T_B+1}^{T}(y_{t-1}-B')^2,$$

$$T^{-2}Y_C'Y_C\Rightarrow\sigma^2\left[\int_0^1 w(r)^2\,dr-\lambda^{-1}\left(\int_0^\lambda w(r)\,dr\right)^2-(1-\lambda)^{-1}\left(\int_\lambda^1 w(r)\,dr\right)^2\right],$$

$$Y_C'E=\sum_{1}^{T_B}(y_{t-1}-A')e_t+\sum_{T_B+1}^{T}(y_{t-1}-B')e_t,$$

$$T^{-1}Y_C'E\Rightarrow(\sigma^2/2)\left(w(1)^2-\sigma_e^2/\sigma^2\right)-\lambda^{-1}\sigma^2w(\lambda)\int_0^\lambda w(r)\,dr$$
$$-\sigma^2(w(1)-w(\lambda))(1-\lambda)^{-1}\int_\lambda^1 w(r)\,dr,$$

$$H_C=\sum_{1}^{T_B}(t-c_1)(y_{t-1}-A')+\sum_{T_B+1}^{T}(t-c_2)(y_{t-1}-B'),$$

$$T^{-5/2}H_C\Rightarrow\sigma\left[\int_0^1 rw(r)\,dr-(\tfrac{1}{2})(1+\lambda)\int_0^1 w(r)\,dr+(\tfrac{1}{2})\int_0^\lambda w(r)\,dr\right],$$

$$J_C=\sum_{1}^{T_B}(t-c_1)(y_{t-1}-A'),\quad T^{-5/2}J_C\Rightarrow\sigma\left[\int_0^\lambda rw(r)\,dr-(\lambda/2)\int_0^\lambda w(r)\,dr\right],$$

$$K_C=\sum_{1}^{T_B}(t-c_1)e_t+\sum_{T_B+1}^{T}(t-c_2)e_t,$$

$$T^{-3/2}K_C\Rightarrow\sigma\left[(\tfrac{1}{2})(1-\lambda)w(1)+(\tfrac{1}{2})w(\lambda)-\int_0^1 w(r)\,dr\right],$$

$$L_C=\sum_{1}^{T_B}(t-c_1)e_t,\quad T^{-3/2}L_C\Rightarrow\sigma\left[(\lambda/2)w(\lambda)-\int_0^\lambda w(r)\,dr\right].$$

Now, using (A.11), we can write the statistics as follows:

(A.12) $\quad T(\hat{\alpha}^A-1)=T^{-5}E_A/T^{-6}F_A,$

(A.13) $\quad t_{\hat{\alpha}}A=T^{-5}E_A/\left[\hat{S}_A^2\cdot T^{-6}F_A\cdot T^{-4}(a_Ac_A-b_A^2)\right]^{1/2},$

(A.14) $\quad T(\hat{\alpha}^i-1)=T^{-7}E_i/T^{-8}F_i,\quad i=B,C,$

(A.15) $\quad t_{\hat{\alpha}}i=T^{-7}E_i/\left[\hat{S}_i^2\cdot T^{-8}F_i\cdot T^{-6}(a_ic_i-b_i^2)\right]^{1/2},\quad i=B,C,$

where $\hat{S}_i^2=T^{-1}\Sigma_1^T\hat{e}_t^i$.

The results of Theorem 2 follow taking the limits of the expressions in (A.12) through (A.15) as $T\to\infty$, using the weak convergence results of the relevant moments (given above) and the fact that $\hat{S}_i^2(i=A,B,C)$ converges in probability to σ_e^2 as $T\to\infty$.

APPENDIX B

Extended Set of Results for Tests of a Unit Root using Split and Full Samples

TABLE A1

Tests for a Unit Root on Pre-1929 Samples

Regression: $y_t = \tilde{\mu} + \tilde{\beta}t + \tilde{\alpha}y_{t-1} + \Sigma_{i=1}^{k}\tilde{d}_i \Delta y_{t-i} + \tilde{e}_t$

		$k=1$	$k=2$	$k=3$	$k=4$	$k=5$	$k=6$	$k=7$	$k=8$	$k=9$	$k=10$	$k=11$	$k=12$
Real GNP	$\tilde{\alpha}$	0.44	0.42	0.43	0.32								
	$t_{\tilde{\alpha}}$	−2.33	−1.83	−1.43	−1.27								
Nominal GNP	$\tilde{\alpha}$	0.60	0.52	0.45	0.44	0.57							
	$t_{\tilde{\alpha}}$	−2.14	−2.04	−1.80	−1.12	−0.89							
Real per capita GNP	$\tilde{\alpha}$	0.39	0.37	0.37	0.23								
	$t_{\tilde{\alpha}}$	−2.44	−1.91	−1.51	−1.36								
Industrial production	$\tilde{\alpha}$	0.69	0.72	0.65	0.64	0.69	0.73	0.68	0.71				
	$t_{\tilde{\alpha}}$	−3.14	−2.57	−3.00	−2.83	−2.18	−1.78	−1.93	−1.43				
Employment	$\tilde{\alpha}$	0.76	0.80	0.80	0.78	0.82	0.74	0.61	0.56				
	$t_{\tilde{\alpha}}$	−2.16	−1.65	−1.72	−1.91	−1.43	−2.05	−2.85	−2.63				
GNP deflator	$\tilde{\alpha}$	0.84	0.80	0.78	0.77	0.79	0.75	0.74	0.71				
	$t_{\tilde{\alpha}}$	−2.44	−2.79	−2.66	−2.54	−2.10	−2.19	−2.05	−2.05				
Consumer prices	$\tilde{\alpha}$	0.95	0.97	0.96	0.96	0.96	0.97	0.96	0.96				
	$t_{\tilde{\alpha}}$	−1.89	−1.28	−1.37	−1.50	−1.47	−1.29	−1.37	−1.41				
Wages	$\tilde{\alpha}$	0.76	0.73	0.68	0.66	0.63	0.54	0.30	0.43				
	$t_{\tilde{\alpha}}$	−2.32	−2.22	−2.35	−2.09	−1.90	−2.08	−2.82	−1.67				
Real wages	$\tilde{\alpha}$	0.44	0.50	0.49	0.43	0.24	0.28	0.09	0.68				
	$t_{\tilde{\alpha}}$	−2.83	−2.23	−2.05	−1.89	−2.21	−1.71	−1.84	−0.63				
Money stock	$\tilde{\alpha}$	0.75	0.71	0.55	0.61	0.55	0.46	0.25	−0.04				
	$t_{\tilde{\alpha}}$	−2.88	−2.89	−4.20	−2.71	−2.53	−2.54	−3.01	−3.37				
Velocity	$\tilde{\alpha}$	0.89	0.90	0.91	0.90	0.93	0.91	0.89	0.90				
	$t_{\tilde{\alpha}}$	−1.52	−1.33	−1.22	−1.17	−0.82	−0.93	−1.12	−1.08				
Interest rate	$\tilde{\alpha}$	0.73	0.71	0.54	0.54								
	$t_{\tilde{\alpha}}$	−1.73	−1.53	−2.06	−1.59								
Common stock prices	$\tilde{\alpha}$	0.81	0.86	0.73	0.75	0.76	0.75	0.64	0.68	0.61			
	$t_{\tilde{\alpha}}$	−1.95	−1.27	−2.29	−1.83	−1.60	−1.55	−2.09	−1.75	−2.06			
Quarterly real GNP[a]	$\tilde{\alpha}$	0.93	0.91	0.92	0.93	0.93	0.92	0.91	0.90	0.90	0.88	0.86	0.89
	$t_{\tilde{\alpha}}$	−2.51	−3.02	−2.52	−2.23	−2.18	−2.41	−2.60	−2.83	−2.68	−3.04	−3.40	−2.62

[a] The sample for Quarterly Real GNP is 47:1–73:I.

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TABLE A2

TESTS FOR A UNIT ROOT ON POST-1929 SAMPLES

Regression: $y_t = \tilde{\mu} + \tilde{\beta} t + \tilde{\alpha} y_{t-1} + \Sigma_{i=1}^{k} \tilde{d}_i \Delta y_{t-i} + \tilde{e}_t$

		$k=1$	$k=2$	$k=3$	$k=4$	$k=5$	$k=6$	$k=7$	$k=8$	$k=9$	$k=10$	$k=11$	$k=12$
Real GNP	$\tilde{\alpha}$	0.72	0.75	0.75	0.78	0.74	0.66	0.56	0.33	0.22	0.18	0.30	0.09
	$t_{\tilde{\alpha}}$	−3.48	−3.00	−2.57	−1.96	−2.16	−2.65	−3.03	−5.32	−3.97	−3.19	−2.05	−2.34
Nominal GNP	$\tilde{\alpha}$	0.76	0.87	0.87	0.89	0.86	0.79	0.72	0.63	0.56	0.51	0.41	0.40
	$t_{\tilde{\alpha}}$	−3.37	−1.87	−1.60	−1.35	−1.66	−2.40	−2.93	−4.10	−3.39	−3.20	−2.91	−2.24
Real per capita GNP	$\tilde{\alpha}$	0.78	0.79	0.79	0.82	0.78	0.71	0.63	0.43	0.34	0.32	0.46	0.30
	$t_{\tilde{\alpha}}$	−3.05	−2.91	−2.55	−1.96	−2.19	−2.64	−3.03	−5.36	−3.91	−3.08	−1.89	−2.13
Industrial production	$\tilde{\alpha}$	0.68	0.69	0.66	0.63	0.71	0.64	0.53	0.23	0.03	−0.11	−0.03	−0.24
	$t_{\tilde{\alpha}}$	−2.84	−2.75	−2.65	−2.52	−1.76	−2.13	−2.55	−5.75	−4.38	−3.61	−2.40	−2.33
Employment	$\tilde{\alpha}$	0.78	0.80	0.80	0.83	0.80	0.72	0.67	0.47	0.55	0.42	0.24	0.10
	$t_{\tilde{\alpha}}$	−3.14	−2.66	−2.34	−1.80	−2.02	−2.64	−2.70	−5.61	−2.94	−3.24	−3.30	−2.79
GNP deflator	$\tilde{\alpha}$	0.85	0.92	0.91	0.87	0.87	0.83	0.72	0.76	0.75	0.81	0.75	0.68
	$t_{\tilde{\alpha}}$	−2.60	−1.32	−1.68	−2.29	−2.25	−2.64	−4.47	−3.08	−2.57	−1.73	−2.14	−2.48
Consumer prices	$\tilde{\alpha}$	0.84	0.91	0.90	0.88	0.85	0.81	0.70	0.68	0.62	0.72	0.67	0.58
	$t_{\tilde{\alpha}}$	−2.92	−1.64	−1.76	−2.10	−2.50	−2.72	−4.55	−3.45	−3.21	−1.98	−2.04	−2.39
Wages	$\tilde{\alpha}$	0.78	0.88	0.89	0.88	0.85	0.81	0.77	0.76	0.78	0.75	0.66	0.60
	$t_{\tilde{\alpha}}$	−3.37	−1.69	−1.41	−1.46	−1.77	−2.12	−2.27	−3.19	−2.02	−2.48	−3.06	−2.81
Real wages	$\tilde{\alpha}$	0.72	0.71	0.70	0.75	0.68	0.54	0.58	0.36	0.40	0.23	0.14	−0.35
	$t_{\tilde{\alpha}}$	−3.33	−3.10	−2.55	−1.84	−2.14	−2.79	−2.05	−3.31	−2.14	−2.34	−1.89	−2.11
Money stock	$\tilde{\alpha}$	0.89	0.93	0.92	0.91	0.89	0.87	0.86	0.79	0.67	0.63	0.59	0.39
	$t_{\tilde{\alpha}}$	−3.01	−1.85	−2.03	−2.55	−2.50	−2.59	−2.57	−4.57	−5.93	−3.61	−2.83	−4.05
Velocity	$\tilde{\alpha}$	0.61	0.67	0.63	0.71	0.69	0.66	0.60	0.52	0.49	0.63	0.50	0.36
	$t_{\tilde{\alpha}}$	−3.82	−2.70	−2.80	−1.97	−1.95	−1.91	−2.11	−2.33	−2.16	−1.43	−1.82	−2.54
Interest rate	$\tilde{\alpha}$	1.07	0.98	1.01	1.03	1.04	1.06	0.97					
	$t_{\tilde{\alpha}}$	1.11	−0.28	0.14	0.37	0.51	0.60	−0.25					
Common stock prices	$\tilde{\alpha}$	0.65	0.84	0.79	0.79	0.75	0.64	0.58	0.64	0.62	0.66	0.58	0.52
	$t_{\tilde{\alpha}}$	−3.48	−1.58	−1.99	−1.89	−2.13	−3.07	−2.96	−1.99	−2.00	−1.63	−1.64	−1.56
Quarterly real GNP[a]	$\tilde{\alpha}$	0.88	0.84	0.85	0.84	0.82	0.80	0.77	0.80	0.73	0.65	0.52	0.52
	$t_{\tilde{\alpha}}$	−2.23	−2.74	−2.39	−2.44	−2.48	−2.63	−2.80	−2.19	−2.78	−3.30	−4.03	−3.17

[a] The sample for Quarterly Real GNP is 73:II–86:III.

TABLE A3

TESTS FOR A UNIT ROOT ON THE FULL SAMPLES

	(1)[a]		$k=1$	$k=2$	$k=3$	$k=4$	$k=5$	$k=6$	$k=7$	$k=8$	$k=9$	$k=10$	$k=11$	$k=12$
Real GNP	(12)	$\tilde{\alpha}$	0.71	0.68	0.66	0.63	0.62	0.55	0.43	0.28	0.19	0.19	0.15	0.13
		$t_{\tilde{\alpha}}$	−4.04	−4.06	−3.86	−3.73	−3.48	−3.87	−4.81	−5.03	−4.89	−4.14	−4.16	−4.20
Nominal GNP	(12)	$\tilde{\alpha}$	0.70	0.69	0.69	0.70	0.66	0.60	0.56	0.47	0.46	0.41	0.23	0.34
		$t_{\tilde{\alpha}}$	−4.43	−4.17	−3.87	−3.58	−4.01	−4.70	−4.88	−5.42	−5.18	−5.38	−7.86	−5.98
Real per capita GNP	(12)	$\tilde{\alpha}$	0.76	0.73	0.72	0.70	0.70	0.64	0.53	0.43	0.39	0.42	0.37	0.34
		$t_{\tilde{\alpha}}$	−3.62	−3.58	−3.37	−3.21	−2.94	−3.27	−4.09	−4.08	−3.89	−3.14	−3.23	−3.17
Industrial production	(12)	$\tilde{\alpha}$	0.67	0.65	0.59	0.56	0.61	0.57	0.48	0.32	0.40	−0.37	−0.29	−0.32
		$t_{\tilde{\alpha}}$	−4.63	−4.46	−4.84	−4.69	−3.83	−3.98	−4.65	−5.47	−4.15	−4.05	−4.45	−4.08
Employment	(12)	$\tilde{\alpha}$	0.78	0.80	0.77	0.76	0.78	0.73	0.67	0.60	0.64	0.62	0.59	0.58
		$t_{\tilde{\alpha}}$	−3.77	−3.29	−3.72	−3.78	−3.12	−3.94	−4.51	−4.76	−3.59	−3.58	−3.59	−3.49
GNP deflator	(12)	$\tilde{\alpha}$	0.84	0.82	0.81	0.78	0.78	0.75	0.74	0.71	0.70	0.69	0.67	0.68
		$t_{\tilde{\alpha}}$	−3.79	−3.99	−3.89	−4.16	−4.04	−4.20	−4.10	−4.32	−4.28	−4.34	−4.35	−4.00
Consumer prices	(12)	$\tilde{\alpha}$	0.97	0.98	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.97	0.97
		$t_{\tilde{\alpha}}$	−1.87	−1.28	−1.68	−2.19	−2.06	−1.89	−2.01	−2.01	−1.90	−1.93	−1.49	−1.44
Wages	(12)	$\tilde{\alpha}$	0.77	0.76	0.74	0.73	0.71	0.68	0.62	0.62	0.64	0.63	0.60	0.67
		$t_{\tilde{\alpha}}$	−4.31	−4.15	−4.25	−4.05	−4.21	−4.73	−5.41	−4.91	−4.62	−4.63	−4.69	−3.64
Real wages	(14)	$\tilde{\alpha}$	0.68	0.63	0.57	0.52	0.49	0.47	0.38	0.30	0.29	0.28	0.27	0.29
		$t_{\tilde{\alpha}}$	−3.87	−3.97	−4.11	−4.06	−3.89	−3.62	−4.02	−4.28	−4.11	−3.82	−3.64	−3.37
Money stock	(12)	$\tilde{\alpha}$	0.87	0.87	0.85	0.86	0.84	0.81	0.78	0.76	0.74	0.74	0.72	0.77
		$t_{\tilde{\alpha}}$	−3.94	−3.61	−3.86	−3.66	−3.82	−4.29	−4.69	−4.56	−4.36	−4.29	−4.32	−3.18
Velocity	(12)	$\tilde{\alpha}$	0.93	0.94	0.95	0.96	0.97	0.97	0.96	0.95	0.96	0.96	0.94	0.98
		$t_{\tilde{\alpha}}$	−1.82	−1.53	−1.41	−1.11	−0.74	−0.79	−0.94	−1.09	−0.91	−0.89	−1.22	−0.49
Interest rate	(12)	$\tilde{\alpha}$	1.01	0.98	0.97	0.98	0.98	0.99	1.004	1.01	1.01	1.03	0.99	0.97
		$t_{\tilde{\alpha}}$	0.12	−0.45	−0.53	−0.34	−0.31	−0.24	0.07	0.22	0.12	0.46	−0.08	-0.40
Common stock prices	(14)	$\tilde{\alpha}$	0.72	0.73	0.72	0.74	0.76	0.76	0.75	0.75	0.73	0.67	0.62	0.60
		$t_{\tilde{\alpha}}$	−4.87	−4.39	−4.43	−3.91	−3.53	−3.52	−3.51	−3.41	−3.52	−4.19	−4.50	−4.35
Quarterly real GNP	(10)	$\tilde{\alpha}$	0.92	0.90	0.91	0.90	0.90	0.90	0.89	0.89	0.88	0.86	0.84	0.87
	$i=B$	$t_{\tilde{\alpha}}$	−3.33	−3.97	−3.47	−3.18	−3.16	−3.39	−3.51	−3.42	−3.55	−3.98	−4.32	−3.28

[a] The number in column (1) refers to the regression model used to test for a unit root using the full samples. See the discussion in the text.

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How Big Is the Random Walk in GNP?

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This paper presents a measure of the persistence of fluctuations in GNP based on the variance of its long differences. That measure finds little long-term persistence in GNP. Previous research on this question found a great deal of persistence in GNP, suggesting models such as a random walk. A reconciliation of this paper's results with previous research shows that conventional criteria for time-series model building can produce misleading estimates of persistence.

I. Introduction

Macroeconomists once viewed fluctuations in gross national product as temporary deviations from a trend. The economic theory of business cycles described temporary deviations from "potential GNP," which was assumed to evolve smoothly over time, and data were routinely detrended prior to analysis. A body of recent empirical work (described below) has questioned this time-honored view. By using a variety of time-series models, it finds that fluctuations in GNP are permanent—that a decline in GNP today lowers forecasts of GNP into the infinite future.

This paper reexamines the long-run properties of GNP and argues that GNP does, in fact, revert toward a "trend" following a shock. However, that reversion occurs over a time horizon characteristic of business cycles—several years at least. Therefore, the short-run properties of GNP are consistent with a model with very persistent shocks,

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and one can incorrectly infer a great deal of long-horizon persistence by fitting a time-series model to this short-run behavior.

The class of time-series model most commonly used to describe temporary deviations about trend is

$$y_t = bt + \sum_{j=0}^{\infty} a_j \epsilon_{t-j}, \tag{1}$$

where y_t stands for log GNP, bt describes the trend, and ϵ_t is a random disturbance.[1] Fluctuations in y_t are temporary if $\Sigma a_j \epsilon_{t-j}$ is a stationary stochastic process (y_t is then called "trend stationary"). For $\Sigma a_j \epsilon_{t-j}$ to be stationary, the a_j must approach zero for large j. As a result, a decline in GNP below trend today has no effect on forecasts of the level of GNP, $E_t(y_{t+j})$, in the far future, and it implies that growth rates of GNP must rise above their historical average for a few periods until the trend line is reestablished.

The simplest time-series model that captures permanent fluctuations in GNP is a random walk with drift:

$$y_t = \mu + y_{t-1} + \epsilon_t. \tag{2}$$

Fluctuations in a random walk are permanent in the following sense: suppose that $\epsilon_t = -1$, so that y_t falls one unit below last period's expected value. Then, since $y_{t+j} = y_t + j\mu + \epsilon_{t+1} + \ldots + \epsilon_{t+j}$, forecasts $E_t(y_{t+j})$ fall by one unit for the indefinite future. Also, a low or negative growth rate today implies nothing about growth rates in the future, and there is no tendency for future levels of GNP to revert to a trend line. The random walk is also nonstationary.

The distinction between a random walk (2) and a trend-stationary series (1) is extreme. Long-range forecasts of a random walk move one for one with shocks at each date, while long-range forecasts of a trend-stationary series do not change at all. There are two related ways to think about a series that lies between these two extremes.

First, one can ask how much long-term forecasts respond to shocks. In one interpretation, the measure of this paper asks the question, How much does a one-unit shock to GNP affect forecasts in the far future? If by one unit, it finds a random walk; if by zero, it finds a trend-stationary process like (1). It can also find numbers between zero and one, characterizing a series that returns toward a "trend" in the far future, but does not get all the way there, or it can find a number greater than one, characterizing a series that will continue to

[1] Simple univariate time-series models like (1) should be thought of as a way of capturing the dynamic behavior of y_t that results from a rich multivariate world. They are not "structural" in any way.

diverge from its previously forecast value following a shock. Campbell and Mankiw (1987) originated and emphasize this interpretation.

Second, one can model a series whose fluctuations are partly temporary and partly permanent as a combination of a stationary series and a random walk. The random walk carries the permanent part of a change and the stationary series carries the temporary part of a change. Then, one can ask how important the permanent or random walk component is to the behavior of the series. In a second interpretation, the measure of this paper asks the question, How large is the variance of shocks to the random walk or permanent component of GNP compared with the variance of yearly GNP growth rates? Or, equivalently, How big is the random walk in GNP?

If the variance of the shocks to the random walk component is zero, the series is trend-stationary, and long-term forecasts do not change in response to shocks. If the variance of the shocks to the random walk component is equal to the variance of first differences, the series is a pure random walk. As before, there is a continuous range of possibilities between zero and one and beyond one.

A model consisting of a random walk plus a stationary component may seem quite special. However, I show below that we can think of *any* series whose growth rates or first differences are stationary (any series with a unit root) as a combination of a stationary series plus a random walk. The decomposition into stationary and random walk components is a convenient way of thinking about the properties of a time series, but it adds no structure. I also show that the response to innovations is proportional to the square root of the variance of shocks to a random walk component, so we can freely transform between these two interpretations.

The idea that GNP may contain a random walk goes back to Irving Fisher's "Monte Carlo hypothesis," examined by McCulloch (1975). There is now a large literature following the first half of Nelson and Plosser (1982) that applies the Dickey and Fuller (1979, 1981) and subsequent tests for unit roots to aggregate time series. Since a series with a unit root is equivalent to a series that is composed of a random walk and a stationary component, tests for a unit root are attempts to distinguish between series that have no random walk component (or for which the variance of shocks to the random walk component is zero) and series that have a random walk component (or for which the variance of shocks to the random walk component is between zero and infinity). Stated this way, it is clear why tests for a unit root have low power: it is hard to tell a stationary series from a stationary series plus a very small random walk. This paper and the related literature cited in it go beyond testing for the presence or absence of a unit root or random walk component and measure how important the unit root or random walk component is to the behavior of a series.

Implications of the Random Walk in GNP

The size of a random walk in GNP is important from a purely statistical viewpoint. Many statistical procedures rely critically on the distinction between series that do not contain a random walk component (1), which we can and should detrend, and first-difference stationary series—(3) below, or series that do contain a random walk component—which we should first-difference prior to analysis. Hypothesis tests that rely on asymptotic distribution theory are an important example because that distribution theory is often quite sensitive to the presence of a random walk component. A measurement of the size of the random walk component can be a better guide to the proper procedure than a unit root test because if the random walk component is small but still nonzero, then an asymptotic distribution theory based on trend stationarity may provide a better approximation in a given small sample than the theory based on a unit root.

The size of a random walk in GNP has been cast as a direct test between competing models of the economy. For example, Nelson and Plosser (1982) interpreted their result that GNP has a large random walk component as evidence for stochastic equilibrium models over traditional monetary or Keynesian business cycle models. They argued that traditional models produce only temporary deviations from trend, while models that find the ultimate source of GNP variability in technology shocks can produce permanent fluctuations.

With the advantages of hindsight, it now seems that the size or existence of a random walk component in GNP cannot directly distinguish broad classes of economic theories of the business cycle at their present stage of development. The Kydland and Prescott (1982) and Long and Plosser (1983) stochastic equilibrium models were constructed precisely to generate temporary fluctuations about trend. On the other hand, King et al. (1987) show that one can modify these models to produce a random walk component by introducing a random walk in the technology shocks or a linear technology for human or physical capital accumulation. Presumably, the same modifications would introduce a random walk component into monetary or "Keynesian" models as well.

Furthermore, the results of this paper are compatible with a variety of random walk components. I show below that an AR(2) about a deterministic trend, which has no random walk component, and a model with a random walk whose variance is 0.18 times the variance of first differences of log GNP account equally well for the results of this paper. Also, the standard errors in this paper are large, and I argue that this is unavoidable. I conclude that the existence or size of a random walk component in GNP is not a precisely measured "stylized fact" that we should require any reasonable model to reproduce.

The most promising direct use for the point estimates of the size of a random walk component in this paper may be the calibration of a given model rather than a test that can distinguish competing classes of models. If a model (like the ones cited above) produces a random walk in GNP, the results of this paper suggest that the parameters of that model should be picked to also generate interesting short-run dynamics of GNP, so that the variance of yearly changes in GNP is much larger than the variance of shocks to its random walk component.

Other Estimates

Several authors have estimated the persistence of fluctuations in GNP, and their estimates vary greatly. Nelson and Plosser (1982) matched a model consisting of permanent and temporary components to a stylized autocorrelation function for growth rates of GNP and concluded that the permanent component was more important than the temporary component. Watson (1986) and Clark (1987) estimated different unobserved components models and found a small permanent component. Campbell and Mankiw (1987) estimated the effect of a shock on long-term forecasts of GNP from the parameters of low-order autoregressive, moving average (ARMA) representations of postwar GNP and found a large random walk component.

Several authors have examined the persistence of fluctuations in other time series using a variety of methods. Rose (1986) presents a survey of papers that find large random walk components in various macroeconomic time series. In finance, conventional wisdom favored the random walk model while macroeconomists favored the trend-stationary model. Poterba and Summers (1987), Fama and French (1988), and Lo and MacKinlay (1988) use variance ratio estimators similar to the one used in this paper and related estimators to document a temporary component in stock prices. Huizinga (1987) uses a closely related estimator to document a temporary component in real exchange rates. Cochrane and Sbordone (1988) present a multivariate extension.

This Paper's Technique

In this paper, I measure the size of a random walk component in GNP from the variance of its long differences. The intuition behind this

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measure comes from the following argument: Imagine that log GNP, denoted y_t, is a pure random walk (model [2]). Then the variance of its k-differences grows linearly with the difference k: $\mathrm{var}(y_t - y_{t-k}) = k\sigma_\epsilon^2$. On the other hand, if log GNP is stationary about a trend (model [1]), the variance of its k-differences approaches a constant, twice the unconditional variance of the series: $\mathrm{var}(y_t - y_{t-k}) \rightarrow 2\sigma_y^2$. Now plot $(1/k)\mathrm{var}(y_t - y_{t-k})$ as a function of k. If y_t is a random walk, the plot should be constant at σ_ϵ^2. If y_t is trend-stationary, the plot should decline toward zero.

Next, suppose that fluctuations in GNP are partly permanent and partly temporary, which we can model as a combination of a stationary series and a random walk. Now the plot of $(1/k)\mathrm{var}(y_t - y_{t-k})$ versus k should settle down to the variance of the shock to the random walk component.

If fluctuations in GNP are partly temporary—if the random walk component is small and a shock today will be partially reversed in the long run—that reversal is likely to be slow, loosely structured, and not easily captured in a simple parametric model. The variance of k-differences can find such loosely structured reversion, whereas many other approaches cannot. I show in Section IV that this difference can reconcile the results of this paper with other measures of the permanence of fluctuations in GNP.

Results

Figure 1 and table 1 present $(1/k)\mathrm{var}(y_t - y_{t-k})$ for log real per capita GNP, 1869–1986. Pre-1939 data are taken from Friedman and Schwartz (1982). I use real per capita GNP to eliminate possible nonstationarity induced by inflation or population growth. (Henceforth, I will refer to log real per capita GNP as just "GNP.") Figure 1 and table 1 also include asymptotic standard errors, discussed below. Table 1 also presents $1/k$ times the variance of k-differences divided by the variance of first differences (the variance ratio). The units in table 1 and figure 1 are annual percentage growth.

Since $1/k$ times the variance of k-differences settles down to about one-third of the variance of first differences, figure 1 and table 1 suggest that the innovation variance of the random walk component is about one-third of the variance of year-to-year changes: annual growth rates of GNP contain a large temporary component. In fact, I show below that the pattern of figure 1 is consistent with a deterministic trend, which has *no* permanent or random walk component, and whose fluctuations are entirely temporary.

Figure 2 presents the log of real per capita GNP. Notice that this data set looks as if it has a trend in it. Fluctuations occur, but the level

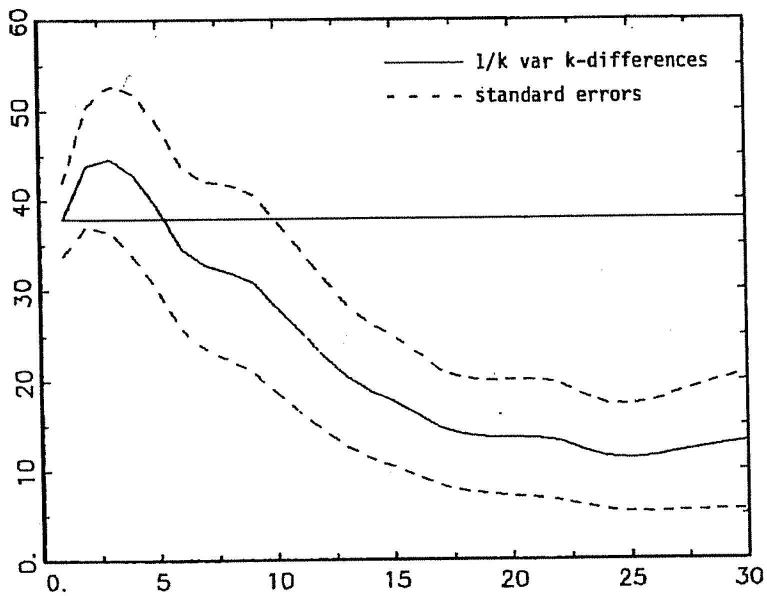

FIG. 1.—$1/k$ times the variance of k-differences of log real per capita GNP, 1869–1986, with asymptotic standard errors.

of the series always returns to the "trend line." Furthermore, that trend line is linear: there are no "waves" of low-frequency movement. These characteristics drive the finding of a small random walk component. (Note that low-frequency movement generated by a nonlinear trend, a shift, etc. would show up as a large random walk component in this and most other estimation techniques based on linear time-series models.)

Prewar GNP data are more variable than postwar data, and one might suspect that this characteristic drives the result. However, figure 3 and table 1 present $1/k$ times the variance of k-differences for postwar GNP, and the same pattern is evident. Both the variance of first differences and the variance of the random walk component are lower, but their proportions do not change much.[2]

[2] The pattern of fig. 2 is sensitive to the precise specification of the variables. First, the variance of quarterly differences of seasonally adjusted GNP is less than one-fourth the variance of yearly differences, so the variance ratio is higher if one uses quarterly rather than annual differences in the denominator. This observation explains most of the difference between fig. 2 and the results reported by Campbell and Mankiw (1988), who use a similar technique on quarterly data. Second, taking the variance of overlapping k-year differences of quarterly data vs. the variance of k-year differences of annual averages, including or excluding population growth, taking logs or not, and even changing the sample by a few years can all change the variance ratio by about one standard error.

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TABLE I

1/k Times the Variance of k-Differences of GNP

	k (Years)									
	1	2	3	4	5	10	15	20	25	30
					1869–1986					
$\hat{\sigma}_k^2$	40.0	43.8	44.6	42.8	39.2	28.2	17.7	13.6	11.3	13.1
	(4.1)	(6.6)	(8.2)	(9.1)	(9.4)	(9.5)	(7.3)	(6.5)	(6.0)	(7.7)
$\hat{\sigma}_k^2/\hat{\sigma}_1^2$	1.00	1.15	1.17	1.13	1.03	.74	.47	.36	.30	.35
	(.11)	(.17)	(.22)	(.24)	(.25)	(.25)	(.19)	(.17)	(.16)	(.20)
$\hat{\sigma}_k$	6.1	6.6	6.7	6.5	6.3	5.3	4.2	3.7	3.4	3.6
					1947–86					
$\hat{\sigma}_k^2$	7.0	8.2	8.0	7.3	6.5	4.5	2.9	2.6		
	(1.3)	(2.2)	(2.6)	(2.8)	(2.8)	(2.7)	(2.1)	(2.2)		
$\hat{\sigma}_k^2/\hat{\sigma}_1^2$	1.00	1.17	1.14	1.05	.93	.63	.42	.38		
	(.19)	(.31)	(.37)	(.39)	(.39)	(.38)	(.30)	(.32)		
$\hat{\sigma}_k$	2.7	2.9	2.8	2.7	2.6	2.1	1.7	1.6		

Note.—$\hat{\sigma}_k^2$ is 1/k times the sample variance of k-differences. Standard errors (in parentheses) are the Bartlett standard error, with $\hat{\sigma}_1^2$ used for the random walk component; i.e., standard error is $(4k/3T)^{.5}\hat{\sigma}_1^2$. $\hat{\sigma}_k^2/\hat{\sigma}_1^2$ and its standard error are the same quantities divided by $\hat{\sigma}_1^2$. $\hat{\sigma}_k$ is the square root of $\hat{\sigma}_k^2$; its units are percentage growth rates.

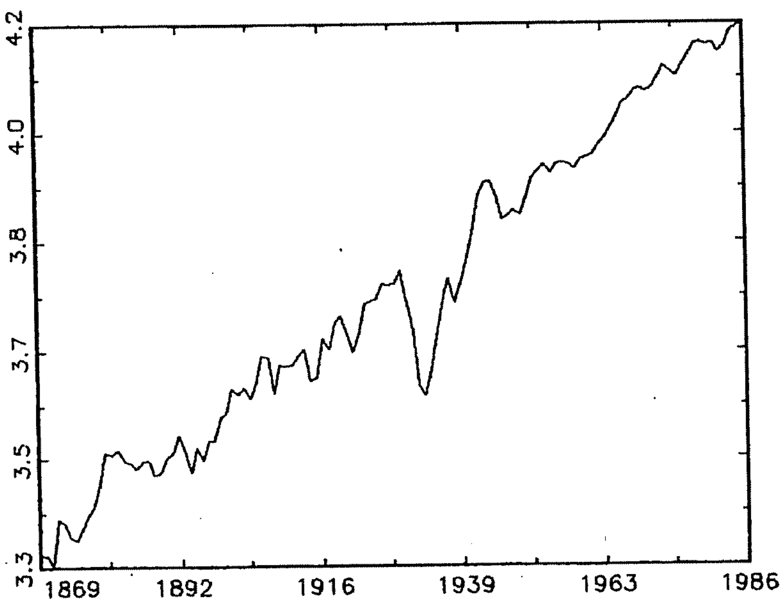

FIG. 2.—Log real per capita GNP, 1869–1986

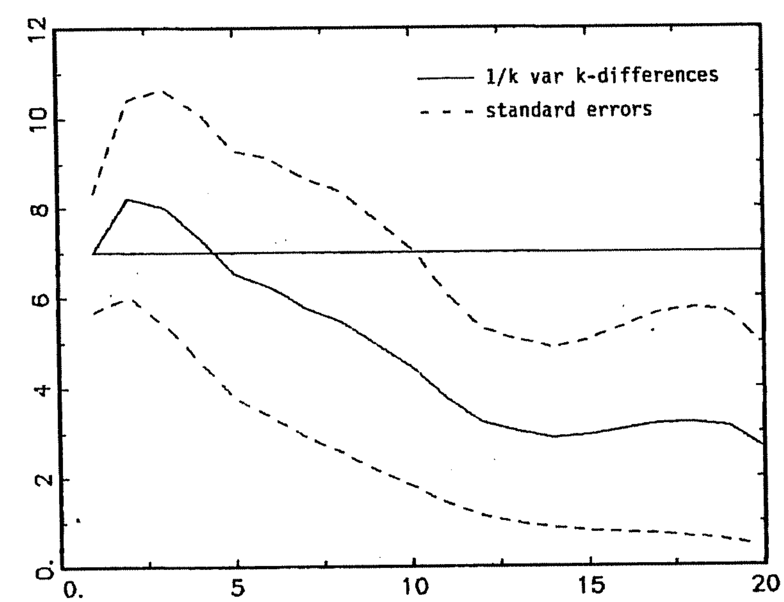

FIG. 3.—$1/k$ times the variance of k-differences of log real per capita GNP, 1947–86, with asymptotic standard errors.

Romer (1986) argued that prewar GNP data overstate the actual cyclical variability of GNP. This possibility will not bias the estimate of the variance of the random walk component. Taking k-differences acts as a filter that ignores cyclical fluctuations and concentrates on the variability of longer "runs," so a different GNP data set will have a different variance of k-differences if the early GNP has a significantly different and more variable trend line, not if its cyclical fluctuations are different. A graph similar to figure 1, using Romer's adjusted early GNP series, produces a variance of a random walk component very similar to that of figure 1. It should because Romer kept the decade trends the same in her corrections for cyclical volatility. Her criticism, or the seasonal adjustment of quarterly data, will affect the variance of first differences, so the variance *ratio* can be biased by excessive volatility or smoothness of the first differences.

The presence of a splice in 1947 also does not drive the result. Every long series of GNP data contains at least one splice. The wide surveys used to construct later data are simply not available for earlier periods, so some projection using a restricted set of industries is unavoidable. However, forcing the *levels* of the "old" and "new" GNP series to match at a certain date does not bias the variance of k-differences. It is biased only if the old series has different growth rates over long horizons.

The body of this paper consists of an investigation of $1/k$ times the variance of k-differences as an estimate of the random walk component in GNP. Section II provides several interpretations of a random walk component. Section III discusses estimation. Section IV reconciles these results with previous research that found a large random walk component by showing how conventional time-series estimation techniques can provide misleading estimates of a random walk component. Section V contains a summary and concluding remarks.

II. Unit Roots and Random Walk Components

This section discusses and documents several claims in the Introduction about the representation of time series. It shows that first-difference stationary time series or time series with a unit root are equivalent to time series that are composed of a stationary and a random walk component. It argues that the variance of shocks to a random walk component is just a convenient interpretation of the parameters of an arbitrary first-difference stationary series, but it requires no additional structure. It shows how to transform between the variance of a random walk component and the response of long-term forecasts to a shock.

Assume that log GNP follows a first-difference stationary linear process; that is, growth rates of GNP are stationary. In this case, log GNP has a moving average representation of the form

$$\Delta y_t = (1 - L)y_t = \mu + A(L)\epsilon_t = \mu + \sum_{j=0}^{\infty} a_j \epsilon_{t-j}, \tag{3}$$

which I take as the starting point; L is the lag operator, $Ly_t = y_{t-1}$. The first equality defines the notation Δy_t and $(1 - L)y_t$ for first differences of y_t. The last equality defines the lag polynomial notation $A(L)$. The ϵ_t are independent identically distributed (i.i.d.) error terms with common variance σ^2_ϵ.

The random walk process (2) obviously has a representation of the form (3). The trend-stationary process (1) is a limiting case of (3): if $\mu = b$ and if the lag polynomial $A(L)$ in (3) has a unit root—that is, we can express $A(L) = (1 - L)B(L)$—we recover (1) by canceling the terms $(1 - L)$. Many unobserved components models are first-difference stationary and hence have a representation (3). Nelson and Plosser (1982) and Watson (1986) are examples. On the other hand, (3) does not include nonlinear processes such as Quah (1986), a process with a nonlinear trend, or second-difference stationary processes (the growth rates of GNP follow a random walk) as in Clark (1987).

Given the representation (3), we have the following fact.

FACT 1. Any first-difference stationary processes can be represented as the sum of stationary and random walk components.

To show that a representation as stationary plus random walk components exists, we simply construct it from the representation (3). This decomposition comes from Beveridge and Nelson (1981). Let

$$y_t = z_t + c_t, \tag{4}$$

where

$$z_t = \mu + z_{t-1} + \left(\sum_{j=0}^{\infty} a_j\right)\epsilon_t,$$

$$-c_t = \left(\sum_{j=1}^{\infty} a_j\right)\epsilon_t + \left(\sum_{j=2}^{\infty} a_j\right)\epsilon_{t-1} + \left(\sum_{j=3}^{\infty} a_j\right)\epsilon_{t-2} + \dots .$$

This decomposition is constructed so that $\lim_{k\to\infty} E_t y_{t+k} = z_t + k\mu$; that is, long-term forecasts of y_t converge to z_t plus $k\mu$. In this sense, z_t is the permanent component of y_t. Beveridge and Nelson call it a stochastic trend. Long-term forecasts of y_t are unaffected by c_t, the temporary component.

The innovation variance of the random walk component $\sigma^2_{\Delta z}$ is a natural measure of the importance of the random walk component.

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From the definition (4) we can write the variance of the random walk component $\sigma^2_{\Delta z}$ in terms of the moving average representation (3):

$$\sigma^2_{\Delta z} = (\Sigma a_j)^2 \sigma^2_\epsilon = |A(1)|^2 \sigma^2_\epsilon \tag{5}$$

(sums without indices run from zero to infinity).

In the Beveridge and Nelson decomposition (4), the innovations in the random walk and stationary components are identical. In a more general combination of random walk and stationary components, the innovations may be correlated:

$$\begin{aligned} y_t &= z_t + c_t, \\ z_t &= \mu + z_{t-1} + \eta_t, \\ c_t &= B(L)\delta_t, \quad E(\eta_t \delta_t) \text{ arbitrary.} \end{aligned} \tag{6}$$

If we start with a process (6), Δy_t is stationary, and so the process has a representation of the form (3). Most processes of the form (3) can be decomposed into a variety of processes (6), with varying correlation between the innovations; but only the decomposition (4) is *guaranteed* to exist.[3]

Since a variety of decompositions into stationary and random walk components of the form (6) exist for any given stationary process (3), a measure based on the variance of the random walk component would be in serious trouble if it depended crucially on which arbitrary decomposition we choose. Fortunately, it does not, as seen in the following fact.

FACT 2. In every decomposition of a process (1) into stationary and random walk components (6), the innovation variance of the random walk component is the same: $\sigma^2_{\Delta z} = (\Sigma a_j)^2 \sigma^2_\epsilon$.

To show fact 2, start with an arbitrary decomposition (6). The corresponding moving average representation of the form (3) is

$$(1 - L)y_t = \mu + \nu_t + (1 - L)B(L)\delta_t \equiv \mu + A(L)\epsilon_t. \tag{7}$$

The last equality defines the parameters $A(L)$ of a moving average representation from the parameters $B(L)$ of (6). Now form the Beveridge and Nelson decomposition of both sides of the last equality in (7). Since the processes on both sides of the last equality are the same, they must have the same variance of a random walk component, so we must have[4] $|A(1)|^2\sigma^2_\epsilon = \sigma^2_\nu$. The correlation between ν_t and

[3] Watson (1986) derives this fact. For example, if we seek a representation with uncorrelated innovations, the spectral density of the combination can be no less than the spectral density of each component; thus such a representation exists only if the spectral density of the first differences has a global minimum at zero.

[4] This statement can be more compactly derived by noting that for the processes on each side of the last equality in (7) to be the same, their spectral densities must be the same at all frequencies, and zero in particular.

δ_t is irrelevant for this argument, so the innovation variance of every decomposition (6) of the same moving average representation (3) must have the same variance of shocks to the random walk component. This argument demonstrates fact 2.

There is one more interpretation, which will be useful in the next section. The spectral density[5] of Δy_t is, by (1), $S_{\Delta y}(e^{-i\omega}) = |A(e^{-i\omega})|^2\sigma_\epsilon^2$. Therefore, we have the following fact.

FACT 3. The innovation variance of the random walk component is equal to the spectral density of Δy_t at frequency zero, that is,

$$\sigma_{\Delta z}^2 = (\Sigma a_j)^2\sigma_\epsilon^2 = S_{\Delta y}(e^{-i0})\sigma_\epsilon^2 \tag{8}$$

or, dividing by the variance of first differences,

$$\frac{\sigma_{\Delta z}^2}{\sigma_{\Delta y}^2} = \frac{(\Sigma a_j)^2}{\Sigma a_j^2} = \frac{S_{\Delta y}(e^{-i0})}{\sigma_{\Delta y}^2}. \tag{8$'$}$$

Equations (8) and (8′) summarize three equivalent ways of looking at the long-run properties of a series: we can break it into permanent (random walk) and temporary (stationary) components, we can examine the response of long-term forecasts to an innovation, or we can examine the spectral density at frequency zero of its first differences. All three interpretations allow us to think of the permanence of the fluctuations in a series as a continuous phenomenon rather than a discrete choice. Furthermore, equations (8) and (8′) show that the quantity $\sigma_{\Delta z}^2$ or $\sigma_{\Delta z}^2/\sigma_{\Delta y}^2$ defined from the Beveridge and Nelson decomposition (3) is no more than a useful interpretation of the sum of the moving average coefficients Σa_j. The decomposition into stationary and random walk components adds no structure.

The variance of shocks to the random walk component or spectral density at frequency zero of first differences also captures *all* the effects of a unit root on the behavior of a series in a finite sample. As a sample of T observations of a series is completely characterized by its $T - 1$ autocovariances, it is also completely characterized by $T - 1$ periodogram ordinates. By changing the periodogram ordinate at frequency zero of first differences without changing the others, we can make a stationary series into a series with a unit root or random walk component and vice versa.[6]

Since the size of a random walk component is a continuous choice, any test for trend stationarity ($\sigma_{\Delta z}^2 = 0$ or $S_{\Delta y}(e^{-i0}) = 0$) must have arbitrarily low power against the alternative of a small enough ran-

[5] I use the notation $S(e^{-i\omega})$ for the spectral density at frequency ω and, hence, $S(e^{i0})$ for the spectral density at $\omega = 0$.

[6] With an infinite sample, or in population, this proposition does not hold. The spectral density is defined only almost everywhere; and in some cases we can bound the variation of the population spectral density function with very weak assumptions.

dom walk component $\sigma^2_{\Delta z}$. As a result, efforts to categorize series as trend-stationary or difference-stationary and read great things into the difference between the two will not be very fruitful.

III. Estimation

I claimed in the Introduction that the variance of k-differences could be used to estimate the innovation variance of a random walk component. To document that claim and to provide standard errors, this section discusses the statistical properties of the variance of k-differences.

Asymptotic Properties

Let σ^2_k denote $1/k$ times the population variance of k-differences of y_t, $\sigma^2_k = k^{-1}\,\mathrm{var}(y_t - y_{t-k})$; σ^2_k is related to the autocorrelation coefficients of Δy_t by

$$\sigma^2_k = \left(1 + 2\sum_{j=1}^{k-1} \frac{k-j}{k}\rho_j\right)\sigma^2_{\Delta y}, \tag{9}$$

where $\sigma^2_{\Delta y} = \mathrm{var}(y_t - y_{t-1})$ and $\rho_j = \mathrm{cov}(\Delta y_t \Delta y_{t-j})/\sigma^2_{\Delta y}$. The derivation is straightforward but tedious, so it is presented in the Appendix. Equation (9) shows that the limit of σ^2_k is indeed the innovation variance of the random walk component:

$$\lim_{k\to\infty} \sigma^2_k = \left(1 + 2\sum_{j=1}^{\infty}\rho_j\right)\sigma^2_{\Delta y} = S_{\Delta y}(e^{-i0}) = \sigma^2_{\Delta z}. \tag{10}$$

The second equality is the definition of spectral density, while the third is reproduced from equation (8).

Equation (9) suggests that we could also estimate $1/k$ times the variance of k-differences by using sample autocorrelations $\hat{\rho}_j$ in the place of their population values ρ_j. (Huizinga [1987] and Campbell and Mankiw [1988] perform the calculation this way.) The right-hand side of (9) with $\hat{\rho}_j$ in place of ρ_j is the definition of the Bartlett estimator of the spectral density at frequency zero (Anderson 1971, p. 511). Hence, $1/k$ times the variance of k-differences is asymptotically equivalent to the Bartlett estimator.[7]

[7] $1/k$ times the variance of k-differences and the conventional Bartlett estimate are not identical in small samples. The estimates of sample autocorrelations implied by the sample variance of k-differences underweight observations k dates away from the endpoints, compared with the usual estimates of autocorrelation. The difference disappears asymptotically but may be important in small samples. Also, the conventional Bartlett estimate is not unbiased in small samples, as the corrected $1/k$ times the variance of k-differences $\hat{\sigma}^2_k$ is for a random walk. I thank John Huizinga for pointing this out.

The properties of the Bartlett estimator are well known, so we can establish the asymptotic properties of $1/k$ times the variance of k-differences by reference to those of the Bartlett estimator. In particular, (1) if $k/T \rightarrow 0$ as $T \rightarrow \infty$, where T is the sample size, $1/k$ times the sample variance of k-differences is a consistent estimate of the spectral density at frequency zero; (2) the asymptotic variance of σ_k^2 is $4kS^2(e^{-i0})/3T$ (Anderson 1971, p. 531).

The equivalence between $1/k$ times the variance of k-differences and the Bartlett estimator provides a useful interpretation of the variance of k-differences for readers familiar with spectral density estimation; in turn, the variance of k-differences is a useful and intuitive time domain counterpart to the Bartlett spectral density estimator. To use the Bartlett estimator, we have to decide what k to use: how many autocovariances or autocorrelations to include in (9) or how many periodogram ordinates to smooth. The choice of k requires a trade-off between bias and efficiency, and it is usually made arbitrarily. In this context, a plot of $1/k$ times the variance of k-differences versus k is an experimental determination of the proper k or window width.

Small-Sample Properties

In small samples, $1/k$ times the variance of k-differences and the Bartlett estimator can be biased, and the asymptotic standard errors may be a poor approximation to the actual standard errors. In this subsection, I discuss corrections for small-sample bias, and I present some Monte Carlo experiments to evaluate standard errors.

I corrected for two sources of small-sample bias in the sample variance of k-differences. These corrections produce an estimator of σ_k^2 that is unbiased when applied to a pure random walk with drift. First, I used the sample mean of the first differences to estimate the drift term μ at all k rather than estimate a different drift term at each k from the mean of the k-differences. Second, I included a degrees of freedom correction $T/(T - k + 1)$. Without this correction, $1/k$ times the variance of k-differences declines toward zero as $k \rightarrow T$ for any process because you cannot take a variance with one data point.

I will use the notation $\hat{\sigma}_k^2$ to denote $1/k$ times the bias-corrected sample variance of k-differences. The formula for $\hat{\sigma}_k^2$ is presented in the Appendix as equation (A3). The Appendix also contains a proof that $\hat{\sigma}_k^2$ is unbiased when y_t is a random walk with drift.

Table 2 presents standard errors from a Monte Carlo experiment using 100 observations of a random walk with drift. I picked the innovation variance of this random walk $\sigma_\epsilon^2 = \sigma_{\Delta z}^2 = 1$. The mean of $\hat{\sigma}_k^2$ was very close to one at all k in this experiment, confirming the bias corrections for a pure random walk. The table presents the standard

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TABLE 2

MONTE CARLO STANDARD ERRORS FOR $1/k$ TIMES THE VARIANCE OF k DIFFERENCES
Model: $y_t = 1 + y_{t-1} + \epsilon_t$; $\sigma_\epsilon^2 = 1$ ($T = 100$, 500 trials)

	100k/T									
	1	2	3	4	5	10	20	30	40	50
Monte Carlo	.137	.160	.200	.231	.263	.409	.607	.772	.888	.896
Bartlett*	.115	163	.200	.231	.258	.365	.516	.632	.730	.816

* This row gives $(4k/3T)^{.5}$

errors from the Monte Carlo experiment and the corresponding Bartlett standard errors for comparison. The Bartlett errors slightly understate the Monte Carlo errors at large k/T, but the difference is small compared to the size of the standard errors. Monte Carlo experiments with different sample sizes and random walk variance confirm that the standard errors of table 2 scale with k/T and the innovation variance of the random walk.

What about processes that are more complicated than a pure random walk? The Appendix presents a derivation of $E(\hat{\sigma}_k^2)$ for a first-order moving average: $(1 - L)y_t = \mu + (1 + \theta L)\epsilon_t$. It shows that $E(\hat{\sigma}_k^2)$ approaches $\sigma_{\Delta z}^2$ for large k, so $\hat{\sigma}_k^2$ can recover the variance of the random walk component for this process as well.

I ran several further Monte Carlo simulations to examine whether the variance of k-differences is robust when applied to more complicated processes for GNP. I fit a variety of ARMA processes to first differences of log real per capita GNP, simulated 118 observations of each process, and computed $\hat{\sigma}_k^2$ in 100 trials. In each case, the mean of $\hat{\sigma}_k^2$ at $k = 30$ was equal to the variance of the random walk component implied by the estimated ARMA processes—$k = 30$ was large enough to identify the random walk from the stationary components—and the standard errors at large k were close to those implied by table 2, scaled to the variance of the random walk component.

All the low-order ARMA processes produced $\hat{\sigma}_k^2$ lines that *rise* for k from 1 to 5 and then are flat at the variance of the random walk component from $k = 10$ on, unlike figure 1. They implied $\sigma_{\Delta z}^2 > \sigma_{\Delta y}^2$. Two processes that do capture the behavior of figure 1 are an AR(15), figure 4, and AR(2) about a deterministic trend, figure 5. In the next section, I will discuss why the low-order ARMA models failed to capture the behavior of figure 1. For now, note that since they replicate the behavior of $\hat{\sigma}_k^2$ for GNP, figures 4 and 5 can provide small-sample standard errors. These standard errors are similar to the asymptotic standard errors used in figure 1.

Figures 4 and 5 also include $\hat{\sigma}_k^2$ for GNP from figure 1, marked

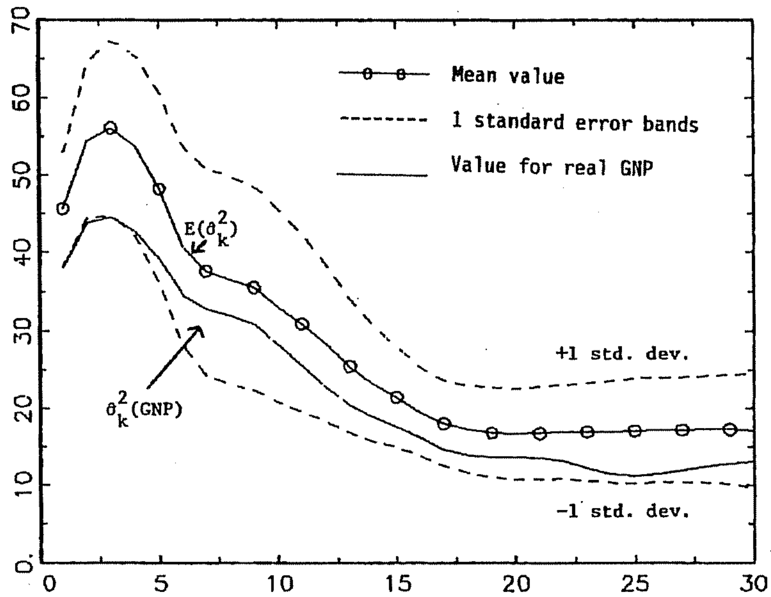

FIG. 4.—Monte Carlo simulation of an AR(15)

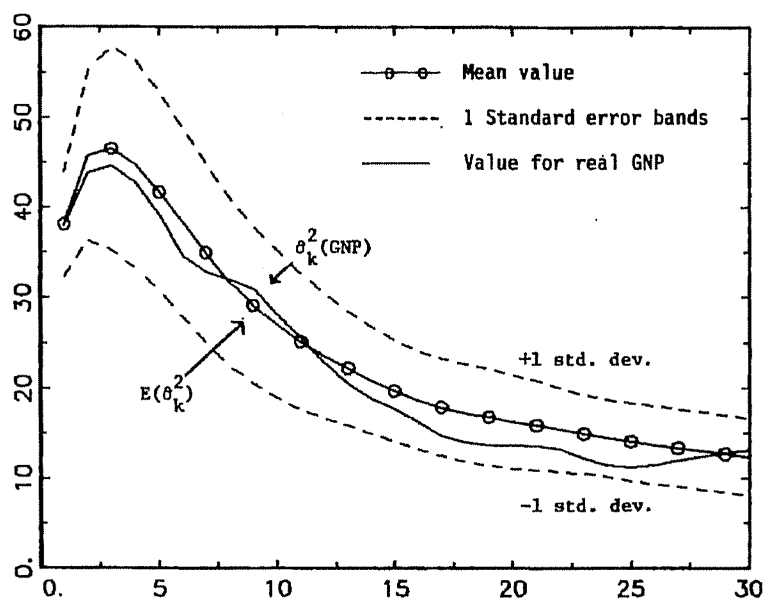

FIG. 5.—Monte Carlo simulation of an AR(2) with a linear trend

$\hat{\sigma}_k^2$(GNP). Since the $\hat{\sigma}_k^2$(GNP) line falls inside the one-standard-error bands, neither model can be rejected for real GNP. However, the standard errors from the random walk (table 2) or any of the other low-order ARMA processes are large enough that we cannot reject them at 5 percent either. (Note that the standard errors scale with the size of the random walk component. Under the hypothesis of a random walk, the standard errors are bigger than indicated in fig. 1.) A confidence interval includes both $\sigma^2_{\Delta z}/\sigma^2_{\Delta y} = 0$ and 1.

While this is unfortunate, I will argue below that estimates of a random walk component are limited by the number of nonoverlapping "long runs" in the data set, so that large efficiency gains are not possible without imposing additional structure on the time-series process for GNP. As a result, this and related exercises can provide a point estimate of the size of a random walk component with associated standard errors but will not provide useful tests to discriminate between models that imply various sizes of the random walk component.

The parameters of the AR(15) model imply that the variance ratio $\sigma^2_{\Delta z}/\sigma^2_{\Delta y} \approx .18$, while the AR(2) about a trend implies $\sigma^2_{\Delta z}/\sigma^2_{\Delta y} = 0$. Hence, the simulations behind figures 4 and 5 also reveal an *upward* bias in $\hat{\sigma}_k^2$ as an estimate of the random walk component when the series has a small random walk component or is trend-stationary.

In summary, $1/k$ times the variance of k-differences $\hat{\sigma}_k^2$ provides an upward-biased point estimate of the variance ratio $\sigma^2_{\Delta z}/\sigma^2_{\Delta y}$ of about .34, and two models with $\sigma^2_{\Delta z}/\sigma^2_{\Delta y} = .18$ and 0 replicate the behavior of the variance of k-differences of GNP. However, standard errors are large enough that we cannot statistically reject variance ratios between zero and one at conventional levels of significance.

IV. Reconciliation with Previous Estimates

Given the definition of the random walk component in terms of the parameters of a moving average representation, (4) or (8) above, the obvious thing to do is either to estimate a parsimonious time-series model for Δy_t and calculate Σa_j or to identify and estimate a simple parametric unobserved components model like (4). Campbell and Mankiw (1987) and Nelson and Plosser (1982) did just that, respectively, and both found large random walk components. Why do Nelson and Plosser and Campbell and Mankiw find large random walk components, while Watson (1986), Clark (1987), and I find small ones? Though there are small differences in definition—which quantities we look at to measure the importance of unit roots or random walk components—the major difference is in estimation strategies.

Nelson and Plosser specified an unobserved components model of the form

$$\begin{aligned} y_t &= u_t + v_t, \\ (1 - L)u_t &= \mu + A(L)\epsilon_t, \quad \epsilon_t \text{ i.i.d.}, \\ v_t &= B(L)\delta_t, \quad \delta_t \text{ i.i.d.} \end{aligned} \tag{11}$$

(ϵ_t and δ_t may be correlated). They identified the two components from a stylized autocorrelation function of GNP growth rates. If the first autocorrelation of Δy_t is positive but the others are zero, then the only model of the form (11) that works is $A(L) = 1$ and $B(L) = (1 + \theta L)$. By examining plausible parameter values for this restricted model, Nelson and Plosser concluded that $\sigma_\epsilon^2 > \sigma_\delta^2$.[8]

Campbell and Mankiw (1987) estimated parsimonious ARMA representations of log GNP, using seasonally adjusted quarterly postwar data. They measured the importance of the random walk component by $\Sigma a_j = A(1)$, the change in z_t (the long-term forecast) in response to a unit univariate innovation in GNP. They found values for $A(1)$ equal to or larger than one, which imply an innovation variance of the random walk component greater than the variance of first differences of GNP.[9]

[8] This measure of the importance of a random walk component has the conceptual disadvantage that it depends on which arbitrary unobserved components decomposition we choose. For example, since every series of the form (11) has a unique moving average representation, we could rewrite (11) as $(1 - L)y_t = \mu + C(L)\nu_t$, ν_t i.i.d., and eliminate the stationary component. Alternatively, we could use the Beveridge and Nelson decomposition of Sec. II to make the component with a unit root into a pure random walk:

$$\begin{aligned} y_t &= z_t + c_t, \\ (1 - L)z_t &= \mu + \nu_t, \quad \nu_t \text{ i.i.d.}, \\ c_t &= C(L)\zeta_t, \quad \zeta_t \text{ i.i.d.} \end{aligned}$$

These representations are observationally equivalent to the first form (11), but the measure $\sigma_\epsilon^2/\sigma_\delta^2$ changes according to which one we choose. In contrast, the innovation variance of a random walk component is invariant to the choice of decomposition (fact 2 in Sec. II). Also, the ratio of the innovation variance of the two components is not a good measure of their relative importance because the proportion of the variance of Δy_t explained by u_t and v_t depends on the coefficients of $A(L)$ and $B(L)$ as well as the ratio $\sigma_\epsilon^2/\sigma_\delta^2$.

[9] There are some conceptual disadvantages to scaling a persistence measure by the univariate innovations of y_t. The univariate innovations are not observable and must be inferred from a model; the univariate innovations do not correspond to the "surprise" movement because we live in a multivariate environment; a series may have small innovations but a large variance. For example, $\Delta y_t = 1.5\Delta y_{t-1} - .95\Delta y_{t-2} + \epsilon_t$. For this process, $\Sigma a_j = 2.22$ but $\sigma_{\Delta z}^2/\sigma_{\Delta y}^2 = (\Sigma a_j)^2/(\Sigma a_j^2) = 0.20$. However, for the GNP data used in this paper, there is little qualitative difference between the two definitions, and the difference in results must be explained by differences in estimation strategy.

In performing the Monte Carlo simulations of Section II, I also found that low-order ARMA models of GNP imply that σ_k^2 should rise with k, and they imply a large random walk component, while in fact σ_k^2 declines and the estimated random walk component is small. To replicate the behavior of σ_k^2 for GNP, I had to estimate an AR(15) or impose a deterministic trend.

To investigate this fact further, I fit a variety of ARMA processes to GNP growth rates, ranging from white noise out to an AR(15) (see table 3).[10] All representations past white noise are adequate by usual standards: the Durbin-Watson statistics are close to 2, the significance levels of the Q-statistic are around .5, the parameters of overfit models are statistically insignificant, and so forth. But the variance ratio and Σa_j start at about 1.2 for second-order processes and decline steadily to a variance ratio of .18 and $\Sigma a_j = .5$ for an AR(15). Low-order ARMA models systematically overestimate the random walk component of GNP, even though they adequately represent the series by all the usual diagnostic tests. The question is, why?

The innovation variance of a random walk component is a property of the very long-run behavior of a series alone. It is the spectral density at the frequency $\omega = 0$ corresponding to a period or "run" of infinity, it is related to the infinite sum of the moving average coefficients $|\Sigma a_j|^2$ or the autocorrelation coefficients $(1 + 2\Sigma \rho_j)$, and it corresponds to the effect of a shock today on forecasts into the infinite future. In theory, then, we should have to wait an *infinite* amount of time to get just one observation on the size of the random walk component!

In practice, we typically believe that the dynamic response of GNP to a shock is flat after a suitable long run has arrived.[11] This belief is implicit above: the graphs stop after the thirtieth difference, reflecting a belief that after 30 years the temporary effects of business cycles are over. The number of nonoverlapping long runs is a rough guide to the number of degrees of freedom (precisely, the number of periodogram ordinates) in this exercise. With a 10–20-year long run there are no more than five to 10 independent observations in 100 years of data and two to four observations in postwar data. Obviously, using more frequently sampled data does not help.

Estimating an unobserved components model or a parsimonious

[10] I used the RATS program to perform the estimation. Autoregressive models are estimated by ordinary least squares and moving average models by conditional maximum likelihood. The unreported moving average models did not converge.

[11] Precisely, if the coefficients of the moving average representation (1) are zero past a long-run value $M < \infty$, then the derivative of the spectral density of Δy at zero is bounded. If y_t is in fact trend-stationary and the spectral density of Δy at frequency zero is in fact zero, then the slope of the spectral density of Δy at zero is also zero.

TABLE 3

ARMA REPRESENTATIONS OF GNP

	White Noise	AR(1)	MA(1)	ARMA (1, 1)	AR(2)	MA(2)	AR(3)
Durbin-Watson statistic	1.67	1.97	1.97	1.99	1.91	1.99	1.96
Q-statistic*	34.82 (30)	27.68 (29)	27.58 (29)	27.43 (28)	26.95 (29)	27.75 (29)	24.58 (27)
Significance level	.25	.54	.54	.49	.52	.48	.60
Variance ratio $(\Sigma a_j)^2/(\Sigma a_j^2)$	1.00	1.39	1.34	1.40	1.23	1.27	.97
A(1) (= Σa_j)	1.00	1.20	1.11	1.18	1.11	1.16	1.02

	MA(3)	AR(4)	ARMA (3, 1)	MA(4)	AR(5)	AR(10)	AR(15)
Durbin-Watson statistic	1.97	2.06	2.00	1.91	1.95	1.99	2.01
Q-statistic*	24.95 (27)	28.63 (26)	24.89 (26)	29.21 (26)	26.16 (25)	20.04 (20)	12.17 (15)
Significance level	.58	.33	.53	.30	.40	.46	.67
Variance ratio	.75	.74	1.07	.34	.53	.41	.18
A(1)	.89	.90	1.07	.60	.77	.69	.45

* Degrees of freedom are in parentheses.

ARMA model is an attempt to circumvent this problem. These models make identifying restrictions across frequencies: they draw inferences about the long-run (high-order autocorrelation or low-frequency) dynamics from a model fit to the short-run (low-order autocorrelation or high-frequency) dynamics. For an example that demonstrates how "effective" these procedures are, Campbell and Mankiw (1987) report estimates such as $A(1) = 1.306 \pm .073$ for the 20-year forecast of GNP. Since there are only two nonoverlapping 20-year forecasts in their data set, it is clear how heavily their estimates of $A(1)$ depend on the identifying assumption that the series follow a given low-order ARMA model.

If the short- and long-run dynamics of GNP can both be captured by the assumed time-series model, these procedures can help estimation because we have much more data on high-frequency fluctuations. However, if the long-run dynamics cannot be captured in the model used to study the short run, these identification procedures bias conclusions about long-run behavior.

I offer two ways to see this fact. First, recall that the variance of the shock to the random walk component is related to the sum of the autocorrelations by

$$\frac{\sigma^2_{\Delta z}}{\sigma^2_{\Delta y}} = 1 + 2\sum_{j=1}^{\infty} \rho_j. \qquad (12)$$

When we model short-run dynamics, we safely ignore high-order statistically insignificant autocorrelations or we slightly misspecify them by fitting a simple model. But all autocorrelations enter into (12) equally, so a large number of small high-order autocorrelations can offset a few large low-order autocorrelations.

Second, GNP growth has a positive autocorrelation at short lags and a small random walk component at long lags. A simple time-series model may not be able to capture both kinds of behavior. For example, if $(1 - L)y_t = \mu + (1 + \theta L)\epsilon_t$, we need $\theta > 0$ to capture positive first-order autocorrelation but $\theta < 0$ to capture a small random walk component. Faced with a choice, maximum likelihood estimates match the short-run behavior (they fit $\theta > 0$ in the example) and misrepresent the long-run behavior.

The Appendix contains a demonstration of this property of maximum likelihood estimates. It shows that maximum likelihood estimates of a model such as a low-order ARMA or a simple parametric unobserved components model pick parameters that match the model's and the actual spectral density over the entire frequency range. Therefore, maximum likelihood will sacrifice accuracy in the small region around $\omega = 0$ to better match spectral densities at higher frequencies.

In summary, the low-order ARMA approach of Campbell and Mankiw and the unobserved components approach of Nelson and Plosser cannot match the short-run dynamics and the small random walk component in the long-run dynamics at the same time. Faced with the choice, they capture the short-run dynamics and incorrectly imply large random walk components.

On the other hand, Clark's (1987) and Watson's (1986) decompositions can accommodate the behavior of GNP in both frequency ranges. (See, e.g., Watson's fig. 1*b*, in which he shows how his model can represent a large number of small high-order autocorrelations that a low-order ARMA cannot match.) Both Watson and Clark find a small random walk component. However, their decompositions also imply identifying restrictions to estimate long-run behavior from short-run dynamics. Since these restrictions are no more or less plausible than Nelson and Plosser's or Campbell and Mankiw's, they might not be able to capture the pattern of high-order correlations in other data sets as they seem to do for GNP.

Since the size of the random walk component is a property of the periodogram ordinate at frequency zero alone, any estimation technique must make some identifying restriction across the frequency range. The variance of k-differences assumes that past a certain k the random walk component is adequately identified, empirically determined as the point in which the graph (fig. 1) flattens out. Therefore, the variance of k-differences (or any other spectral window estimator) uses 10–20-year period information to identify the infinite-run property, the random walk component. The variance of k-differences does not use information about dynamics at business cycle frequencies to identify long-run movements, and this is its important advantage.

V. Conclusion

The variance of k-differences (fig. 1 and table 1) produced a point estimate that the innovation variance of the random walk component of GNP is about one-third the variance of yearly GNP growth rates. That estimate is upward biased for small random walk components: the parameters of two models that replicated the behavior of the variance of k-differences of GNP implied variance ratios of .18 (AR(15)) and 0 (AR(2) about a deterministic trend). I conclude that if there is a random walk component in GNP at all, it is small.

Another way to characterize these results, without reference to random walk components, is that GNP growth is positively autocorrelated at short lags, but there are many small negative autocorrelations at long lags. These bring future GNP back toward, if not all the way back to, its previously forecast value following a shock.

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These results do *not* mean that "GNP follows an AR(2) about a deterministic trend." Our forecasts of the future may quite rightly be much more variable than the "trend" in GNP we have seen in the recent 118-year past might suggest.[12] These results *do* mean that an AR(2) about a deterministic trend or a difference-stationary ARMA process with a very small random walk component is a good in-sample characterization of the behavior of GNP.

In reconciling these results with previous research, I argued that conventional criteria for time-series model identification and estimation can produce misleading estimates of the random walk component of a series like GNP. The random walk component is a property of all autocorrelations taken together, but conventional procedures concentrate on the first few autocorrelations in order to parsimoniously capture short-run dynamics. When used to estimate the size of a random walk component, they impose identifying restrictions across the frequency range to infer the long-run properties of a series from its short-run dynamics. I argued that, in the absence of credible identifying restrictions, it is best to leave the short run out altogether, as the variance of k-differences or some other spectral window estimator does.

However, this view—that we should use only long-run properties of GNP data to estimate the long-run behavior of GNP—implies that standard errors of univariate estimates of the random walk component will remain large in century-long macroeconomic data and larger still in postwar macroeconomic data because there are inherently few nonoverlapping long runs available. These observations argue against the research strategy that says that the presence of a unit root and the size of a random walk component are crucial and well-documented stylized facts that any theoretical model must replicate.

Appendix

A. *Derivation of Equation (9)*

Start with

$$(1 - L)y_t = \mu + A(L)\epsilon_t = \mu + \sum_{j=0}^{\infty} a_j \epsilon_{t-j}. \tag{A1}$$

[12] A plausible model for GNP should have some random walk component. If GNP is truly stationary about a linear trend, then the variance of the forecast error of the level of GNP is the same for all dates in the far future. As long as there is some random walk component, the variance of forecast errors will grow unboundedly over the forecast horizon. However, only a very small random walk component is required to achieve this desirable property.

Using

$$(1 - L^k)(1 - L)^{-1} = (1 + L + L^2 + \ldots + L^{k-1}),$$

$$y_t - y_{t-k} = k\mu + \sum_{j=0}^{k-1}\left(\sum_{l=0}^{j} a_l\right)\epsilon_{t-j} + \sum_{j=k}^{\infty}\left(\sum_{l=j-k+1}^{j} a_l\right)\epsilon_{t-j}. \tag{A2}$$

Taking its variance,

$$\sigma_k^2 \equiv k^{-1}\operatorname{var}(y_t - y_{t-k}) = k^{-1}\left[\sum_{j=0}^{k-1}\left(\sum_{l=0}^{j} a_l\right)^2 + \sum_{j=k}^{\infty}\left(\sum_{l=j-k+1}^{j} a_l\right)^2\right]\sigma_\epsilon^2.$$

To simplify the algebra, express σ_k^2 as a difference equation

$$k\sigma_k^2 - (k-1)\sigma_{k-1}^2 = \left[\sum_{j=0}^{\infty}\left(a_j^2 + 2a_j\sum_{l=1}^{k-1} a_{j+l}\right)\right]\sigma_\epsilon^2,$$

$$\sigma_1^2 = \left(\sum_{j=0}^{\infty} a_j^2\right)\sigma_\epsilon^2,$$

so

$$1 + 2\sum_{j=1}^{k-1}\rho_j = \frac{k\sigma_k^2 - (k-1)\sigma_{k-1}^2}{\sigma_1^2},$$

where ρ_j = the jth autocorrelation of $(1 - L)y_t$, $\rho_j = \Sigma_{l=0}^{\infty} a_l a_{l+j}/\Sigma_{l=0}^{\infty} a_l^2$. Therefore,

$$\frac{\sigma_k^2}{\sigma_1^2} = k^{-1}[1 + (1 + 2\rho_1) + (1 + 2\rho_1 + 2\rho_2) + \ldots] = 1 + 2\sum_{j=1}^{k-1}\frac{k-j}{k}\rho_j.$$

B. Derivation of $E(\hat{\sigma}_k^2)$ *for an MA(1)*

Assume that (A1) takes the form

$$(1 - L)y_t = \mu + (1 + \theta L)\epsilon_t$$

and assume that ϵ_t are i.i.d. normal. The data set is $T + 1$ observations of the levels of y_t or T observations of its first differences. By definition,

$$\hat{\sigma}_k^2 = \frac{T}{k(T-k)(T-k+1)}\sum_{j=k}^{T}\left[y_j - y_{j-k} - \frac{k}{T}(y_T - y_0)\right]^2. \tag{A3}$$

Equation (A2) specializes to

$$y_j - y_{j-k} = k\mu + \epsilon_j + \theta\epsilon_{j-k} + (1 + \theta)\sum_{l=1}^{k-1}\epsilon_{j-l},$$

and similarly for $y_T - y_0$. Collecting terms in ϵ_j and noting that $E(\epsilon_j\epsilon_k) = 0$ if $j \neq k$, we get (after some algebra)

$$E(\hat{\sigma}_k^2) = (1 + \theta)^2\sigma_\epsilon^2 - \frac{2\theta}{k}\frac{1 + (k^2/T^2) - [2k/T(T - k - 1)]}{1 - (k/T)}\sigma_\epsilon^2.$$

Note that (1) as $T \to \infty$, $E(\hat{\sigma}_k^2) \to [(1+\theta)^2 - (2\theta/k)]\sigma_\epsilon^2$; (2) as $k \to \infty$, $k < T$, $E(\hat{\sigma}_k^2) \to (1+\theta)^2\sigma_\epsilon^2 = \sigma_{\Delta z}^2$; (3) for $\theta = 0$, $E(\hat{\sigma}_k^2) = \sigma_\epsilon^2 = \sigma_{\Delta z}^2$ for all k, T such that $k < T$.

C. How Maximum Likelihood Imposes Identifying Restrictions across Frequencies

Let $x_t = (1 - L)y_t = A(L)\epsilon_t$. Assume that $A(0) = 1$, that $A(L)$ is one-sided and has zeros outside the unit circle, so that the spectral density of x is bounded away from zero, and that A has an inverse, so that x has an autoregressive representation $B(L)x_t = \epsilon_t$. Consider estimating $A(L)$ or $B(L)$ by maximum likelihood via a simple time-series or unobserved components model. For simplicity, assume infinite data, $\epsilon_t \sim N(0, \sigma_\epsilon^2)$, and σ_ϵ^2 known. (The same point survives generalization to more complex estimation environments.) In this case, maximum likelihood is equivalent to

$$\min E[\hat{B}(L)x_t]^2 \quad \text{subject to } \hat{B}(L) \in \mathfrak{B}, \tag{A4}$$

where $\hat{B}(L)$ is the autoregressive representation of the estimated model, and $\mathfrak{B}$ is the restricted space of autoregressive representations allowed by the chosen time-series model. Since variance is the integral of spectral density, (A4) is the same as

$$\min(2\pi^{-1}) \int_{-\pi}^{\pi} |\hat{B}(e^{-i\omega})|^2 S_x(e^{-i\omega})d\omega \quad \text{subject to } \hat{B}(e^{-i\omega}) \in \mathfrak{B}. \tag{A5}$$

The following expression is equivalent:

$$\min \int_{-\pi}^{\pi} |\hat{B}(e^{-i\omega}) - B(e^{-i\omega})|^2 S_x(e^{-i\omega})d\omega \quad \text{subject to } \hat{B}(e^{-i\omega}) \in \mathfrak{B}. \tag{A6}$$

To see this, expand $|\hat{B} - B|^2$ and substitute $AA^*\sigma_\epsilon^2 = S_x$ (an asterisk denotes complex conjugation; I dropped the $e^{-i\omega}$'s). Then (A6) becomes

$$\min \int_{-\pi}^{\pi} (\hat{B}\hat{B}^* + BB^* - B\hat{B}^* - B^*\hat{B})AA^*d\omega. \tag{A7}$$

The first term is just (A5). Since $A^{-1} = B$, the second term is 2π, and the third and fourth are

$$\int_{-\pi}^{\pi} (\hat{B}A + \hat{B}^*A^*)d\omega.$$

Under the assumption that A and B are one-sided and that $A(0) = B(0) = 1$,

$$\int_{-\pi}^{\pi} \hat{B}A\,d\omega = \int_{-\pi}^{\pi}\left(1 + \sum_{j=1}^{\infty} \hat{b}_j e^{-i\omega j}\right)\left(1 + \sum_{j=1}^{\infty} a_j e^{-i\omega j}\right)d\omega;$$

since $\int_{-\pi}^{\pi} e^{-i\omega j}d\omega = 0$, $\int_{-\pi}^{\pi} \hat{B}A\,d\omega = \int_{-\pi}^{\pi} \hat{B}^*A^*d\omega = 2\pi$. Therefore, (A6) reduces to (A5) plus constants.

Equation (A6) is analogous to Sims's (1972) approximation formula, reproduced in Sargent (1979, p. 293). The message of (A6) is that maximum likelihood attempts to match the frequency response of the autoregressive representation across the entire frequency range, weighted by the true spectral density of x_t. The method of maximum likelihood will sacrifice accuracy of the estimated $B(e^{-i\omega})$ at a point in the frequency range ($\omega = 0$) in order to achieve a better fit over an interval. Similarly, it will sacrifice accuracy in a small window (20 years to infinity is $\pi/10$ wide) to gain accuracy in a large window (2–4 years is $\pi/2$ wide). If $S_x(e^{-i\omega})$ is smaller near $\omega = 0$ than elsewhere, as the variance of k-differences suggests for GNP, then (A6) shows that maximum likelihood further deemphasizes accuracy in windows about zero.

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CASE: UE 210
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 810

Exhibits in Support Of Opening Testimony

July 24, 2009

Docket No. 08-035-38

Committee of Consumer Services Witness:

Daniel J. Lawton
Exhibits CCS 3.1 through 3.9

January 8, 2009

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Services Rates In Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations	§ § § § § § §	**Docket No. 08-035-38** **Direct Rate of Return Testimony of Daniel J. Lawton For the Committee of Consumer Services**

January 8, 2009

TABLE OF CONTENTS

DIRECT TESTIMONY OF DANIEL J. LAWTON

SECTION I: INTRODUCTION/BACKGROUND/SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Daniel J. Lawton. My business address is 701 Brazos, Suite 500, Austin, Texas 78701.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I have been working in the utility consulting business as an economist since 1983. Consulting engagements have included electric utility load and revenue forecasting, cost of capital analyses, revenue requirements/cost of service reviews, and rate design analyses in litigated rate proceedings before federal, state and local regulatory authorities. I have worked with municipal utilities developing electric rate cost of service studies for reviewing and setting rates. In addition, I have a law practice based in Austin, Texas. My main areas of legal practice include administrative law representing municipalities in electric and gas rate proceedings and other litigation and contract matters. I have included a brief description of my relevant educational background and professional work experience in Exhibit CCS 3.1.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN RATE PROCEEDINGS?

A. Yes. A list of cases where I have previously filed testimony is included in my Exhibit CCS 3.1.

Q. ON WHOSE BEHALF ARE YOU FILING TESTIMONY IN THIS PROCEEDING?

A. I have been retained to review Rocky Mountain Power's ("Company" or "RMP") cost of capital request on behalf of the Committee of Consumer Services ("Committee").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to address the Company's requested overall cost of capital. I will address the Company's requested rate of return, capital structure, and cost rates for equity, debt and preferred stock, which is presented in the direct testimony and second supplemental direct testimony of its cost of capital witnesses, Dr. Samuel Hadaway and the direct and second supplemental testimony of Mr. Bruce Williams.

In addition, I will address the second supplemental direct testimony of RMP witness Walje regarding the rate increase and the business risk impacts of cutting specific costs and services to Utah customers.

Q. WHAT MATERIALS DID YOU REVIEW AND RELY ON FOR THIS TESTIMONY?

A. I have reviewed the Company's testimony (both direct and supplemental), Company responses to interrogatories, Value Line Investment Survey ("Value Line"), financial reports of the Company, and various other financial information available in the public domain. When relying on other sources, I have referenced such sources in my testimony and on attached schedules and included copies or summaries in my attached schedules or workpapers.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE.

A. My analyses of the Company's 8.69% overall cost of capital and 11.0% return on equity indicate that the Company's request is overstated given current costs of debt and equity capital. I have calculated an alternative cost of long-term debt and common equity for this case which would result in an overall cost of capital of 8.10%, to be earned on RMP's rate base investment.

Based on my analyses (which are fully explained in the following pages), I make the following conclusions and recommendations:

(i) The Company's proposed 8.69% overall return on investment is overstated and should not be adopted as representative of the Company's cost of capital requirements;

(ii) RMP's proposed 11.0% return for equity shareholders is an overstatement of the required return on equity to hold and attract equity capital;

(iii) The Company's required return on equity is 10.0%;

(iv) The Company's estimated interest cost of an $800 million pro forma long-term debt issue of 8.47% is excessive;

(v) The Company's interest cost for new long-term debt issues should be 6.07%, resulting in an overall long-term debt cost for the test year of 6.08%; and

(vi) The Company's overall cost of capital to be earned on rate base investment should be set at 8.10% for setting just and reasonable rates for Utah customers in this proceeding.

SECTION II: <u>REGULATORY ISSUES AND COST OF CAPITAL</u>

Q. PLEASE EXPLAIN THE COST OF CAPITAL CONCEPT AS IT RELATES TO THE REGULATORY PROCESS.

A. The overall rate of return to be earned on rate base investment is an essential element in the regulatory and rate setting process. The overall return to be earned on rate base investment is typically a major part of overall revenue requirements. For example, in this case the Company's requested overall return is 8.69%[1] and the Company's requested rate base is $4,549,640,747.[2] Thus, the Company's requested overall return is $395,363,781 (8.69% x $4,549,640,747). Return on rate base investment represents approximately 26% of total requested annual revenue requirements of $1,546,937,908. In other words, 26 cents of every dollar collected from customers goes to satisfy after tax return requirements of the Company.

A small change in return requirements can have a large impact on revenue requirements. For example, I am recommending an overall return of 8.10% in this case. The before tax impact of this return change is about a $26.8 million reduction to the Company's costs. The impact is larger when the associated federal income tax impact is included.

Q. PLEASE EXPLAIN HOW THE VARIOUS COMPONENTS OF COST OF CAPITAL ARE DETERMINED.

A. The overall rate of return in the regulatory process is best explained in two parts. First,

[1] Second Supplemental Direct Testimony Bruce Williams at 7:142-149.
[2] See Exhibit RMP__ (SRM-1SS) p.2, line 61.

return to senior securities, such as debt and preferred stock, which is contractually set at issuance. The reasonableness of the cost of this contractual obligation between the utility and its investors is examined by regulatory agencies as part of the utility's overall cost of service.

The second part of a company's overall return requirement is the appropriate cost rate to assign the equity portion of capital costs. The return to equity should be established at a level that will permit the firm an opportunity to earn a fair rate of return. By fair rate of return, I mean a return to equity holders, which is sufficient to hold and attract capital, sufficient to maintain financial integrity, and a return to equity comparable to other investments of similar risks.

Two U.S. Supreme Court decisions are often cited as the legal standards for rate of return determination. The first is *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia*, 262. U.S. 679 (1923). The *Bluefield* case established the following general standards for a rate of return: The return should be sufficient for maintaining financial integrity and capital attraction and a public utility is entitled to a return equal to that of investments of comparable risks.

The second U.S. Supreme Court decision is the *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1942). In the *Hope* decision, the Court affirmed its earlier *Bluefield* standards and found that methods for determining return are not the test of reasonableness rather the result and impact of the result are controlling.

The cost of capital is defined as the annual percentage that a utility must receive to maintain its financial integrity, to pay a return to security owners and to insure the continued attraction of capital at a reasonable cost and in an amount adequate to meet future needs. Mathematically, the cost of capital is the composite of the cost of several classes of capital used by the utility – debt, preferred stock, and common stock, weighted on the basis of an appropriate capital structure.

The ratemaking process requires the regulator to determine the utility's cost of capital for debt, preferred stock and equity costs. These calculations of cost rates, when combined with the proportions of each type of capital in the capital structure, result in a percentage figure that is then multiplied by the value of assets (investment) used and useful in the production of the utility service to ultimately arrive at a rate charged to customers. Rates should not be excessive (exceed actual costs) or burdensome to the customer and at the same time should be just and reasonable to the utility.

In summary, the objective of overall rate of return determination in the regulatory process is to compute the return such that the embedded (contractually required) cost of senior securities is recovered. In addition, a regulated utility should be provided an opportunity to generate additional earnings that are sufficient to compensate equity investors at a level that will hold existing investors, attract new investors, and maintain the financial integrity of the utility.

Q. PLEASE EXPLAIN THE COST OF EQUITY CONCEPT.

A. The cost of equity, or return on equity capital, is the return expected by investors over some prospective time period. The cost of equity one seeks to estimate in this proceeding is the return investors expect prospectively when the rates from this case will be in effect.

The cost of common equity is not set by contract, and there are no hard and fast mathematical formulae with which to measure investor expectations with regard to equity requirements and perceptions of risk. As a result, any valid cost of equity recommendation must reflect investors' expectations of the risks facing a utility.

Q. WHAT PRINCIPAL METHODOLOGY DO YOU EMPLOY IN YOUR COST OF EQUITY CAPITAL ANALYSES?

A. I employ the Discounted Cash Flow ("DCF") methodology for estimating the cost of equity, keeping in mind the general premise that any utility's cost of equity capital is the risk free return plus the premium required by investors for accepting the risk of investing in an equity instrument. It is my opinion that the best analytical technique for measuring a utility's cost of common equity is the DCF methodology. Other return on equity modeling techniques such as the Capital Asset Pricing Model ("CAPM") or risk premium are often used to check the reasonableness of the DCF results.

Q. PLEASE DESCRIBE THE RISKS YOU REFER TO ABOVE.

A. As I stated earlier in this testimony, equity investors require compensation above and beyond the risk free return because of the increased risk factors investors face in the equity markets. Thus, investors require the risk free return plus some risk premium above the risk free return. The basic risks faced by investors that make up the equity risk premium include business risks, financial risks, regulatory risks, and liquidity risks.

Q. PLEASE DESCRIBE ROCKY MOUNTAIN POWER.

A. The Company is one of three business units owned by PacifiCorp. The Rocky Mountain Power business unit provides electrical service to customers in Utah, Wyoming and Idaho. PacifiCorp was acquired and is now a division owned by MidAmerican Energy Holdings Company ("MEHC") in 2006. The equity investment of Rocky Mountain Power is not publicly traded.

Q. PLEASE DISCUSS YOUR UNDERSTANDING OF THE COMPANY'S UPDATED REVENUE REQUIREMENT FILING AND THE TEST YEAR ORDERED BY THE PUBLIC SERVICE COMMISSION OF UTAH ("COMMISSION") IN THIS CASE.

A. On December 8, 2008, the Company filed an updated case to reflect this Commission's determination of a December 31, 2009 ending test year. The Company's current rate increase request is approximately $116.1 million annually. The rate request includes an overall return on investment of 8.69% which includes a return to equity shareholders of 11.0 percent.

SECTION III: <u>CURRENT CAPITAL MARKET CONDITIONS</u>

Q. ARE CURRENT ECONOMIC CONDITIONS DECLINING AS WE END THE LAST QUARTER OF 2008?

A. Yes. The U.S. and global financial markets continue to struggle with liquidity issues following the collapse of the subprime mortgage markets. The Federal Reserve and central banks around the world have been ramping up lending in an all out effort to keep the financial markets functioning.

The Federal Reserve Chairman, Bernanke predicts that the global financial markets crisis will restrain the U. S. economic growth well into 2009. Thus, while inflation issues have recently receded, economic conditions have worsened prospects of economic growth.

The Federal Reserve has taken numerous steps to address financial market issues including the recent cut in the federal funds rate to a target range of 0% to 0.25% as of December 16, 2008. While rates for longer-term Treasury Bonds (20 and 30 year) are lower than levels in early 2006, the shorter term rates on Treasury Bills have declined dramatically. High quality corporate bond rates Aaa level until October 2008 have been consistent with interest rate levels ranging back to early 2006. Now, again these higher quality corporate debt securities have seen yield declines of over 100 basis points in December 2008. But, lower quality BBB corporate bond rates have increased by about 200 basis points in the past two years. Again, the December 2008 levels show a yield decrease even for lower quality BBB debt securities. I have included in my Exhibit CCS 3.2 monthly bond yields for various securities showing changes by month since January 2006 through December 2008.

Q. HAVE STOCK PRICES DECLINED AS A RESULT OF THE FINANCIAL MARKET PROBLEMS?

A. Yes, the Dow Jones Industrial Average ("DJI") declined from about the 14,000 level in November 2007 to 8451 on October 10, 2008. Most of this 5600 point drop in the DJI occurred in the first 10 days of October 2008. Many investors in a flight to safety moved funds from stocks to short-term Treasuries driving 3 month Treasury rates well below 1%. Also, the Dow Jones Utility Average ("DJU") like the DJI dropped substantially during the first part of October 2008.

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS CONCERNING THE RECENT TRENDS IN ECONOMIC CONDITIONS AND THE IMPACT ON CAPITAL COSTS?

A. Yes. As a general matter the U.S. economy has enjoyed general growth, prosperity and stability since the early 1990's. Over this time period there has been a general level of economic expansions accompanied by historical low levels of inflation and interest rates.

Now, the economy has slowed significantly at least initially as a result of the "sub-prime" mortgage problems and more recently as a result of the liquidity crisis in the financial markets. Moreover, the economic slow down is having global impacts as can be seen in declining energy prices (natural gas, oil) as well as general commodity prices.

The financial sector crisis has intensified in recent months with the collapse and/or bailout of such institutions as Bear Stearns, Lehman Brothers, Merrill Lynch, Freddie Mac, Fannie Mae, AIG and Citigroup, Inc. The U. S. Government and governments around the world have been and continue to employ unprecedented monetary actions to minimize the impacts of the financial crisis on economic growth. While the impacts of these government rescue efforts and other monetary policy actions have not yet resolved all the tight credit market problems – that does not mean there has been no impact or continued impact. For example, the upward trend in corporate bond yields for AAA and BBB rated debt has reversed in December 2008 as shown in my Exhibit CCS 3.2.

The one sure thing is that economic slow down has occurred and is expected to continue. For this reason economic growth will be lower than past forecast estimates have suggested. This is true across all economic sectors including the utility industry. Thus, while utility stock prices may be lower and dividend yields rise – the other side of the coin shows lower economic growth expectations by investors.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM CURRENT ECONOMIC CONDITIONS IN PROVIDING GUIDANCE IN SETTING EQUITY CAPITAL COSTS IN THIS PROCEEDING?

A. As a general matter capital costs remain low in comparison to historical levels. While the bottom tier of corporate bond rates (BBB) has increased dramatically since September 2008 – such increases do not appear to be a trend, but rather the direct impact of an atypical event in the capital markets. As I stated above, BBB bond yields decreased 76 basis points between November and December 2008. Moreover, the economic slow down or recession will cause general investor expectations of growth to decline. The bottom line is that the general economic data does not support increasing capital costs. Further, it is not sound ratemaking to establish revenue requirements and rates on atypical or abnormal events – especially when such events (continuation of the financial crisis) are not likely to continue for a long period of time.

Q. IN YOUR OPINION SHOULD THE COMMISSION SET RATE OF RETURN IN THIS CASE BASED ON THE EVENTS AND RESULTS OF THE RECENT FINANCIAL/LIQUIDITY CRISIS?

A. Only if the Commission believes that these economic factors are representative of the future when the final rates are implemented for RMP customers. In my opinion these events are not going to continue and the market will adjust.

While certainly there does appear to be significant economic slow down in the future, recent market events are not likely to be repeated in the near term future. Central banks across the world are now working together to restore and assure confidence in the financial markets. These central banks including the Federal Reserve have developed bail out plans, rescue packages, lowered interest rates, and guaranteed bank lending along with a list of other programs to address these economic/financial issues.

SECTION IV <u>COST OF EQUITY CAPITAL DCF ANALYSIS</u>

Q. YOU STATED ABOVE THAT YOU RELIED ON A DCF ANALYSIS. PLEASE DESCRIBE HOW YOU CONDUCTED YOUR DCF ANALYSIS.

A. For my DCF analyses I employ a comparable risk group of companies because there is no market financial data for RMP. The Company is a division of PacifiCorp which is a wholly owned subsidiary of MidAmerican Energy Holding Company. Thus, without financial data a DCF analysis cannot be computed directly on RMP or for that matter PacifiCorp. The comparable risk group of companies for which there is market data available serve as a proxy for RMP.

I applied the DCF method employing market data, as well as forecasted data of various financial parameters to a comparable group of fifteen electric utility companies. The comparable group of fifteen utility companies employed in my analysis comes from the same group of companies used by RMP's witness Dr. Hadaway in this case. Given that I am basing my analysis on the same group of comparable companies as employed by Dr. Hadaway, the equity cost calculation issue is narrowed to the methodology of estimation. I discuss in detail in Section VII the problems I have with Dr. Hadaway's specific cost of equity analyses.

Q. WHY HAVE YOU EXAMINED COMPARABLE ELECTRIC COMPANIES?

A. There are several reasons why the estimate of a cost of capital requires an analysis of a group of comparable risk companies rather than the single firm subject of the analysis:

(1) A comparable risk group analysis is consistent with the requirements of a fair and reasonable return addressed in the *Hope* and *Bluefield* cases. The return on investment should be commensurate with returns earned by firms with comparable risk. Thus, there is a need to examine firms of comparable risk to identify the fair and reasonable comparable returns being earned. In addition, the equity returns of comparable firms are viewed as opportunity costs of forgone investments in the market which, like other investment opportunities, will directly impact the cost of equity of the Company.

(2) The reliability of the cost of equity estimate is enhanced when the calculation is based on equity capital estimates from a variety of risk equivalent companies. A group of comparable companies can be employed as a check on a single company analysis. Further, the comparable group analysis, whether employed as a check or the primary analysis, mitigates any distortions resulting from measurement errors in dividend yield and expected growth measures and estimates. For example, the average growth rate estimate based on forecasts of several comparable firms is less likely to deviate from investor expectations of growth than an estimate for a single firm. Moreover, the general assumptions underlying the DCF model are more likely to be met for a group of companies than for a single firm.

(3) An analysis of a comparable group also avoids circularity problems. In the analysis of investor-owned utilities, the stock price (that is, the cost of capital) is a direct function of an investor's growth rate expectations, which is also a function of an investor's perception of the regulatory environment. The bottom line is that the cost of equity depends in part on the anticipated regulatory environment and actions. Thus, both the components of the DCF model – dividend yield and growth expectations – are influenced by the regulatory process.

(4) Extending the sample size of comparable companies beyond a single regulatory influence will mitigate the regulatory circularity problem. Specific conditions concerning a subject utility often requires that a comparable company analysis be employed. One of the most common conditions is the lack of market data necessary to perform a DCF analysis. In times of utility consolidation and merger, many electric utilities are owned and controlled by a single parent holding company, which is the case with RMP.

Q. HAVE YOU PROVIDED A LISTING OF THE COMPANIES IN THE COMPARABLE GROUP?

A. Yes. Contained in my Exhibit CCS 3.3 is a list of the fifteen companies in the comparable group along with additional data of Company Beta and equity ratio projected for 2008, 2009 and 2012.

Q. PLEASE EXPLAIN THE DCF METHODOLOGY YOU HAVE EMPLOYED IN YOUR ANALYSIS.

A. The foundation of the DCF model is in the theory of security valuation. The price that an investor is willing to pay for a share of common stock today is determined by what income stream the investor expects to receive from the investment. The return the investor expects to receive over the investment time horizon is composed of: (i) dividend payments, and (ii) the appreciated sale value of the investment. A proper analysis adds dividends to the gain on the final sale value, and discounts these expected future earnings to a percent value.

To determine or estimate investor requirements using the DCF model, one computes a cost of capital requirement, or discount rate from the current market data and the expected dividend stream. The DCF model stated as a formula is as follows:

$K = D/P + G$

where:

K = required return on equity,

D = dividend rate,

P = stock price,

D/P = dividend yield, and

G = growth in dividends.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE DIVIDEND YIELD FOR THE COMPARABLE COMPANIES.

A. The dividend yield is the ratio of the dividend rate to the stock price. When calculating the dividend yield, one must be cautious and not rely on spot stock prices. One must be equally cautious not to rely on long periods of time as the data becomes unrepresentative of market conditions. The objective is to use a period of time such that the resulting dividend yield is representative of the prospective period when rates will be in effect.

While there is no fixed period for selecting the denominator of the dividend yield (i.e., stock price), the key guideline is that the yield not be distorted due to fluctuations in stock market prices. On the other hand, dividends, the numerator of the yield calculation, are relatively stable, as opposed to the stock prices, which are subject to daily and cyclical market fluctuations. The selection of a representative time period will dampen the effect of stock market changes.

The price and dividend data used for each of the companies in the comparable group is contained in my Exhibit CCS 3.4.

As I discussed in Section III of this testimony there has been substantial volatility in the market during the first part of October 2008 due to impacts associated with the current financial market crisis. For these reasons I have employed an average 52-week high and low price for the twelve month period ending December 15, 2008. For this period I employ the average of the high and low stock prices to calculate a representative price for the dividend yield calculation.

To calculate dividends, I employed the current Value Line estimate for next year's 2009 dividend to estimate dividend payment expected by investors. The resulting dividend yield is shown on my Exhibit CCS 3.4 for the comparable group.

Q. HOW DOES YOUR DIVIDEND YIELD CALCULATION COMPARE TO DR. HADAWAY'S ESTIMATES?

A. As shown on my Exhibit CCS 3.4 the comparable group average dividend yield is between 4.62% and 4.66%. Dr. Hadaway's analysis shown in his Exhibit RMP __(SCH-3SS) page 2 of 5, shows a dividend yield range for the comparable group of

4.56% to 4.65%. The average of his range is 4.60% which is consistent with my 4.60% estimate for the comparable group.

Q. PLEASE EXPLAIN HOW YOU HAVE CALCULATED THE EXPECTED GROWTH RATE IN YOUR DCF ANALYSIS FOR THE COMPANIES IN THE COMPARABLE GROUP.

A. Like dividend yields, there exists no single or simple method to calculate growth rates. The calculation of investor growth expectations is the most difficult part of the DCF analysis. To estimate investor expectations of growth, I have examined historical growth and forecasted growth rates, and other financial data for each of the companies in the comparable group.

Implementation of the DCF model requires the exercise of considerable judgment with regards to estimating investor expectations of growth and it is a difficult task, but such difficulties are not insurmountable. Many factors affect capital markets in general and individual stocks specifically, investors are aware and informed of current economic conditions and expectations. Such economic variables entail the current state of the economy, the trade deficit, federal budget uncertainty, fiscal policy, inflation and Federal Reserve Board policies on interest rates.

Investors generally have good information on the economic and financial variables outlined above. All of this information is available quickly, especially in recent decades with easy access to the worldwide web. This information influences return expectations and, as a result, the maximum price an investor will pay for various securities.

Like the information available on the general economy, investors also have access to a wealth of information about particular types of securities, industries and specific company investments. This information is also factored into investor expectations and therefore the stock price individuals are willing to pay.

Common earnings growth rate forecasts and historical growth rate data may be found in the Value Line Investment survey ("Value Line") publication. These Value Line earnings estimates are five year projections in annual earnings. Again, Value Line is widely available to the public, and is a good source of earnings projections. Other earnings estimates are forecasted by Zacks as well as First Call projections, widely available on the internet at Zacks.com and Yahoo Finance respectively. Those earnings projections along with other stock specific financial data provide a range of estimates of earnings and are readily available at no cost.

Another growth estimate is referred to as the sustainable growth or retention ratio growth estimate. To project future growth in earnings under the sustainable growth method, one multiplies the fraction of a firm's earnings expected to be retained (not paid out as dividends) by the expected return on book equity. As a formula:

(growth = b x r)

Where:

b =1-(dividends per share/earnings per share)

r =earnings per share / net book value share

All the data necessary to calculate the elements of the sustainable growth method are available on a forecasted basis in Value Line.

Q. PLEASE EXPLAIN YOUR GROWTH RATE ANALYSIS.

A. I have included in my Exhibit CCS 3.5 the growth rates I have reviewed in my analysis. The first set of growth rates examined is the five year and ten year historical growth rates in earnings per share, dividends per share, and book value per share as reported by Value Line. The second set of growth rates is the Value Line forecasted growth rates in earnings per share, dividends per share, and book value per share for each company in the comparable group. The third set of growth rates examined is the Zacks forecasted growth rates in earnings. The fourth growth estimate considered is the First Call growth rates which are readily available to investors at Yahoo Finance.

In addition, I have examined the growth rates based on the forecasted retention ratio growth estimate discussed above. These calculations are included in my Exhibit CCS 3.5.

The growth rates described above provide a range of estimates for each of the comparable companies. The resulting range of average growth rates for the group is from 4.0% to 6.0% when looking at internal growth forecasts and earnings per share

("EPS") forecast estimates for the comparable group. Relying on the combined forecasted earnings per share estimates and internal growth rate estimates, the growth rate average range can be narrowed to 5.0% to 5.2% as shown in Exhibit CCS 3.5.

Q. HOW DO THESE GROWTH RATES COMPARE TO GROWTH ESTIMATES EMPLOYED BY DR. HADAWAY?

A. Reviewing Dr. Hadaway's Exhibit RMP__(SCH-3SS) page 2 of 5, it appears Dr. Hadaway has relied upon a 6.12% growth average for the comparable group. This estimate is limited to Value Line, Zacks and Yahoo Finance estimates that are both outdated and overstated. The end result is Dr. Hadaway's estimates should not be relied on in this case.

Q. PLEASE SUMMARIZE YOUR CONSTANT GROWTH DCF ANALYSIS.

A. I have summarized these results in my Exhibit CCS 3.6. For the comparable group based on an average yield of 4.6% to 4.7% and a growth rate range of 5.0%[3] to 5.2%[4] the ROE estimate based on the comparable group is 9.8% to 10.0%. Employing the midpoint of the range for these estimates results in an ROE estimate of 9.9%.

Q. HAVE YOU CALCULATED ADDITIONAL DCF ANALYSES FOR THE COMPARABLE GROUP COMPANIES?

A. Yes. I have calculated a two stage non-constant growth DCF analysis for the comparable group companies.

Q. PLEASE DESCRIBE YOUR TWO-STAGE NON-CONSTANT GROWTH DCF.

This analysis calculates equity cost using a non-constant growth Two Stage DCF Model. The constant growth DCF model is often adjusted to reflect multiple growth assumptions because the constant growth rate assumption is often not consistent with investor expectations. As an example, it is often the case where short-term growth estimates are not consistent with long-term sustainable growth projections. In those instances, where more than one growth rate estimate is appropriate, a multi-stage non-constant growth model can be employed to derive a cost of capital estimate. In other

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[3] Forecasted average EPS for Value Line, Zacks and Yahoo Finance and Internal Growth.

[4] Forecasted EPS Value Line, Zacks and Yahoo Finance.

words, the constant growth model is adjusted to incorporate multiple growth rate periods, assuring a constant growth (long-term) rate is estimated for a longer period.

For the first growth stage (years 1-4) of the model, the Value Line growth in dividends is employed and an annual dividend is calculated. The second stage (years 5 and beyond)[5] an earnings growth estimate based on the comparable group average of 5.5% is employed. This long-run earnings estimate is based on the Value Line, Zacks, and First Call earnings forecasts along with the internal growth estimate. I employed a 5.5% midpoint of the 5% to 6% range.

In the two-stage model the dividend cash flows are discounted equal to the price[6] paid for the stock. The calculated discount rate or internal rate of return is the cost of equity capital estimate.

Q. WHAT ARE THE RESULTS OF THE TWO-STAGE NON-CONSTANT GROWTH DCF ANALYSIS?

A. The results of the two-stage non-constant growth DCF analysis are shown in Exhibit CCS 3.7. The comparable group average indicates a cost of equity of 10.0% and 10.2%.

Q. PLEASE SUMMARIZE YOUR DCF ESTIMATES.

A. The table below is a summary of the DCF results:

TABLE 1
SUMMARY OF COMPARABLE GROUP DCF ANALYSES

Description		**COMPARABLE GROUP**
Constant Growth DCF		9.8% to 10.0%
Non-Constant Growth Two Stage DCF		10.0% to 10.2%

This range of estimates of 9.8% to 10.2% indicates a cost of equity of about 10% for the group.

SECTION V: <u>RISK PREMIUM/CAPM COST OF EQUITY ESTIMATE</u>

Q. PLEASE DESCRIBE THE RISK PREMIUM ANALYSIS.

A. Debt instruments such as bonds (long-term debt) are less risky than common equity

[5] The model is ended at year 150.
[6] Price is based on the 52 week average of the high and low price discussed earlier.

when both classes of capital are issued by the same entity. Bondholders have a prior contractual claim to the earnings of the corporation and returns on bonds are less variable and more predictable than stocks. The bottom line is that debt is less risky than equity. There are numerous return studies of capital market investments, all of which show lower returns with lower risks and higher returns with higher risk investments. These financial truisms provide a sound theoretical basis and foundation for the risk premium method for estimating equity costs. The risk premium approach is useful in that the analysis is based on current market interest rates, that is, the current observable cost of debt capital. But, the risk premium approach is not without its problems and drawbacks. In practice, there is considerable debate as to the time period to analyze in the determination of the bond/equity return risk spread. Historical debt/equity risk spreads measured over many decades may not be relevant to current capital market requirements. Others argue that a long-term analysis is necessary, since the goal is to measure investors' long-term expectations.

Another version of the risk premium method is the capital asset pricing model ("CAPM"). Generally, the CAPM begins with a theoretically risk-free interest rate such as a three-month Treasury bill rate. The risk premium, or equity spread above and beyond the risk free rate is adjusted by the stock beta.[7] The risk free return measure is combined with the equity risk premium adjusted for the measure of beta to arrive at a CAPM result.

Like the risk premium discussed above, the CAPM is subject to measurement uncertainties. First, the general problem of how to measure the equity risk premium and the time period for which the premium is analyzed is subject to considerable debate. This problem and associated criticisms is generic to all variants of the risk premium model. Second, measures of beta are often unstable from period to period and may not reflect the equity risk spread measure.

For all of the above reasons, risk premium methods should be viewed with considerable caution. The risk premium analysis and CAPM described below consists of analyses of

[7] Beta is a measure of the volatility of the specific stock movement relative to that of a market measure such as the S&P 500. A beta below 1.0 means that a specific stock is less volatile than the market measure, while a beta above 1.0 indicates a specific stock is more volatile than the market measure.

A. I have applied the CAPM to each company in the comparable risk group as is show in my Exhibit CCS 3.9. For the risk free rate I have employed a three month average yield (October 2008 – December 2008) for 20 year U.S. Treasury Bonds. Over the 3 month period 20 year Treasury Bonds had an average yield of 4.03%.

The market risk premium component (Rm-Rf) represents the investor expected risk premium over the risk free return. For this calculation I have relied on the 2008 Morningstar yearbook which provides long-term (1926-2007) market and government bond returns. The market return over this time horizon is 10.4%[8] while the long-term government bond return is 5.5%[9] resulting in a risk premium of 4.9% based on the geometric average return calculation. I also ran the calculation employing arithmetic average returns which show a market return (1926 – 2007) of 12.3%[10] and a long-term government bond return of 5.8%[11] resulting in a risk premium of 6.5%.

Q. PLEASE DESCRIBE THE BETA YOU EMPLOYED IN YOUR CAPM ANALYSIS.

A. Beta is a measure of specific stock volatility relative to a market index. Betas less than 1.0 move less that the market while Betas greater than 1.0 have more movement or volatility relative to a market index. For this case I employed the Value Line Betas for each company in the comparable group.

Q. WHAT ARE THE RESULTS OF YOUR CAPM ROE ESTIMATES?

A. My analysis for CAPM is contained in my Exhibit CCS 3.8. The CAPM result is 8.91%.

Q. PLEASE SUMMARIZE YOUR DCF, RISK PREMIUM AND CAPM ANALYSES?

A. The following table 2 summarized the cost of equity results for each analysis:

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[8] Morningstar at 31.
[9] *Id.*
[10] *Id.*
[11] *Id.*

shorter time horizons and are employed as a check on the DCF results described earlier.

Q. HOW DID YOU CALCULATE YOUR RISK PREMIUM ANALYSIS?

A. For the calculation of risk premium I employed the basic analysis presented in Dr. Hadaway's Direct Testimony at Exhibit RMP__(SCH-5) page 1 of 2. This analysis is updated and corrected for a more reasoned estimate of expected single-A bond yield. I outline the calculations in my Exhibit CCS 3.8. Employing a single-A debt rate of 6.07% and a 4.46% risk premium, results in a risk premium estimate of 10.5%.

Q. DID YOU CALCULATE AN ALTERNATIVE RISK PREMIUM?

A. Yes. An alternative analysis entailed calculating a risk premium based on the difference between returns on stocks (10.4%) and the returns on long-term corporate bonds (5.9%) for the period covering 1926 – 2007 as reported in the 2008 Stocks, Bonds and Inflation Classic Yearbook published by Morningstar, Inc. The resulting risk premium is 4.5% (10.4% - 5.9%=4.5%) employing the geometric mean average returns. Combining a 4.5% risk premium and a 6.07% single-A debt rate results in a 10.6% ROE based on a risk premium approach.

<u>CAPITAL ASSET PRICING MODEL ANALYSIS</u>

Q. PLEASE DESCRIBE THE CAPITAL ASSET PRICING MODEL.

A. The Capital Asset Pricing Model ("CAPM") is a version of the risk premium approach described above. The CAPM measures the relationship between a specific security's investment risk and its return. The general mathematical form of the CAPM can be described as follows:

$K=RF+B(RM-RF)$

Where: K = cost of equity
Rf=risk free return
Rm=return on market
B=Beta
Rm-Rf= market risk premium

Q. HOW HAVE YOU CALCULATED YOUR CAPM ESTIMATES?

TABLE 2
COST OF EQUITY CAPITAL SUMMARY

Model	Range	Midpoint
Constant Growth DCF	9.8% - 10.0%	9.9%
Two-Stage DCF	10.0% - 10.2%	10.1%
CAPM	8.91%	
Risk Premium	10.5% - 10.6%	

The DCF results range from 9.8% to 10.2% with a midpoint of 10.0%. The high end of the CAPM 8.91% and Risk Premium results of 10.5% - 10.6% indicate an average of 9.8%. Thus, an equity return of 10% is consistent with the results of the DCF models and it is supported by the CAPM and Risk Premium check.

Q. IS YOUR RECOMMENDATION CONSISTENT WITH THIS COMMISSION'S RECENT DECISION IN THIS COMPANY'S LAST RATE CASE – DOCKET NO. 07-035-93?

A. Yes, it is. This Commission recently (August 11, 2008) issued a final order addressing all issues in RMP's 2007 rate case. One of the issues decided in Docket No. 07-035-93 was cost of equity capital and overall cost of capital. With regard to the cost of equity the Commission stated the following:

> Through our consideration of the financial models as we deem appropriate, with the inputs or components and weighting we believe reasonable, and weighing all of the expert financial testimony and other witness testimony received, we find and conclude that a rate of return on common equity of 10.25 percent is reasonable.[12]

The commission pointed out that the DCF-based range of estimates considered was from 6.82% to 11.3% and the risk premium/CAPM evidence ranged from 6.48% to 11.43% in the last case.[13] From that the Commission considered the parties range of estimates at 9.85% to 10.75%.[14]

The evidence in this case, just 6 months later suggest about the same range of estimates is before the Commission. The Company's original ROE estimate was 10.75% before

[12] Docket No. 07-035-93 Final Order at 18 (August 11, 2008).
[13] *Id.* at 16.
[14] *Id.* at 17.

the recent update to 11.0%. Moreover, my recommendation of 9.85% in the last case is within the range of DCF results and CAPM/Risk Premium results discussed above.

Given all of the above, it would appear that my recommendations are consistent with recent decisions of this Commission and Dr. Hadaway's proposals are simply overstated.

SECTION VI: CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. Based on the Second Supplemental Direct Testimony of Company witness Bruce Williams, RMP is proposing the following capital structure, cost rates and overall cost of capital to be earned on rate base investment as follows:

TABLE 3[15]
ROCKY MOUNTAIN POWER
OVERALL COST OF CAPITAL

Description	Percent	Cost	Weighted Cost
Long-Term Debt	48.2%	6.23%	3.00%
Preferred Stock	0.3%	5.41%	0.02%
Common Equity	51.5%	11.00%	5.67%
Total	100.00%	-	8.69%

Thus, the Company requests an overall cost of capital to be earned on rate base investment of 8.69% in this case.

Q. HAS THE COMPANY'S CAPITAL STRUCTURE AND CLAIMED COST RATES CHANGED SINCE THE FILING OF DIRECT TESTIMONY?

A. Yes. When the Company filed its direct case the following capital structure, cost rates and overall cost of capital were requested:

[15] Second Supplemental Direct Testimony Bruce Williams at 7:142.

TABLE 4[16]
ROCKY MOUNTAIN POWER
OVERALL COST OF CAPITAL

Description	**Ratio**	**Cost**	**Weighted Cost**
Long-Term Debt	47.7%	6.24%	2.98%
Preferred Stock	0.4%	5.41%	0.02%
Common Equity	51.9%	10.75%	5.58%
Total	100.0%	=	8.58%

The Company's new capital structure (Table 3 above) shows that the equity level and preferred stock ratio have fallen slightly while the debt capitalization has increased slightly. These slight capitalization ratio changes are the result of updating for the December 31, 2009 Commission ordered test year for this case. In addition, the Company now proposes an 11% return to equity shareholders rather than the original request of 10.75%. Lastly, long-term debt cost changed slightly between the Company's original and current proposals.

Q. WHAT IS THE SIGNIFICANCE OF CAPITAL STRUCTURE?

A. The overall cost of capital is the sum of the weighted average cost rates of various sources of capital. The quantity or portion of each type of capital, combined with the cost rate of capital determines the overall rate of return that the Company should be allowed to earn in this proceeding. The most significant relationship in any capital structure is the debt to equity ratio.

Q. DOES THERE EXIST SOME SET RELATIONSHIP OR IDEAL MIX OF DEBT AND EQUITY CAPITAL?

A. There exists no set debt/equity relationship for all firms or all industries in terms of leveraging. However, the ideal capital structure is one that minimizes the overall cost of capital to the firm, while still maintaining financial integrity so as to maintain the ability to attract capital at reasonable costs to meet future needs. Because the cost of debt is generally lower than the cost of equity, and also because the cost of debt represents a tax deductible expense, any increase in the quantity of debt capital tends to decrease the

[16] Direct Testimony Bruce Williams at 3:48-55.

overall cost of capital relative to equity financing. One must keep in mind that increases in the quantity of debt financing can cause the financial risk of the Company to increase. In other words, there is a cost for the savings associated with increased debt leveraging. That cost is increased financial risk to the firm.

In summary, it is not possible to determine with precision the exact proportion of debt and equity that minimizes the overall cost of capital without imposing undue financial risk upon the Company. There does exist some range of capital structure that generally, meets the goal of minimizing the overall cost of capital while maintaining the firm's financial integrity.

Q. WHAT CRITERIA SHOULD REGULATORS EMPLOY IN DETERMINING THE APPROPRIATE CAPITAL STRUCTURE TO BE USED FOR RATEMAKING?

A. In my opinion, rate regulation should focus on two criteria to determine the appropriate capital structure. Those factors as outlined below should be economy and safety.

The advantage of debt in the capital structure is that debt costs less than equity. Moreover, interest charges are deductible for income tax purposes and act to reduce taxes. Thus, the more debt in the capital structure the lower the cost of capital will be. The question of economy is addressed by examining whether increases in the debt ratio act to increase the cost rates of both debt and equity so as to over balance the benefits of the larger proportion of debt.

In addition, there is always the overriding question of safety. In other words, financial risk is increased if the proportion of debt is increased by such a magnitude that interest obligations cannot be covered during periods of depressed earnings.

Q. HOW DOES THE COMPANY'S PROPOSED CAPITAL STRUCTURE WHICH INCLUDES A 51.5% EQUITY RATIO COMPARE WITH THE CAPITAL STRUCTURE RATIOS OF THE COMPARABLE RISK COMPANIES?

A. The Company's proposed capital structure compares quite favorably to the equity ratios in the comparable risk group. As can be seen from Exhibit CCS 3.3 the comparable group equity ratio averages 49 percent for 2009, while RMP has an equity ratio of 51.5% for the test year ending 2009. Thus, RMP has less financial risk than the comparable group companies.

Q. DO YOU HAVE ANY COMMENTS ON THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. Yes. It must also be remembered that the Company is being afforded the opportunity to employ a forecasted test period and capital structure. While the Commission has determined the forecast test period is calendar year 2009 and not the 12 months ending June 30, 2009, the test year is even more forward looking than originally requested by RMP. A forecasted test year provides the Company benefits by reducing risks associated with regulatory lag. In other words, future investment and cost changes that are reasonably expected to occur in the rate effective period are reflected in the Company's revenue requirement and capital structure. For example, the capital structure proposed by RMP reflects expected 2009 financings.

Q. HOW DID THE COMPANY CALCULATE THE COST FOR LONG-TERM DEBT FOR THE TEST YEAR ENDING DECEMBER 31, 2009?

A. The Company calculated the cost of long-term debt of 6.23% based on averaging the weighted average cost of long-term debt at December 31, 2008 and projected December 31, 2009.[17]

Q. DID THE COMPANY ADJUST THE OUTSTANDING BOOK VALUES OF LONG-TERM DEBT FOR DEBT ISSUES DURING JULY 2008?

A. Yes. The Company reflected two long-term debt issues made in July 2008 in the total amount of $800 million.[18] The weighted interest cost of these two debt issues is approximately 6.0%.

Q. IN THE COMPANY'S LAST CASE, DOCKET NO. 07-035-93 DID RMP INCLUDE AN ADJUSTMENT FOR A PRO FORMA LONG-TERM DEBT ISSUANCE.

A. Yes. In RMP's last case the Company included a projected or pro forma debt issue of $700 million of additional long-term debt issues in the end of 2008. The Company through the testimony of witness Bruce Williams estimated the cost of this pro forma

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[17] Second Supplemental Direct Testimony Bruce Williams at 2:43-46. Also see Exhibit RMP__(BNW-155).

[18] *Id.* at 3:52-57.

issuance to be 6.52%.[19] In that previous case, I pointed out the problems with Mr. Williams' estimate and I recommended that the pro forma debt cost should be estimated at 6.07%.

In July 2008, the Company issued $800 million of long-term debt in two separate issuances.[20] The weighted average debt cost of these two long-term debt issues for July 2008 was about 6.0% - well below Mr. William's estimate of 6.52%, but quite close to the 6.07% I estimated in the last case.

Q. DOES THE COMPANY INCLUDE IN THE LONG-TERM DEBT COST ESTIMATE AN ADDITIONAL PRO FORMA ESTIMATE FOR ADDITIONAL LONG-TERM DEBT TO BE ISSUED IN 2009?

A. Yes. The Company has included an additional or pro forma estimate of $800 million of long-term debt to be issued in 2009 at an interest rate estimated to be 8.47%.

Q. HOW DOES THE COMPANY ESTIMATE THE INTEREST RATE FOR THE $800 MILLION PRO FORMA LONG-TERM DEBT ISSUE?

A. The Company employs the same erroneous estimation methodology that led to the overstatement of debt costs in the last RMP case. The Company's debt cost estimation methodology is as follows:

(i) The Company "estimates" the credit spread between corporate debt and long-term treasury rates to be 3.87% at December 31, 2009;[21]

(ii) The Company employs a 4.51% "estimate" for the December 31, 2009 30 year Treasury Bond; [22] and

(iii) The Company assumed an additional .09 percent for issuance costs.[23]

When the three components above; credit spread (3.87%), estimated December 2009 long-term Treasury rate (4.51%) and issuance cost (.09%) are added together, the Company estimates a pro forma interest cost of 8.47% for the $800 million of forecasted

[19] Docket No. 07-035-93, Direct Testimony of Bruce Williams at 10:224-229.
[20] Williams Second Supplemental Direct Testimony at 3:52-59.
[21] Williams Second Supplemental Direct Testimony at 4:71 – 75.
[22] *Id.*
[23] *Id.*

debt issues.[24]

Q. DO YOU AGREE WITH THE COMPANY'S PRO FORMA LONG-TERM DEBT INTEREST COST ESTIMATE?

A. No. Just like the previous case the Company's future estimates of interest cost on long-term debt are overstated. Moreover, as discussed earlier, the results of RMP's last case demonstrates the interest cost overstatement. Allowing RMP to charge an 8.47% long-term debt cost will lead to an overstatement of revenue requirement and unreasonable customer rates.

It is also important to note that when Mr. Williams filed his direct testimony, his estimate for pro forma debt was 6.58%.[25]

Now, a few short months later, Mr. Williams claims the interest rate should be 8.47% or 1.89% higher than originally projected. On an $800 million dollar debt issue such an increase amounts to $15,120,000 in increased <u>annual</u> revenue requirements. (1.89% x $800,000,000 = $15,120.000).

Q. HAVE YOU QUANTIFIED AN ALTERNATIVE PRO FORMA LONG-TERM DEBT INTEREST COST?

A. Yes. Employing a four month credit spread (July 08 – October 08) presented in Dr. Hadaway's second supplemental direct testimony results in a credit spread of 2.30%.[26] Rather than rely on historical high credit spreads a four month average tends to normalize the credit spreads. The current 30 year Treasury Bond yield is about 3.68% based on a three month average (October 2008 – December 2008). Accepting the Company's claimed issuance expense of 0.09% combined with historical (not estimated) credit spreads and 30 year Treasury Bond yields results in a pro forma long-term debt interest estimate of 6.07% (2.30% + 3.68% + 0.09% = 6.07%). This 6.07% long-term debt interest rate is consistent with my 6.07% estimate provided in my testimony just a few months ago in the last docket.

Q. WHAT IS THE ANNUAL IMPACT ON REVENUE REQUIREMENTS OF

[24] *Id.*
[25] Direct Testimony of Bruce N. Williams at 11:232.
[26] Second Supplemental Direct Testimony of S. Hadaway at 5:91-92.

EMPLOYING A 6.07% RATHER THAN THE COMPANY PROPOSED 8.47% INTEREST RATE FOR THE $800 MILLION PRO FORMA DEBT ISSUE?

A. The difference in interest rates (prior to considering income tax impacts) is about $19,200,000 per year in lower interest costs. Employing a more realistic interest rate assumption of 6.07% for the $800 million pro-forma debt issue results in lowering the long-term debt interest cost in capital structure from 6.23% to 6.08%. I recommend a long-term debt rate of 6.08% in capital structure for this case.

Q. WHAT CAPITAL STRUCTURE AND COST RATES ARE YOU RECOMMENDING THAT THE COMMISSION ADOPT IN THIS CASE?

A. I am recommending that the Commission approve the Company's proposed capitalization levels for the test period ending December 31, 2009, but I also recommend that the long-term debt cost rate and common equity cost rate be reduced to the levels I recommended earlier in this testimony.

Based on the analyses and results discussed above, I am recommending the following capital structure, cost rates and overall cost of capital for this case:

TABLE 5
RECOMMENDED OVERALL COST OF CAPITAL
FOR ROCKY MOUNTAIN POWER
TEST YEAR ENDING DECEMBER 31, 2009

Description	Ratio	Cost	Weighted Cost
Long-term Debt	48.2%	6.08%	2.93%
Preferred Stock	0.3%	5.41%	0.02%
Common Equity	51.5%	10.00%	5.15%
Total	100.0%	—	8.10%

As can be seen from the above table when the long-term debt cost rates and common equity cost rates reflect current market conditions, the Company's overall cost of capital is 8.10%.

Q. PLEASE SUMMARIZE YOUR OVERALL COST OF CAPITAL

RECOMMENDATION IN THIS CASE.

A. The Company's requested 11.0% return on equity is overstated. A more reasoned cost of equity analysis results in a required return on shareholder equity of 10%. The Company's claimed cost of long-term debt of 6.23% should be reduced to 6.08% to correct for a significant overstatement of future financing costs. The combination of these recommended adjustments results in an overall cost of capital of 8.10% in this case.

Q. WILL YOUR RECOMMENDED RETURN PROVIDE THE COMPANY SUFFICIENT INTEREST COVERAGE TO MAINTAIN ITS FINANCIAL INTEGRITY?

A. Yes. Based on the capital structure above, my recommended 8.10% overall cost of capital provides coverage ratios of 3.71x and 2.76x for pretax and after-tax interest coverage respectively. In my opinion, these coverage ratios are sufficient for the Company to maintain financial integrity.

SECTION VII: <u>COMMENTS ON DR. SAMUEL C. HADAWAY TESTIMONY</u>

Q. DO YOU HAVE ANY GENERAL COMMENTS ON DR. HADAWAY'S ANALYSES?

A. Yes. First, Dr. Hadaway's recommendation in this case of an 11.0% to 11.5% return on equity is an overstatement of the cost of equity. Such a return if adopted would lead to excessive, unjust and unreasonable rates for customers.

As I discuss below, Dr. Hadaway's results are overstated for the following reasons:

1. The growth rates employed for the constant growth DCF averaging 6.12% are overstated, outdated and fail to take into account declining expectations of growth during an economic slow down or recession. When Dr. Hadaway's growth rates are updated and corrected his DCF results are consistent with the 9.8% to 10.0% DCF results I calculated and discussed above.

2. The growth rate employed for the long-term GDP growth DCF of 6.5% fails to reflect investor expectations and should be in the range of 5.2% - 5.5%. When this analysis is corrected his DCF results are consistent with my 9.8% to 10% results

discussed earlier.

3. The long-term growth rates employed in Dr. Hadaway's two-stage DCF suffer from the same infirmities as discussed in (2) above. When these long-term growth rates are corrected even to the 5.5%, level his two-stage DCF results match my 10.0% - 10.2% estimates discussed earlier for the two-stage DCF analysis.

4. Dr. Hadaway's updated risk premium analyses ranging from 10.83% to 12.44% are significantly overstated. When corrected for a realistic risk premium level and/or corrected for a more reasonable estimate of single-A rated debt yield – these risk premium results like the DCF analyses are dramatically reduced.

Overall, despite Dr. Hadaway's attempts to support an ROE estimate of 11.0% to 11.5% the facts just do not support his analysis.

Q. PLEASE COMMENT ON DR. HADAWAY'S UPDATED EQUITY RETURN RECOMMENDATION CONTAINED IN HIS SECOND SUPPLEMENTAL DIRECT TESTIMONY.

A. Dr. Hadaway is now recommending an equity return of 11.0% to 11.5% - which is higher than his direct testimony point estimate for equity return of 10.75%. The problem with his updated analysis is that Dr. Hadaway has allowed abnormal or atypical events to cloud his view of fundamental ratemaking and establishing reasonable estimates.

For example, at page 3 of his updated testimony Dr. Hadaway describes the events as follows:

- "…more turbulent than at any time since the 1930's", Second Supplemental at 3:49
- "Extremely large daily swings in the stock market…", *id.* at 3:49-50
- "…unprecedented corporate interest rate spreads in the debt markets have resulted in near chaos." *Id.* at 3:50-51
- "The financial markets have been reeling from a credit crisis." *Id.* at 3:57
- "The Federal government enacted emergency legislation …to stabilize the economy." *Id.* at 3:65-67

- "…the Federal Reserve pledged to pump another $800 billion into ailing credit markets…", *id.* at 4:70 – 71

- "…investment grade spreads are at or near 5-year highs with utility company spreads in excess of 500 basis points." *Id.* at 4:85 – 86

- "These virtually unprecedented spreads reflect the market conditions…". *Id.* at 6:134-135

Dr. Hadaway's description of recent capital market events are accurate and I agree with his use of such adjectives as "turbulent", "unprecedented", "chaos", "financial markets reeling", "unprecedented [credit] spread" as descriptive of financial events. But, rates and rate of return should be established not based on markets "reeling" or in "chaos" or "unprecedented [credit] spreads" – unless this Commission believes such events will continue into the future when rates from this case will be implemented.

In my opinion, instead of relying on extreme results that are "unprecedented", "chaotic", or the result of "reeling" financial markets – one needs to look to how the U.S. and world governments have responded and continue to address the situation. In light of government action such as economic stimulus packages, rescue plans for major financial institutions and other industries and overall efforts to increase credit market liquidity – the recent or post July 2008 events are not likely to continue or be repeated anytime soon.

While economic growth continues to be dampened and recession has impacted growth expectations, turbulent times in the credit markets are more likely to improve than get worse or stay the same. Dr. Hadaway's own forecast source "Trends & Projects"/October 2008 shows declining credit spreads from the beginning to the end of 2009. Further, his forecasting source also shows declining interest rates on new issue corporate debt.

Bottom line – unless it can be shown that chaos will continue to rule the financial markets for the foreseeable future – Dr. Hadaway's data and analyses do not reflect a realistic assessment of future capital costs.

Q. EARLIER YOU STATED THAT DR. HADAWAY'S UPDATED CONSTANT GROWTH DCF ANALYSIS INCLUDES OVERSTATED GROWTH ESTIMATES. PLEASE EXPLAIN.

A. Dr. Hadaway has relied on earnings per share forecasts of growth from Value Line, Zacks and Yahoo Finance/Thomson to arrive at his 6.12% average growth estimate. At this time, the Zacks and Thomson forecast estimates are overstated from about 15-30 basis points. Given the economic slowdown one would expect growth forecasts to decline. I expect these growth estimates will continue to decline over the next few months.

Q. YOU STATED THAT DR. HADAWAY'S USE OF A 6.5% GDP GROWTH RATE OVERSTATES THAT COST OF CAPITAL. PLEASE EXPLAIN.

A. As a long-term growth measure of the future, relying on the GDP historical growth measure as one of the measures to predict future earnings growth is not unreasonable. So long as future growth in GDP approaches the historical GDP measure, then the GDP growth rate proxy could be a reasonable estimate. However, caution should be taken in relying on historical GDP growth as the sole measure of expected growth in earnings.

I also differ with Dr. Hadaway in his change in methodology in calculating the GDP measure. In previous testimony such as the PacifiCorp rate case, Docket No. 03-2035-02, filed in May 2003, Dr. Hadaway employed a simple 20-year historical average of GDP growth for his long-term earnings growth proxy, which would produce a 5.5% GDP growth estimate. Since the 2003 case, Dr. Hadaway changed his methodology for calculating the historical GDP long-term growth rate. Rather than using the 20-year GDP average of 5.5%, Dr. Hadaway now takes an average of six different GDP growth period averages as illustrated in Table 3 below:

TABLE 6[27]
SUMMARY GDP GROWTH AVERAGES

10-year GDP average	5.2%
20-year GDP average	5.5%
30-year GDP average	6.6%
40-year GDP average	7.3%
50-year GDP average	7.1%
60-year GDP average	7.0%
Average of periods	**6.5%**

[27] Dr. Hadaway Direct Testimony Exhibit RMP_ (SCH-3).

In other words, Dr. Hadaway's new methodology averages the historical averages. Dr. Hadaway provides no explanation or basis for his changed methodology, the net impact of which is to increase the long-term growth estimate from the 20-year average of 5.5% to 6.5%.

Q. DO YOU RECOMMEND THE COMMISSION ACCEPT DR. HADAWAY'S NEW METHODOLOGY FOR COMPUTING LONG TERM GROWTH?

A. No. A 20-year period is certainly a sufficiently long time period to smooth aberrations and/or outliers to project into the future. I find no theoretical (economic or mathematical) reason to employ an average of the 10, 20, 30, 40, 50 and 60 year averages. It could be argued that more recent GDP growth data is more important, and the 10-year GDP average of 5.2% would be the best GDP proxy of growth. This may be especially true given recent Federal Reserve projections of a much lower and declining GDP growth. In my opinion, if the GDP average is to be used as one of the growth rate estimates, then the 10-year or 20-year average of 5.2% to 5.5% is a reasonable compromise for consideration in this case. The mid-point of 5.35% as a GDP growth rate proxy is consistent with analyst estimates for earnings and reflects current expectations of declining GDP growth. For example, a 5.4% growth estimate is consistent with analyst's estimates at this time.

Q. IF DR. HADAWAY'S GDP GROWTH RATE CALCULATION IS CORRECTED WHAT DCF RESULTS DOES HIS DATA AND MODEL PRODUCE?

A. Reducing the GDP growth estimate from 6.5% to 5.4% is a 110 basis point reduction to Dr. Hadaway's claimed 11.1% to 11.2% results. Thus, correcting Dr. Hadaway's results using a 5.5% GDP growth rate indicates a 10.0% to 10.1% constant growth DCF result.

It is important to note that the corrected ROE results above are consistent with the constant growth results of 10% I calculated earlier.

Q. DID DR. HADAWAY ESTIMATE A DCF RESULT EMPLOYING A MULTI-STAGE DCF GROWTH MODEL?

A. Yes. Dr. Hadaway's two-stage growth rate DCF model produces DCF estimates for ROE of 10.8% - 11.0%.[28] The problem with this analysis is his primary reliance on the

[28] Exhibit RMP_ (SCH-5) p.1.

faulty 6.5% GDP growth measure. When Dr. Hadaway's results are corrected for a 5.4% GDP growth rate, the results are in the 10% to 10.2% range. Thus, the corrected multi-stage DCF model produces results consistent with the previous DCF analyses discussed above.

Q. PLEASE COMMENT ON DR. HADAWAY'S RISK PREMIUM ANALYSES.

A. Dr. Hadaway presents three risk premium results at page 9 of his Second Supplemental Testimony as follows:

TABLE 7

<u>DR. HADAWAY RISK PREMIUM MODEL RESULTS</u>

Model	Interest Rate	Risk Premium	ROE
Forecasted Interest Rate and Risk Premium	6.55%	4.29%	10.84%
October Interest Rate and Risk Premium	7.56%	3.87%	11.43%
New Debt Interest Rate and Risk Premium	9.30%	3.14%	12.44%

First, Dr. Hadaway's third model "New Debt Interest Rate and Risk Premium" is such an outlier at 12.44% even he discards that result.

As to methods 1 and 2, Dr. Hadaway employs two estimates for single A debt. First, his 6.55% estimate is based on a three month average credit spread (August 08 – October 08) of 2.45%,[29] which is added to the 4.1% 30 year Treasury Bond forecast.[30] The 429 basis point risk premium is a direct calculation from Dr. Hadaway's risk premium analysis at (SCH-4SS) page 1 of 2.

For his second model, Dr. Hadaway's interest rate (single-A corporate debt) of 7.56% is the reported October 2008 cost rate as shown in his Exhibit RMP__ (SCH-2SS) page 1. This interest rate is employed in his updated analysis at Exhibit RMP__ (SCH-5SS) page 1 and the result is 11.43%.

The problem with these analyses is the overstatement of the single-A debt cost. In the

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[29]Exhibit RMP__ (SCH-255) p.1.
[30] *Id.* at 2.

supplemental testimony the Company has presented this Commission three very different single-A debt costs. First, Mr. Williams claims single-A debt costs are 8.47% and that amount is included in the calculation of long-term debt.

Dr. Hadaway claims single-A debt costs are forecasted to be 6.55% and the October 2008 level is calculated at 7.56%. The Company is not a model of consistency with regard to estimating single-A debt costs in this case.

I provided a reasoned analysis demonstrating that the single-A debt cost is in the 6.07% range. Moreover, I also demonstrated that the Company's past single-A debt cost estimates were wrong by a wide margin. Thus, if a more reasonable cost of single-A debt were used, such as the 6.07% estimate discussed earlier, Dr. Hadaway's risk premium results would support an equity return of 10% which is consistent with correcting his DCF results.

Q. PLEASE SUMMARIZE YOUR COMMENTS REGARDING DR. HADAWAY'S EQUITY RETURN PROPOSALS.

A. Dr. Hadaway's analyses overstate the cost of equity and should not be accepted by this Commission to set rates in this case. In my opinion, when Dr. Hadaway's analyses are adjusted to reflect more realistic and normalized estimates – the results indicate a 10% return on equity is appropriate.

SECTION VIII: COMMENTS ON A RICHARD WALJE TESTIMONY

Q. DO YOU HAVE ANY COMMENTS REGARDING THE TESTIMONY OF A. RICHARD WALJE?

A. Yes, I have a number of comments. First, Mr. Walje's statement that the $116.1 million or 8.6% increase represents an 11 cent per day increase of an average residential electricity user is irrelevant as to the merits of the increase.[31] Certainly, when one measures an annual increase in days or hours of the year – one can make large changes look small. But, the issue is whether the costs included in the Company's $116.1 million annual increase are just, reasonable and necessary for the provision of electric service.

[31] Second Supplemental District Testimony of A. Richard Walje at 1:19-23.

Thus, while customer rate impacts are important – it is more important to address whether the costs being imposed on customers are reasonable and necessary.

Q. AT PAGE 3, LINES 57-60 OF HIS SUPPLEMENTAL TESTIMONY MR. WALJE STATES "THE COST OF OUR INPUTS HAVE GONE UP AND THE POPULATION IN THE STATE OF UTAH HAS GROWN: THE COMPANY AND OUR SHAREHOLDERS HAVE ABSORBED MORE THAN 20 YEARS OF INFLATION AND GROWTH. ADDITIONAL SAVINGS CAN ONLY BE ACHIEVED BY SACRIFICING QUALITY OF SERVICE." DO YOU HAVE ANY COMMENTS?

A. Yes. Until the last docket, the Company had settled a number of rate proceedings in Utah. There is no evidence that the Company subsidized customer rates to the detriment of shareholder returns as suggested by Mr. Walje. Moreover, productivity improvements combined with growth in sales keeps unit costs lower – a factor not considered when analyzing nominal price changes since 1985.[32]

Further, when comparing regulatory authority responses to rate requests the equity return granted in Utah is consistent with the level authorized the Company in other states. Thus, to suggest the Utah authorized rate revenue levels do not provide the Company the opportunity to meet its obligations[33] is not consistent with the facts.

Q. AT PAGE 6, LINES 119-137 MR. WALJE SUGGESTS THAT THE REGULATORY LAG ASSOCIATED WITH PUTTING LARGE INVESTMENTS IN RATES CAUSES A LOSS IN EARNINGS – DO YOU HAVE ANY COMMENTS?

A. Yes. First, Utah does allow for a case to include a future test period. For example, in this case the test year end is December 31, 2009. This allows the Company to address regulatory lag issues. Second, Mr. Walje's quantification of earnings erosion is one-sided and fails to consider all attendant impacts related to accumulated depreciation and revenue growth. For example, assuming annual depreciation expense is $183.3 million and overall return is 8.69%, the loss of one year of accumulated depreciation to customers is $15,929,000 ($183,300,000 *.0869). Thus, the quantification of a three month lag for a wind project of $11 million of lost return also has cost offsets from the customer side of the ledger.

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[32] *Id.* at 2:27-28.
[33] *Id.* at 4:72-73.

Q. IN YOUR OPINION, IF THE COMMISSION ALLOWS THE COMPANY TO RECOVER ITS REASONABLE AND NECESSARY COSTS AND AUTHORIZES AN OVERALL RETURN CONSISTENT WITH YOUR RECOMMENDATION WILL RMP BE REQUIRED TO IMPLEMENT ADDITIONAL COST REDUCTION MEASURES LIKE THOSE ADDRESSED IN MR. WALJE'S TESTIMONY AT PAGE 13 LINES 288-298?

A. No. No regulatory authority should micro-manage a utility operation – and as such the assumption is that the Company will spend funds as outlined in its rate request. Once a rate change is granted the Company management will allocate funds to expenditures as management deems necessary. However, if management practices result in deficient service to customers in an effort to boost corporate profits or a failure to carry out prudent responsible management practices then such matters can be addressed in future proceedings as necessary. To the extent management practices cause cost and/or risk increases such costs and risk should be the Company shareholder burden not the customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 210
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 811

Exhibits in Support
Of Opening Testimony

July 24, 2009

Mathematical Appendix

Discounted Cash Flow Models

The generalized Discounted Cash Flow (DCF) single-stage, or "Gordon growth" model has the form:

$$P_0 = \frac{D_1}{(1+K)} + g$$

Where:

P_0	=	current price per share
D_1	=	dividend payment in period 1
K	=	cost of equity capital; and
g	=	the perpetuity growth rate (the constant rate of periodic growth to an infinite horizon)

The generalized multistage DCF model has the form:

$$P_0 = \frac{D_1}{1+K} + \frac{D_2}{(1+K)^2} + \frac{D_3}{(1+K)^3} + \cdots + \frac{D_n}{(1+K)^n} + \frac{D_n(1+g)}{(K-g)}$$

Where:

P_0	=	current price per share
D_n	=	dividend payment in period n
K	=	cost of equity capital
g	=	the sustainable and constant rate of periodic growth beyond the nth period

Staff's multistage DCF model includes a terminal valuation. This model has the form:

$$P_0 = \frac{D_1}{1+K} + \frac{D_2}{(1+K)^2} + \frac{D_3}{(1+K)^3} + \cdots + \frac{D_n}{(1+K)^n} + \frac{D_n(1+g)}{(1+K)^{n+1}} + \frac{D_n(1+g)^2}{(1+K)^{n+2}} + \frac{D_n(1+g)^3}{(1+K)^{n+3}} + \cdots + \frac{P_T}{(1+K)^T}$$

Where:

P_0 = current price per share
D_n = dividend payment in period n
K = cost of equity capital
g = the sustainable and constant rate of periodic growth beyond the n^th period
P_T = the derived share price in period T (2048); and
g = $(b \times r) + (s \times v)$

Where:

b = the proportion of earnings retained (the "ploughback ratio" or "earnings retention ratio")
r = the expected return on average book value
s = annual issuances of common stock as a percent of common stock outstanding
v = the percent of stock sale proceeds accruing to shareholders at P_0

Staff's DCF model uses values provided by Value Line for periods 1 through 6 (2009 through 2014). Values for periods 7 through 40 (2015 through 2048) are based on the long-term sustainable growth rate g, where:

b is the retention rate of the period prior to this stage; i.e., the derived value for 2014
r is 10.47%, and
s is assumed to be 0%.

Therefore, using values in Staff's base case:

$$\begin{aligned} g &= (b \times r) + (s \times v) \\ &= (46\% \times 10.67\%) + (0\% \times v) \\ &= 4.91\% . \end{aligned}$$

CASE: UE 210
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 900

Opening Testimony

July 24, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Jorge Ordonez. I am employed by the Oregon Public Utility Commission (OPUC) as the Senior Financial Economist in the Economic and Policy Analysis Section. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualifications Statement is found in Exhibit Staff/901, Ordonez /1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the cost of preferred stock and long-term debt for PacifiCorp ("Company").

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes, I have prepared Staff Exhibit/901 consisting of one page, Staff Exhibit/902 consisting of nine pages, and Staff Exhibit/903 consisting of two confidential pages.

SUMMARY RECOMMENDATION

Q. WHAT IS YOUR SUMMARY RECOMMENDATION?

A. I recommend the Commission reject PacifiCorp's proposed cost of preferred stock of 5.414% and adopt Staff's recommendation of 5.048%. I also recommend the Commission reject PacifiCorp's proposed cost of long-term debt of 5.979% and adopt Staff's recommendation of 5.882%.

Q. HAVE YOU PREPARED TABLES THAT SUMMARIZES STAFF'S RECOMMENDATION?

A. Yes, Table 1 summarizes Staff's and the Company's recommendations on the cost of preferred stock and cost of long-term debt.

Table 1

Issue	Company Proposal	Staff Proposal
Cost of Preferred Stock	5.414%	5.048%
Cost of Long-Term Debt	5.979%	5.882%

EMBEDDED COST OF PREFERRED STOCK

Q. WHAT IS PACIFICORP'S RECOMMENDED COST OF PREFERRED STOCK?

A. In Exhibit PPL/306 Williams/1, PacifiCorp's proposed embedded cost of preferred stock is 5.414%.

Q. HOW DID PACIFICORP ARRIVE AT THE 5.414% FIGURE?

A. PacifiCorp calculated the cost of preferred stock by first determining the cost of money for each issue.[1] This is the result of dividing the annual dividend rate[2] by the percentage of gross proceeds[3] for each series of preferred stock. The cost of money associated with each series was then multiplied by the total par or stated value outstanding[4] for each issue to yield the annualized cost for

[1] *See* Exhibit PPL/306 Williams/1, column 10.
[2] *See* Exhibit PPL/306 Williams/1, column 4.
[3] *See* Exhibit PPL/306 Williams/1, column 9.
[4] *See* Exhibit PPL/306 Williams/1, column 6.

each issue.[5] The sum of the annualized cost for each issue produces the total annual cost for the entire preferred stock portfolio ($2,244,853). This total annual cost was divided by the amount of preferred stock outstanding ($41,463,300) to produce the weighted average cost for all issues (5.414%). PacifiCorp further included $151,974 ($67,955 + $84,019) of unamortized costs associated with two Quarterly Income Debt Securities (QUIDS) that were redeemed in 2000 by using cash received from the sale of its Australian subsidiary.

Q. WHAT IS STAFF'S RECOMMEND COST OF PREFERRED STOCK?

A. I recommend PacifiCorp's embedded cost of preferred stock to be 5.048%.[6]

Q. WHAT ADJUSTMENTS DID YOU MAKE TO PACIFICORP'S EMBEDDED COST OF PREFERRED STOCK?

A. I removed $151,974 of costs identified as amortized expenses associated with QUIDS.

Q. WHY DID YOU REMOVE THE UNAMORTIZED EXPENSES ASSOCIATED WITH THE QUIDS FROM YOUR CALCULATION OF THE EMBEDDED COST OF PREFERRED STOCK?

A. The unamortized expense associated with the QUIDS should not be reflected in rates for three reasons. First, the QUIDS are no longer outstanding and no specific replacement debt has been identified. Second, the expenses are non-recurring, and therefore should not be included in rates. Third, in previous rate

[5] *See* Exhibit PPL/306 Williams/1, column 11.

[6] *See* Staff/902, Ordonez / 1.

cases, PacifiCorp did not identify new debt issuances used to specifically refund the QUIDS.

Q. HAS THE COMMISSION REVIEWED THIS ISSUE IN THE PAST?

A. Yes, the Commission excluded the unamortized expense associated with the QUIDS in Order No. 01-787 in 2001.[7]

EMBEDDED COST OF LONG-TERM DEBT

Q. WHAT IS LONG-TERM DEBT?

A. The Commission has historically defined long-term debt as debt with a maturity of more than one year.

Q. WHAT IS PACIFICORP'S PROPOSED COST OF LONG-TERM DEBT?

A. In Exhibit PPL/301 Williams/1-3, PacifiCorp proposes that its embedded cost of long-term debt be 5.979%.

Q. HOW DID PACIFICORP ARRIVE AT THE 5.979% FIGURE?

A. PacifiCorp calculated the cost of debt by issue, based on each debt series' interest rate (coupon rate)[8] and net proceeds at the issuance date[9] to produce a bond yield to maturity or "money to company" for each debt series.[10] In the event that a bond was issued to refinance a higher-cost bond, the pre-tax

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[7] *See* Order No. 01-787, UE 116, Contested Issues, I. Rate of Return, C. Cost of Preferred Stock, Commission Resolution, page at 19.

[8] *See* Exhibit PPL/301 Williams/2-3, column "a."

[9] *See* Exhibit PPL/301 Williams/2-3, column "k."

[10] *See* Exhibit PPL/301 Williams/2-3, column "m."

premium and any unamortized cost associated with the refinancing were subtracted from the net proceeds of the issued bonds. The bond yield[11] was then multiplied by the principal amount outstanding of each debt issue,[12] resulting in an annualized cost of each debt issue.[13] Aggregating the annual cost of each debt issue produces the total annualized cost of debt ($381,027,408). Dividing the total annualized cost of debt ($381,027,408) by the total principal amount of debt outstanding ($6,372,343,000) produces the weighted average cost for all long-term debt issues of 5.979%. In addition to all existing long-term securities, PacifiCorp proposed a $14.6 million *pro forma* debt of First Mortgage Bonds (FMBs). PacifiCorp calculated the coupon rate of 6.32% for this *pro forma* debt by summing the projected long-term 30-year Treasury rate as of December 31, 2009 (3.2207%) and the credit spread of PacifiCorp's long-term issuance as of January, 2009 (3.10% or 310 bps).[14] Note that a portion of PacifiCorp's debt portfolio is composed of variable-rate, tax-exempt Pollution Control Revenue Bonds (PCRBs).[15] Exhibit PPL/305 Williams/1-2 shows that these securities, on average, had been trading at approximately 85% of the 30-day LIBOR (London Interbank Offer Rate) from January 2000 through December 2008. The Company applied a factor of 85% to the forward 30-day LIBOR rate on December 31, 2009 of 1.72% and then

[11] *See* Exhibit PPL/301 Williams/2-3, column "m."

[12] *See* Exhibit PPL/301 Williams/2-3, column "h."

[13] *See* Exhibit PPL/301 Williams/2-3, column "n."

[14] *See* response to Data Request OPUC 156, attached as Exhibit Staff/902 Ordonez/2.

[15] *See* Exhibit PPL/301 Williams/3, lines 72-99.

added credit enhancement and remarketing fees for each floating-rate, tax-exempt to calculate the debt series' interest rate (coupon rate).

Q. WHAT IS STAFF'S FORECAST OF PACIFICORP'S EMBEDDED COST OF LONG-TERM DEBT?

A. I forecast an embedded cost of long-term debt of 5.882%.[16] This differs from the PacifiCorp-calculated 5.979%.

Q. WHAT ADJUSTMENTS DO YOU MAKE TO PACIFICORP'S EMBEDDED COST OF LONG-TERM DEBT?

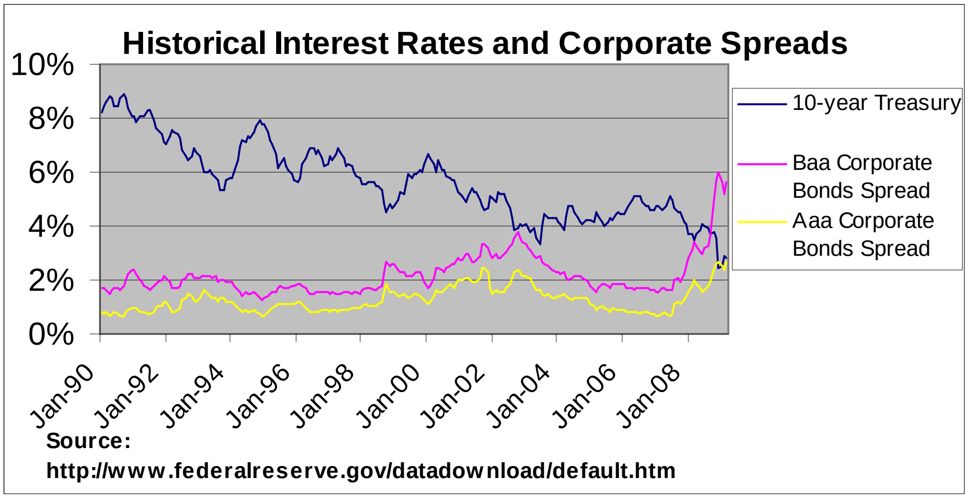
A. I made two adjustments to PacifiCorp's long-term cost of debt forecast. First, for the *pro forma* First Mortgage Bond (FMB) debt of $14.6 million, I used interest rates and spreads as of the same point of time, assuming a seven-year maturity term for the *pro forma* debt. Second, for the variable-rate, tax-exempt PCRBs, I used the current London Interbank Offered Rate (LIBOR) interest rate instead of the forward rate used by the Company and adjusted the ratio between the PCRBs and the 30-day LIBOR.

Q. WHY DID YOU USE INTEREST RATES AND SPREADS AT THE SAME POINT IN TIME?

A. Staff used interest rates and spreads as of the same point in time because they are not independent. As shown in Chart 1, historically spreads decline when interest rates rise. Capturing spreads at one point of time and applying them on a different date would likely produce inaccurate results given that interest rates vary over time.

[16] *See* Staff/902, Ordonez/3.

Chart 1



Q. PLEASE EXPLAIN YOUR DECISION TO ASSUME A SEVEN-YEAR MATURITY FOR THE *PRO FORMA* DEBT SERIES.

A. In the past, Staff has used five-, seven-, and 10-year maturities when estimating the cost of *pro forma* debt for First Mortgage Bonds. In this case, Staff assumes a seven-year maturity for the $14.6 million *pro forma* debt because, according to PacifiCorp's response to Data Request OPUC 109-1,[17] the Company has significantly less debt maturing in the seventh year (2016) than in the fifth (2014) or tenth (2019) years. Given the minor amount of debt refunding of $14.6 million, the significantly less debt maturing in the seventh year compared to the fifth and tenth, using a seven-year maturity yield seems reasonable compared to taking a weighted average of five, seven and ten maturity yields.

[17] *See* Exhibit Staff/902 Ordonez/6.

Q. WHAT IS STAFF'S RESULTING ESTIMATED INTEREST RATE FOR THE *PRO FORMA* DEBT?

A. Based on information in PacifiCorp's confidential response to Data Request OPUC 30, Staff has selected a coupon rate of 4.787%,[18] which is the average of the coupon rates quoted by three different investment banks for the issuance of FMBs with a seven-year maturity as of April 14, 2009. Assuming the same percentage (1.0%) of issuance cost as that proposed by PacifiCorp, the all-in cost for this maturity is 4.958%.[19]

Q. PLEASE EXPLAIN HOW PACIFICORP CALCULATED THE COUPON RATE FOR THE PORTION OF VARIABLE-RATE POLLUTION CONTROL REVENUE BONDS (PCRBS).

A. As previously mentioned, PacifiCorp applied a factor of 85% to the forward 30-day LIBOR rate of 1.72% on December 31, 2009, which yields an interest rate of 1.46%. Subsequently, PacifiCorp added credit enhancement and remarketing fees for each floating-rate, tax-exempt bond, which results in the coupon rates shown in Exhibit PPL/301 Williams/ 3, column "a", lines 72-99.

Q. WHAT IS STAFF'S RESULTING ESTIMATED COUPON RATE FOR THE VARIABLE PORTION OF POLLUTION CONTROL REVENUE BONDS (PCRBS)?

A. Staff chose the LIBOR rate of 0.4525%[20] as of April 14, 2009, because that is the same date on which quotes from three different investment banks were

[18] *See* confidential Exhibit Staff/903 Ordonez/1.

[19] *See* Exhibit Staff/902 Ordonez /3, line 25.

[20] *See* Staff/902, Ordonez /7.

obtained to calculate the coupon rate for the *pro forma* long-term debt. Additionally, Staff adjusted the ratio between the PCRBs and the 30-day LIBOR to 81% for the period between January 2000 and May 2008,[21] excluding the period between June and December 2008, when the ratio of yields of PCRBs to LIBOR was, on average, 132% due to adverse market conditions. Then, Staff multiplied the LIBOR rate of 0.4525% by the adjusted PCRB/LIBOR ratio of 81% to calculate the projected rate of 0.37%. Finally, Staff added credit enhancement and remarketing fees for each floating-rate, tax-exempt bond.[22]

Q. DOES STAFF INTEND TO UPDATE THE INTEREST RATES AND RESULTING ADJUSTMENTS?

A. Yes. For Staff's Surrebuttal Testimony, I intend to update the interest rate quotes from which I will update my adjustments.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[21] *See* Staff/902, Ordonez /8-9.

[22] *See* confidential Exhibit Staff/903 Ordonez/2.

CASE: UE 210
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 901

Witness Qualification Statement

July 24, 2009

WITNESS QUALIFICATION STATEMENT

NAME	Jorge D. Ordonez
EMPLOYER	Public Utility Commission of Oregon
TITLE	Senior Financial Economist, Economic and Policy Analysis Section
ADDRESS	550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2115
EDUCATION AND TRAINING	Fulbright Scholar, MBA, concentration in finance, Willamette University, Oregon, 2005 BS, Mechanical Engineering, energy and thermal power efficiency, Electrical & Mechanical Engineering School San Antonio Abad University, Peru, 1998 Utility Management Certificate, Willamette University, Oregon, 2008 Certificate in Management of Hydropower Development Swedish International Development Cooperation Agency and Vattenfall Power Consultant AB. Sweden, 2006 & South Africa, 2007 Certificate in Project Appraisal and Management Maastricht School of Management, Netherlands, 2002
EXPERIENCE	I received a Bachelors of Science degree in Mechanical Engineering from San Antonio Abad University in Cusco, Peru in 1998. Subsequently, as a Fulbright Scholar, I received an MBA with an emphasis in finance from Willamette University in 2005. From 1999 to 2008, I worked for a Peruvian power generation company and was promoted many times, working as an Engineer, Resource Scheduler, Manager of Economic Planning and Vice-President of Generation, Commercial and Trading. Since January 2009, I have been employed by the Public Utility Commission of Oregon as a Senior Financial Economist in the Economic Research and Financial Analysis Division, evaluating utilities' financial applications and researching utilities' cost of capital.

CASE: UE 210
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Exhibits in Support
Of Opening Testimony

July 24, 2009

PACIFICORP
Electric Operations
Cost of Preferred Stock - Staff's Adjustments
December 31, 2009

Line No.	Description of Issue (1)	Issuance Date (2)	Call Price (3)	Annual Dividend Rate (4)	Shares O/S (5)	Total Par or Stated Value O/S (6)	Net Premium & (Expense) (7)	Net Proceeds to Company (8)	% of Gross Proceeds (9)	Cost of Money (10)	Annual Cost (11)	Line No.
1	**5% Preferred Stock, $100 Par Value**	(a)	110.00%	5.000%	126,243	$12,624,300	($98,049)	$12,526,251	99.223%	5.039%	$636,156	1
2												2
3	**Serial Preferred, $100 Par Value**											3
4	4.52% Series	Oct-55	103.50%	4.520%	2,065	$206,500	($9,676)	$196,824	95.314%	4.742%	$9,793	4
5	7.00% Series	(b)	None	7.000%	18,046	$1,804,600	(c)	$1,804,600	100.000%	7.000%	$126,322	5
6	6.00% Series	(b)	None	6.000%	5,930	$593,000	(c)	$593,000	100.000%	6.000%	$35,580	6
7	5.00% Series	(b)	100.00%	5.000%	41,908	$4,190,800	(c)	$4,190,800	100.000%	5.000%	$209,540	7
8	5.40% Series	(b)	101.00%	5.400%	65,959	$6,595,900	(c)	$6,595,900	100.000%	5.400%	$356,179	8
9	4.72% Series	Aug-63	103.50%	4.720%	69,890	$6,989,000	($30,349)	$6,958,651	99.566%	4.741%	$331,320	9
10	4.56% Series	Feb-65	102.34%	4.560%	84,592	$8,459,200	($49,071)	$8,410,129	99.420%	4.587%	$387,990	10
11												11
12		May-95	(d)									12
13		Oct-95	(e)									13
14												14
15	**Total Cost of Preferred Stock**			5.026%	414,633	$41,463,300	($187,146)	$41,276,155		5.048%	$2,092,879	15

Excluded QUIDS

Staff's proposed cost of preferred stock.

(a) Issue replaced 6% and 7% preferred stock of Pacific Power & Light Company and Northwestern Electric Company and 5% preferred stock of Mountain States Power Company, most of which sold in the 1920's and 1930's.
(b) These issues replaced an issue of The California Oregon Power Company as a result of the merger of that Company into Pacific Power & Light Co.
(c) Original issue expense/premium has been fully amortized or expensed.
(d) Column 11 is the after-tax annual amortization of expenses related to the 8.375% QUIDS due 6/30/35 which were redeemed 11/20/00.
(e) Column 11 is the annual amortization of expenses related to the 8.55% QUIDS due 12/31/25 which were redeemed 11/20/00.

UE-210/PacifiCorp
May 4, 2009
OPUC Data Request 156

OPUC Data Request 156

Regarding Exhibit PPL/301 Williams/2, please:

a. Explain, for the Pro forma Series debt (Line 25), how the 6.320% coupon was estimated. Please also provide the calculations in electronic format, with cell references and formulae intact.

If any spread and benchmark was considered in estimating the coupon of 6.320% for the debt in "a," please provide the supporting information (pdf files, publications, etc.) used in calculating the estimated spread; please also provide the calculations in electronic format, with cell references and formulae intact.

Response to OPUC Data Request 156

a. The coupon is the result of the projected long-term Treasury rate as of December 31, 2009 and the credit spread from the Company's January, 2009 long-term debt issuance.

Projected 30 year Treasury rate as of December 31, 2009	3.2207%
Company's credit spread	3.10 %
Projected coupon rate	6.32%

The projected 30 year Treasury rate is shown in the workpapers of Bruce Williams.

Please refer to Mr. Williams' testimony, page 11 line 19 for the credit spread.

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Summary - Staff's Adjustements
December 31, 2009

LINE NO.	DESCRIPTION	AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	INTEREST RATE	ALL-IN COST	ORIG LIFE	YTM	LINE NO.
1											1
2	**Total First Mortgage Bonds**	$5,633,973,000	($59,191,887)	($32,177,777)	$5,542,603,335	$358,697,431	6.208%	6.367%	23.5	18.7	2
3											3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	$400,470,000	($10,560,810)	($9,550,194)	$380,358,996	$11,899,470	2.671%	2.971%	28.0	11.5	4
5	Subtotal - Pollution Control Revenue Bonds	$337,900,000	($4,294,232)	($7,621,229)	$325,984,539	$4,192,653	1.082%	1.241%	27.8	8.2	5
6	**Total Pollution Control Revenue Bonds**	$738,370,000	($14,855,042)	($17,171,423)	$706,343,535	$16,092,123	1.944%	2.179%	27.9	10.0	6
7											7
8	**Total Cost of Long Term Debt**	$6,372,343,000	($74,046,929)	($49,349,200)	$6,248,946,871	$374,789,554	5.714%	5.882%	24.0	17.7	8
9											9

Staff's proposed cost of long-term debt

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Detail - Staff's Adjustments
December 31, 2009

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	YTM	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1															1
2		**First Mortgage Bonds**													2
3	7.978%	C-U Series due thru Oct 2011	04/15/92	10/01/11	19	1	$4,422,000	$412,000	$0	$0	$412,000	$100.000	7.978%	$32,869	3
4	8.493%	C-U Series due thru Oct 2012	04/15/92	10/01/12	20	2	$19,772,000	$3,590,000	$0	$0	$3,590,000	$100.000	8.493%	$304,899	4
5	8.797%	C-U Series due thru Oct 2013	04/15/92	10/01/13	20	2	$16,203,000	$4,247,000	$0	$0	$4,247,000	$100.000	8.797%	$373,609	5
6	8.734%	C-U Series due thru Oct 2014	04/15/92	10/01/14	21	3	$28,218,000	$9,301,000	$0	$0	$9,301,000	$100.000	8.734%	$812,349	6
7	8.294%	C-U Series due thru Oct 2015	04/15/92	10/01/15	21	3	$46,946,000	$17,918,000	$0	$0	$17,918,000	$100.000	8.294%	$1,486,119	7
8	8.635%	C-U Series due thru Oct 2016	04/15/92	10/01/16	22	4	$18,750,000	$8,318,000	$0	$0	$8,318,000	$100.000	8.635%	$718,259	8
9	8.470%	C-U Series due thru Oct 2017	04/15/92	10/01/17	22	5	$19,609,000	$9,585,000	$0	$0	$9,585,000	$100.000	8.470%	$811,850	9
10	**8.506%**	**Subtotal - Amortizing FMBs**			**21**	**3**		**$53,371,000**	**$0**	**$0**	**$53,371,000**		**8.506%**	**$4,539,954**	10
11															11
12	6.900%	Series due Nov 2011	11/21/01	11/15/11	10	2	$500,000,000	$500,000,000	($5,338,849)	$0	$494,661,151	$98.932	7.051%	$35,255,000	12
13	5.450%	Series due Sep 2013	09/08/03	09/15/13	10	4	$200,000,000	$200,000,000	($1,654,660)	($5,967,819)	$192,377,521	$96.189	5.961%	$11,922,000	13
14	4.950%	Series due Aug 2014	08/24/04	08/15/14	10	5	$200,000,000	$200,000,000	($2,170,365)	$0	$197,829,635	$98.915	5.090%	$10,180,000	14
15	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	22	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	$98.766	7.807%	$23,421,000	15
16	5.900%	Series due Aug 2034	08/24/04	08/15/34	30	25	$200,000,000	$200,000,000	($2,614,365)	$0	$197,385,635	$98.693	5.994%	$11,988,000	16
17	5.250%	Series due Jun 2035	06/08/05	06/15/35	30	25	$300,000,000	$300,000,000	($3,992,021)	($1,295,995)	$294,711,984	$98.237	5.369%	$16,107,000	17
18	6.100%	Series due Aug 2036	08/10/06	08/01/36	30	27	$350,000,000	$350,000,000	($4,048,711)	$0	$345,951,289	$98.843	6.185%	$21,647,500	18
19	5.750%	Series due Apr 2037	03/14/07	04/01/37	30	27	$600,000,000	$600,000,000	($613,216)	$0	$599,386,784	$99.898	5.757%	$34,542,000	19
20	6.250%	Series due Oct 2037	10/03/07	10/15/37	30	28	$600,000,000	$600,000,000	($5,873,367)	$0	$594,126,633	$99.021	6.323%	$37,938,000	20
21	5.650%	Series due Jul 2018	07/17/08	07/15/18	10	9	$500,000,000	$500,000,000	($3,827,364)	$0	$496,172,636	$99.235	5.752%	$28,760,000	21
22	6.350%	Series due Jul 2038	07/17/08	07/15/38	30	29	$300,000,000	$300,000,000	($3,874,418)	$0	$296,125,582	$98.709	6.448%	$19,344,000	22
23	5.500%	Series due Jan 2019	01/08/09	01/15/19	10	9	$350,000,000	$350,000,000	($4,795,000)	$0	$345,205,000	$98.630	5.681%	$19,883,500	23
24	6.000%	Series due Jan 2039	01/08/09	01/15/39	30	29	$650,000,000	$650,000,000	($12,285,000)	$0	$637,715,000	$98.110	6.139%	$39,903,500	24
25	4.787%	Pro Forma Series	12/31/09	12/31/16	7	7	$14,602,000	$14,602,000	($146,020)	$0	$14,455,980	$99.000	4.958%	$723,967	25
26	**6.033%**	**Subtotal - Bullet FMBs**			**23**	**20**		**$5,064,602,000**	**($54,934,666)**	**($7,263,815)**	**$5,002,403,520**		**6.153%**	**$311,615,467**	26
27															27
28	9.150%	Series C due Aug 2011	08/09/91	08/09/11	20	2	$8,000,000	$8,000,000	($75,327)	$0	$7,924,673	$99.058	9.254%	$740,320	28
29	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	2	$20,000,000	$20,000,000	($132,118)	$0	$19,867,882	$99.339	9.022%	$1,804,400	29
30	8.920%	Series C due Sep 2011	08/16/91	09/01/11	20	2	$20,000,000	$20,000,000	($188,318)	$0	$19,811,682	$99.058	9.022%	$1,804,400	30
31	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	2	$25,000,000	$25,000,000	($175,398)	$0	$24,824,602	$99.298	9.026%	$2,256,500	31
32	8.290%	Series C due Dec 2011	12/31/91	12/30/11	20	2	$3,000,000	$3,000,000	($23,040)	($410,784)	$2,566,175	$85.539	9.972%	$299,160	32
33	8.260%	Series C due Jan 2012	01/09/92	01/10/12	20	2	$1,000,000	$1,000,000	($7,649)	($136,928)	$855,423	$85.542	9.938%	$99,380	33
34	8.280%	Series C due Jan 2012	01/10/92	01/10/12	20	2	$2,000,000	$2,000,000	($13,297)	($273,856)	$1,712,847	$85.642	9.947%	$198,940	34
35	8.250%	Series C due Feb 2012	01/15/92	02/01/12	20	2	$3,000,000	$3,000,000	($22,946)	($410,784)	$2,566,270	$85.542	9.925%	$297,750	35
36	8.530%	Series C due Dec 2021	12/16/91	12/16/21	30	12	$15,000,000	$15,000,000	($115,202)	($2,053,922)	$12,830,877	$85.539	10.066%	$1,509,900	36
37	8.375%	Series C due Dec 2021	12/31/91	12/31/21	30	12	$5,000,000	$5,000,000	($38,400)	($684,641)	$4,276,959	$85.539	9.889%	$494,450	37
38	8.260%	Series C due Jan 2022	01/08/92	01/07/22	30	12	$5,000,000	$5,000,000	($33,243)	($684,641)	$4,282,117	$85.642	9.745%	$487,250	38
39	8.270%	Series C due Jan 2022	01/09/92	01/10/22	30	12	$4,000,000	$4,000,000	($30,594)	($547,712)	$3,421,693	$85.542	9.768%	$390,720	39
40	**8.766%**	**Subtotal - Series C MTNs**			**23**	**4**		**$111,000,000**	**($855,533)**	**($5,203,268)**	**$104,941,200**		**9.354%**	**$10,383,170**	40
41															41
42	8.130%	Series E due Jan 2013	01/20/93	01/22/13	20	3	$10,000,000	$10,000,000	($75,827)	($671,687)	$9,252,486	$92.525	8.939%	$893,900	42
43	8.050%	Series E due Sep 2022	09/18/92	09/18/22	30	13	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	$87.820	9.258%	$1,388,700	43
44	8.070%	Series E due Sep 2022	09/09/92	09/09/22	30	13	$8,000,000	$8,000,000	($70,118)	($904,302)	$7,025,580	$87.820	9.280%	$742,400	44
45	8.110%	Series E due Sep 2022	09/11/92	09/09/22	30	13	$12,000,000	$12,000,000	($105,177)	($1,356,453)	$10,538,370	$87.820	9.325%	$1,119,000	45
46	8.120%	Series E due Sep 2022	09/11/92	09/09/22	30	13	$50,000,000	$50,000,000	($438,238)	($5,651,887)	$43,909,875	$87.820	9.336%	$4,668,000	46
47	8.050%	Series E due Sep 2022	09/14/92	09/14/22	30	13	$10,000,000	$10,000,000	($87,648)	($1,130,377)	$8,781,975	$87.820	9.258%	$925,800	47
48	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	13	$25,000,000	$25,000,000	($200,190)	($2,061,627)	$22,738,182	$90.953	8.953%	$2,238,250	48
49	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	13	$26,000,000	$26,000,000	($208,198)	($2,938,981)	$22,852,821	$87.895	9.283%	$2,413,580	49
50	8.230%	Series E due Jan 2023	01/29/93	01/20/23	30	13	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	$99.056	8.316%	$332,640	50
51	8.230%	Series E due Jan 2023	01/20/93	01/20/23	30	13	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	$92.525	8.951%	$447,550	51
52	**8.100%**	**Subtotal - Series E MTNs**			**29**	**12**		**$165,000,000**	**($1,303,552)**	**($16,835,712)**	**$146,860,736**		**9.194%**	**$15,169,820**	52
53															53
54	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	14	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	$93.730	7.804%	$858,440	54
55	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	14	$27,000,000	$27,000,000	($246,981)	($1,445,880)	$25,307,139	$93.730	7.804%	$2,107,080	55
56	7.230%	Series F due Aug 2023	08/16/93	08/16/23	30	14	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	$97.294	7.457%	$1,118,550	56
57	7.240%	Series F due Aug 2023	08/16/93	08/16/23	30	14	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	$97.294	7.467%	$2,240,100	57

Adjusted coupon

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Detail - Staff's Adjustments
December 31, 2009

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	YTM	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
58	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	14	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.810%	$136,200	58
59	6.720%	Series F due Sep 2023	09/14/93	09/14/23	30	14	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.780%	$135,600	59
60	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	14	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	$98.552	6.865%	$343,250	60
61	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	14	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	$99.238	6.810%	$817,200	61
62	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	14	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	$99.238	6.810%	$1,089,600	62
63	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	14	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	$99.238	6.810%	$1,362,000	63
64	**7.044%**	**Subtotal - Series F MTNs**			**30**	**14**		**$140,000,000**	**($1,193,670)**	**($2,874,983)**	**$135,931,347**		**7.291%**	**$10,208,020**	64
65															65
66	6.710%	Series G due Jan 2026	01/23/96	01/15/26	30	16	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	$99.096	6.781%	$6,781,000	66
67	**6.710%**	**Subtotal - Series G MTNs**			**30**	**16**		**$100,000,000**	**($904,467)**	**$0**	**$99,095,533**		**6.781%**	**$6,781,000**	67
68															68
69	**6.208%**	**Total First Mortgage Bonds**			**23**	**19**		**$5,633,973,000**	**($59,191,887)**	**($32,177,777)**	**$5,542,603,335**		**6.367%**	**$358,697,431**	69
70															70
71		**Pollution Control Revenue Bonds**													71
72	1.049%	Moffat 94 due May 2013	11/17/94	05/01/13	18	3	$40,655,000	$40,655,000	($874,159)	($74,912)	$39,705,929	$97.666	1.190%	$483,795	72
73	~~4.002%~~	Converse 88 due Jan 2014	01/14/88	01/01/14	26	4	$17,000,000	$17,000,000	($155,970)	($579,849)	$16,264,181	$95.672	4.280%	$727,600	73
74	4.002%	Sweetwater 84 due Dec 2014	12/12/84	12/01/14	30	5	$15,000,000	$15,000,000	($227,887)	$0	$14,772,113	$98.481	4.091%	$613,650	74
75	3.645%	Lincoln 91 due Jan 2016	01/17/91	01/01/16	25	6	$45,000,000	$45,000,000	($771,836)	($2,578,602)	$41,649,562	$92.555	4.125%	$1,856,250	75
76	4.229%	Forsyth 86 due Dec 2016	12/29/86	12/01/16	30	7	$8,500,000	$8,500,000	($304,824)	$0	$8,195,176	$96.414	4.447%	$377,995	76
77	5.745%	Lincoln 93 due Nov 2021	11/01/93	11/01/21	28	12	$8,300,000	$8,300,000	($426,105)	($414,778)	$7,459,117	$89.869	6.538%	$542,654	77
78	5.770%	Emery 93A due Nov 2023	11/01/93	11/01/23	30	14	$46,500,000	$46,500,000	($1,624,793)	($2,842,053)	$42,033,154	$90.394	6.502%	$3,023,430	78
79	5.745%	Emery 93B due Nov 2023	11/01/93	11/01/23	30	14	$16,400,000	$16,400,000	($1,015,051)	($819,557)	$14,565,392	$88.813	6.607%	$1,083,548	79
80	0.989%	Carbon 94 due Nov 2024	11/17/94	11/01/24	30	15	$9,365,000	$9,365,000	($206,519)	($58,574)	$9,099,907	$97.169	1.100%	$103,015	80
81	0.990%	Converse 94 due Nov 2024	11/17/94	11/01/24	30	15	$8,190,000	$8,190,000	($209,778)	($86,323)	$7,893,899	$96.385	1.132%	$92,711	81
82	0.956%	Emery 94 due Nov 2024	11/17/94	11/01/24	30	15	$121,940,000	$121,940,000	($3,274,246)	($1,925,767)	$116,739,987	$95.736	1.124%	$1,370,606	82
83	1.097%	Lincoln 94 due Nov 2024	11/17/94	11/01/24	30	15	$15,060,000	$15,060,000	($422,858)	($81,427)	$14,555,715	$96.651	1.231%	$185,389	83
84	0.969%	Sweetwater 94 due Nov 2024	11/17/94	11/01/24	30	15	$21,260,000	$21,260,000	($510,479)	($88,352)	$20,661,169	$97.183	1.079%	$229,395	84
85	4.231%	Converse 95 due Nov 2025	11/17/95	11/01/25	30	16	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	$97.509	4.381%	$232,193	85
86	4.330%	Lincoln 95 due Nov 2025	11/17/95	11/01/25	30	16	$22,000,000	$22,000,000	($404,262)	$0	$21,595,738	$98.162	4.442%	$977,240	86
87	**2.671%**	**Subtotal - Secured PCRBs**			**28**	**12**		**$400,470,000**	**($10,560,810)**	**($9,550,194)**	**$380,358,996**		**2.971%**	**$11,899,470**	87
88															88
89	0.934%	Sweetwater 88B due Jan 2014	01/14/88	01/01/14	26	4	$11,500,000	$11,500,000	($84,822)	($392,250)	$11,022,928	$95.852	1.119%	$128,685	89
90	0.934%	Sweetwater 90A due Jul 2015	07/25/90	07/01/15	25	6	$70,000,000	$70,000,000	($660,750)	($795,122)	$68,544,128	$97.920	1.029%	$720,300	90
91	0.935%	Emery 91 due Jul 2015	05/23/91	07/01/15	24	6	$45,000,000	$45,000,000	($872,505)	($2,568,859)	$41,558,636	$92.353	1.306%	$587,700	91
92	0.962%	Sweetwater 88A due Jan 2017	01/14/88	01/01/17	29	7	$50,000,000	$50,000,000	($422,443)	($882,101)	$48,695,456	$97.391	1.067%	$533,500	92
93	0.934%	Forsyth 88 due Jan 2018	01/14/88	01/01/18	30	8	$45,000,000	$45,000,000	($380,198)	($1,013,283)	$43,606,519	$96.903	1.055%	$474,750	93
94	0.934%	Gillette 88 due Jan 2018	01/14/88	01/01/18	30	8	$63,000,000	$41,200,000	($351,905)	($1,006,013)	$39,842,082	$96.704	1.063%	$437,956	94
95	0.473%	Converse 92 due Dec 2020	09/29/92	12/01/20	28	11	$22,485,000	$22,485,000	($242,164)	($303,303)	$21,939,533	$97.574	0.567%	$127,490	95
96	0.473%	Sweetwater 92A due Dec 2020	09/29/92	12/01/20	28	11	$9,335,000	$9,335,000	($167,524)	($134,094)	$9,033,382	$96.769	0.598%	$55,823	96
97	0.473%	Sweetwater 92B due Dec 2020	09/29/92	12/01/20	28	11	$6,305,000	$6,305,000	($151,908)	($97,735)	$6,055,357	$96.041	0.627%	$39,532	97
98	0.932%	Sweetwater 95 due Nov 2025	12/14/95	11/01/25	30	16	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	$97.322	1.037%	$253,028	98
99	6.150%	Emery 96 due Sep 2030	09/24/96	09/30/30	34	21	$12,675,000	$12,675,000	($735,013)	$0	$11,939,987	$94.201	6.579%	$833,888	99
100	**1.082%**	**Subtotal - Unsecured PCRBs**			**28**	**8**		**$337,900,000**	**($4,294,232)**	**($7,621,229)**	**$325,984,539**		**1.241%**	**$4,192,653**	100
101															101
102	**1.944%**	**Total PCRB Obligations**			**28**	**10**		**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**		**2.179%**	**$16,092,123**	102
103															103
104	**5.714%**	**Total Long-Term Debt**			**24**	**18**		**$6,372,343,000**	**($74,046,929)**	**($49,349,200)**	**$6,248,946,871**		**5.882%**	**$374,789,554**	104
105															105

Adjusted coupons

Staff/902
Ordonez/5

PacifiCorp
Long Term Debt Principal Payment Projection - Staff's Adjustments
December 31, 2010 Pro Forma
$m

	FMBs	MTNs	Fixed PCRBs	Variable PCRBs	
2011	510.7	76.0	-	-	586.7
2012	11.2	6.0	-	-	17.2
2013	210.1	10.0	-	40.7	260.7
2014	209.3	-	32.0	11.5	252.8
2015	7.2	-	-	115.0	122.2
2016	3.3	-	53.5	-	56.8
2017	1.7	-	-	50.0	51.7
2018	500.0	-	-	86.2	586.2
2019	350.0	-	-	-	350.0
2020	-	-	-	38.1	38.1
2021	-	20.0	8.3	-	28.3
2022	-	155.0	-	-	155.0
2023	-	149.0	62.9	-	211.9
2024	-	-	-	175.8	175.8
2025	-	-	27.3	24.4	51.7
2026	-	100.0	-	-	100.0
2027	-	-	-	-	-
2028	-	-	-	-	-
2029	-	-	-	-	-
2030	-	-	12.7	-	12.7
2031	300.0	-	-	-	300.0
2032	-	-	-	-	-
2033	-	-	-	-	-
2034	200.0	-	-	-	200.0
2035	300.0	-	-	-	300.0
2036	350.0	-	-	-	350.0
2037	1,200.0	-	-	-	1,200.0
2038	300.0	-	-	-	300.0
2039	664.6	-	-	-	664.6
	5,118.0	**516.0**	**196.7**	**541.7**	**6,372.3**

Less debt will mature in 2016 than in 2014 or 2019.

BORROWING BENCHMARKS

Money Rates

April 14, 2009

Key annual interest rates paid to borrow or lend money in U.S. and international markets. Rates below are a guide to general levels but don't always represent actual transactions.

Inflation

	Feb. index level	CHG FROM (%) Jan.'09	Feb.'08
U.S. consumer price index			
All items	212.193	0.5	0.2
Core	217.685	0.4	1.8

International rates

	Latest	Week ago	—52-WEEK— High	Low
Prime rates				
U.S.	3.25	3.25	5.25	3.25
Canada	2.50	2.50	5.25	2.50
Euro zone	1.25	1.50	4.25	1.25
Japan	1.475	1.475	1.875	1.475
Switzerland	0.51	0.53	4.09	0.51
Britain	0.50	0.50	5.00	0.50
Australia	3.00	3.25	7.25	3.00
Hong Kong	5.25	5.25	5.50	5.00
Overnight repurchase				
U.S.	0.18	0.18	2.30	0.08
U.K. (BBA)	0.558	0.550	5.742	0.535
Euro zone	0.92	0.85	4.50	0.85

U.S. government rates

	Latest	Week ago	—52-WEEK— High	Low
Discount	0.50	0.50	2.50	0.50
Federal funds				
Effective rate	0.19	0.17	3.47	0.12
High	0.5000	0.5000	10.0000	0.2500
Low	0.0100	0.0200	2.2500	0.0000
Bid	0.0625	0.1250	3.0000	0.0000
Offer	0.2500	0.2500	7.0000	0.0500
Treasury bill auction				
4 weeks	0.080	0.160	1.990	0.000
13 weeks	0.180	0.200	2.050	0.005
26 weeks	0.370	0.400	2.350	0.250

Secondary market

	Latest	Week ago	—52-WEEK— High	Low
Freddie Mac				
30-year mortgage yields				
30 days	4.30	4.33	6.49	3.98
60 days	4.40	4.43	6.56	4.14
One-year RNY	3.375	3.375	3.375	3.375
Fannie Mae				
30-year mortgage yields				
30 days	4.380	4.432	6.566	4.099
60 days	4.462	4.524	6.618	4.186

	Latest	Week ago	—52-WEEK— High	Low
Bankers acceptances				
30 days	0.55	0.75	5.13	0.45
60 days	0.75	1.00	5.13	0.60
90 days	0.95	1.25	5.00	0.75
120 days	1.10	1.40	5.00	0.95
150 days	1.25	1.50	5.00	0.95
180 days	1.53	1.75	5.00	1.25

Other short-term rates

	Latest	Week ago	—52-WEEK— High	Low
Call money	2.00	2.00	4.00	2.00
Commercial paper				
30 to 30 days	0.30	...	...	...
31 to 59 days	n.q.	...	...	...
60 to 73 days	0.24	...	...	...
74 to 89 days	n.q.	...	...	...
90 to 119 days	n.q.	...	...	...
120 to 149 days	n.q.	...	...	...
150 to 164 days	n.q.	...	...	...
165 to 174 days	n.q.	...	...	...
175 to 270 days	n.q.	...	...	...
Dealer commercial paper				
30 days	0.49	0.55	5.95	0.49
60 days	0.89	0.90	5.95	0.69
90 days	1.04	1.05	5.95	0.84
Euro commercial paper				
30 day	0.76	0.73	4.75	0.70
Two month	0.97	0.96	4.80	0.96
Three month	1.25	1.25	5.00	1.25
Four month	1.31	1.31	5.00	1.31
Five month	1.34	1.34	5.02	1.34
Six month	1.39	1.40	5.07	1.37
London interbank offered rate, or Libor				
One month	0.45250	0.46938	4.58750	0.32875
Three month	1.12188	1.14938	4.81875	1.08250
Six month	1.66000	1.70313	4.39375	1.46500
One year	1.92938	1.97875	4.23375	1.73750

	Latest	Week ago	—52-WEEK— High	Low
New York Funding Rate				
One month	0.4456	0.4950	4.8273	0.3348
Three month	1.1222	1.1850	4.9000	1.0420
Libor Swaps (USD)				
Two year	1.423	1.515	3.978	1.257
Three year	1.756	1.871	4.325	1.542
Five year	2.316	2.454	4.661	1.903
Ten year	2.975	3.121	4.968	2.304
20 year	3.325	3.461	5.200	2.438
30 year	3.340	3.480	5.248	2.365
Euro Libor				
One month	0.993	1.016	5.186	0.993
Three month	1.423	1.450	5.391	1.423
Six month	1.616	1.640	5.438	1.616
One year	1.783	1.796	5.514	1.783
Euro interbank offered rate (Euribor)				
One month	1.000	1.035	5.197	1.000
Three month	1.423	1.453	5.393	1.423
Six month	1.609	1.632	5.448	1.609
One year	1.774	1.796	5.526	1.774
Hibor				
One month	0.307	0.323	4.993	0.149
Three month	0.897	0.906	4.442	0.751
Six month	1.177	1.187	4.100	1.100
One year	1.526	1.537	3.950	1.509
Asian dollars				
One month	0.472	0.494	4.588	0.328
Three month	1.132	1.159	4.780	1.086
Six month	1.678	1.706	4.438	1.450
One year	1.946	1.975	5.408	1.708

	LATEST Offer	Bid	Week ago	52-WEEK High	Low
Eurodollars (mid rates)					
One month	0.50	1.00	0.68	6.25	0.45
Two month	0.80	1.30	0.95	5.50	0.70
Three month	0.95	1.50	1.18	5.75	0.90
Four month	1.00	1.60	1.33	5.25	1.03
Five month	1.20	1.70	1.50	5.25	1.13
Six month	1.40	1.90	1.75	5.25	1.38

Notes on data:
U.S. prime rate and discount rate are effective December 16, 2008. U.S. prime rate is the base rate on corporate loans posted by at least 70% of the 10 largest U.S. banks.; Other prime rates aren't directly comparable; lending practices vary widely by location; Discount rate is the charge on loans to depository institutions by the New York Federal Reserve Banks; Federal-funds rate is on reserves traded among commercial banks for overnight use in amounts of $1 million or more; Call money rate is the charge on loans to brokers on stock-exchange collateral; Dealer commercial paper rates are for high-grade unsecured notes sold through dealers by major corporations; Freddie Mac RNY is the required net yield for the one-year 2% rate-capped ARM. Libor is the British Bankers' Association average of interbank offered rates for dollar deposits in the London market; Libor Swaps quoted are mid-market, semi-annual swap rates and pay the floating 3-month Libor rate. New York Funding Rate is the survey-based average of unsecured bank funding costs.

Sources: Merrill Lynch; Bureau of Labor Statistics; ICAP plc.; Thomson Reuters; General Electric Capital Corp.; Tullett Prebon Information, Ltd.

Source: Wall Street Journal newspaper as of April 15, 2009

PCRB Variable Rates and 30-day LIBOR - Staff's Adjustments

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Jan-00	5.81%	3.33%	57%
Feb-00	5.89%	3.62%	62%
Mar-00	6.05%	3.68%	61%
Apr-00	6.16%	4.02%	65%
May-00	6.54%	4.89%	75%
Jun-00	6.65%	4.35%	65%
Jul-00	6.63%	3.99%	60%
Aug-00	6.62%	4.09%	62%
Sep-00	6.62%	4.50%	68%
Oct-00	6.62%	4.36%	66%
Nov-00	6.63%	4.33%	65%
Dec-00	6.68%	4.14%	62%
Jan-01	5.88%	3.10%	53%
Feb-01	5.53%	3.59%	65%
Mar-01	5.13%	3.18%	62%
Apr-01	4.82%	3.72%	77%
May-01	4.16%	3.38%	81%
Jun-01	3.92%	3.03%	77%
Jul-01	3.82%	2.65%	69%
Aug-01	3.64%	2.36%	65%
Sep-01	3.17%	2.42%	76%
Oct-01	2.48%	2.18%	88%
Nov-01	2.13%	1.79%	84%
Dec-01	1.96%	1.64%	84%
Jan-02	1.81%	1.49%	82%
Feb-02	1.85%	1.39%	75%
Mar-02	1.89%	1.46%	77%
Apr-02	1.86%	1.58%	85%
May-02	1.84%	1.67%	91%
Jun-02	1.84%	1.58%	86%
Jul-02	1.83%	1.49%	81%
Aug-02	1.80%	1.49%	83%
Sep-02	1.82%	1.69%	93%
Oct-02	1.81%	1.84%	102%
Nov-02	1.44%	1.66%	115%
Dec-02	1.42%	1.57%	110%
Jan-03	1.36%	1.40%	103%
Feb-03	1.34%	1.43%	107%
Mar-03	1.31%	1.45%	111%
Apr-03	1.31%	1.52%	115%
May-03	1.31%	1.56%	119%
Jun-03	1.16%	1.38%	119%
Jul-03	1.11%	1.12%	102%
Aug-03	1.11%	1.16%	104%
Sep-03	1.12%	1.24%	111%
Oct-03	1.12%	1.24%	111%
Nov-03	1.13%	1.36%	121%
Dec-03	1.15%	1.32%	114%
Jan-04	1.11%	1.21%	110%
Feb-04	1.10%	1.17%	107%
Mar-04	1.09%	1.20%	110%
Apr-04	1.10%	1.27%	115%
May-04	1.10%	1.29%	117%
Jun-04	1.25%	1.28%	102%
Jul-04	1.41%	1.26%	89%
Aug-04	1.60%	1.40%	88%
Sep-04	1.78%	1.49%	83%
Oct-04	1.90%	1.72%	91%
Nov-04	2.19%	1.65%	75%
Dec-04	2.39%	1.67%	70%
Jan-05	2.49%	1.78%	72%
Feb-05	2.61%	1.88%	72%
Mar-05	2.81%	1.95%	69%
Apr-05	2.97%	2.50%	84%

PCRB Variable Rates and 30-day LIBOR - Staff's Adjustments

	30 Day LIBOR Daily Ave (a)	Floating Rate PCRBs Daily Ave (b)	PCRB / LIBOR (b)/(a)
May-05	3.09%	2.93%	95%
Jun-05	3.25%	2.39%	74%
Jul-05	3.43%	2.28%	67%
Aug-05	3.69%	2.44%	66%
Sep-05	3.78%	2.55%	68%
Oct-05	3.99%	2.66%	67%
Nov-05	4.15%	2.93%	71%
Dec-05	4.36%	3.10%	71%
Jan-06	4.48%	3.02%	67%
Feb-06	4.58%	3.13%	68%
Mar-06	4.76%	3.11%	65%
Apr-06	4.92%	3.45%	70%
May-06	5.08%	3.52%	69%
Jun-06	5.24%	3.74%	71%
Jul-06	5.37%	3.60%	67%
Aug-06	5.35%	3.53%	66%
Sep-06	5.33%	3.61%	68%
Oct-06	5.32%	3.57%	67%
Nov-06	5.32%	3.62%	68%
Dec-06	5.35%	3.70%	69%
Jan-07	5.32%	3.64%	68%
Feb-07	5.32%	3.63%	68%
Mar-07	5.32%	3.64%	68%
Apr-07	5.32%	3.79%	71%
May-07	5.32%	3.90%	73%
Jun-07	5.32%	3.76%	71%
Jul-07	5.32%	3.66%	69%
Aug-07	5.52%	3.76%	68%
Sep-07	5.48%	3.84%	70%
Oct-07	4.98%	3.56%	72%
Nov-07	4.75%	3.53%	74%
Dec-07	5.00%	3.25%	65%
Jan-08	3.95%	3.02%	76%
Feb-08	3.14%	2.86%	91%
Mar-08	2.80%	3.79%	135%
Apr-08	2.79%	2.23%	80%
May-08	2.63%	1.93%	73%
Jun-08			
Jul-08			
Aug-08			
Sep-08			
Oct-08			
Nov-08			
Dec-08			
Average			81%

The period from June through December 2008 has been excluded because the average rate ratio of PCRB to LIBOR is 132%.

	30 Day LIBOR* (1)	Historical Floating Rate PCRB / 30 Day LIBOR (2)	Forecast Floating Rate PCRB (1) * (2)
4/14/2009	0.4525%	81%	0.3700%

* Source: Wall Street Journal newspaper (4/15/2009) attached as Exhibit Staff/902, Orc

CASE: UE 210
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 903

Exhibits in Support
Of Opening Testimony

July 24, 2009

STAFF EXHIBIT 903

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 09-120. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 210 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 210
WITNESS: Robert Clark

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1000

Opening Testimony

July 24, 2009

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 1000

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 09-120. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 210 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Robert Clark. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/1001.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I propose changes to the Company's Coincident Peak forecasts, appearing in Exhibit PPL/702, Dalley/page 11.5, before "Monsanto" and "MagCorp" adjustments. These forecasts are used in calculating the system capacity (SC) allocation factor, which appears in same exhibit, page 11.2.

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/1002, consisting of 1 page; Exhibit Staff/1003, consisting of 2 pages; Exhibit Staff/1004 (confidential), consisting of 12 pages; Exhibit Staff/1005, consisting of 4 pages; Exhibit Staff/1006, consisting of 4 pages; Exhibit Staff/1007, consisting of 22 pages; Exhibit Staff/1008 (confidential), consisting of 13 pages; Exhibit Staff/1009, consisting of 1 page; Exhibit Staff/1010, consisting of 1 page; Exhibit Staff/1011, consisting of 1 page; and Exhibit Staff/1012 (confidential), consisting of 1 page.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

I. Assessment of PPL's coincident peak forecasting

II. Methods used for developing Staff's changes to PPL's forecast coincident peak

III. Discussion of these recommended changes on a month-by-month basis

Q. PLEASE PROVIDE A SUMMARY OF STAFF'S PROPOSED COINCIDENT PEAK FORECAST CHANGES BY STATE AND MONTH.

A. Table A presents staff's proposed changes to the Company's coincident peak forecast by state and month.

Table A
Coincident Peaks Under Staff's Proposal

State	Month *	PPL Forecast	Staff Forecast (Megawatts)	change
Oregon				
	January	2712.7	2561.4	-151.3
	February	2587.0	2486.2	-100.8
	September	2191.4	2035.8	-155.6
	Total			-407.7
Utah				
	January	3179.9	3371.6	191.7
	March	2860.2	2938.6	78.4
	April	2793.6	2983.4	189.8
	May	3590.8	3662.1	71.3
	June	4141.8	4320.3	178.5
	July	4466.0	4544.1	78.1
	September	3996.7	4086.4	89.7
	October	2722.5	2922.7	200.2
	November	3456.4	3557.1	100.7
	Total			1178.4

* Staff proposes no changes to other states or months.

Q. HOW WOULD YOUR PROPOSED REVISIONS CHANGE REVISED ALLOCATION PROTOCOL FACTOR VALUES AND OREGON DOLLAR AMOUNTS?

A. The system capacity factor (SC) would change from 1.84%, 27.50%, 8.16%, 41.26%, 5.47%, 15.41%, and 0.37% for the states/jurisdictions California, Oregon, Washington, Utah, Idaho, Wyoming, and FERC, respectively, to 1.82%, 26.89%, 8.09%, 42.11%, 5.42%, 15.30%, and 0.36%, rounded to two decimal places. These proposed changes in the SC factor values would also cause changes in SG, SG-P, SG-U, DGP, SSCCT, SSCCH, SSGCH, MC, SNPPN, TROJP, TROJD, AND SGCT factor values. These changes to revised protocol allocation factor values would change various Oregon dollar amounts. However, Staff is in the process of ascertaining further information to estimate these dollar amount impacts.

I. Assessment of PPL's Coincident Peak Forecasting

Q. PLEASE DESCRIBE PPL'S COINCIDENT PEAK FORECASTING METHODS.

A. PPL's peak forecasting methods are described in PPL/605, Duvall/6-7. To summarize, PPL prepares an hourly load forecast from which the Company identifies system coincident peaks by month and state/jurisdiction. This hourly forecast starts with a monthly energy sales forecast and projects monthly non-coincident peaks for each state based on peak-producing temperature inputs compiled from actual temperature data recorded during the period 1990-2007. The hourly forecast is filled for the remaining hours by using remaining temperature data from the same period and also day-type (weekend or major holiday versus weekday). Finally, this hourly forecast is grossed-up for line losses and calibrated to monthly model forecasts for peaks and seasonal peaks.

Q. WHAT ARE YOUR CONCERNS REGARDING PPL'S PEAK FORECASTING METHODS?

A. I have a couple of concerns. First, the hourly forecast is adjusted foremost to conform to monthly non-coincident state peaks, and secondarily to coincident state peaks. It is the latter, coincident state peaks, which determine the SC allocation factor. More often than not, non-coincident peaks for Oregon and Utah occur on different days than do coincident peaks, potentially distorting PPL's coincident peak forecasts. Exhibit Staff/1005 and Exhibit Staff/1006 (PPL's Data Responses OPUC 177c and 177c -2d 1st supplemental) support this finding of divergent coincident and non-coincident peak days. I believe non-coincident peak forecasts have a central influence in determining PPL's hourly forecast after reviewing language in both Exhibit Staff/1007 (PPL's Data Response OPUC 179a, pages 20-21 in particular), and Exhibit Staff/1008-Confidential (PPL Data Response OPUC 178a, page 8 of 13 in particular).

Q. WHAT IS YOUR SECOND CONCERN REGARDING PPL'S PEAK FORECASTING METHODS?

A. My second concern is it is not clear from either PPL's testimony or the aforementioned Company-provided information, how many years are used to estimate the mathematical relationships between actual non-coincident state monthly peaks, weather variables and time series variables. The use of an eighteen year historical weather record does not mean peak-related mathematical relationships were also estimated over such a period. Coefficient estimates for trend and for weather variable effects are likely to vary with different lengths of historical time periods used for their calculation.

Q. HOW DO YOU ADDRESS THESE CONCERNS?

A. I assessed PPL's coincident peak forecasts against actual historical coincident peaks, by month and state, considering effects of actual weather, PPL's peak-producing weather, and time trend over the time period 1996 through 2008. This allows for a more transparent and direct check of PPL's coincident peak than pursuing in-depth training and access to PPL's myriad of load forecasting equations.

Q. WHAT DO YOU FIND AFTER ASSESSING PPL'S COINCIDENT PEAK FORECASTS WITH THESE METHODS (ALSO DESCRIBED IN SECTION II BELOW)?

A. I find a few months for which PPL's forecast of Oregon's coincident peak is likely too high, and I find several months for which PPL's forecast of Utah's coincident peak is likely too low. Historical data for the few months in which Oregon's coincident peak forecast is too high show almost no time trend, and are dominated by temperature data. Historical data for several months in which the Company's forecast of Utah's coincident peak is too low exhibit strong time trend.

II. Methods for Developing Staff's Proposed Coincident Peak Changes

Q. PLEASE EXPLAIN THE EQUATIONS USED TO DEVELOP STAFF'S COINCIDENT PEAK FORECASTS CONTAINED IN TABLE A (ABOVE).

A. Equations developed and tested by Staff for both Oregon and Utah model coincident peak used time and temperature data as independent variables. For each month 13 sets of observations are used for fitting equations covering actual coincident peaks for the historical years 1996 through 2008. Coincident peak information from Exhibit Staff/1005 (PPL's Data Response OPUC 177c) provides actual coincident peak and its day of month attribute. Staff uses Company-provided daily average temperature data (PPL's Data Response OPUC 177b-confidential), and weather station weightings from Exhibit Staff/1010 (PPL's Data Response OPUC 177a), to compile temperature data for fitting equations. Staff solved for daily temperature weightings, on the day of peak and two days prior, so as to maximize the correlation between coincident peak and weighted average daily temperatures. Please see Exhibit Staff/1002 for graphical illustration of equations used to develop Staff's coincident peak forecasts.

Q. WHY DOES STAFF USE THE TIME PERIOD 1996 THROUGH 2008 FOR FITTING FORECAST EQUATIONS?

A. Values for coincident peak by state are unavailable prior to 1996 per Exhibit Staff/1005 (PPL's Data Response OPUC 177c). However, the period used does provide a number of observations for assessing trends in coincident peak by state, and the effects of weather in determining these peaks.

Q. HOW DOES TIME PERFORM AS AN EXPLANATORY VARIABLE FOR HISTORICAL COINCIDENT PEAKS?

A. Time actually performs reasonably accurately for explaining Utah's coincident peak historically. It does not perform very accurately for explaining Oregon's coincident peak. Oregon's coincident peak for most months has been fairly flat outside of temperature induced variations over the 13 year historical period, 1996 to 2008. There is a hint of time influence for Oregon's July coincident peak, and to a lesser extent, Oregon's August coincident peak. Despite its explanatory weakness for Oregon's monthly coincident peak, time is a reasonable variable for predicting demographic and economic variables. Please see Exhibit Staff/1003. Economic cycles do have influence and Staff's equations are fitted using a time period which includes the effects of the 2001 economic recession. Staff also adjusts downward its Utah coincident peak forecasts, resulting from Staff's time-fitted equations, to allow for added discounting of the current economic recession. In these incidences, Staff uses 70% of standard equation error so as to leave a 75% chance of under forecasting coincident peak, based on time as the independent variable and per the t-distribution.

Q. WHAT CONSIDERATIONS DID YOU WEIGH IN CHOOSING TO ADJUST PEAK DEMANDS BY 70% OF ONE STANDARD EQUATION ERROR TO ACCOUNT FOR THE CURRENT RECESSION?

A. Staff considered Company's testimony regarding the current economic recession (PPL/600 and PPL/605). Staff's standard equation error picks up not only variance due to economic factors, such as recession, but also other, non-economic factors. Staff subjectively selected the 70% adjustment of standard equation error so as to include effects of the current economic recession while excluding other non-economic factors.

Q. HOW MUCH DOES 70% OF ONE STANDARD ERROR REDUCE UTAH'S PEAK LOADS?

A. It reduces Utah's peak load by an average of about 82 MW per month, calculated over the 9 months for which Staff proposes forecast changes.

Q. HOW DOES TEMPERATURE PERFORM AS AN EXPLANATORY VARIABLE FOR HISTORICAL COINCIDENT PEAKS?

A. For most months with proposed revisions in Table A, temperature adds important accuracy in predicting coincident peak, which is not so surprising. There are a few months in which temperature exhibits weak explanatory power, at least historically. In these incidences, time is a much more significant explanatory variable than temperature.

II. Month-by-Month Discussion

Q. PLEASE EXPLAIN STAFF'S PROPOSED CHANGE FOR OREGON'S JANUARY COINCIDENT PEAK.

A. Oregon's January coincident peak is fairly flat over the historic period 1996 through 2008, with no significant time trend and variance only for temperature. Staff uses the temperature-fitted equation shown in Exhibit Staff/1004, Clark/1, to forecast an Oregon January coincident peak of 2,561 megawatts (MW), versus PPL's forecast of 2,713 MW. Staff's forecast uses an Oregon peak-producing temperature of [redacted] degrees (F) based on Exhibit 1011 (PPL OPUC 322 Data Response), which identifies historical year 1992 as that used by PPL to produce the Company's January coincident peak forecasts by state. For comparative purposes, the average temperature for Oregon's coincident peak compiled for the historical period, 1996 to 2008, is [redacted] degrees (F). For further comparative purposes, the average Oregon coincident peak for this historical period is 2,594 MW. Exhibit Staff/1004, Clark/1, presents detailed analytical data associated with these findings.

Q. PLEASE EXPLAIN STAFF'S PROPOSED CHANGE FOR OREGON'S FEBRUARY COINCIDENT PEAK.

A. Oregon's February coincident peak exhibits no significant time trend, reflecting primarily temperature-induced variance instead. Staff uses the temperature fitted equation shown in Exhibit Staff/1004, Clark/1-2, to forecast an Oregon February coincident peak of 2,486 MW, versus PPL's 2,587 MW. Staff's forecast uses a peak producing temperature of [redacted] degrees (F), which is based on Company provided information in Exhibit Staff/1011. For comparative purposes, the average temperature for Oregon's February coincident peak over Staff's historical period is [redacted] degrees (F). For further comparative purposes, the average Oregon coincident peak for Staff's historical period is 2,529 MW.

Q. PLEASE EXPLAIN STAFF'S PROPOSED CHANGE FOR OREGON'S SEPTEMBER COINCIDENT PEAK.

A. Oregon's September coincident peak also exhibits no significant time trend, reflecting primarily temperature-induced variance instead. Staff's equation, shown in Staff/1004 Clark/2-3, forecasts a September coincident peak of 2,036 MW, versus PPL's 2,191 MW. Staff's forecast uses a temperature of [redacted] degrees (F), based on historical year 1997 as identified by PPL (Exhibit Staff/1011). This temperature compares against an average peak-producing temperature of [redacted] degrees (F) ascertained from Staff's historical period.

Q. PLEASE EXPLAIN STAFF'S PROPOSED CHANGE FOR UTAH'S JANUARY COINCIDENT PEAK.

A. Utah's January coincident peak exhibits a strong time trend and a slight temperature contribution. Staff's equation shown in Exhibit Staff/1004, Clark/3-4, forecasts a January coincident peak of 3,447 MW. Staff reduced this forecast by approximately 70% of one standard error to subjectively account for any effects of the current economic recession. After this adjustment, Staff projects 3,372 MW for Utah's January coincident peak, versus PPL's 3,180 MW. Staff's projection uses a peak-producing temperature of [redacted] degrees (F) based on PPL's stated peak-producing temperature year of 1992. For comparative purposes, average January coincident peak-producing temperature during Staff's historical period is [redacted] degrees (F).

Q. PLEASE EXPLAIN STAFF'S PROPOSED CHANGE FOR UTAH'S MARCH COINCIDENT PEAK.

A. Utah's March coincident peak exhibits time trend and a modest temperature contribution. Staff's equation shown in Exhibit Staff/1004, Clark/4-5, forecasts a March coincident peak of 3,016 MW, but Staff reduces this forecast similarly for any recessionary effects to 2,939 MW. Staff's forecast uses a peak-producing temperature of [redacted] degrees (F) based on PPL's identified temperature year of 2004. By comparison, average peak-producing temperature for this month during Staff's historical period is [redacted] (F).

Q. PLEASE EXPLAIN STAFF'S PROPOSED CHANGES FOR UTAH'S APRIL AND MAY COINCIDENT PEAKS.

A. Each of these Utah peaks exhibits time trend and temperature contributions. Staff's equations, shown in Exhibit Staff/1004, Clark/5-7, forecast April and May coincident peaks of 2,983 MW and 3,662 MW, respectively. The May forecast uses time and temperature in a multiple regression, instead of the combination of two simple regression equations as used in other incidences. The latter approach would have yielded a higher forecast for Utah's May coincident peak. Staff's April coincident peak forecast is based on a weighted peak-producing temperature of [redacted] degrees (F), which is derived for analyzing temperature for year 1999 as identified by PPL. Staff's May coincident peak forecast is based on a weighted peak-related temperature of [redacted] degrees (F), which compares to an average peak-related May temperature of [redacted] degrees (F) as incurred during Staff's historic period.

Q. PLEASE EXPLAIN STAFF'S PROPOSED CHANGES FOR UTAH'S JUNE AND JULY COINCIDENT PEAKS.

A. Both June and July Utah coincident peaks exhibit strong time trend with R^2 in excess of 90%. Temperature has a more moderate explanatory contribution.

Staff equations shown in Exhibit Staff/1004, Clark/7-9, forecast a coincident peak of 4,320 MW and a coincident peak of 4,540 MW for June and July, respectively. The July forecast uses time and temperature in a multiple regression form instead of the combination of two regression equations. Staff's June coincident peak forecast is based on a weighted peak-related temperature of [redacted] degrees (F), and compares to an average weighted peak-related temperature of [redacted] degrees (F) as incurred during Staff's historical period. Staff's July coincident peak forecast is based on a peak–related temperature of [redacted] (F), which is slightly higher than the average peak-related July temperature observed during Staff's historical period.

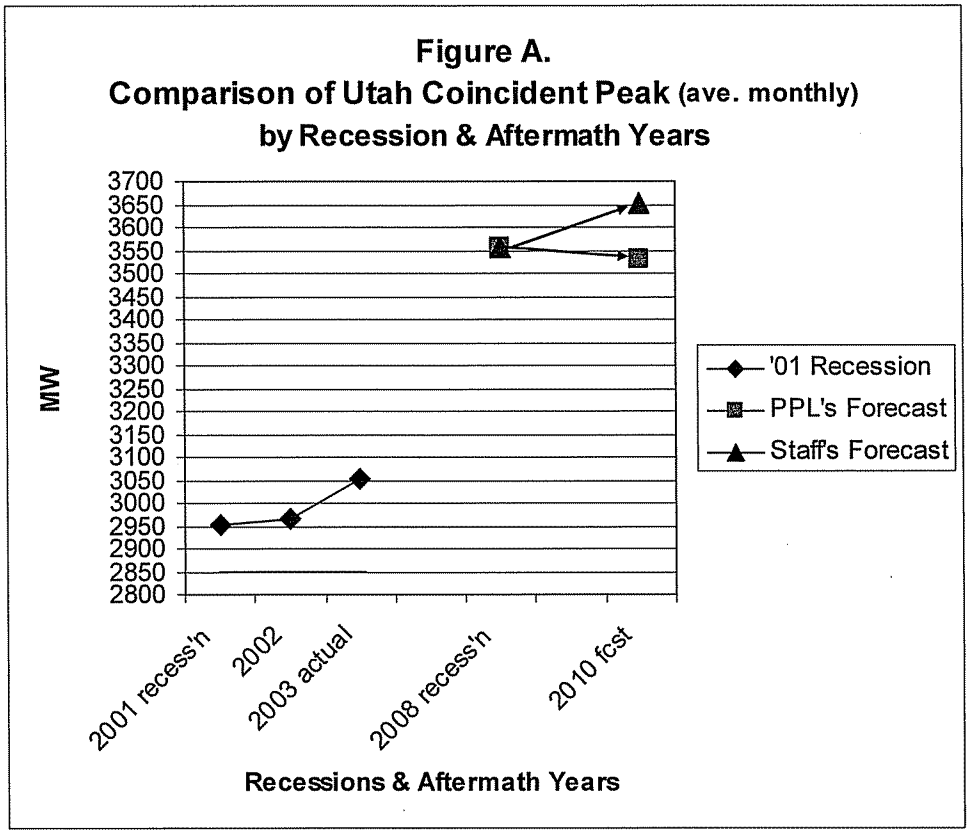
Q. PLEASE EXPLAIN STAFF'S PROPOSED CHANGE FOR UTAH'S SEPTEMBER, OCTOBER AND NOVEMBER COINCIDENT PEAKS.

A. Utah's September coincident peak exhibits both time trend and temperature contribution. Staff's equation for September as shown in Exhibit Staff/1004, Clark/9-10, results in a peak forecast of 4,086 MW, after adjusting as in other incidences for standard error. This forecast is based on an average weighted peak-related temperature of [redacted] degrees (F), slightly higher than the average historic weighted peak-related temperature of [redacted] degrees (F). Utah's October coincident peak exhibits both moderate time trend and temperature contribution. Staff's equation for October, as shown in Exhibit Staff/1004, Clark/10-11, results in a forecast coincident peak of 2,854 MW. This forecast is based on a weighted peak-related temperature of [redacted] degrees (F). Finally, Utah's November peak exhibits both time trend and temperature contribution.

Staff's equation for November, as shown in Exhibit Staff/1004, Clark 11/12, results in a coincident peak forecast of 3,557 MW. This forecast is based on a weighted peak-related temperature of [redacted] degrees (F).

Q. WHY SHOULD THE COMMISSION ADOPT STAFF'S PROPOSED COINCIDENT PEAK FORECASTS IN PLACE OF PPL'S COINCIDENT PEAK LOAD FORECASTS?

A. The Company adjusted model results for year 2010 loads to subjectively account for the effects of the current economic recession. The company uses the 2001-2002 recession as an analogy for adjusting model results for the current recession (PPL/600, Duvall/7 and PPL/605, Duvall/8). However, the Company's forecast for Utah coincident peak does not comport accurately with the 2001-2002 recession analogy. The Company forecasts a decline for Utah average monthly coincident peak for the year 2010 versus 2008 actual. However, when one looks back on the 2001-2002 economic recession, Utah's average monthly coincident peak for the years 2002 and 2003 continued to increase. In fact, Utah's average monthly coincident peak was about 100 MW higher two years after the 2001 recession, after adjusting for load factor. Using Sfaff's proposed changes for Utah coincident peaks would cause the 2010 forecast to be just about 100 MW greater than the 2008 actual. Figure A below demonstrates these comparisons.



Q. WHY SHOULD THE COMMISSION ADOPT STAFF'S PROPOSED OREGON COINCIDENT PEAK FORECASTS IN PLACE OF PPL'S FORECASTS?

A. Staff believes PPL's Oregon coincident peak forecasts imply an average monthly load factor for Oregon that is too low. PPL hourly load forecasting methodology does allow for targeting load factor (Exhibit Staff/1008, page 12 of 13). However, PPL does not use this technique in the case of its Oregon forecast. Instead, PPL's implied average monthly load factor is allowed to continue at 72%, which is its historical low. Exhibit Staff/1013 calculates average monthly load factor by historical year. Staff believes year 2008's load factor value may be lower than normal because of unusual weather. Exhibit Staff/1014 illustrates the extreme nature of 2008 weather in summed heating degree days (HDD) and cooling degree days (CDD). Staff's proposed coincident peak forecasts would raise Oregon' year 2010 average monthly load factor to 73.8%, still moderately lower than the average posted for the 1997-2008 historical record (75%).

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 210
WITNESS: Robert Clark

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualification Statement

July 24, 2009

WITNESS QUALIFICATION STATEMENT

NAME:	Robert Clark
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist, Electric and Natural Gas Division, Resource and Market Analysis
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.
EDUCATION:	Masters of Science in Economics Portland State University B.S. Portland State University Major: Economics Other focus: Mathematics
EXPERIENCE:	From 1981 to 2005, I was employed by the Bonneville Power Administration as an industry economist. I worked on a variety of matters including load forecasting, industrial rates, natural gas price forecasts, natural gas generating resource proposals, transaction pricing, option pricing, and wholesale marketing strategies. From 2008 to the present, I have been employed by the OPUC. My responsibilities include investigating utility costs, conducting complex research and analysis of energy and telecommunication issues, and providing written and verbal testimony in formal state and federal hearings.

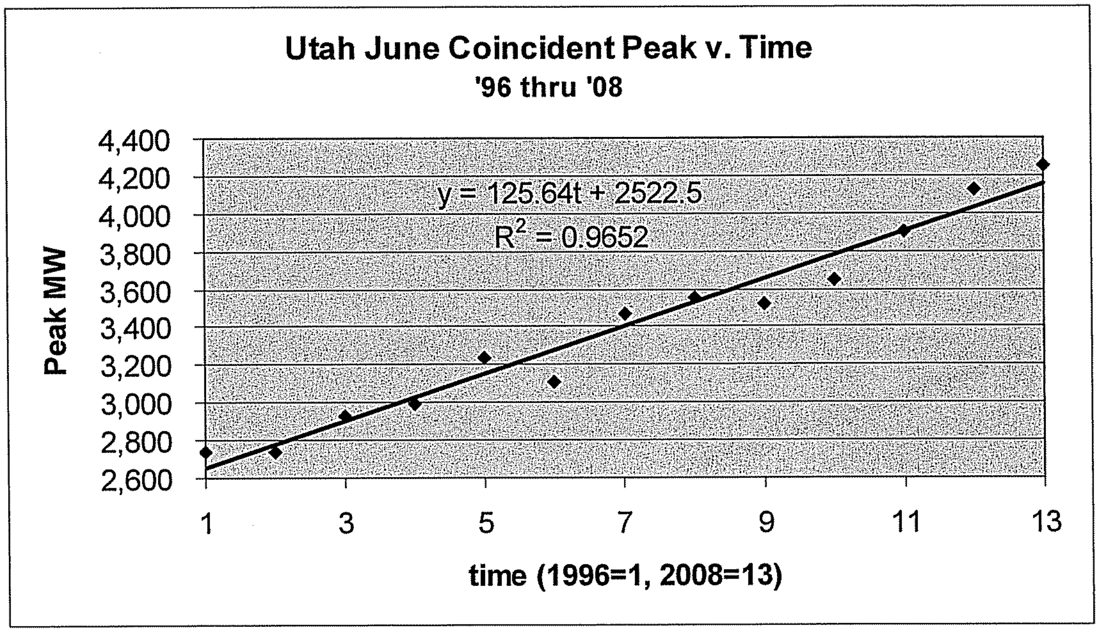
CASE: UE 210
WITNESS: Robert Clark

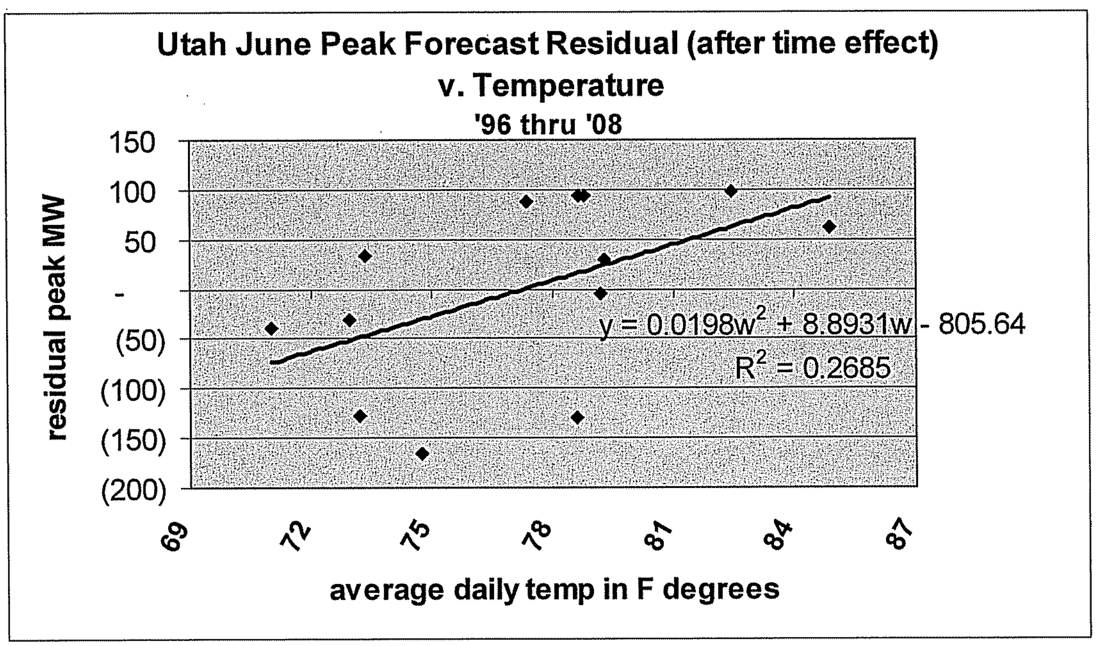
PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1002

Exhibits in Support Of Opening Testimony

July 24, 2009


Utah June Coincident Peak v. Time
'96 thru '08
y = 125.64t + 2522.5
R^2 = 0.9652
Peak MW
4,400
4,200
4,000
3,800
3,600
3,400
3,200
3,000
2,800
2,600
1
3
5
7
9
11
13
time (1996=1, 2008=13)


Utah June Peak Forecast Residual (after time effect)
v. Temperature
'96 thru '08
y = 0.0198w^2 + 8.8931w - 805.64
R^2 = 0.2685
residual peak MW
150
100
50
-
(50)
(100)
(150)
(200)
69
72
75
78
81
84
87
average daily temp in F degrees

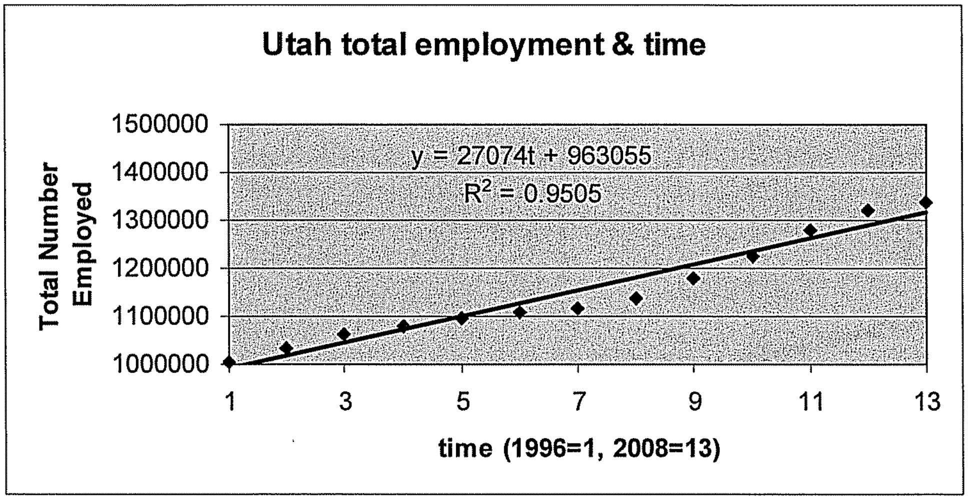
CASE: UE 210
WITNESS: Robert Clark

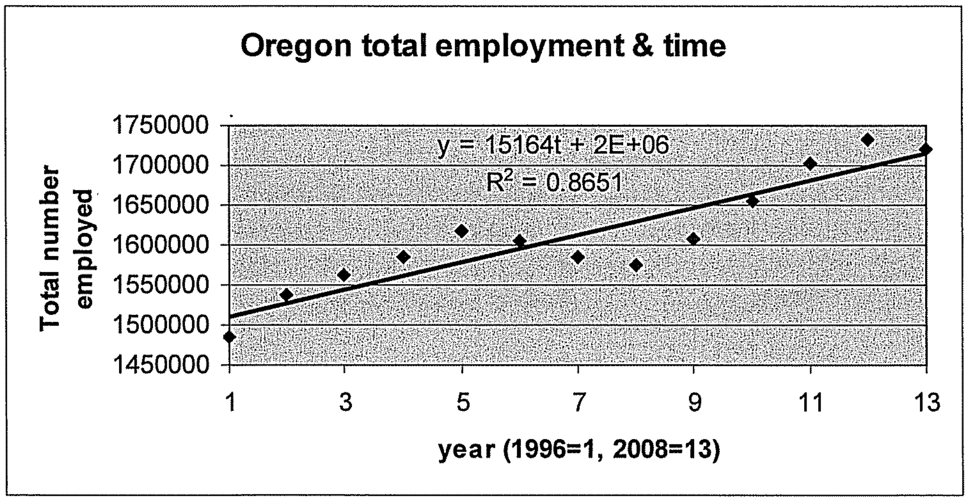
PUBLIC UTILITY COMMISSION OF OREGON

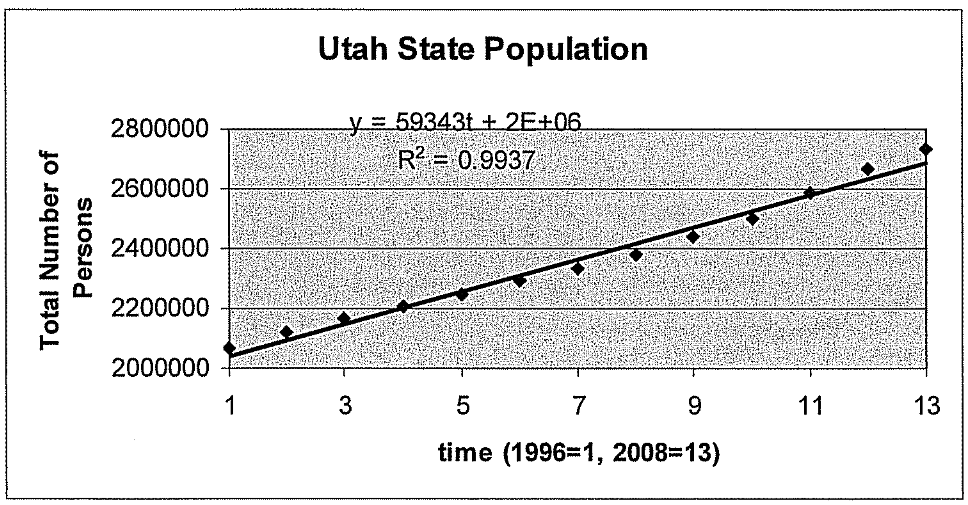
STAFF EXHIBIT 1003

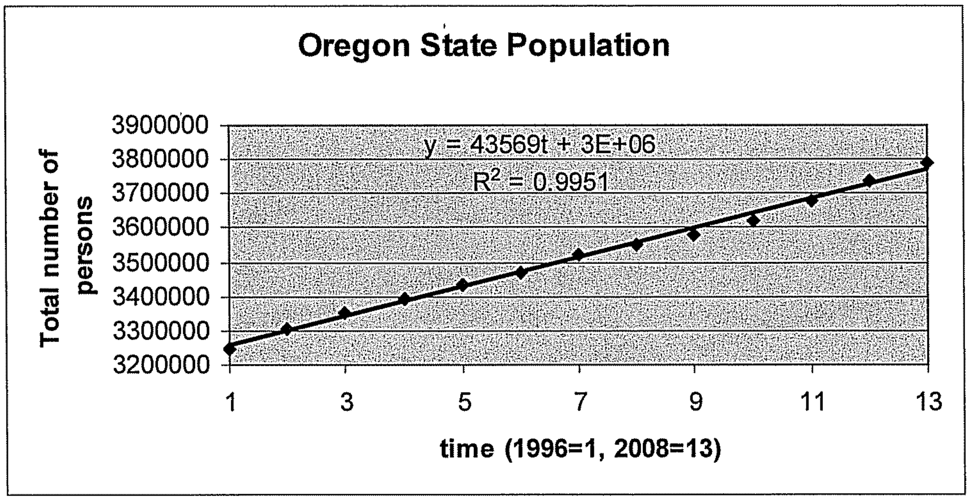
Exhibits in Support Of Opening Testimony

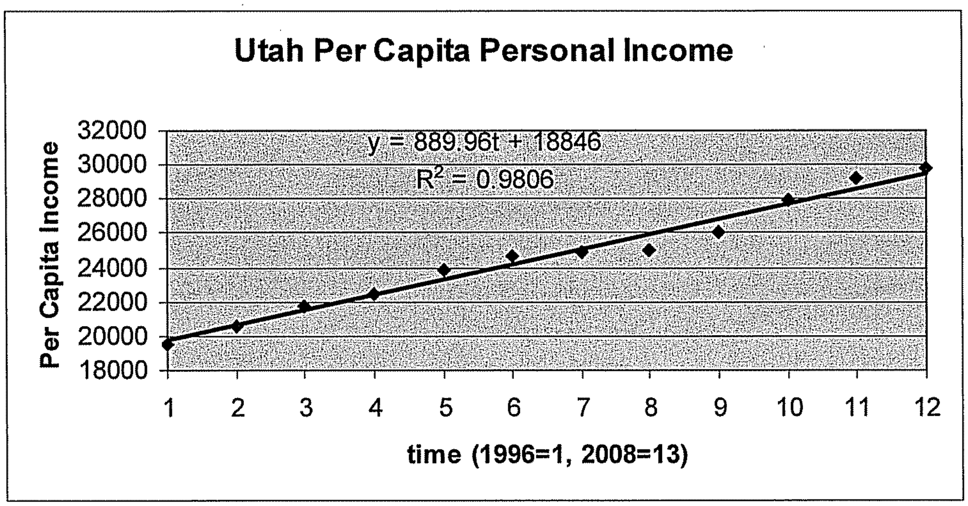
July 24, 2009

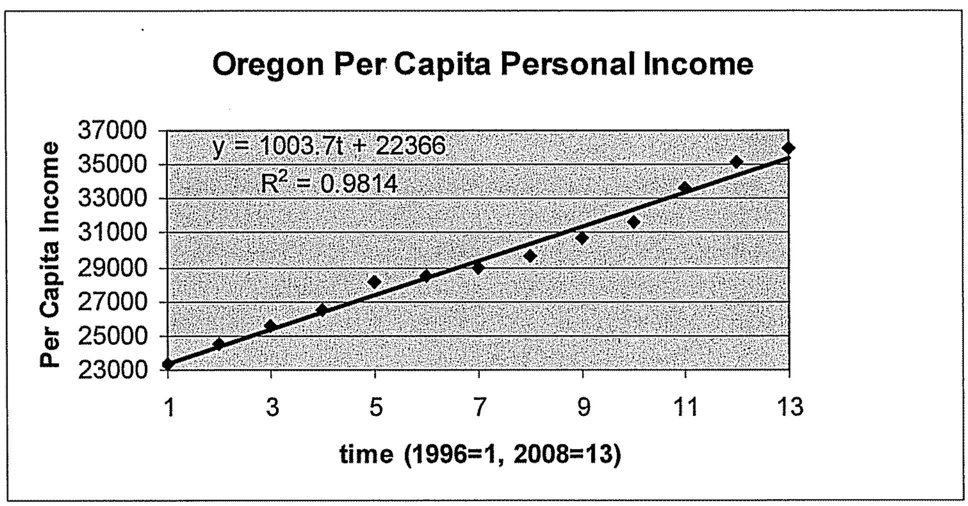

Utah total employment & time
y = 27074t + 963055
R2 = 0.9505
Total Number Employed
1500000
1400000
1300000
1200000
1100000
1000000
1
3
5
7
9
11
13
time (1996=1, 2008=13)


Oregon total employment & time
y = 15164t + 2E+06
R2 = 0.8651
Total number employed
1750000
1700000
1650000
1600000
1550000
1500000
1450000
1
3
5
7
9
11
13
year (1996=1, 2008=13)


Utah State Population
y = 59343t + 2E+06
R2 = 0.9937
Total Number of Persons
2800000
2600000
2400000
2200000
2000000
1
3
5
7
9
11
13
time (1996=1, 2008=13)







Sources: Employment history, Utah Department of Workforce Services and Oregon Employment Department. Population and per capita income: Bureau of Economic Analysis, U.S Department of Commerce.

CASE: UE 210
WITNESS: Robert Clark

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1004

Exhibits in Support
Of Opening Testimony

July 24, 2009

STAFF EXHIBIT 1004

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 09-120. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 210 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 210
WITNESS: Robert Clark

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1005

Exhibits in Support
Of Opening Testimony

July 24, 2009

UE 210

Staff/1005
Clark/1

Source: PPL Data Response OPUC 177c

Year	mm	dd	hr	Peak	CA	ID	OR	UT	WA	WYOMING
1996	1	31	8	7,721	155	414	2,700	2,336	922	1,193
1996	2	2	9	7,822	165	409	2,738	2,379	906	1,225
1996	3	1	8	6,966	149	341	2,438	2,202	711	1,125
1996	4	19	9	6,373	142	306	2,177	2,130	535	1,083
1996	5	13	14	6,319	104	436	1,799	2,502	461	1,017
1996	6	10	13	6,949	123	568	1,895	2,742	531	1,088
1996	7	26	15	7,556	145	600	2,233	2,784	675	1,119
1996	8	14	15	7,465	155	433	2,189	2,929	672	1,087
1996	9	4	15	6,770	110	450	1,845	2,756	522	1,088
1996	10	21	8	6,783	157	376	2,325	2,174	681	1,071
1996	11	26	18	7,128	132	384	2,134	2,575	769	1,134
1996	12	18	8	7,605	175	418	2,580	2,489	770	1,174
1997	1	14	8	7,770	174	415	2,799	2,490	843	1,049
1997	2	6	8	7,298	159	401	2,519	2,437	746	1,035
1997	3	4	8	7,013	159	379	2,462	2,306	706	1,002
1997	4	11	8	6,627	150	345	2,235	2,230	657	1,010
1997	5	16	15	6,496	129	451	1,933	2,477	575	932
1997	6	26	15	6,865	131	605	1,839	2,735	550	1,005
1997	7	21	14	7,438	143	616	2,101	2,876	690	1,013
1997	8	22	16	7,343	124	414	2,105	3,014	681	1,004
1997	9	9	16	6,924	136	435	1,946	2,839	599	970
1997	10	24	8	6,718	139	302	2,312	2,272	684	1,009
1997	11	17	18	7,096	146	384	2,207	2,578	652	1,129
1997	12	11	18	7,443	141	419	2,262	2,823	683	1,115
1998	1	12	18	7,413	136	363	2,457	2,652	780	1,025
1998	2	10	19	7,057	146	379	2,315	2,574	626	1,017
1998	3	6	9	7,076	152	385	2,466	2,444	630	999
1998	4	16	8	6,558	146	316	2,329	2,244	586	937
1998	5	20	11	6,267	137	396	1,987	2,375	478	893
1998	6	30	16	7,150	130	530	1,952	2,933	669	937
1998	7	16	16	7,993	168	647	2,306	3,166	710	996
1998	8	13	15	7,739	157	507	2,279	3,074	748	975
1998	9	3	16	7,569	146	481	2,209	2,999	735	999
1998	10	30	8	6,562	141	357	2,254	2,171	669	969
1998	11	9	18	7,062	145	381	2,180	2,730	620	1,007
1998	12	21	19	8,354	190	440	2,900	2,968	810	1,046
1999	1	4	8	7,276	149	384	2,471	2,561	750	962
1999	2	11	8	7,248	174	368	2,547	2,521	721	917
1999	3	11	8	6,952	158	378	2,449	2,385	653	929
1999	4	1	8	6,603	173	378	2,366	2,255	604	826
1999	5	28	13	6,540	167	463	1,908	2,595	538	870
1999	6	30	16	7,196	167	554	1,973	2,994	601	908
1999	7	12	15	7,972	214	697	2,208	3,170	791	892
1999	8	2	17	7,781	185	536	2,138	3,242	804	876
1999	9	13	17	6,737	154	376	2,050	2,646	644	868
1999	10	27	8	6,671	132	369	2,171	2,371	752	876
1999	11	22	18	7,244	176	394	2,252	2,801	675	946
1999	12	13	18	7,688	180	407	2,393	3,029	696	983

Year	mm	dd	hr	Peak	CA	ID	OR	UT	WA	WYOMING
2000	1	31	8	7,382	161	387	2,503	2,664	713	954
2000	2	18	8	7,172	159	383	2,466	2,525	724	914
2000	3	1	8	6,897	137	295	2,431	2,460	659	915
2000	4	24	8	6,439	121	365	2,234	2,250	589	880
2000	5	23	15	6,836	137	490	1,903	2,895	539	872
2000	6	28	16	7,960	166	651	2,263	3,239	707	934
2000	7	31	16	8,480	154	523	2,347	3,721	756	979
2000	8	1	15	8,295	162	546	2,246	3,644	701	995
2000	9	14	16	7,402	106	406	2,018	3,240	662	971
2000	10	23	8	6,826	126	360	2,294	2,441	664	941
2000	11	22	9	7,566	140	368	2,575	2,745	724	1,014
2000	12	11	18	7,985	124	400	2,602	3,076	770	1,012
2001	1	17	8	7,693	143	370	2,739	2,652	724	1,064
2001	2	13	8	7,595	146	342	2,690	2,653	687	1,077
2001	3	1	8	7,126	127	376	2,358	2,560	669	1,037
2001	4	9	8	6,959	126	384	2,420	2,384	621	1,023
2001	5	24	17	7,310	133	573	2,018	2,941	665	979
2001	6	21	17	7,595	152	491	2,124	3,111	682	1,035
2001	7	3	15	7,854	129	564	1,987	3,464	657	1,053
2001	8	7	14	7,899	124	421	2,122	3,514	627	1,091
2001	9	4	16	7,301	120	391	1,924	3,209	627	1,031
2001	10	1	16	6,689	88	363	1,858	2,931	458	991
2001	11	29	18	7,418	119	411	2,169	2,982	670	1,068
2001	12	10	18	7,688	132	423	2,346	3,017	692	1,079
2002	1	30	8	7,459	157	413	2,621	2,596	680	992
2002	2	5	8	7,396	142	419	2,404	2,736	693	1,002
2002	3	1	8	7,134	129	405	2,410	2,550	664	976
2002	4	17	9	6,494	131	331	2,125	2,395	567	945
2002	5	30	16	7,203	143	518	1,803	3,247	511	981
2002	6	26	15	8,035	155	563	2,102	3,464	705	1,047
2002	7	11	16	8,549	162	689	2,139	3,758	758	1,043
2002	8	15	16	7,967	149	537	2,150	3,497	684	950
2002	9	4	16	7,361	114	491	1,741	3,446	551	1,018
2002	10	31	8	7,295	140	397	2,423	2,480	771	1,083
2002	11	26	8	7,227	124	394	2,270	2,708	707	1,023
2002	12	18	18	7,613	139	416	2,207	3,073	682	1,096
2003	1	8	8	7,331	138	400	2,392	2,698	667	1,036
2003	2	25	8	7,417	139	356	2,452	2,687	747	1,036
2003	3	4	8	6,929	146	393	2,241	2,524	604	1,020
2003	4	3	8	6,669	138	375	2,178	2,445	583	949
2003	5	29	16	7,822	150	533	1,921	3,646	599	972
2003	6	17	15	8,049	153	594	2,102	3,557	672	971
2003	7	22	15	8,922	155	573	2,360	4,038	774	1,022
2003	8	13	16	8,310	156	498	2,020	3,924	666	1,045
2003	9	4	16	7,948	115	416	2,155	3,520	744	997
2003	10	31	8	6,971	116	396	2,234	2,580	678	968
2003	11	24	18	7,429	126	418	2,160	2,999	657	1,068
2003	12	29	18	7,697	133	417	2,343	3,002	719	1,083
2004	1	5	18	8,069	146	367	2,525	3,052	886	1,093
2004	2	11	8	7,599	164	416	2,407	2,831	703	1,078
2004	3	3	8	7,010	137	390	2,239	2,553	624	1,067

Year	mm	dd	hr	Peak	CA	ID	OR	UT	WA	WYOMING
2004	4	20	9	6,518	136	394	1,983	2,498	523	983
2004	5	6	16	6,856	158	513	1,656	3,040	501	987
2004	6	23	17	8,024	130	619	1,967	3,526	750	1,033
2004	7	14	16	8,628	120	603	2,202	3,869	740	1,094
2004	8	13	16	8,473	156	501	2,261	3,746	774	1,035
2004	9	1	16	7,632	135	450	1,905	3,529	601	1,012
2004	10	25	8	6,906	151	403	2,109	2,569	660	1,014
2004	11	29	18	7,943	158	366	2,358	3,241	721	1,098
2004	12	6	18	7,965	167	437	2,337	3,244	700	1,079
2005	1	5	18	7,864	149	433	2,335	3,096	739	1,113
2005	2	15	8	7,599	140	406	2,501	2,768	732	1,053
2005	3	1	8	6,916	159	396	2,070	2,647	605	1,040
2005	4	8	9	6,740	132	387	2,062	2,590	561	1,008
2005	5	27	16	6,988	117	465	1,937	2,907	596	967
2005	6	21	15	7,862	110	519	1,839	3,650	693	1,051
2005	7	20	17	8,937	171	681	2,240	4,056	708	1,081
2005	8	9	16	8,540	173	476	2,221	3,822	773	1,074
2005	9	7	17	7,871	146	452	1,888	3,673	666	1,046
2005	10	27	8	6,769	131	369	2,116	2,475	644	1,035
2005	11	28	18	8,019	144	364	2,422	3,251	705	1,133
2005	12	14	18	8,438	164	412	2,488	3,348	844	1,182
2006	1	31	18	7,832	149	416	2,428	3,081	678	1,080
2006	2	17	9	8,048	152	451	2,602	2,898	806	1,138
2006	3	13	8	7,525	158	425	2,550	2,651	666	1,077
2006	4	6	8	6,922	144	381	2,170	2,669	536	1,022
2006	5	18	16	8,118	170	547	2,067	3,610	715	1,010
2006	6	26	16	9,010	157	666	2,500	3,900	766	1,022
2006	7	24	15	9,322	156	561	2,684	4,011	816	1,094
2006	8	22	17	8,728	137	512	2,135	4,140	704	1,100
2006	9	5	17	8,485	129	492	2,229	3,825	752	1,059
2006	10	31	8	7,521	153	351	2,493	2,720	743	1,061
2006	11	29	18	8,617	149	460	2,507	3,521	803	1,177
2006	12	18	18	8,686	168	465	2,595	3,494	773	1,192
2007	1	16	8	8,644	178	430	2,844	3,228	789	1,174
2007	2	2	8	8,433	163	462	2,684	3,137	793	1,193
2007	3	1	19	7,809	160	387	2,311	3,139	641	1,171
2007	4	30	15	7,037	125	451	1,748	3,197	470	1,046
2007	5	31	17	7,804	150	643	2,150	3,209	631	1,021
2007	6	20	17	8,887	159	646	2,163	4,123	678	1,117
2007	7	10	17	9,775	160	701	2,606	4,424	754	1,129
2007	8	14	17	9,406	165	606	2,310	4,473	707	1,144
2007	9	4	16	8,254	129	502	1,860	3,996	626	1,142
2007	10	31	8	7,144	131	370	2,181	2,723	690	1,049
2007	11	28	18	8,395	145	460	2,438	3,475	711	1,166
2007	12	11	18	8,650	155	433	2,517	3,552	762	1,230
2008	1	23	8	8,924	174	480	2,911	3,304	862	1,193
2008	2	5	8	8,278	169	463	2,558	3,149	695	1,244
2008	3	5	8	7,848	155	445	2,493	2,958	649	1,148
2008	4	1	8	7,785	146	422	2,523	2,896	645	1,152
2008	5	19	16	8,427	158	497	2,166	3,856	634	1,117
2008	6	30	14	9,371	147	727	2,261	4,253	742	1,241

Year	mm	dd	hr	Peak	CA	ID	OR	UT	WA	WYOMING
2008	7	9	17	9,501	171	682	2,522	4,189	728	1,208
2008	8	14	17	9,396	156	528	2,590	4,194	755	1,173
2008	9	8	16	8,081	135	463	2,207	3,577	602	1,098
2008	10	1	16	7,588	109	436	1,878	3,462	571	1,133
2008	11	5	18	7,839	138	425	2,202	3,243	623	1,210
2008	12	15	18	9,176	163	451	2,796	3,594	848	1,325

UE 210

CASE: UE 210
WITNESS: Robert Clark

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1006

Exhibits in Support
Of Opening Testimony

July 24, 2009

UE 210

Staff/1006
Clark/1

MW

Year	Month	CA	ID	OR	UT	WA	Total Wyoming
1996	1	157	433	2,705	2,528	922	1,224
1996	2	165	430	2,748	2,462	930	1,229
1996	3	149	388	2,438	2,319	711	1,170
1996	4	142	367	2,182	2,237	560	1,083
1996	5	138	444	2,061	2,508	576	1,058
1996	6	132	630	1,992	2,742	604	1,088
1996	7	152	692	2,288	2,850	708	1,162
1996	8	163	540	2,270	2,929	693	1,122
1996	9	139	477	2,013	2,756	617	1,091
1996	10	160	396	2,325	2,342	681	1,100
1996	11	164	392	2,259	2,575	769	1,158
1996	12	181	421	2,608	2,704	780	1,226
1997	1	174	438	2,799	2,734	863	1,063
1997	2	159	416	2,519	2,567	801	1,038
1997	3	159	403	2,462	2,474	706	1,041
1997	4	166	386	2,274	2,287	658	1,018
1997	5	150	496	2,082	2,477	610	981
1997	6	149	629	2,015	2,735	601	1,011
1997	7	157	697	2,159	2,947	695	1,042
1997	8	158	488	2,340	3,071	783	1,052
1997	9	149	469	2,048	2,852	611	1,047
1997	10	147	396	2,312	2,543	684	1,073
1997	11	152	393	2,327	2,604	710	1,139
1997	12	178	419	2,476	2,854	749	1,157
1998	1	157	406	2,482	2,706	801	1,025
1998	2	158	401	2,401	2,661	661	1,019
1998	3	161	396	2,501	2,522	657	1,020
1998	4	170	383	2,329	2,330	598	971
1998	5	155	426	2,095	2,425	600	927
1998	6	148	556	1,980	2,933	674	989
1998	7	181	686	2,370	3,213	804	1,026
1998	8	181	528	2,313	3,160	795	988
1998	9	160	508	2,273	2,999	746	1,028
1998	10	141	397	2,254	2,355	674	998
1998	11	149	389	2,322	2,730	677	1,009
1998	12	212	440	3,118	3,015	863	1,063
1999	1	167	430	2,497	2,741	750	983
1999	2	174	410	2,574	2,696	747	975
1999	3	183	390	2,449	2,554	683	940
1999	4	173	381	2,366	2,391	647	907
1999	5	175	468	2,153	2,665	645	904
1999	6	182	636	2,102	3,062	718	932
1999	7	229	711	2,227	3,270	805	953
1999	8	204	562	2,192	3,270	809	903
1999	9	177	431	2,119	2,732	689	926
1999	10	162	415	2,171	2,577	752	953
1999	11	189	401	2,283	2,805	720	973
1999	12	197	411	2,482	3,029	749	1,011
2000	1	172	413	2,598	2,860	785	966

MW

Year	Month	CA	ID	OR	UT	WA	Total Wyoming
2000	2	159	395	2,485	2,793	724	966
2000	3	146	368	2,431	2,586	659	955
2000	4	144	399	2,234	2,580	589	931
2000	5	150	574	2,146	2,936	556	906
2000	6	176	686	2,274	3,303	708	952
2000	7	169	682	2,347	3,721	759	1,000
2000	8	172	560	2,289	3,644	745	1,011
2000	9	136	426	2,062	3,267	666	994
2000	10	134	389	2,294	2,713	664	956
2000	11	164	398	2,588	2,896	756	1,062
2000	12	160	411	2,605	3,076	778	1,050
2001	1	144	422	2,739	2,925	755	1,087
2001	2	146	399	2,690	2,887	725	1,097
2001	3	128	403	2,358	2,604	669	1,080
2001	4	133	409	2,422	2,549	625	1,029
2001	5	149	609	2,164	2,966	667	1,021
2001	6	154	616	2,124	3,255	682	1,044
2001	7	141	616	2,160	3,464	718	1,058
2001	8	150	475	2,281	3,516	746	1,104
2001	9	141	469	1,974	3,209	661	1,031
2001	10	125	412	2,146	2,931	624	1,076
2001	11	155	411	2,394	2,982	705	1,086
2001	12	162	424	2,475	3,019	702	1,124
2002	1	174	424	2,639	2,900	750	1,047
2002	2	153	434	2,474	2,890	701	1,030
2002	3	145	423	2,410	2,629	691	1,026
2002	4	146	386	2,158	2,463	600	991
2002	5	154	560	2,073	3,257	611	1,003
2002	6	160	674	2,127	3,538	720	1,081
2002	7	168	713	2,227	3,810	760	1,089
2002	8	169	568	2,303	3,497	739	1,029
2002	9	146	523	2,049	3,446	681	1,022
2002	10	140	404	2,423	2,600	771	1,083
2002	11	139	418	2,299	2,920	754	1,075
2002	12	145	418	2,223	3,073	716	1,113
2003	1	138	423	2,392	2,869	715	1,057
2003	2	148	421	2,452	2,883	747	1,079
2003	3	146	404	2,241	2,649	625	1,047
2003	4	149	391	2,178	2,595	606	972
2003	5	153	633	1,931	3,646	609	1,009
2003	6	167	697	2,161	3,640	700	1,008
2003	7	169	722	2,428	4,038	788	1,072
2003	8	156	595	2,230	3,995	731	1,056
2003	9	142	502	2,206	3,520	745	997
2003	10	132	436	2,234	2,889	678	1,007
2003	11	137	418	2,281	2,999	728	1,072
2003	12	157	429	2,356	3,147	758	1,126
2004	1	151	441	2,525	3,076	920	1,097
2004	2	164	447	2,411	2,989	709	1,109
2004	3	150	406	2,239	2,740	631	1,070
2004	4	140	448	2,111	2,599	581	1,031

MW

Year	Month	CA	ID	OR	UT	WA	Total Wyoming
2004	5	164	530	1,832	3,046	543	998
2004	6	172	661	2,063	3,531	751	1,060
2004	7	176	708	2,351	3,900	762	1,111
2004	8	174	509	2,339	3,832	778	1,049
2004	9	148	476	1,913	3,529	636	1,015
2004	10	156	408	2,109	2,752	660	1,033
2004	11	183	449	2,457	3,241	755	1,098
2004	12	193	445	2,384	3,291	759	1,109
2005	1	189	436	2,540	3,096	806	1,121
2005	2	170	448	2,501	3,050	735	1,109
2005	3	159	411	2,178	2,817	622	1,099
2005	4	147	392	2,191	2,691	651	1,048
2005	5	136	481	1,937	3,249	603	1,020
2005	6	167	657	2,085	3,650	722	1,094
2005	7	186	753	2,371	4,119	775	1,129
2005	8	174	575	2,336	3,915	773	1,128
2005	9	164	483	2,063	3,679	707	1,082
2005	10	139	408	2,116	2,708	644	1,075
2005	11	153	429	2,422	3,251	742	1,155
2005	12	181	454	2,722	3,399	844	1,224
2006	1	171	455	2,443	3,159	730	1,145
2006	2	161	463	2,724	3,143	822	1,147
2006	3	159	434	2,550	2,915	666	1,079
2006	4	149	403	2,236	2,715	600	1,073
2006	5	180	604	2,149	3,610	723	1,048
2006	6	164	723	2,500	3,940	790	1,109
2006	7	163	715	2,704	4,357	816	1,138
2006	8	144	580	2,403	4,140	757	1,123
2006	9	130	510	2,229	3,864	752	1,075
2006	10	153	413	2,493	2,899	752	1,122
2006	11	170	460	2,689	3,521	803	1,177
2006	12	177	465	2,672	3,543	803	1,208
2007	1	187	491	2,856	3,447	834	1,195
2007	2	174	470	2,691	3,343	793	1,223
2007	3	172	406	2,487	3,139	690	1,172
2007	4	161	470	2,250	3,203	640	1,088
2007	5	159	671	2,153	3,543	637	1,047
2007	6	170	773	2,170	4,189	685	1,160
2007	7	167	789	2,606	4,615	797	1,180
2007	8	166	609	2,438	4,544	763	1,189
2007	9	137	543	2,215	3,996	676	1,148
2007	10	154	430	2,190	2,942	690	1,125
2007	11	169	460	2,559	3,499	751	1,182
2007	12	171	465	2,698	3,601	762	1,230
2008	1	176	494	2,922	3,521	866	1,271
2008	2	178	465	2,582	3,387	718	1,256
2008	3	168	461	2,526	3,094	674	1,203
2008	4	150	443	2,523	2,968	662	1,174
2008	5	167	525	2,235	3,856	641	1,179
2008	6	160	740	2,316	4,294	766	1,250
2008	7	171	759	2,522	4,416	744	1,259

MW

Year	Month	CA	ID	OR	UT	WA	Total Wyoming
2008	8	161	629	2,590	4,523	784	1,247
2008	9	144	482	2,261	3,631	665	1,177
2008	10	137	452	2,211	3,462	664	1,207
2008	11	151	425	2,256	3,243	702	1,241
2008	12	187	461	2,910	3,594	923	1,339

UE 210

CASE: UE 210
WITNESS: Robert Clark

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STAFF EXHIBIT 1007

Exhibits in Support
Of Opening Testimony

July 24, 2009

Load Forecasting Methodology

Prepared for April 30, 2009
Meeting with OPUC Staff

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What changed in methodology?

- Weather response specification was improved
  - Use of hourly load research data by state by class
  - Creation of composite splines for heating degree days and cooling degree days
- Weather normalization integrated in the model and definition of normal weather was updated from the NOAA's 30 year period of 1971-2000 to the 20 year time period of 1988-2007
- Monthly energy forecasts were improved by adopting the following
  - Statistically Adjusted End Use model for Residential Sales
  - Simple Econometric model for Commercial Sales
- Model forecasts Peaks (monthly by state) directly

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Development of weather response

- ✓ Big picture: Development of composite weather variable
- ✓ Why use Load Research Data?
- ✓ Modeling Weather Response and Energy use
- ✓ Develop Weather Adjustment
- ✓ Development of HDD and CDD Splines

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Development of Composite Weather Variable

Load Research Data (Hourly by Class) + Daily Temperature, Calendar variables

↓

Run through Neural Network Model

↓

Decision on final break points based on statistical results and scatter plots

↓

Weights of break points are derived from regression equation

↓

Development of composite HDD & CDD Splines

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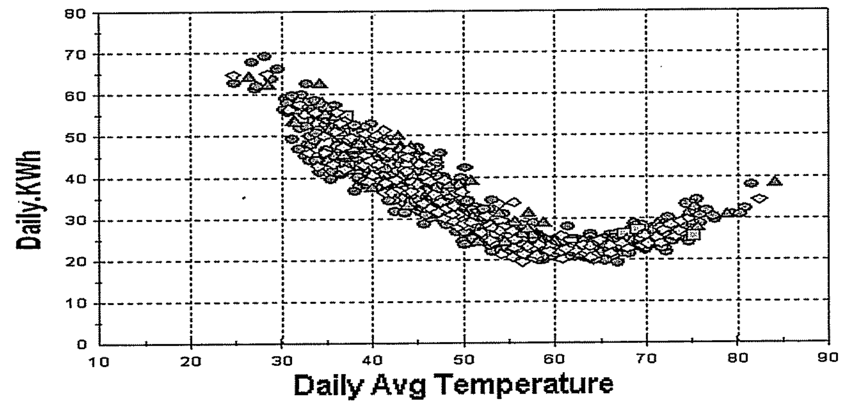
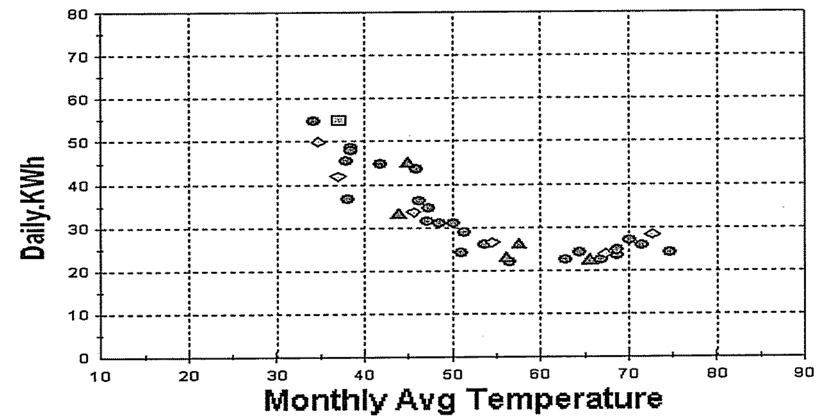
Why use Load Research Data?

- Load research profile data provides a very powerful basis for understanding weather relationships since there are 365 points per year, a strong advantage over monthly data

- Greater frequency and more data points associated with this hourly data make it better suited to capture load changes driven by changes in temperature



OR - Residential



OR - Residential

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Modeling Weather Response and Energy use

- To determine temperature levels over which load response varies (i.e., breakpoints)
  - The Company identified multipart slopes (weights) and breakpoints through a Neural Network framework
    - Using load research data by customer class, the Company analyzed the weather response, and identified the break points and shape of the weather impacts using a Neural Network model
    - Finally, composite weather variable was developed in order to capture the relationship between sales and temperature with a single variable

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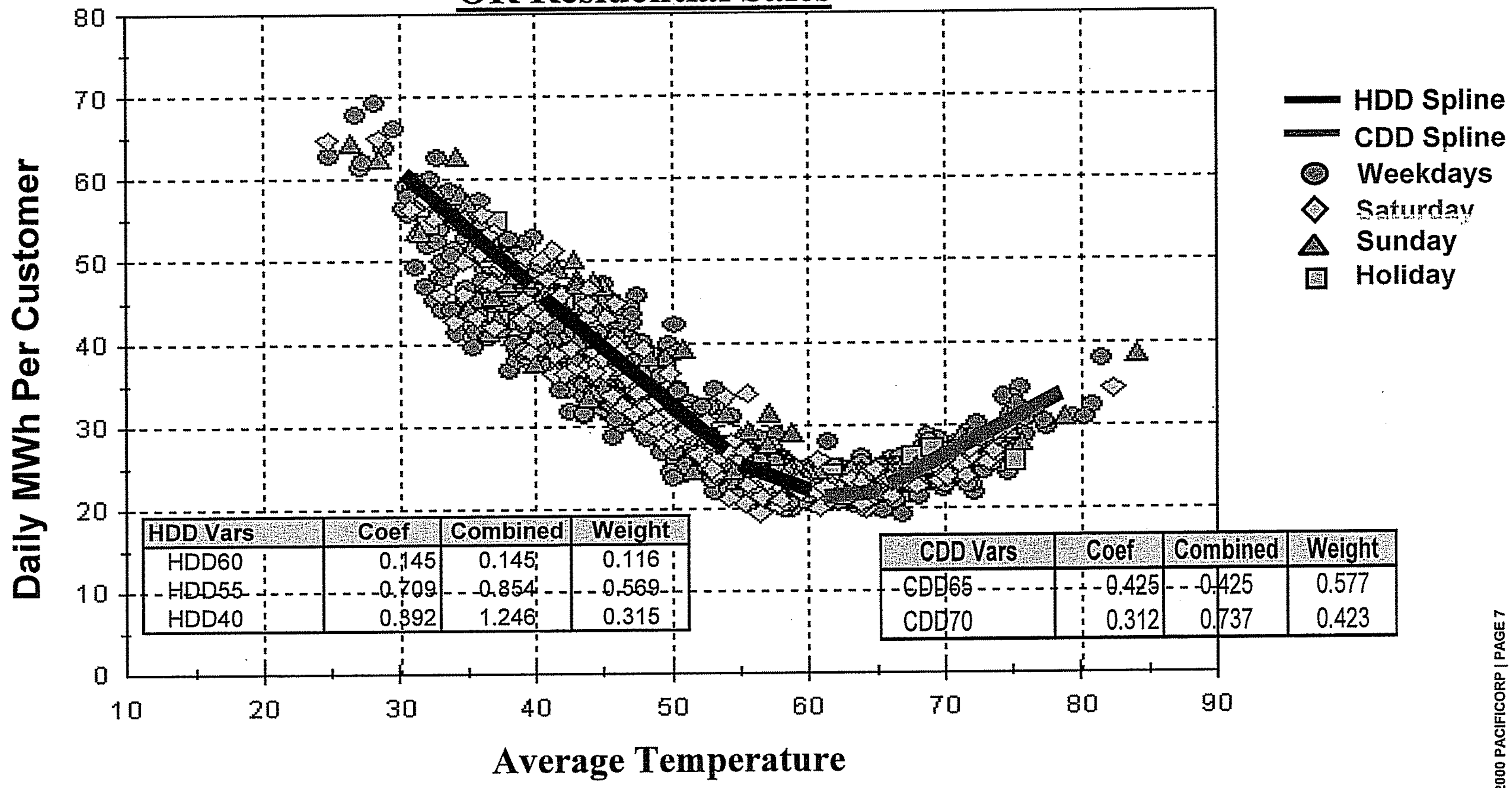
Develop Weather Adjustment

OR Residential Sales



HDD Vars	Coef	Combined	Weight
HDD60	0.145	0.145	0.116
HDD55	0.709	0.854	0.569
HDD40	0.392	1.246	0.315

CDD Vars	Coef	Combined	Weight
CDD65	0.425	0.425	0.577
CDD70	0.312	0.737	0.423

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Development of HDD and CDD Splines

- Weights of the weather variables were developed with regression analysis
- Composite heating and cooling variables were created using weights which increased the flexibility of capturing extreme temperature days within a month

Composite variable → Weights → Weather variables

$$\text{CDDSpline} = .577 \times \text{CDD65} + .423 \times \text{CDD70}$$

$$\text{HDDSpline} = .116 \times \text{HDD60} + .569 \times \text{HDD55} + .315 \times \text{HDD40}$$

OR - Residential Model

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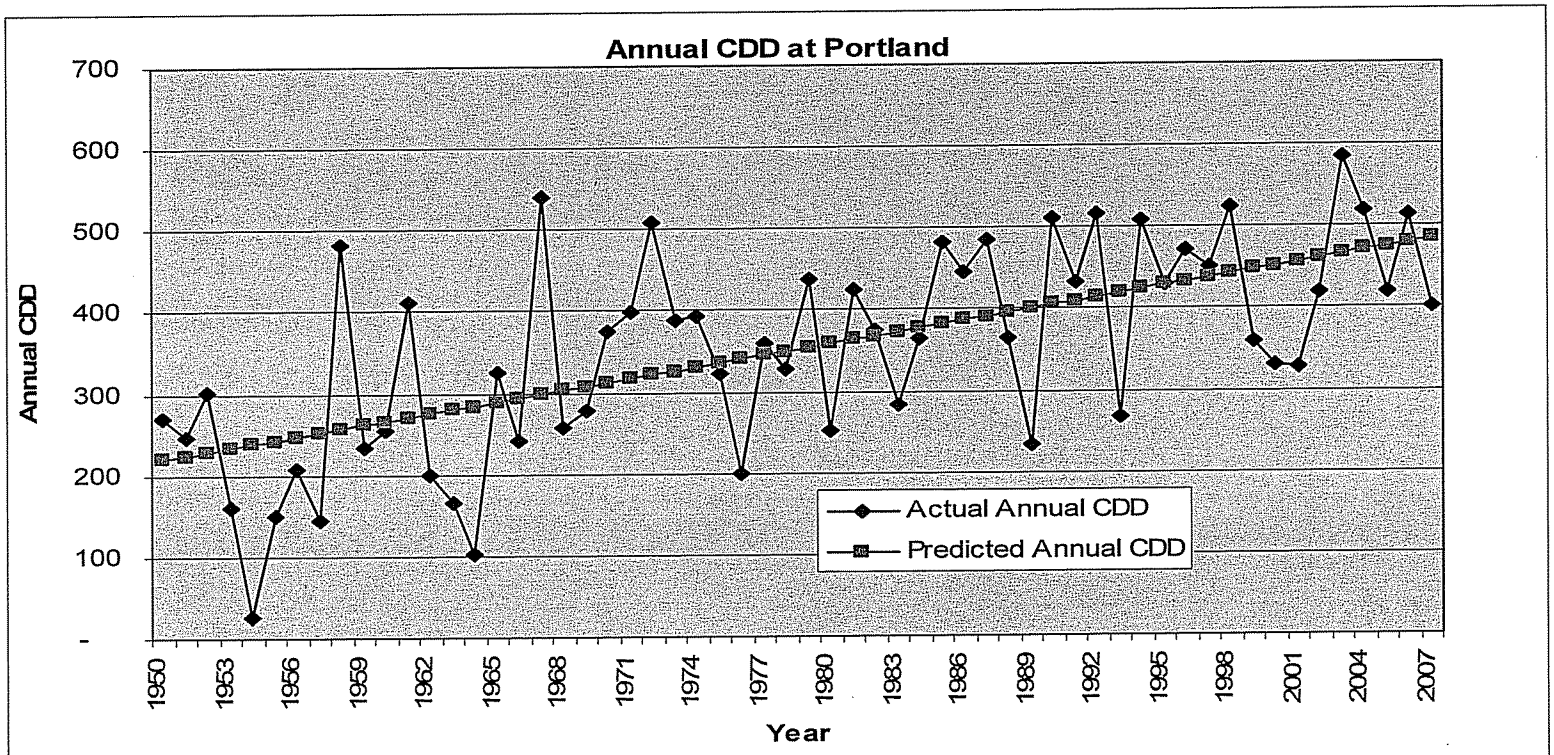
Change in weather definition

- ❖ **Definition of normal weather was updated from the NOAA's 30 year period of 1971-2000 to the 20 year time period of 1988-2007**
  - ➢ **20 year rolling average better fits recent weather trends**



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Development of Energy Forecast

- ✓ Inputs to the model
  - ✓ General data used
  - ✓ End Use Data and Lighting Efficiency Standards
- ✓ Statistically Adjusted End Use Modeling Framework
- ✓ Synopsis of Energy Modeling Techniques
- ✓ Residential and Commercial model and model results
- ✓ Industrial Forecast Development

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Type of Data Used for Energy Forecasting

- Actual historical usage data from Company records (1997-2009 January)
- End use data
- Economic data from Global Insight : employment, population, number of household, manufacturing and non manufacturing employment
  - Utah: State level data
  - Other states: County level data
- Industrial forecast for large customers and new additions/expansions from Customer Account Managers (CAM)

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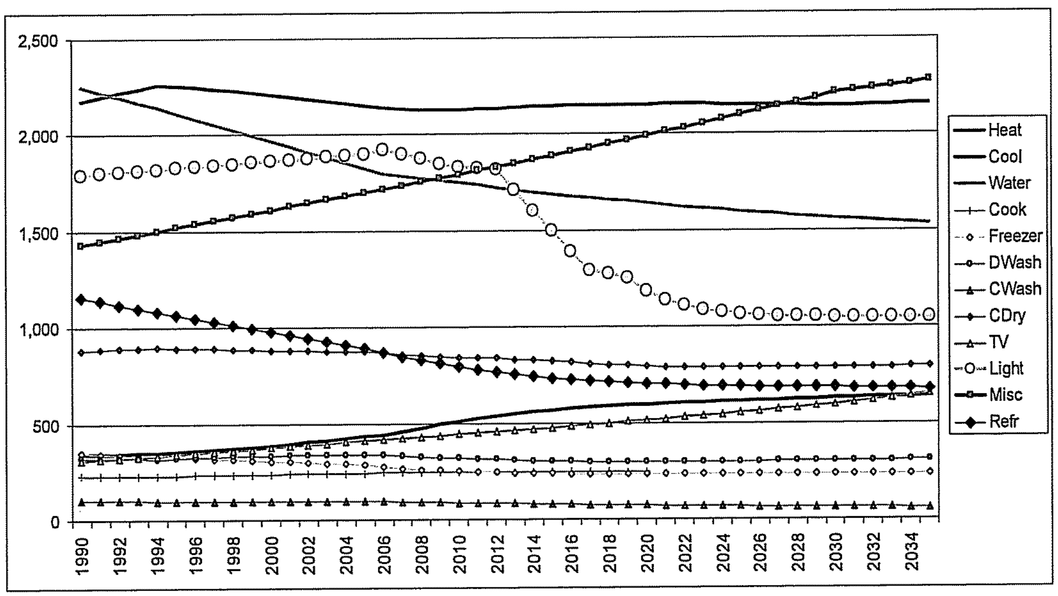
End Use Data

- Need to account for growth in weather sensitivity over years (e.g., for Oregon residential customers, response to hot weather has increased significantly between late 1990's & 2005-2007 on a per customer basis)
- Develop annual share and efficiency trend by end use to be used for residential sales model
- Both historic and forecast data based on Department of Energy (DOE) technology analysis and PacifiCorp residential appliance saturation survey

Oregon End Use Energy Consumption



Saturation Survey Results

Survey Year	Oregon Central Air	Oregon Electric Heat
1994	8%	16%
1999	12%	17%
2001	11%	16%
2004	16%	15%
2006	21%	24%

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Light Efficiency EIA

- **Per EISA, starting 2012, lighting efficiency will have a major efficiency impact in residential sector**
- **We incorporated this information in our SAE modeling for residential sales**

EISA 2007 General Service Lighting Standards (Residential)

- 2012 - 2014
  - 2012: ~ 100 watt bulbs restricted to 72 watts.
  - 2013: ~ 75 watt bulbs restricted to 53 watts.
  - 2014: ~ 60 watt bulbs restricted to 43 watts.
  - 2014: ~ 45 watt bulbs restricted to 29 watts.
- Incandescent bulbs can meet 2012-2014 standards
  - Example: Philips Halogena.
- 2020
  - Standard is 45 lumens per watt as backstop requirement.
  - Incandescent technology not available today.
- NEMS Representation
  - ~67 watt bulb restricted to 48.3 watts in 2013.
  - ~67 watt bulb restricted to 22.2 watts in 2020.

Energy Forecasting Group Meeting 2008 eia 15

❖EIA: Energy Information Administration, section of US Department of Energy

❖EISA: Extended Industry Standard Architecture

❖NEMS: The National Energy Modeling System

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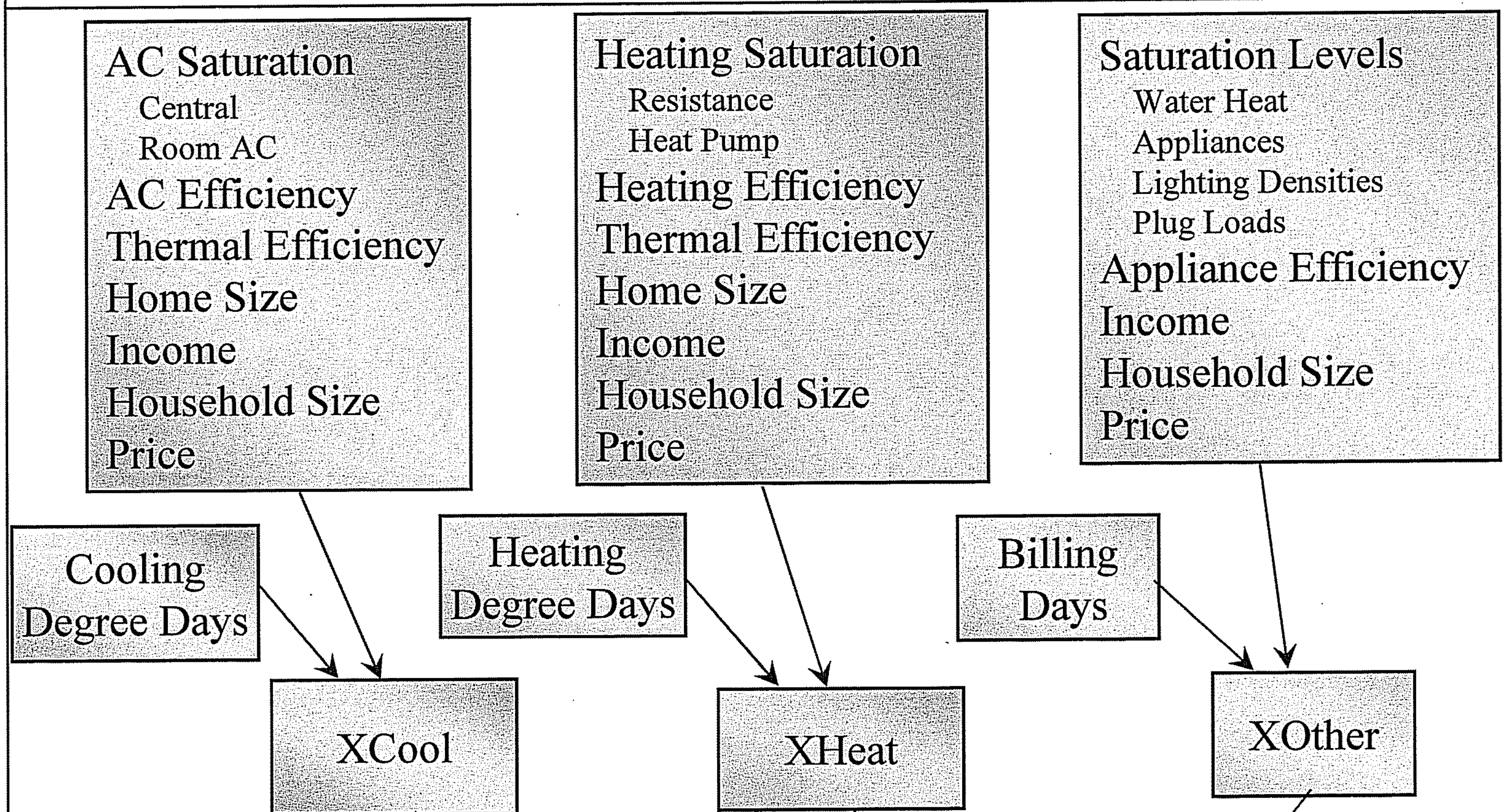
Statistically Adjusted End-Use (SAE) Framework



$$Sales_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + e_m$$

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Synopsis of Energy Modeling Techniques

- The residential, commercial, irrigation, public street lighting and sales to public authority sales forecasts by jurisdiction is developed as a use per customer times the forecasted number of customers
- Summary of Modeling Techniques:

Dependent Variable	Model Techinque	Major Drivers
Residential Use Per Customer	Statistical End Use Model	Weather-related variables, end-use information such as equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price
Commercial Use Per Customer	Regression Analysis	Non-manufacturing employment and weather related variables
Irrigation, Public Street Lighting, Sales to Public Authority Use per Customer	Regression Analysis	Time trend
Total Number of Customer	Regression Analysis and Exponential Smoothing	Number of household

Energy Forecast Models – Residential, Commercial

OR Residential

Variable	Coefficient	StdErr	T-Stat
Cyc_WthrT.XHeat	1.168	0.075	15.609
Cyc_WthrT.XHeatTrend	-0.014	0.006	-2.396
Cyc_WthrT.XCool	0.732	0.148	4.943
Cyc_WthrT.XCoolTrend	0.008	0.014	0.538
ResVars.XOther	1.106	0.033	33.418
Mnth_Bin.Jan	2.917	0.316	9.220
Mnth_Bin.Feb	1.179	0.340	3.465
Mnth_Bin.Mar	1.167	0.369	3.165
Mnth_Bin.Apr	0.473	0.451	1.050
Mnth_Bin.May	-0.465	0.589	-0.789
Mnth_Bin.Jun	-0.880	0.747	-1.178
Mnth_Bin.Jul	-0.713	0.958	-0.745
Mnth_Bin.Aug	-0.737	1.216	-0.606
Mnth_Bin.Sep	-1.401	1.002	-1.398
Mnth_Bin.Oct	-1.579	0.751	-2.102
Mnth_Bin.Nov	-0.729	0.471	-1.546
Constants.Year2008Plus	-0.127	0.495	-0.258
AR(1)	0.483	0.089	5.406
SAR(1)	-0.044	0.105	-0.418

Observations	132
Degree of Freedom	113
Adjusted R squared	0.987
Durbin-Watson Statistic	2.429
Std.Error	0.81
MAD	0.56
MAPE	1.63%

OR Commercial

Variable	Coefficient	StdErr	T-Stat
Cyc_WthrT.Com_HDD	2.397	0.566	4.234
Cyc_WthrT.Com_CDD	3.624	0.783	4.628
Mnth_Bin.Jan	170.261	4.108	41.447
Mnth_Bin.Feb	168.922	3.572	47.295
Mnth_Bin.Mar	168.460	2.638	63.851
Mnth_Bin.Apr	165.594	2.118	78.174
Mnth_Bin.May	162.499	2.093	77.654
Mnth_Bin.Jun	158.897	3.206	49.566
Mnth_Bin.Jul	156.928	5.661	27.722
Mnth_Bin.Aug	160.699	7.532	21.336
Mnth_Bin.Sep	160.924	5.942	27.081
Mnth_Bin.Oct	165.247	3.276	50.443
Mnth_Bin.Nov	164.933	2.064	79.927
Mnth_Bin.Dec	164.833	3.242	50.842
Constants.Dec08Plus	-6.590	3.717	-1.773
SAR(1)	0.179	0.080	2.223

Observations	133
Degree of Freedom	117
Adjusted R squared	0.728
Durbin-Watson Statistic	1.861
Std.Error	4.70
MAD	3.36
MAPE	1.88%

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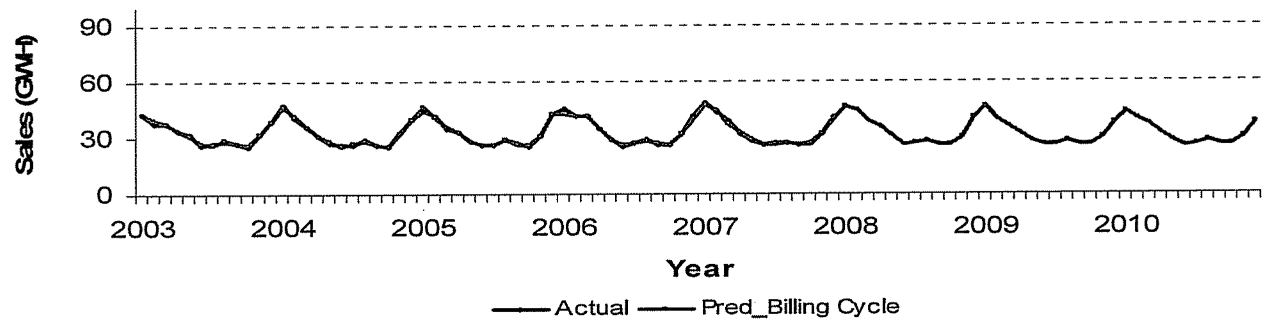
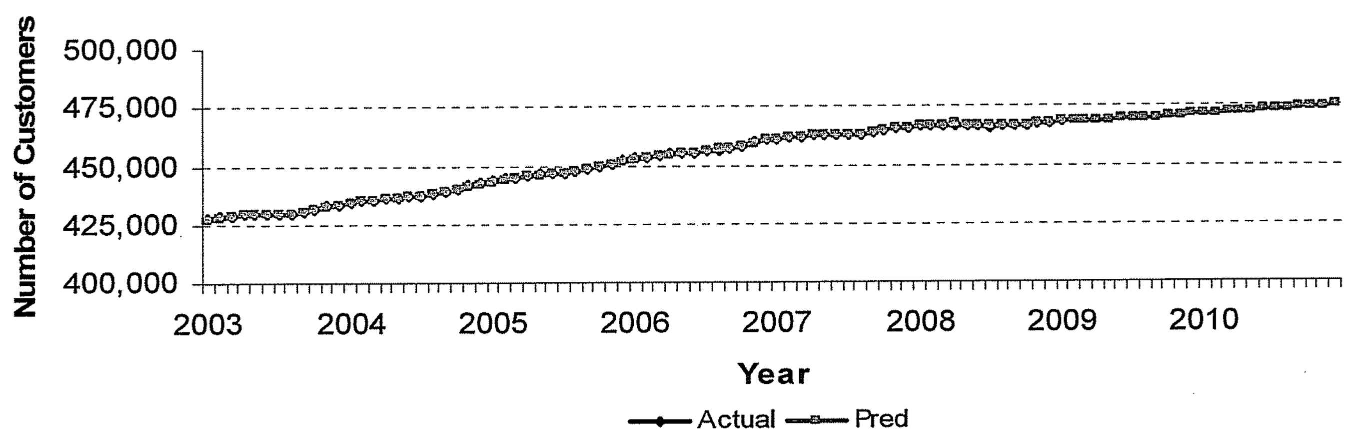
Residential Energy Forecast – Model Results

Oregon Residential Sales Model Results



Oregon Residential Number of Customer Model Results



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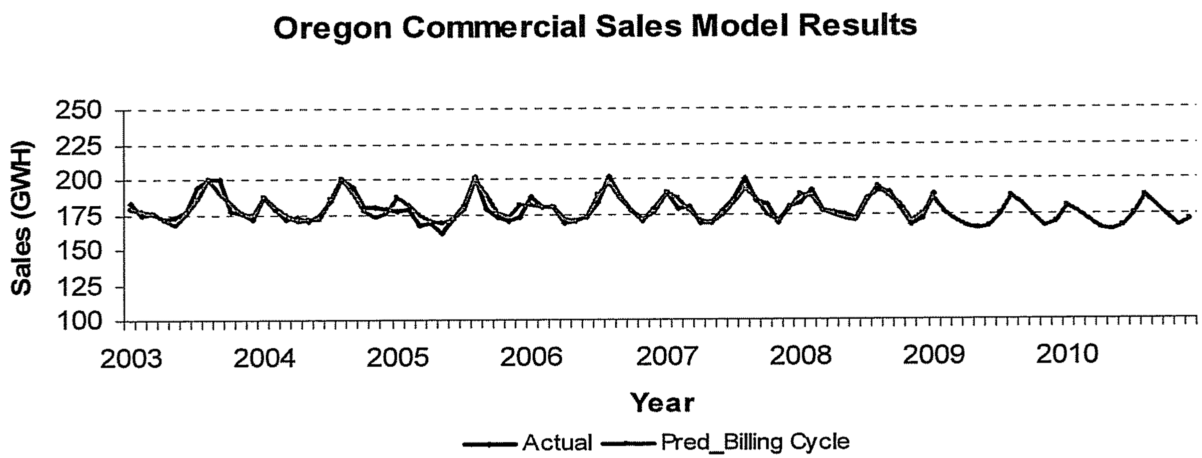
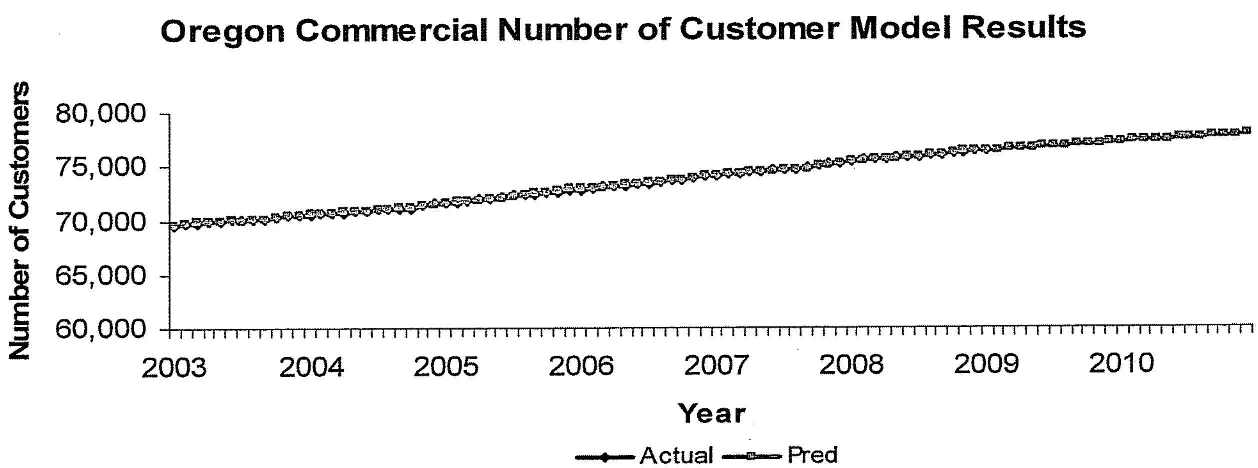
Commercial Energy Forecast – Model Results





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Industrial Energy Forecast

- The industrial customers are separated into three categories:
  - Existing customers tracked by the Customer Account Managers (CAMs)
    - » CAMs provide 3 year forecast for existing customers (2009-2011)
  - New large customer or expansions by existing large customers
    - » CAMs provide
      1) Peak, MW by month through 2018
      2) Probability
      3) Load factors
  - Existing customer not tracked by the CAMs is forecasted within the model

State	Existing	New	% of Total MWH
UT	66	50	77%
WY	35	55	79%
ID	2	1	87%
OR	30	23	63%
WA	5	2	61%
CA	1	5	47%
Total	139	136	76%

- The forecast for the first two categories is developed through the data gathered by the CAMs. The forecast for the last category is modeled using regression analysis with trend and economic variables. Manufacturing employment is the major economic driver.
- The total industrial sales forecast is developed by aggregating the three categories.

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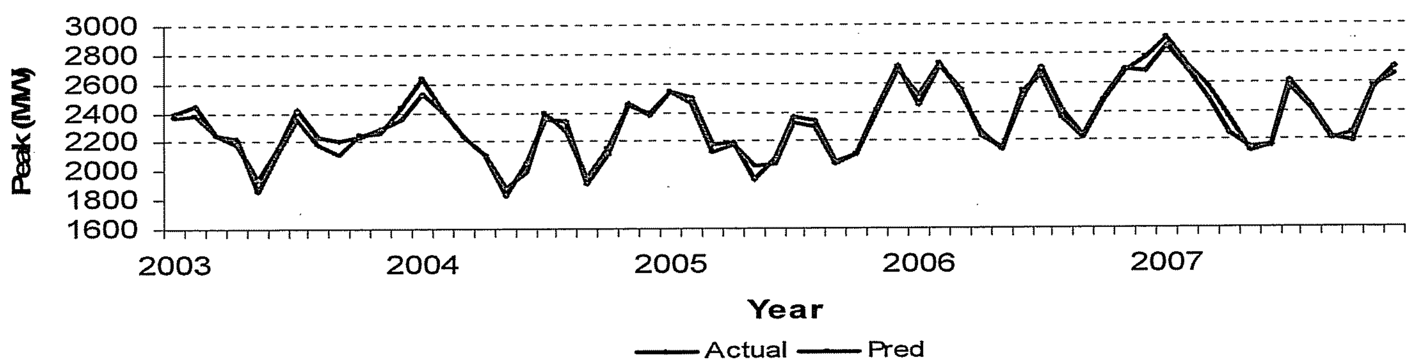
Model forecasts Peaks directly

- Peak Forecast is developed using a separate econometric model
  - ✓ **Monthly and seasonal peak forecast for each state are developed from historic peak producing weather and several weather related variables, such as: average temperature on the peak day and lagged average temperature**
  - ✓ **Changes in Heating and Cooling stock are used to capture the dynamic response to weather, which changes due to changes in equipment saturation and efficiency**
  - ✓ **Regress monthly peaks against weather and base sales (i.e. non weather related portion of Sales by customer class).**

Oregon Peak Model Results



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System Load and Peak Development

- Hourly load forecasts reflect jurisdictional energy and peak forecasts as described in previous slides
- Hourly loads are aggregated to the total company system level
- Coincident system peak is identified by month as well as the contribution of each jurisdiction to those monthly system peaks

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Recap of Major Improvements

- Weather response specification was improved
  - **Use of hourly load research data by state by class**
  - **Creation of composite splines for heating degree days and cooling degree days**
- Weather normalization integrated in the model and definition of normal weather was updated from the NOAA's 30 year period of 1971-2000 to the 20 year time period of 1988-2007
- Monthly energy forecasts were improved by adopting the following
  - **Statistically Adjusted End Use model for Residential Sales**
  - **Simple Econometric model for Commercial Sales**
- Model forecasts Peaks (monthly by state) directly

CASE: UE 210
WITNESS: Robert Clark

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STAFF EXHIBIT 1008

Exhibits in Support
Of Opening Testimony

July 24, 2009

STAFF EXHIBIT 1008

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WITNESS: Robert Clark

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STAFF EXHIBIT 1009

Exhibits in Support Of Opening Testimony

July 24, 2009

Utah Weather Weights		
City	Code	Weight
Salt Lake City	KSLC	100.0%

Oregon Weather Weights		
City	ID	Weight
Astoria	KAST	3.6%
Klamath Falls	KLMT	7.8%
Medford	KMFR	29.8%
North Bend	KOTH	5.1%
Portland	KPDX	24.5%
Redmond	KRDM	6.7%
Salem	KSLE	22.4%

Washington Weather Weights		
City	Code	Weight
Yakima	KYKM	100.0%

West Wyoming Weather Weights		
City	Code	Weight
Casper	KCPR	88.5%
Salt Lake City	KSLC	11.5%

East Wyoming Weather Weights		
City	Code	Weight
Casper	KCPR	88.5%
Salt Lake City	KSLC	11.5%

Idaho		Weight
Pocatello	KPIH	100.0%

California		Weight
Medford	KMFR	100.0%

CASE: UE 210
WITNESS: Robert Clark

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Exhibits in Support
Of Opening Testimony

July 24, 2009

Historical year found in step 4b for each month of the forecast period CY 2010

Jan	1992
Feb	2002
Mar	2004
Apr	1999
May	1994
Jun	2001
Jul	2007
Aug	1996
Sep	1997
Oct	1992
Nov	1993
Dec	1993

CASE: UE 210
WITNESS: Robert Clark

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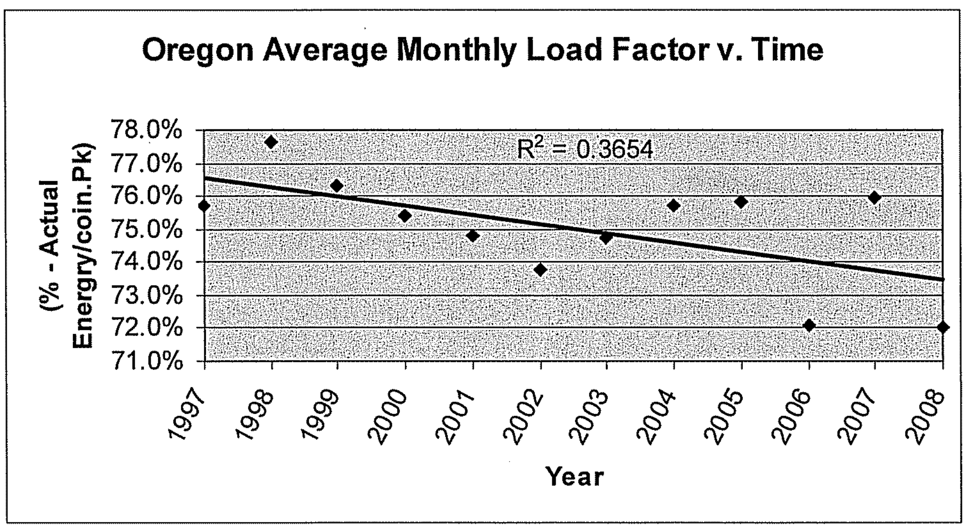
STAFF EXHIBIT 1011

Exhibits in Support
Of Opening Testimony

July 24, 2009

Oregon Load data History & Fcst

	Energy (aMW)	coincid. Pk	Implied "Load Factor"
1997	1686	2227	75.7%
1998	1788	2303	77.6%
1999	1712	2244	76.3%
2000	1752	2323	75.4%
2001	1669	2230	74.8%
2002	1623	2200	73.8%
2003	1654	2213	74.7%
2004	1638	2163	75.7%
2005	1651	2177	75.8%
2006	1739	2413	72.1%
2007	1760	2318	75.9%
2008	1748	2426	72.0%
2010 PPL	1674	2301	**72.0%**
		Stdev:	0.017
		Mean	**75.0%**



CASE: UE 210
WITNESS: Robert Clark

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STAFF EXHIBIT 1012

Exhibits in Support Of Opening Testimony

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CASE: UE 210
WITNESS: George R. Compton

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STAFF EXHIBIT 1100

Opening Testimony

July 24, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is George R. Compton. I am a Senior Economist, employed by the Economic Research and Financial Analysis Division (ERFA) of the Oregon Public Utility Commission (OPUC). My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found as Exhibit Staff/1101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. This testimony responds to the PacifiCorp (or Company) rate spread and rate design portions of their application. In that regard, I will 1) propose some modifications to the PacifiCorp cost-of-service study; 2) present some large-customer time-of-use rates that would better track costs and provide customers with a greater opportunity to reduce their electricity charges; 3) provide specific observations and recommendations on overall rate spread; and 4) provide recommendations on some specific rate design issues.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

Topic 1 – General Cost of Service and Rate Spread Discussion
Topic 2 – Updated Energy Costs
Topic 3 – Full Generation Capacity Costs
Topic 4 – Reformulated Distribution Feeder Costs
Topic 5 – General Rates Design Discussion

Topic 6 – Alternative Summertime Rates Structures for Large Industrial Customers.

Q. DID YOU PREPARE ANY EXHIBITS FOR THIS CASE?

A. Yes, they are listed as follows:

1101 – Witness Qualification Statement
1102 – Original PacifiCorp Principal Cost-of-Service Worksheets
1103 – Generation-Related Worksheets with Staff-Updated Energy Costs
1104 – Generation-Related Worksheets with Staff-Augmented Capacity Costs
1105 – Generation-Related Worksheets with Staff-Revised Energy and Capacity Costs
1106 – Distribution-Related Worksheets with Staff-Revised Feeder Model
1107 – Cost-of-Service Results Incorporating All of Staff's Revisions
1108 – Transitioning from Cost-of-Service Results to the Rate Designs: PGE and PacifiCorp Contrasted
1109 – Contrasting PacifiCorp's Large Industrial Rates Designs for Utah and Oregon
1110 – The Time-of-Day-Sensitive Nature of Summertime Spot Market Prices (Confidential)
1111 – Some Alternative Time-of-Use Rate Designs for Large Industrial Customers

Q. PLEASE INTRODUCE YOUR PRINCIPAL THEMES FOR THIS TESTIMONY.

A. My testimony:

a) seeks to develop a more accurate estimate of marginal production/generation costs;

b) introduces greater internal consistency and inter-class fairness into the Company's distribution feeder model; and

c) presents for Parties' consideration three large industrial rate-design alternatives that, in comparison with PacifiCorp's proposal, better reflect diurnal electricity cost patterns during the months of July and August.

Q. WHAT CONCERNS DO YOU HAVE REGARDING ESTIMATING MARGINAL PRODUCTION/GENERATION COSTS?

A. Marginal production costs reflect both marginal energy and marginal capacity costs. The effects on customers of either of these two cost components being estimated inaccurately will depend on the relative intensities by which the customers "use" energy and capacity. The allocation of marginal generation costs to high load factor customers will tend to be overstated if *either* marginal energy costs are overstated *or* marginal capacity costs are understated. As filed in their direct case, *both* problems occur with PacifiCorp's marginal cost model.

The Company's long run marginal energy cost estimate appears to be overstated. This comes from the Company using a pre-recession natural gas price forecast in the $8/MMBTU neighborhood when something closer to $5/MMBTU seems to be the current long-run projection. To remedy this overstatement problem, Staff requested the Company to substitute a more current gas price projection in its cost-of-service analysis. The effect of this adjustment is to lower the marginal cost of energy.

Q. PLEASE DISCUSS YOUR CONCERNS REGARDING ESTIMATING OF MARGINAL CAPACITY COSTS.

A. PacifiCorp's estimates for marginal capacity costs are understated in two respects. First, PacifiCorp used a capacity demand level that reflects a twelve-month average of peak loads rather than using the highest monthly peak demand over the year. An average of twelve numbers will always be less that the maximum value of twelve numbers as long as each of the twelve values is not identical. In its planning process, PacifiCorp lays out how it expects to meet its maximum demand, not just some average level of demand. Second, in computing capacity costs, PacifiCorp failed to include the effect of planning reserve margins. That is, when peak loads increase by 1 MW, the Company not only needs one additional MW of capacity, the Company also needs 0.12 MW of capacity reserve, assuming a 12% capacity planning reserve margin. Correcting for understating demand and not including the capacity planning reserve margin increases the total capacity costs by almost 50%.

Q. WHAT CHANGES DO YOU HAVE TO THE DISTRIBUTION COST STUDY?

A. My principal change is to reclassify customer costs to demand costs within a portion of the distribution cost study. PacifiCorp has developed a "feeder model" in order to capture the different cost burdens imposed by customer classes insofar as some tend to be located at greater distances from the substations—and therefore cause more poles and longer conductor lengths to be installed. The multi-"branch" feeder model distinguishes between "demand" costs and minimum system, or "commitment," costs. The latter are allocated to customer classes residing on the particular branches where each are located. Demand costs reflect the cost causation attributable to customer loads. A portion of a branch's demand costs are allocated to downstream branches insofar as loads of downstream branches are partly responsible for the greater load-bearing capability of the subject branch. I criticize the model for not being consistent in recognizing the commitment portion of costs in all branches, not just branches carrying no downstream loads. More fundamentally, I provide economic arguments against classifying commitment costs as "customer" costs while allocating them on an un-weighted customer basis—i.e., without regard for the fact that large customers reap greater benefits from the existence of the minimum distribution system. This testimony advocates the allocation of the commitment costs on the same basis as the Company allocates the demand portion of the costs; i.e., on a 12-month average share of the jurisdictional peaks.

In contrast, I advocate the winter-oriented single-distribution-coincident-peak (1 DCP) contribution as the measure best reflecting cost causation in the allocation of the demand portion of distribution costs. To a considerable degree, the 1 DCP-based allocation of feeder demand costs cancels the effects of substituting a demand allocator for the customer allocator with regard to the commitment portion of distribution costs. That is because the wintertime is when the residential class experiences its greatest loads.

Q. PLEASE SUMMARIZE YOUR LAST THEME, WHICH IS LARGE INDUSTRIAL ALTERNATIVE RATE OPTIONS.

A. While PacifiCorp has for some time had On-Peak and Off-Peak rates for large industrial customers (Schedules 47/48), there is only a tenth of a cent difference between the two rates. During the months of July and August at least, the wholesale electric market super-peak/off-peak price differential is in the multiple-cents range. The larger difference is incorporated in three alternative time-of-use schedules that are displayed in this testimony.

TOPIC 1 – GENERAL COST OF SERVICE AND RATE SPREAD DISCUSSION

Q. AT THIS PHASE OF THE CASE, WHAT IS PACIFICORP RECOMMENDING AS OVERALL PERCENTAGE RATE INCREASES FOR THE VARIOUS CUSTOMER SCHEDULES?

A. The table below contains the percentage increases that PacifiCorp has targeted for the major customer schedules in its rate design development. (The percentages shown come directly from the cost-of-service results found in the Craig Paice Exhibit PPL/905 Paice/1.)

Residential	8.52%
General Service Sched. 23 (Secondary)	10.25%
General Service Sched. 28 (Secondary)	14.81%
General Service Sched. 30 (Secondary)	15.70%

Large Power Service Sched. 48 (Secondary)	15.41%
Large Power Service Sched. 48 (Primary)	17.62%
Large Power Service Sched. 48 (Trans.)	19.94%
Irrigation Schedule 41	16.82%
Street Lighting Sched's. 51, 53, 54	54.71%
Overall Total	**11.72%**

I would note at this point that, not surprisingly, the very large Street Lighting increase shown in the table was found to be in error. PacifiCorp will be submitting corrected figures as part of its reply filing.

Q. WHAT IS THE PURPOSE OF A COST-OF-SERVICE STUDY FOR UTILITIES?

A. "Rate spread," or "spreading of the revenue requirement" refers to how the utility's entire revenue requirement is allocated to the various customer classes. The purpose of the cost-of-service study is to provide a guide to the rate spread process.

Q. GENERALLY SPEAKING, DID PACIFICORP FOLLOW PREVIOUSLY ESTABLISHED COMMISSION GUIDELINES IN THE PREPARATION OF ITS COST-OF-SERVICE STUDY?

A. Yes, to the best of my understanding. A brief summary of PacifiCorp's COS process follows: 1) The overall revenue requirement is split according to three large functions (generation, transmission, distribution) plus several smaller functions (e.g., customer – billing). The functions are targeted to earn equal rates of return. 2) Marginal costs are estimated for major elements that are abstracted from within the functions and applied as if the entire utility load was served by those elements. (Example: While PacifiCorp's generation is served by hydro, coal, and wind resources as well as natural-gas-fired facilities, generation marginal costs have been determined *as if* the only generation resources were simple-cycle and combined-cycle gas combustion turbines [i.e., SCCTs and CCCTs].) 3) Percentage shares of the various functions' marginal costs are assigned to the individual rate classes/schedules using more or less well established procedures. (Example: Percentage shares of the energy portion of generation marginal costs are assigned to the schedules in proportion to their relative shares of annual energy consumption.) 4) Those same percentages are applied against the previously established revenue requirement embedded cost functions, with the results then aggregated to obtain the target revenue requirement for each rate schedule. 5) The new/target revenue requirement is compared to the revenues that current rates would yield (applying test period sales volumes) so as to obtain the requested percentage "rate" increase for each schedule.

Q. UPON WHICH OF THOSE FIVE AREAS OF THE COST-OF-SERVICE PROCESS DOES YOUR TESTIMONY CONCENTRATE?

A. I focus on the second and third areas. Those areas are where I have significant differences with the Company.

Q. ASSUMING PACIFICORP RECEIVED THE REVENUE INCREASE IT REQUESTED, DO YOU HAVE AN ALTERNATIVE RATE SPREAD?

A. I have. Preliminary figures appear as follows:

Residential	7.85%
General Service Sched. 23 (Secondary)	6.18%
General Service Sched. 28 (Secondary)	18.71%
General Service Sched. 30 (Secondary)	19.88%
Large Power Service Sched. 48 (Secondary)	15.92%
Large Power Service Sched. 48 (Primary)	16.23%
Large Power Service Sched. 48 (Trans.)	17.14%
Irrigation Schedule 41	18.92%
Street Lighting Sched's. 51, 53, 54	TBD
Overall Total	**11.72%**

I would urge caution regarding the very low indicated increase for the General Service Schedule 23. It is based in part upon a suspiciously high feeder load factor estimate (Company-supplied) of 90%.

Q. WHY DO YOU SAY "PRELIMINARY FIGURES"?

A. I expect that I'll find modifications to be appropriate after I have reviewed the opening filings by CUB and ICNU and the reply filing by the Company.

Q. AT A VERY HIGH LEVEL CAN YOU EXPLAIN THE BASIS OF THE MAJOR DISCREPANCIES BETWEEN YOUR COS RESULTS AND THE COMPANY'S?

A. Yes. Reducing the energy cost estimates while increasing the capacity cost estimate reduced allocated generation function costs for the higher load-factor customers. Reclassifying a major share of the distribution costs as demand-related rather than customer-related reduced the distribution cost allocation to residential and small commercial customers while increasing that allocation to all the customers who do not take power directly from the transmission lines. Allocating a major portion of distribution costs on the basis of the January distribution system peak rather than the average of the twelve monthly peaks increased the distribution cost allocation to residential customers while reducing it for irrigation customers.

Q. YOU HAVE PRESENTED THE COMPANY'S AND YOUR OWN SET OF COST-OF-SERVICE RESULTS. WOULD YOU BE RECOMMENDING THE DIRECT ADOPTION OF THOSE RESULTS FOR THE PURPOSE OF THE "RATES SPREAD," I.E., THE ACTUAL PERCENTAGE INCREASES APPLICABLE TO THE INDIVIDUAL CUSTOMER SCHEDULES?

A. It is too early in the case to make any kind of definitive recommendation in this regard. For policy and rate shock considerations, I may have some adjustments to the rate spreads instead of deriving them solely from narrow cost-of-service considerations. For example, and depending upon the ultimate size of the overall general revenue increase, I may propose that no customer schedule should receive an increase that is more than twice the overall percentage increase. Also, it is commonplace for schedules that have roughly the same COS percentage increase results to receive identical increases via the rate spread process rather than increases that precisely match the COS results.

TOPIC 2 – UPDATED ENERGY COSTS

Q. THE LARGEST, BY FAR, OF THE FUNCTIONALIZED REVENUE REQUIREMENT CATEGORIES IS GENERATION. IT ACCOUNTS FOR

OVER ONE-HALF OF THE TOTAL REVENUE REQUIREMENT. WHAT ARE THE PRIMARY COST COMPONENTS OF GENERATION IN PACIFICORP'S MARGINAL COST (MC) ANALYSIS?

A. The two cost components are demand, or capacity, and energy. The "stand-in" for energy costs is the cost of fuel needed to produce one kWh by a combined-cycle combustion turbine (CCCT), plus the amount on a capacity factor-adjusted, per kWh basis by which capitalized fixed costs of a CCCT exceed those of a simple-cycle combustion turbine (SCCT).

Q. WHAT IS THE THEORY BEHIND INCLUDING FIXED CAPITAL COSTS AS PART OF THE ENERGY COMPONENT OF MARGINAL GENERATION COSTS?

A. The inclusion of incremental fixed costs associated with a CCCT is justified based on the fact that CCCTs enjoy appreciably lower fuel costs than do SCCT. The portion of fixed costs that is not incurred to meet the utility's capacity needs but rather to economize on fuel is appropriately classified as an energy cost.

Q. HOW ARE FUEL COSTS ESTIMATED?

A. The principal energy element (i.e., approximately 90% of the total) used in its cost study is the Company's discounted twenty-year natural gas market price projection.

Q. WOULD YOU PLEASE GIVE ME A SENSE OF THE PRICES USED IN THAT PROJECTION?

A. The 2010 figure is $8 per MMBtu, and over the course of the subsequent nineteen years the range extends from $7.52 to $8.89/MMBtu, with $8.60/MMBtu being the estimate for 2029.

Q. PUBLISHED NATURAL GAS PRICES HAVE DECLINED IN RECENT MONTHS. HAVE YOU UPDATED THE PACIFICORP COST-OF-SERVICE (COS) STUDY TO REFLECT CURRENT PRICE PROJECTIONS?

A. Staff Data Request No. 325 asks the Company to update its primary energy cost worksheet, Tab: 5.1 of Exhibit PPL/907. To get some sense of the effect on the cost-of-service (COS) results of a reduction in natural gas prices, I replicated the Company's COS study, with the only modification being a reduction of the Company's yearly fuel price estimates by three-eighths (e.g., for 2010, $5/MMBtu was substituted for $8/MMBtu).

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE EFFECTS ON THE COS RESULTS OF REDUCING THE NATURAL GAS PRICE PROJECTIONS?

A. Yes, it is Exhibit Staff/1103, consisting of four pages. **NOTE: For cross-referencing ease, the center footer labels in this and other Staff exhibits denotes the Company's hard-copy Exhibit ID and page or Tab number.** The first page of Exhibit Staff/1103 is an exact duplication of Tab: 5.1 of Exhibit PPL/907, except each figure in the Company's original Column (H) has been reduced by three-eighths. The second page is an exact duplication of Tab: 2.3 of Exhibit PPL/907, except the 20-year energy cost estimate of $36.21/MWh on Line 26 has been substituted for the original Company figure of $55.70/MWh. The third page, except for the caveat conveyed in the footnote, is an exact duplication of Tab: 2.4 of Exhibit PPL/907, except total energy marginal costs depicted on Line 15 have been recalibrated to incorporate the updated unit fuel costs from Compton/2, and the generation Total MC Revenue Requirement (Line 32) incorporates the new energy cost portion. Page 4 is an exact duplication of Page 1 of Exhibit PPL/905, but with Line 5 containing the new generation marginal costs from Line 32 of Compton/3.

Q. HAVE YOU PROVIDED, FOR DIRECT COMPARISON PURPOSES, WORKSHEETS FROM THE COMPANY'S ORIGINAL FILING?

A. Yes. These worksheets compose Exhibit Staff/1102, consisting of the original worksheets corresponding to the latter three described above. As previously noted, the center footer entry for Exhibits Staff/1102 consists of page and tab identifications from the Company's filed hard-copy exhibits. The left footer entry contains 1) the file name of the Staff's replication of the Company's electronic version of the marginal cost model, and 2) the tab label appearing on both the Company's and Staff's electronic versions of the model.

Q. I NOTE THAT WHILE GENERATION ENERGY-RELATED MARGINAL COSTS SHRINK FROM $768 MILLION TO $499 MILLION (COMPARING COLUMN [A], LINE 15 ON, RESPECTIVELY, PAGES 2 AND 3 OF EXHIBITS 1102 AND 1103), THERE WAS OFTEN VERY LITTLE IMPACT ON THE FINAL RESULTS SHOWN ON LINE 36 OF THE RESPECTIVE LAST PAGES OF THE EXHIBITS. PLEASE EXPLAIN.

A. The final step of the COS process is to reconcile marginal costs with functionalized embedded costs. Unless a particular customer schedule's *share* of total marginal costs is significantly affected by the energy cost recalibration, that schedule's final cost allocation *of embedded cost requirements* will not change significantly. I would point out that one schedule, Large Power Service Schedule 48 – Transmission, would receive approximately a 1.5% reduction in its COS allocation due to this energy cost modification.

Q. WHAT IS THE CONCEPTUAL/COST-CAUSATION JUSTIFICATION FOR REDUCING SOME SCHEDULES' COST ALLOCATIONS WHILE INCREASING OTHERS ACCORDING TO THE ENERGY COST MODIFICATION YOU RECOMMEND?

A. If the relative cost of energy is overstated compared to demand, or capacity, costs, then high load-factor customers (i.e., those whose energy consumption is comparatively large relative to their demand) are penalized by way of a larger generation cost allocation than would be justified according to cost-causation principles. Conversely, inflated relative energy costs will allow low load-factor customers to receive a smaller cost allocation than would be justified according to cost-causation principles. That is because increasing the weight given to energy translates to a reduced weight given to demand, where the low load-factor customers place the comparatively greater burden on the utility system.

TOPIC 3 – FULL GENERATION CAPACITY COSTS

Q. EARLIER IN THIS TESTIMONY, YOU STATED THAT MARGINAL GENERATION COSTS ARE DIVIDED INTO TWO CATEGORIES: CAPACITY AND ENERGY. HOW DOES PACIFICORP ESTIMATE MARGINAL UNIT CAPACITY COSTS?

A. As shown in Tab: 4.1 of Exhibit PPL/907, PacifiCorp uses a twenty-year long-run discounted projection of the annualized capacity costs of a Simple-Cycle Combustion Turbine (SCCT) to establish unit marginal capacity costs.

Q. HOW DOES PACIFICORP CONVERT MARGINAL UNIT CAPACITY COSTS TO TOTAL SCHEDULE ALLOCATIONS?

A. Load factors based upon each schedule's loads averaged over the twelve months' system peaks are first formulated and then applied to the respective schedule's annual average hourly energy consumption to obtain a 12CP-based (i.e., twelve coincident peak-based) system demand level (in MWs at the generator) for each customer schedule. The "Peak…System" demand levels are shown on Line 5 of page 1 of Exhibit Staff/1102. The peak demand figure is then multiplied by the unit marginal capacity cost figure (Line 20 of that same page) to obtain the demand-related portion of marginal generation costs (Line 1 of page 2 of Exhibit Staff/1102).

Q. DO YOU HAVE CONCERNS WITH THE DESCRIBED PACIFICORP APPROACH?

A. Yes. My main concern is that this approach understates the amount of capacity the PacifiCorp system actually requires—as measured by loads used under the Multi-State-Process to allocate system capacity costs to Oregon. While the referenced (i.e., on page 1 of Exhibit Staff/1102) Line 5 label reads "Peak Mw…," what is conveyed in that line does not sum up to the Oregon jurisdictional system 12-CP monthly *average* demand, much less the peak demand.[1] Page 11.5 of Exhibit PPL/702 shows the Oregon jurisdiction sum-of-the-twelve-monthly-system-peaks to be 27,608 MWs, for a monthly average of 2,301 MWs. That same PPL exhibit page shows the Oregon jurisdictional peak capacity at the time of the system annual peak (in August) to be 2,417 MWs. I would argue that to accommodate Oregon's load on an annual peak basis requires 2,417 MWs of capacity.[2] That contrasts with the previously referenced Line 5 sum of 1,990 MWs.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE DESCRIBED PACIFICORP APPROACH TO DETERMINING MARGINAL GENERATION CAPACITY COSTS?

A. I do. Another concern is that this approach does not capture the 12% capacity reserve requirement. I accomplish such by inflating the Company's unit capacity cost by 12%, i.e., raising it from $74.46 to $83.40.

Q. HAVE YOU PREPARED AN EXHIBIT THAT RESOLVES YOUR CONCERNS REGARDING THE DETERMINATION OF MARGINAL GENERATION CAPACITY COSTS?

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[1] Much of the discrepancy in the two load projections is attributed to one group within the Company performing total system load forecasting while a separate group performs individual customer class load research.

[2] The principal focal point of PacifiCorp's IRP is the achievement of its annual system peak capacity requirements on a best cost/risk basis.

A. Yes, Exhibit Staff/1104. Line 20 shows the higher capacity unit cost. And a new Line 6, "System Capacity Requirement," has been added to page 1 of this worksheet (which is substituted for page 1 of Exhibit Staff/1102 [i.e., Tab: 2.3 of Exhibit PPL/907]). As indicated in the footnote to this worksheet, the Line 6 figures are merely the original Line 5 figures ratioed-up to reflect the full system capacity needs attributable to Oregon. The intent is to preserve the Company's 12CP *relative* allocation across the schedules while recognizing the full system capacity requirements in establishing the full marginal demand-related costs that are shown on Line 1 of page 2 of this exhibit (i.e., Exhibit Staff/1104). The combined effect of the unit cost increase and the recognition of the annual peak capacity requirement is to increase the demand-related marginal generation costs by about a third—as seen by comparing the page 2 total (i.e., Line 1, Column (A)) with the total shown on page 2 of Exhibit Staff/1202. Comparing Line 36 of page 3 of Exhibit Staff/1204 with that same line on page 3 of Exhibit Staff/1102 (i.e., page 1 of Exhibit PPL/905) reveals the effect on the final COS allocation of expanding the demand or capacity portion of marginal generation costs such that they now reflect the entire amount of Oregon's system capacity burden. Just as the PacifiCorp MC model develops total jurisdictional energy costs based upon the total projected volume of energy supplied to customers, so should the MC model of total demand costs reflect the total jurisdictional capacity burden.

Q. I NOTE THAT, FOR MOST OF THE CUSTOMER SCHEDULES, EXPANDING THE GENERATION DEMAND-RELATED MARGINAL COST HAS VERY LITTLE IMPACT ON THE FINAL RESULTS SHOWN ON LINE 36 OF THE LAST PAGE OF STAFF'S EXHIBIT 1104. PLEASE EXPLAIN.

A. As expressed previously, the final step of the COS process is to reconcile marginal costs with functionalized embedded costs. A particular customer schedule's final cost allocation will not change significantly unless the demand cost recalibration significantly affects its relative *share* of total marginal costs (i.e., combining energy and capacity costs). I would point out that one schedule, Large Power Service Schedule 48 – Transmission, would receive approximately a 1% reduction in its COS allocation due to this demand cost modification.

Q. WHAT IS THE CONCEPTUAL/COST-CAUSATION JUSTIFICATION FOR REDUCING SOME SCHEDULES' COST ALLOCATIONS WHILE INCREASING OTHERS ACCORDING TO THE DEMAND COST MODIFICATION YOU RECOMMEND?

A. High load-factor customers enjoy a comparative advantage with regard to demand insofar as they consume more energy from a given level of capacity than do other customers. If the importance of demand, or capacity, costs is diminished compared to the importance of energy costs, then high load-factor customers will be penalized by way of a larger generation cost allocation than would be justified according to cost-causation principles. Conversely, deflated relative capacity costs will allow low load-factor customers (i.e., those who place a comparatively greater capacity burden on the Company's system) to receive a smaller cost allocation than would be justified according to cost-causation principles.

Q. HAVE YOU PREPARED AN EXHIBIT INCORPORATING BOTH THE FULL SYSTEM CAPACITY REQUIREMENT PLUS THE UPDATED ENERGY COSTS IN THE DETERMINATION OF MARGINAL GENERATION CAPACITY COSTS?

A. Yes, Exhibit Staff/1105. This exhibit is identical to Exhibit Staff/1104 except for the consequences of substituting, on Line 26 of this Exhibit's page 1, the lower generation energy cost from Exhibit Staff/1103.

TOPIC 4 – REFORMULATED FEEDER COSTS

Q. I NOTICED THAT, FOR PURPOSES OF MODELING MARGINAL COSTS, GENERATION COSTS ARE BROKEN INTO TWO CATEGORIES: ENERGY AND CAPACITY. ARE DISTRIBUTION COSTS MODELED SIMILARLY?

A. Yes, in the sense that there are multiple categories. The categories are: Substations; (line) transformers; and poles and conductors. The latter two comprise what are referred to as feeders.

Q. UTILITY COSTS ARE COMMONLY CLASSIFIED AS DEMAND-, ENERGY-, OR CUSTOMER-RELATED—WITH THE CLASSIFICATION PROVIDING SOME DIRECTION AS TO HOW THE COSTS SHOULD BE ALLOCATED. HOW ARE SUBSTATIONS AND TRANSFORMERS CLASSIFIED?

A. Substations are classified as "demand" because the principal cost driver is the peak level of load that a substation is designed to serve. Transformers are largely classified as "customer" because most of the cost of service here is from merely providing some minimal capacity transformer to either a single customer, or, if they are in close physical proximity, to as many as three or four customers.

Q. HOW ARE POLES AND CONDUCTORS, I.E., FEEDERS, CLASSIFIED?

A. It is my understanding that most utilities, including PGE, classify them as "demand." That classification reflects the fact that distribution lines and poles must be sized to meet the expected amount of peak load placed on them.

Q. DOES PACIFICORP CLASSIFY POLES AND CONDUCTORS AS "DEMAND"?

A. PacifiCorp has developed a rather elaborate, and abstract, "Feeder Model" for allocating marginal pole and conductor costs. It employs a two-part classification, "demand" and "customer," for allocating feeder costs to the different customer schedules.

Q. WHAT ARE MERITS OF THE COMPANY'S FEEDER MODEL?

A. The Feeder Model represents a few advantages relative to the traditional straight distribution-demand allocation approach in two respects. First, the model recognizes that the biggest cost driver is not meeting capacity requirements *per se*, but "merely" covering the necessary line miles to serve the Company's customers. Generally speaking, most of the costs of poles and wires would be incurred even if the lines had zero load-bearing capacity.

Secondly, recognizing that distance is the primary cost-causative influence on feeder line costs, the model explicitly incorporates the fact that customer classes vary in average distance from substations, and thereby impose different degrees of cost to the system.

Q. HOW DOES THE COMPANY DISTINGUISH THE DIRECTLY DEMAND-RELATED FROM THE "OTHER-RELATED" PORTION OF FEEDER COSTS, AND WHERE DOES THE CUSTOMER CLASSIFICATION ENTER THE PICTURE?

A. There are two categories of costs within the Feeder Model: Commitment costs and Demand costs. Commitment costs have to do with providing a minimum-capacity system for connecting customers to substations. The costs here are a direct function of the number of miles being traversed, the number and unit cost of minimum-sized poles per mile, and the minimum-capacity conductor costs per mile. Demand costs within the Company's Feeder Model are the costs of upgrading portions of the network with larger poles and higher-capacity conductors so as to accommodate greater customer kW demand than would be associated with the minimum-system/Commitment configuration. PacifiCorp has classified the Commitment portion of the feeder costs as "customer."

Q. DO YOU AGREE WITH HOW THE COMPANY HAS CONSTRUCTED ITS FEEDER MODEL?

A. I agree with much of the Company feeder model, and the Company should be commended for its ingenuity and resourcefulness in developing it. Having said that, there are three aspects of the Feeder Model with which I take exception.

Q. WOULD YOU PLEASE DESCRIBE YOUR FIRST AREA OF CONCERN REGARDING THE COMPANY'S FEEDER MODEL?

A. Yes, after first providing some detail describing the basic elements of the Model itself. Those details are as follows:

1. The Feeder Model's basic structure consists of seven feeder branches of equal length, with two of the branches (trunks) sized to accommodate the loads of the downstream branches (limbs) attached to them. Importantly and properly, the additional trunk costs caused by the downstream limbs are assigned to the limb-occupying customer classes in proportion to the degree in which the classes' loads impose incremental demand, or capacity, burdens upon those trunks. Because no other downstream limbs "feed" through them, the five limbs only have to accommodate their own loads.
2. As stated earlier, pole and conductor costs are divided into two categories, Commitment and Demand. Commitment costs are a direct function of the number of miles in the branch, the number of minimum-sized poles per mile and their unit costs, and the minimum-capacity conductor costs per mile. Demand costs are the costs of upgrading all or some portion of a given branch's length with larger poles and higher-capacity conductors so as to accommodate greater customer

kW demand than would be associated with the minimum-system/Commitment configuration.

3. While downstream <u>limbs</u> of the Model have demand/upgrade costs and minimum-system/Commitment costs separately identified, PacifiCorp classifies the *total* costs of the <u>trunks</u> as demand. This is where I first depart from the Company.

Q. PLEASE ELABORATE.

A. According to the way the term is defined, “commitment” is required, or can be visualized, as something that takes place regardless of how much capacity is ultimately required on a particular length of feeder line. Commitment” exists in order that customers can be *connected* to the portion of the system on which they reside. The responsibility for the Commitment portion of a line segment’s cost properly belongs to the occupants of that segment themselves, and not to those who reside upstream or downstream from that segment. Downstream (i.e., limb) customers should only have to help pay for the extra capacity burden they place on the upstream segment. In other words, the “downstreamers” should only have to share in the *Demand* portion of the costs of an upstream branch, not the Commitment portion. Occupants of the limbs have to bear their own Commitment costs (i.e., their customer classes receive the associated cost allocation); it is only proper that the occupants of the upstream trunks also bear their own commitment costs.

Q. WHAT IS THE PRACTICAL IMPLICATION OF WHAT YOU ARE SAYING?

A. A portion of the costs of the trunks should be recognized as Commitment costs. That portion of costs, in turn, should be allocated to the occupants of the trunks, and not shared with downstream customers. The effect is to assign slightly more of the costs to industrial and large commercial customers who reside closer to the substations, and to assign slightly less of the costs to the residential and other customers who tend to reside farther away.

Q. WOULD YOU PLEASE DESCRIBE YOUR SECOND AREA OF CONCERN REGARDING THE COMPANY'S FEEDER MODEL?

A. My second objection is the classifying of Commitment costs as Customer costs despite the fact that the number of customers occupying a particular line segment has *nothing* to do with Commitment cost-causation and does not appear in the Company's Commitment cost formula (which is limited to the conductor/pole-miles and unit costs).

Q. I AM AWARE THAT UTILITY COSTS ARE ROUTINELY CLASSIFIED AS EITHER CUSTOMER-, DEMAND-, OR ENERGY-RELATED. IT DOES NOT APPEAR THAT ANY OF THOSE THREE TERMS CAPTURE COMMITMENT COST CAUSATION. WHY WOULD THE COMPANY ELECT THE CUSTOMER CLASSIFICATION FOR COMMITMENT COSTS?

A. Since commitment costs are clearly neither demand- nor energy-related, it is understandable that the Company would elect to label them as customer-related—i.e., by default.

Q. BUT IF DISTRIBUTION FEEDER COMMITMENT COSTS ARE NOT, *PER SE*, CUSTOMER-CAUSED, THEN HOW *SHOULD* THEY BE CLASSIFIED?

A. To answer that question I would look to both convention and a consideration of fairness.

Q. WHAT IS THE CONVENTION?

A. As was mentioned earlier, the convention is for feeder costs to be classified for allocation purposes as entirely demand-related.

Q. HOW WOULD A DEMAND CLASSIFICATION SERVE THE END OF FAIRNESS?

A. If costs cannot be allocated on a cost-causation basis, they should perhaps be allocated on a benefits-received basis. Both energy consumed by customers and the demand imposed by them correlate with benefits received by customers from the minimal electric network.

Q. ARE THERE OTHER JUSTIFICATIONS FOR NOT CLASSIFYING FEEDER COMMITMENT COSTS AS CUSTOMER-RELATED?

A. I have two justifications. First, minimum distribution system poles and wires—i.e., the Commitment cost portion—can be viewed as an example of a local public good infrastructure. County roads are an example of public good infrastructure that has many elements in common with the Commitment element of the electric network. The cost of both is what it takes to connect point A with point B. Traffic is not a factor. (In my neighborhood of rural Polk County, most of the county roads have gravel surfaces. Most of the costs of what might have been a paved road [in order to meet greater traffic demand] come from the "commitment" itself, i.e., from procuring and clearing the land, leveling it somewhat, and laying down a fairly thick road base.) Depending on zoning limitations, along the county road may be family farms, mansions on large estates, and smallish old or manufactured homes on limited acreage parcels. Unlike the case with ordinary private goods, which can be priced by the unit and sold directly to consumers, pricing and cost recovery for public good infrastructures is typically indirect. Maintenance and construction of county roads are generally viewed as being funded by local property taxes, perhaps supplemented by other local taxes—all of which have an ability-to-pay aspect. Public good infrastructure is seldom, if ever, funded by a poll or head tax.

Classifying Commitment costs as customer-costs on a "one-per-customer" basis without regard for the size and diversity among customers is equivalent on a macro basis to allocating public infrastructure costs via a poll tax, where the customer is the polling unit. In the everyday world of public infrastructure supply, when we observe some good or service being shared by members of the public, those members pay for the good or service in proportion to how much they use it as individuals or in proportion to their taxable wealth, income, or some other measure of ability-to-pay.[3] From the perspective of having rates that, if not cost-based, are at least benefits-based, it is appropriate that the Commitment portion of the basic electric distribution infrastructure also be paid for by a measure that correlates with usage and

[3] Rural parks and campgrounds are good examples of public infrastructure paid for by a combination of user fees and general tax funds.

benefits received; i.e., according to demand imposed upon, or energy consumed from, the electric system more broadly conceived.

Q. WHAT IS THE SECOND JUSTIFICATION FOR NOT CLASSIFYING COMMITMENT COSTS AS CUSTOMER-RELATED COSTS?

A. Consider two utilities that are identical in every respect except utility A's service territory is replete with master-metered multi-family dwellings while utility B's service territory has only individually metered multi-family dwelling units. Since utility B has many more "customers" than does utility A, classifying Commitment costs as customer-related causes the former's residential class to bear a much greater portion of the distribution costs than would be the case with utility A. Conversely, non-residential customers located in utility B's service territory would benefit from a smaller cost allocation and lower rates than would identical non-residential customers located in utility A's service territory. Insofar as the residential class as a whole has the same demand and energy consumption in both utilities, classifying the Commitment costs as demand- or energy-related rather than customer-related avoids having overall cost allocations and rates being an artifact of the method by which multi-unit housing developers choose to wire and meter their buildings.[4]

Q. YOU HAVE RECOMMENDED CLASSIFYING COMMITMENT COSTS AS DEMAND-RELATED. THERE ARE A NUMBER OF DIFFERENT DEMAND-

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[4] Due to the extra metering and billing expenses of utility B, *that* portion of utility B's costs are obviously greater than that for utility A. Conservation advantages of customers being cost-responsible for their own consumption, enabled by individual metering, should lead to lower total costs for utility B.

BASED ALLOCATORS—SUCH AS SYSTEM SINGLE DISTRIBUTION LEVEL COINCIDENT PEAK (1 DCP), JURISDICTION SUM-OF-TWELVE COINCIDENT PEAKS (12CP), AND CUSTOMER CLASS NON-COINCIDENT PEAKS (NCP). DO YOU RECOMMEND ONE OF THESE OR SOMETHING ELSE FOR ALLOCATING COMMITMENT COSTS?

A. For purposes of this case, I recommend the feeder twelve monthly peaks (12CP) approach for allocating the Commitment portion of feeder costs.

Q. WHY?

A. It embodies a broad-based perspective that reflects benefits received over the course of the entire year. Perhaps that is why PacifiCorp has chosen this approach for allocating the portion of feeder costs that *it* classifies as demand-related.

Q. WOULD YOU USE THIS SAME 12 CP APPROACH FOR ALLOCATING YOUR NON-COMMITMENT PORTION OF FEEDER COSTS THAT PACIFICORP USED TO ALLOCATE ITS DEMAND-RELATED PORTION?

A. No, and this brings us to my third area of concern regarding PacifiCorp's Feeder Model. I am personally unaware of the 12 CP approach being used in the industry for allocating demand-related distribution costs.[5]

Q. STAFF SEEMS TO BE ACCEPTING IN THIS CASE THE COMPANY'S USE OF A 12 CP APPROACH TO ALLOCATING SYSTEM GENERATION CAPACITY COSTS. WHY ARE YOU REJECTING SUCH AN APPROACH

[5] In his book, *ENERGY UTILITY RATE SETTING*, former Utah Commission Chief-of-Staff, Lowell Alt, states (p. 71) "Distribution costs classified as demand-related might be allocated using relative class or schedule non-coincident peaks or distribution coincident peaks."

FOR ALLOCATING THE NON-COMMITMENT PORTION OF FEEDER COSTS?

A. Some would even allocate *generation* capacity costs based solely on loads that transpire at the time of the annual coincident peak (i.e., 1CP). However, there are other considerations. The "off-season" scheduled maintenance of a large baseload plant can render a utility as short, in terms of meeting its reserves obligation, as it would be during a period of high loads with no maintenance. Seasonal market prices and seasonal hydro conditions also affect the opportunity cost of electric capacity over the course of the year. But the same non-load-based considerations do not appear with regards to distribution costs. Therefore, a better case for cost-causation based on a single annual peak or a limited number of monthly peaks can be made for distribution capacity costs than for generation capacity costs. As just acknowledged, to the degree that several months have distribution peaks that are close to the annual maximum figure, it may be desirable to use a multiple-peak approach rather than the single peak approach. Obviously, what is "close" may entail a controversial judgment call.

Q. HOW DO YOU PROPOSE TO ALLOCATE THE NON-COMMITMENT PORTION OF FEEDER COSTS?

A. I propose using a January single distribution coincidental peak (1 DCP) approach to allocate the portion of feeder costs that the Company has classified as Demand. I would add at this point that the same argument that justifies the use of the 1 DCP approach to allocating feeder Demand costs will also apply to the allocation of the substation portion of distribution costs. Table 7 (i.e., Compton/15) of Exhibit Staff/1106 shows substations being allocated on a 1 DCP basis.

Q. HAVE YOU PREPARED AN EXHIBIT ILLUSTRATING THE NUMERICAL CONSEQUENCES OF THE FEEDER MODEL REFORMULATION MEASURES YOU HAVE PRESENTED?

A. I have. Exhibit Staff/1106 consists of worksheets that incorporate the recognition of trunk commitment costs, that reclassify all Commitment costs as 12 CP-demand-related, and that allocate the non-commitment portion of the feeder demand costs on a single month's (i.e., January's) distribution coincident peak (1 DCP) demand basis.

Q HAVE YOU PREPARED AN EXHIBIT WHICH INCORPORATES ALL OF THE MARGINAL COST MODEL REVISIONS (I.E., PERTAINING TO BOTH GENERATION AND DISTRIBUTION COSTS) THAT YOU HAVE PRESENTED THUS FAR IN YOUR TESTIMONY?

A. Yes. It is Exhibit Staff/1107.

Q. DOES EXHIBIT STAFF/1107 COMPRISE STAFF'S RECOMMENDATION IN THIS CASE?

A. On a preliminary basis, yes.

TOPIC 5 – GENERAL RATE DESIGN DISCUSSION

Q. IS ACHIEVING EQUITY AMONG THE CUSTOMER SCHEDULES YOUR PRIMARY OBJECTIVE IN THE JOINT COST-OF-SERVICE AND RATES SPREAD PROCESS?

A. Yes.

Q. ALONG SIMILAR LINES, WHAT WOULD YOU SAY IS A PRIMARY OBJECTIVE OF THE RATE DESIGN PROCESS?

A. A primary objective of rate design is to foster economic efficiency—typically by making prices approximate marginal costs as much as is feasible. Also, in the process of setting marginal-cost-oriented rates, equity *within* each customer schedule should not be neglected. I note that there are other objectives as well, such as administrative ease and simplicity of understanding by customers.

Q. WOULD YOU GIVE ME AN EXAMPLE OF HOW FOSTERING ECONOMIC EFFICIENCY MIGHT BE IN CONFLICT WITH PROMOTING RATES FAIRNESS WITHIN A SCHEDULE?

A. Yes. Consider the current residential schedule (#4). It incorporates a basic charge of $7.50 per month and an energy charge tail-block rate of 5.149¢ per kWh. For purposes of this discussion, assume that the marginal cost of energy was 7¢ per kWh. Assume furthermore that something close to that figure could be achieved (i.e., while still collecting the same amount of total revenues from the residential customers) by eliminating the basic charge entirely. The drawback to such a rate design is that the design would significantly reduce electric bills for customers who used very small amounts of electricity: They would be relieved of carrying their share of the customer costs (e.g., for the service line, the meter, meter reading, and billing) that they impose on the system.

Q. WHAT IS THE PRIMARY MEANS BY WHICH INTRA-CLASS EQUITY IS FOSTERED?

A. Intra-class equity is fostered by having the rate elements bear some connection with the per-unit costs of the functionalized cost elements described near the beginning of this testimony. While this may not be economically efficient, it is more equitable among customers from a judgmental standpoint.

Q. HOW WELL HAS PACIFICORP ACCOMPLISHED WHAT YOU JUST DESCRIBED?

A. Frankly, it is hard to say. Unlike the case with the latest PGE general rate case filing, PacifiCorp does not post COS-based functionalized revenue targets on its rate design formulation pages. This makes monitoring the connection between functionalized costs and functionalized revenues quite cumbersome. Based upon cursory comparisons of PacifiCorp's rate design worksheets and COS results, the targets have not always been closely achieved.

Q. HAVE YOU PREPARED AN EXHIBIT THAT ILLUSTRATES THAT LAST POINT? IF SO, PLEASE DESCRIBE IT.

A. Yes, it is Exhibit Staff/1108. The first page is from the referenced PGE filing. The first numeric column on the top of the page shows the functionalized cost allocation targets (i.e., "Allocated Inputs"). ("Charge" should be read as "Cost," and "Basic" refers to "Customer.") From these targets, prices are developed, and how closely the proposed rates yield revenues that match the allocated Input targets can readily be discerned. Now turn to the second page of the exhibit, which shows a sheet from the current PacifiCorp filing. Note that while the general cost functions are displayed, there are no functionalized "Allocated Inputs," or targets. To obtain the latter, one must turn to Exhibit PPL/905 Paice/1 (which is reproduced here as Staff/1102 Compton/3).

Now consider the "Transmission & Ancillary Service Charge" and costs as an example for comparing elements of page 2 of Staff/1109 with elements of page 3 of Staff/1102. The proposed *revenues* for this cost category are shown on page 2 of Staff/1108 as $3,787,830. By contrast, the combined Transmission and Ancillary Services *costs* on page 3 of Staff/1102 (i.e., Line 28 plus Line 30 of Column B) equal $6,821,000), an 80% larger amount. No specific explanation or justification was provided for this discrepancy. But such discrepancies are not necessarily the norm: the Energy Charge revenues of page 2 of Staff/1108 match the Generation costs figure of page 3 of Staff/1102 precisely.

Q. ARE MISMATCHES SUCH AS YOU JUST ILLUSTRATED NECESSARILY PROBLEMATIC?

A. No, not necessarily. As long as the schedule's overall revenue target is met, low charges for one functional category will be balanced by high charges in another. But if, for example, cost recovery takes place through an energy charge for a category whose cost-causative nature is demand-based, then there *may* indeed be a problem. But again, such problems are not inevitable—particularly when other recognized regulatory objectives (e.g., energy conservation) are taken into consideration. Also, in many instances (as was seen in the Feeder Model discussion) there can be a lot of ambiguity regarding the true cost-causative nature of the various accounting line-items that are included in the functional cost categories.

Q. YOUR DISCLAIMER ASIDE REGARDING THE DIFFICULTY OF AUDITING PACIFICORP'S PRICES RELATIVE TO FUNCTIONAL COST CATEGORIES, IS STAFF RECOMMENDING REVISIONS TO THE COMPANY'S RATE DESIGNS AS PROPOSED?

A. Not generally, and not at this phase of the case. However, I should mention a number of improvements that could be made to formulate rates that better capture cost causation.

Q. WOULD YOU GIVE ME SOME EXAMPLES OF POSSIBLE IMPROVEMENTS?

A. The largest incremental production resource to be included with PacifiCorp's western division portfolio over the next several years (i.e., 2012-2016) is a three- or four-hundred megawatt third quarter (i.e., July-September), heavyload-hour, Mid-Columbia front-office transaction.[6] Accordingly, a case can be made that summer loads are expected to drive the Company's marginal costs more than winter loads will. Nevertheless, seasonal rate distinctions do not appear in PacifiCorp's rate design proposal for Oregon. (They do appear prominently in PacifiCorp's Utah tariff.) Elevating the residential tail block rate in the summer and providing a super-peak time-of-use (TOU) rate for large industrial customers would be two ways of better capturing cost causation in PacifiCorp's electric utility rates.

Q. WILL YOU BE PROVIDING ANY RECOMMENDATIONS TO REFLECT A RELATIVELY HIGH SUPER-PEAK/OFF-PEAK SUMMER ENERGY COST DIFFERENTIAL?

A. Yes. The next section of this testimony presents some large industrial TOU options for consideration.

Q. BEFORE MOVING ON, PLEASE PROVIDE SOME DISCUSSION REGARDING WHAT IS PROBABLY THE SINGLE MOST PROMINENT PRICE IN THE ENTIRE TARIFF—THE RESIDENTIAL BASIC CHARGE, WHICH IS CURRENTLY $7.50 PER MONTH.

A. The Company is proposing that the basic charge be elevated to $8.50 per month, which represents a 13% increase. That amount seems high in view of the facts that the overall increase requested across all schedules is less than 12%, and the percentage increase requested for the residential class is "only" 8.52%. Given also that the primary cost driver in this case is production

6 See Table 8.44 – Preferred Portfolio, Detail Level on page 245 of the 2008 PacifiCorp IRP (Vol. 1).

costs, one might question why a customer charge should receive a larger percent increase than the energy charge receives. Furthermore, reclassifying distribution Commitment costs as demand- rather than customer-related removes an important underlying cost justification for a higher basic charge.

Therefore, I recommend increasing the residential basic charge at most to $8.00 per month. In the event that PacifiCorp's final revenue requirement adopted by the Commission is appreciably less than that requested by the Company, I recommend that the basic charge remain at its current level of $7.50 per month.

<u>TOPIC 6 – ALTERNATIVE SUMMERTIME RATES STRUCTURES FOR LARGE INDUSTRIAL CUSTOMERS</u>

Q. GIVEN, ON YOUR PART, SOME FAMILIARITY WITH LARGE INDUSTRIAL PRICING BY PACIFICORP IN BOTH UTAH AND OREGON, WHAT IS MOST STRIKING REGARDING DIFFERENCES BETWEEN THE TWO STATE TARIFF STRUCTURES?

A. The two sets of prices are shown in Exhibit Staff/1109. The major differences are:

1. No seasonality in the Oregon rates;
2. An almost indiscernible distinction in Oregon between the daily on-peak and off-peak rates; and
3. The existence in Utah, but not in Oregon, of a summer "super-peak," but not a "peak," rating period. The summer's off-peak/super-peak price

separation is much greater than is the winter's off-peak/on-peak difference.

4. Demand charges appear much more prominently in the Utah rates—for the recovery of some of the generation costs, not just distribution costs.

Q. JUDGING FROM THE TITLE OF THIS SECTION OF YOUR TESTIMONY, I ASSUME YOU WILL BE PROPOSING FOR OREGON SOMETHING SIMILAR TO WHAT HAS EXISTED FOR SOME TIME IN UTAH. GIVEN THE DIFFERENCES IN LOAD PATTERNS BETWEEN UTAH AND OREGON, WHY MIGHT YOU THINK SOME FORM OF SUPER-PEAK RATE STRUCTURE WOULD BE APPROPRIATE FOR OREGON?

A. I suggest the following three reasons, any one of which would probably be sufficient:

First, Pacific Power & Light Company is a system that integrates through transmission lines its Pacific and Rocky Mountain divisions. Except when those transmission lines are saturated, and possibly allowing for line losses, the two divisions should face similar marginal operating costs. Under the Multi-State regulatory agreement (endorsed by all of PacifiCorp's jurisdictions except Washington and, perhaps, California), the largest portion of fixed generation costs are also held in common. Apart from a portion of hydroelectric costs being carved out in favor of the Northwest, energy costs are allocated among the states on a simple kWh's-of-annual-gross-consumption basis.

Second, even if PP&L were not affiliated with Rocky Mountain Power, or were not interconnected with the American Southwest via California (resulting in high summertime market prices), the fact remains that since daily load patterns are different in the summer than in the winter (with air-conditioning dominating in the summer and space heating and lighting dominating in the winter), the summertime diurnal pattern of opportunity costs here in the Northwest is quite different from the pattern in the winter. The winter season tends to have both a morning and an early evening peak while the summer peak is unitary and greatest in the afternoon.

Third, a two-part rate with the highest rate occupying only eight hours is more likely to be advantageous to both customers and the Company. My presumption is that a customer will be more likely and able to reduce usage (to a considerable degree if not entirely) during an eight-hour high-priced period than during an entire sixteen-hour high-priced peak period. Also, the Company's high super-peak-period energy and capacity costs are reduced as customer load reductions are focused upon the corresponding highest cost periods.

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE DIURNAL LOCAL SPOT MARKET PRICE PATTERNS FOR THE TWO SUMMER PEAK MONTHS (JULY AND AUGUST) OF THE LAST CALENDAR YEAR (2008)?

A. Yes, in Confidential Exhibit Staff/1110. It shows the non-Sunday hourly averages, the Sunday 24-hour averages, and the averages for what are designated as the super-peak, shoulder-peak, off-peak, and on-peak intervals.

Q. HAVE YOU PREPARED AN EXHIBIT WHICH DISPLAYS LARGE INDUSTRIAL (I.E., SCHEDULES 47/48) ENERGY CHARGES THAT WOULD COLLECT THE SAME REVENUES FROM THOSE SCHEDULES FOR THE MONTHS OF JULY AND AUGUST AS THE CHARGES PROPOSED BY PACIFICORP, BUT WOULD BE MORE INDICATIVE OF OPPORTUNITY-COST PATTERNS?

A. Yes, it is Exhibit Staff/1111.

Q. DOES STAFF HAVE A RECOMMENDATION TO MAKE FROM AMONG THE ALTERNATIVES IN THAT EXHIBIT?

A. No, not at this stage of the case. Our preference is to withhold any formal recommendation until we have been able to get feedback from representatives of the affected customers and from the Company.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 210
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualification Statement

July 24, 2009

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Oregon Public Utility Commission

TITLE: Senior Economist (3/4), Economic Research & Financial Analysis Division (ERFA)

ADDRESS: 550 Capital Street NE, Suite 215
Salem, OR 97301-2551

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah I also taught economics part-time for about ten years at BYU. Prior to my utility regulatory career I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California. I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement have included the IRP/CO_2 Risk Guideline (UM 1302), the AVISTA General Rate Case (UG 181), and the 2008 PGE General Rate Case (UE 197).

CASE: UE 210
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1102

Original PacifiCorp
Principal Cost-of-Service Worksheets

July 24, 2009

Table 3

ORIGINAL PACIFICORP WORKSHEET

PacifiCorp
Oregon Marginal Cost Study
20 Year Costing Inputs and Customer Data
Marginal Unit Costs
December 2010 Dollars

Line	Description		(A) Residential (sec)	(B) General Service - Schedule 23 0-15 kW (sec)	(C) 15+ kW (sec)	(D) Primary (pri)	(E) General Service - Schedule 28 0-50 kW (sec)	(F) 51-100 kW (sec)	(G) > 101kW (sec)	(H) Primary (pri)
	Billing Units									
	Demand									
1	Load Factors	System	78.75%	88.41%	74.04%	75.50%	77.67%	68.93%	75.29%	73.67%
2		Feeder	57.08%	89.84%	73.88%	75.48%	74.08%	69.79%	74.90%	73.48%
3		Transformer	30.26%	27.16%	49.98%	N/A	51.09%	57.17%	59.46%	N/A
4										
5	Peak Mw @ Generator	System	862	82	73	0	69	122	153	3
6		Feeder	1,189	81	73	0	73	120	154	3
7		Transformer	2,244	268	107	N/A	106	147	194	N/A
8										
9	Energy									
10	Energy - Annual Mwh	@ Meter	5,435,846	582,532	430,256	1,152	431,990	672,435	922,391	18,249
11	Energy Loss Factor		1.0940	1.0940	1.0940	1.0595	1.0940	1.0940	1.0940	1.0595
12	Energy - Annual Mwh	@ Generator	5,946,598	637,267	470,683	1,220	472,580	735,617	1,009,059	19,335
13										
14	Customer									
15	Annual Customers		478,485	64,649	9,372	34	4,491	3,525	2,034	50
16	Average Customers									
17										
18	Unit Costs									
19										
20	Generation	$ / System Peak Kw	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46
21	Transmission	$ / System Peak Kw	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47
22	Poles, Cond., Subst.	$ / Feeder Kw	$82.45	$86.68	$86.68	$86.68	$66.57	$66.57	$66.57	$66.57
23	Transformers	$ / Xfmr Kw	$1.51	$1.96	$1.96	$0.00	$1.96	$1.96	$1.96	$0.00
24										
25	Energy - @ Generator									
26	Generation	$ / Kwh	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570
27	Transmission	$ / Kwh	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382
28										
29	Poles	$ / Cust / Year	$95.59	$109.53	$109.53	$109.53	$46.87	$46.87	$46.87	$46.87
30	Conductor	$ / Cust / Year	$38.28	$43.86	$43.86	$43.86	$18.77	$18.77	$18.77	$18.77
31	Transformers	$ / Cust / Year	$74.20	$221.25	$496.66	$0.00	$688.85	$804.03	$883.01	$0.00
32	Service Drop	$ / Cust / Year	$70.83	$91.18	$218.20	$0.00	226.92	237.05	522.35	-
33	Meters	$ / Cust / Year	$15.54	$18.38	$38.08	$1,199.32	36.81	46.53	207.91	1,199.32
34	Meter Reading	$ / Cust / Year	$14.00	$17.36	$17.36	$17.36	16.80	16.80	16.80	16.80
35	Billing & Collections	$ / Cust / Year	$32.27	$30.49	$30.49	$30.49	32.60	32.60	32.60	32.60
36	Uncollectables	$ / Cust / Year	$10.15	$2.73	$2.73	$2.73	25.17	25.17	25.17	25.17
37	Customer Service / Other	$ / Cust / Year	$12.82	$12.11	$12.11	$12.11	15.01	15.01	15.01	15.01
38	Total Commitment & Billing	$ / Cust / Year	$363.68	$546.91	$969.04	$1,415.41	$1,107.81	$1,242.83	$1,768.49	$1,354.54

Line	Description		(I) General Service - Schedule 30 0-300 kW (sec)	(J) 301+ kW (sec)	(K) Primary (pri)	(L) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(M) 1 - 4 MW (pri)	(N) > 4 MW (sec)	(O) > 4 MW (pri)	(P) Trans (trn)	(Q) Irrigation Sch 41 (sec)	(R) Irrigation Sch 33* (sec)
	Billing Units											
	Demand											
1	Load Factors	System	76.42%	77.06%	77.01%	76.07%	82.02%	92.58%	87.26%	99.33%	67.15%	67.15%
2		Feeder	76.00%	75.71%	75.73%	74.77%	79.59%	98.15%	87.10%	N/A	67.15%	67.15%
3		Transformer	64.58%	68.79%	N/A	50.73%	N/A	67.13%	N/A	N/A	32.07%	32.07%
4												
5	Peak Mw @ Generator	System	34	175	15	98	61	7	163	48	25	22
6		Feeder	34	178	15	99	63	7	163	N/A	25	22
7		Transformer	40	196	N/A	146	N/A	10	N/A	N/A	53	46
8												
9	Energy											
10	Energy - Annual Mwh	@ Meter	206,234	1,078,480	93,931	594,746	414,743	54,345	1,175,179	404,889	136,792	118,046
11	Energy Loss Factor		1.0940	1.0940	1.0595	1.0940	1.0595	1.0940	1.0595	1.0361	1.0940	1.0940
12	Energy - Annual Mwh	@ Generator	225,612	1,179,814	99,519	650,629	439,416	59,451	1,245,090	419,485	149,645	129,138
13												
14	Customer											
15	Annual Customers		230	572	52	121	56	2	34	2	6,108	2,062
16	Average Customers										2,834	756
17												
18	Unit Costs											
19												
20	Generation	$ / System Peak Kw	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46
21	Transmission	$ / System Peak Kw	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47
22	Poles, Cond., Subst.	$ / Feeder Kw	$68.95	$68.95	$68.95	$56.67	$56.67	$23.37	$23.37	$0.00	$149.33	$171.83
23	Transformers	$ / Xfmr Kw	$1.96	$1.96	$0.00	$1.96	$0.00	$1.96	$0.00	$0.00	$1.96	$1.96
24												
25	Energy - @ Generator											
26	Generation	$ / Kwh	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570
27	Transmission	$ / Kwh	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382
28												
29	Poles	$ / Cust / Year	$55.18	$55.18	$55.18	$16.34	$16.34	$0.00	$0.00	$0.00	$294.43	$371.91
30	Conductor	$ / Cust / Year	$22.11	$22.11	$22.11	$6.54	$6.54	$0.00	$0.00	$0.00	$117.93	$148.96
31	Transformers	$ / Cust / Year	$1,070.36	$1,072.63	$0.00	$1,074.16	$0.00	$1,074.16	$0.00	$0.00	$894.11	$1,045.59
32	Service Drop	$ / Cust / Year	522.13	522.12	-	$937.60	$0.00	$937.60	$0.00	$0.00	$0.00	$0.00
33	Meters	$ / Cust / Year	209.71	209.92	1,199.32	$262.55	$1,199.32	$262.55	$1,199.32	$42,924	$37.44	$45.09
34	Meter Reading	$ / Cust / Year	75.73	75.73	75.73	114.93	$114.93	$114.93	$114.93	$114.93	$26.74	$26.67
35	Billing & Collections	$ / Cust / Year	32.60	32.60	32.60	238.20	$238.20	$238.20	$238.20	$238.20	$33.07	$33.02
36	Uncollectables	$ / Cust / Year	180.30	180.30	180.30	1,110.75	$1,110.75	$1,110.75	$1,110.75	$1,110.75	$12.33	$9.21
37	Customer Service / Other	$ / Cust / Year	40.89	40.89	40.89	182.97	$182.97	$182.97	$182.97	$182.97	$14.72	$14.32
38	Total Commitment & Billing	$ / Cust / Year	$2,209.01	$2,211.48	$1,606.13	$3,944.05	$2,869.07	$3,921.17	$2,846.18	$44,570	$1,430.75	$1,694.78

Sources:
Lines 1 - 3 Tab 17.4 (Cust Data 4:) 'Customer Load Factors12 Months Ended December 2010'
Lines 10 & 15 Tab 17.2 (Cust Data 2:) 'Customers and MWh's12 Months Ended December 2010 - Normalized'
Line 11 Tab 16.1 (Losses:) 'Energy Loss Factors'
Line 20 Tab 4.1 (Capacity:) 'Marginal Capacity Costs Based on Avoided Capacity Costs'
Line 21 Tab 6.1 (Transm1:) 'Marginal Transmission Investment and O&M Expenses'
Line 22 Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'
Line 26 Tab 5.1 (Energy:) 'Marginal Generation Energy Costs'
Line 27 Tab 2.6 (Table 6:) 'Marginal Cost of Transmission Investment and Associated Expenses'
Lines 29 - 37 Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'

* Schedule 33 Cost of Service results are provided for informational purposes only.

Table 4

ORIGINAL PACIFICORP WORKSHEET

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
December 2010 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg	Sch 51,53,54
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 M	> 4 MW	> 4 M	Trans	Sch 41	Sch 33*	Streetlighting
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)	(sec)
	Demand Related Marginal Cost																				
1	Generation	$148,195	$64,189	$6,127	$5,403	$14	$5,172	$9,071	$11,393	$223	$2,509	$13,014	$1,098	$7,270	$4,554	$546	$12,128	$3,590	$1,894	$1,635	
2	Transmission	$150,207	$65,060	$6,210	$5,477	$14	$5,242	$9,194	$11,547	$226	$2,544	$13,191	$1,113	$7,369	$4,616	$553	$12,293	$3,638	$1,920	$1,657	
3	Distribution																				
4	Poles	$42,784	$26,664	$1,960	$1,760	$4	$1,139	$1,882	$2,404	$48	$563	$2,955	$249	$1,132	$718	$0	$0	$0	$1,305	$1,331	
5	Conductor	$71,273	$43,588	$3,166	$2,843	$7	$2,007	$3,317	$4,239	$83	$982	$5,152	$434	$2,174	$1,380	$0	$0	$0	$1,901	$1,929	
6	Substations	$53,241	$27,798	$1,893	$1,700	$4	$1,702	$2,813	$3,595	$70	$792	$4,158	$351	$2,322	$1,473	$162	$3,814	$0	$595	$513	
7	Subtotal: Pole, Cond, Subs	$167,297	$98,050	$7,019	$6,304	$15	$4,848	$8,011	$10,238	$201	$2,338	$12,265	$1,034	$5,628	$3,571	$162	$3,814	$0	$3,800	$3,773	
8	Transformers	$5,872	$3,388	$525	$211	$0	$207	$288	$380	$0	$78	$384	$0	$287	$0	$20	$0	$0	$105	$90	
9	Distribution subtotal	$173,169	$101,438	$7,544	$6,515	$15	$5,054	$8,300	$10,617	$201	$2,415	$12,649	$1,034	$5,915	$3,571	$182	$3,814	$0	$3,905	$3,863	
10																					
11	Total Demand Related	$471,571	$230,687	$19,881	$17,395	$43	$15,468	$26,565	$33,557	$650	$7,468	$38,854	$3,245	$20,554	$12,741	$1,281	$28,235	$7,228	$7,719	$7,155	
12	(Lines 1+2+9)																				
13																					
14	Energy Related Marginal Cost																				
15	Generation Energy Related	$768,041	$331,225	$35,496	$26,217	$68	$26,323	$40,974	$56,205	$1,077	$12,567	$65,716	$5,543	$36,240	$24,475	$3,311	$69,352	$23,365	$8,335	$7,193	$1,552
16	Transmission Energy Related	$52,647	$22,705	$2,433	$1,797	$5	$1,804	$2,809	$3,853	$74	$861	$4,505	$380	$2,484	$1,678	$227	$4,754	$1,602	$571	$493	$106
17	Total Energy	$820,689	$353,930	$37,929	$28,014	$73	$28,127	$43,783	$60,057	$1,151	$13,428	$70,220	$5,923	$38,724	$26,153	$3,538	$74,105	$24,967	$8,907	$7,686	$1,659
18																					
19	Customer Related Marginal Cost																				
20	Poles	$62,289	$45,737	$7,081	$1,027	$4	$211	$165	$95	$3	$12	$31	$3	$1	$1	$0	$0	$0	$1,799	$767	$6,119
21	Conductor	$22,545	$18,319	$2,835	$411	$1	$84	$67	$38	$1	$5	$12	$1	$1	$0	$0	$0	$0	$720	$307	$48
22	Transformers	$68,752	$35,505	$14,304	$4,654	$0	$3,094	$2,834	$1,796	$0	$246	$614	$0	$131	$0	$3	$0	$0	$5,461	$2,156	$111
23	Service Drops	$45,280	$33,890	$5,895	$2,045	$0	$1,019	$835	$1,063	$0	$120	$299	$0	$113	$0	$1	$0	$0	$0	$0	
24	Meters	$10,523	$7,438	$1,188	$357	$41	$165	$164	$423	$60	$48	$120	$62	$32	$67	$1	$41	$86	$229	$93	$2
25	Meter Reading	$8,321	$6,698	$1,122	$163	$1	$75	$59	$34	$1	$17	$43	$4	$14	$6	$0	$4	$0	$76	$20	$2
26	Billing & Collections	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$32
27	Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
28	Customer Service / Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
29	Total Commitment & Billing Rel.	$248,994	$174,017	$35,358	$9,082	$48	$4,976	$4,380	$3,597	$69	$508	$1,265	$84	$477	$161	$8	$97	$89	$8,454	$3,387	$6,326
30																					
31	Total Revenue @ Full MC																				
32	Generation	$916,236	$395,414	$41,623	$31,620	$82	$31,495	$50,045	$67,598	$1,300	$15,076	$78,730	$6,641	$43,510	$29,029	$3,857	$81,480	$26,955	$10,229	$8,828	$1,552
33	Transmission	$202,854	$87,765	$8,643	$7,274	$19	$7,046	$12,003	$15,400	$300	$3,405	$17,696	$1,493	$9,853	$6,294	$780	$17,047	$5,240	$2,491	$2,150	$106
34	Distribution	$372,038	$234,889	$37,660	$14,652	$21	$9,462	$12,200	$13,609	$205	$2,799	$13,605	$1,038	$6,161	$3,573	$186	$3,814	$0	$11,884	$7,094	$6,279
35	Customer - Billing	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$32
36	Customer - Metering	$18,842	$14,136	$2,311	$520	$41	$241	$223	$457	$61	$66	$163	$66	$46	$74	$1	$45	$86	$304	$113	$2
37	Customer - Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
38	Revenue (less Uncollectables)	$1,535,514	$753,779	$92,991	$54,465	$164	$48,458	$74,639	$97,160	$1,868	$21,362	$110,236	$9,242	$59,621	$38,993	$4,825	$102,400	$32,282	$25,045	$18,221	$7,984
39																					
40	Customer - Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
41	Total Revenue	$1,541,254	$758,634	$93,168	$54,490	$164	$48,571	$74,727	$97,212	$1,869	$21,404	$110,339	$9,251	$59,756	$39,055	$4,827	$102,437	$32,284	$25,079	$18,228	$7,984

Source: Tab 2.3 (Table 3:) '20 Year Costing Inputs and Customer Data Marginal Unit Costs'
Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'

Line 1 Generation (Table 3, Row 5) x (Table 3, Row 20)/1000
Line 2 Transmission (Table 3, Row 5) x (Table 3, Row 21)/1000
Lines 4-6 Poles, Cond., Subst. (Table 3, Row 6) x (Table 7, Row 1 - 3) x (1 + .3605) (Dist OM, Row 32)
Line 8 Transformers (Table 3, Row 7) x (Table 7, Row 7) x (1 + .3605) (Dist OM, Row 32)
Lines 15-16 Energy Related (Table 3, Row 12) x (Table 3, Row 26 - 27)
Lines 20-29 Commitment Related (Table 3, Row 15) x (Table 7, Row 13 - 27) including O&M Adders

* Schedule 33 Cost of Service results are provided for informational purposes only.

ORIGINAL PACIFICORP WORKSHEET
STATE OF OREGON
Combined GRC and TAM
December 31, 2010 Unbundled Revenue Requirement Allocation by Rate Schedule

Line	Description	Total	(A) Residential	(B) General Service	(C)	(D) General Service	(E)	(F) General Service	(G)	(H) Large Power Service	(I)	(J)	(K) Irrigation	(L) Street Lgt.
				Sch 23		Sch 28		Sch 30			Sch 48T		Sch 41	Sch 51, 53, 54
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	
1	**Total Operating Revenues**	$915,181	$471,595	$90,790	$99	$124,369	$1,123	$73,370	$5,318	$35,927	$77,376	$17,402	$14,323	$3,489
2	**MWH**	12,680,407	5,435,846	1,012,789	1,152	2,026,816	18,249	$1,284,715	93,931	649,091	1,589,921	404,889	136,792	$26,217
3														
4	**Functionalized 20 Year Full Marginal Costs - Class $**													
5	Generation	$916,236	$395,414	$73,243	$82	$149,137	$1,300	$93,805	$6,641	$47,367	$110,509	$26,955	$10,229	$1,552
6	Transmission	$202,854	$87,765	$15,917	$19	$34,449	$300	$21,101	$1,493	$10,633	$23,341	$5,240	$2,491	$106
7	Distribution	$372,038	$234,889	$52,312	$21	$35,272	$205	$16,404	$1,038	$6,347	$7,387	$0	$11,884	$6,279
8	Customer - Billing	$18,233	$15,441	$2,257	$1	$328	$2	$26	$2	$29	$21	$0	$94	$32
9	Customer - Metering	$18,842	$14,136	$2,830	$41	$921	$61	$229	$66	$46	$118	$86	$304	$2
10	Customer - Other	$7,310	$6,133	$897	$0	$151	$1	$33	$2	$23	$16	$0	$42	$12
11	Total	$1,535,514	$753,779	$147,456	$164	$220,257	$1,868	$131,598	$9,242	$64,446	$141,393	$32,282	$25,045	$7,984
12														
13	**Functional Revenue Requirement Allocation Factors**													
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**													
15	Generation	100.00%	43.16%	7.99%	0.01%	16.28%	0.14%	10.24%	0.72%	5.17%	12.06%	2.94%	1.12%	0.17%
16	Transmission	100.00%	43.26%	7.85%	0.01%	16.98%	0.15%	10.40%	0.74%	5.24%	11.51%	2.58%	1.23%	0.05%
17	Distribution	100.00%	63.14%	14.06%	0.01%	9.48%	0.06%	4.41%	0.28%	1.71%	1.99%	0.00%	3.19%	1.69%
18	Ancillary Service	100.00%	43.16%	7.99%	0.01%	16.28%	0.14%	10.24%	0.72%	5.17%	12.06%	2.94%	1.12%	0.17%
19	Customer - Billing	100.00%	84.69%	12.38%	0.01%	1.80%	0.01%	0.14%	0.01%	0.16%	0.12%	0.00%	0.51%	0.18%
20	Customer - Metering	100.00%	75.02%	15.02%	0.22%	4.89%	0.32%	1.22%	0.35%	0.25%	0.63%	0.46%	1.62%	0.01%
21	Customer - Other	100.00%	83.90%	12.27%	0.01%	2.06%	0.01%	0.45%	0.03%	0.31%	0.23%	0.01%	0.57%	0.17%
22	Embedded DSM - (mWh)	100.00%	42.87%	7.99%	0.01%	15.98%	0.14%	10.13%	0.74%	5.12%	12.54%	3.19%	1.08%	0.21%
23	Regulatory & Franchise	100.00%	51.53%	9.92%	0.01%	13.59%	0.12%	8.02%	0.58%	3.93%	8.45%	1.90%	1.57%	0.38%
24	Taxes (Revenue)													
25														
26	**Functionalized Class Revenue Requirement - (Target)**													
27	Generation	$612,171	$264,191	$48,936	$55	$99,644	$869	$62,675	$4,437	$31,648	$73,835	$18,010	$6,835	$1,037
28	Transmission	$75,967	$32,867	$5,961	$7	$12,901	$112	$7,902	$559	$3,982	$8,741	$1,962	$933	$40
29	Distribution	$246,801	$155,820	$34,703	$14	$23,398	$136	$10,882	$688	$4,211	$4,900	$0	$7,884	$4,165
30	Ancillary Services	$10,758	$4,643	$860	$1	$1,751	$15	$1,101	$78	$556	$1,298	$316	$120	$18
31	Customer - Billing	$11,737	$9,940	$1,453	$1	$211	$1	$17	$1	$19	$14	$0	$60	$21
32	Customer - Metering	$28,029	$21,029	$4,210	$62	$1,370	$90	$341	$99	$69	$176	$128	$453	$3
33	Customer - Other	$13,088	$10,980	$1,605	$1	$270	$1	$59	$4	$40	$29	$1	$75	$22
34	Embedded DSM - (mWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Regulatory & Franchise T	$23,859	$12,295	$2,367	$3	$3,242	$29	$1,913	$139	$937	$2,017	$454	$373	$91
36	Total	$1,022,411	$511,764	$100,095	$142	$142,788	$1,254	$84,889	$6,005	$41,462	$91,010	$20,871	$16,733	$5,397
37														
38	**Ratio of Operating Revn to Revenue Requirement-(Target)**	89.51%	92.15%	90.70%	69.86%	87.10%	89.58%	86.43%	88.57%	86.65%	85.02%	83.38%	85.60%	64.64%
39	(Line 1 / Line 36)													
40														
41	**Increase or (Decrease)**	$107,229	$40,169	$9,305	$43	$18,419	$131	$11,520	$687	$5,535	$13,635	$3,469	$2,409	$1,909
42	(Line 36 - Line 1)													
43														
44														
45	**Percent Increase (Decrease)**	11.72%	8.52%	10.25%	43.14%	14.81%	11.64%	15.70%	12.91%	15.41%	17.62%	19.94%	16.82%	54.71%
46	(Line 41 / Line 1)													

CASE: UE 210
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1103

Generation-Related Worksheets With Staff-Updated Energy Costs

July 24, 2009

Energy

STAFF SUBSTITUTE WORKSHEET -- UPDATED ENERGY COSTS

PacifiCorp
Oregon Marginal Cost Study
Marginal Generation Energy Costs
Nominal Mills / kWh

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Calendar Year (12 Mo Ended Dec)	SCCT Fixed Costs ($/kW-yr) (1)	SCCT Fixed Costs ($/kW-mo) (2)	CCCT Fixed Costs ($/kW-yr) (3)	CCCT Fixed Costs ($/kW-mo) (4)	Capitalized Energy Cost ($/kW-mo) (4) - (2) = (5)	Capitalized Energy Cost 48.7% CF ($/MWh) (6)	Purchase Cost ($/MWh) (7)	Updated Gas Price ($/MMBtu) (8)	CCCT Energy Costs 7270 Btu/kWh ($/MWh) (9)	Variable Avoided Energy Cost ($/MWh) (7) + (9) =(10)	Capitalized Energy Cost 48.7% CF ($/MWh) (6)=(11)	Total Avoided Energy Cost ($/MWh) 10) + (11) =(12	Present Value Factors (13) @ 8.55%	Present Value of Energy (14) (12)*(13)
2010	74.50	6.21	90.39	7.53	1.32	3.72	0.00	5.00	36.35	36.35	3.72	40.07	1.0000	40.08
2011	76.06	6.34	92.27	7.69	1.35	3.80	0.00	4.86	35.35	35.35	3.80	39.15	0.9212	36.07
2012	77.59	6.47	94.12	7.84	1.38	3.87	0.00	4.71	34.21	34.21	3.87	38.09	0.8487	32.33
2013	79.05	6.59	95.92	7.99	1.41	3.95	0.00	4.70	34.17	34.17	3.95	38.12	0.7819	29.81
2014	80.55	6.71	97.74	8.15	1.43	4.03	0.00	4.86	35.35	35.35	4.03	39.38	0.7203	28.37
2015	82.08	6.84	99.60	8.30	1.46	4.11	0.00	5.08	36.94	36.94	4.11	41.05	0.6636	27.24
2016	83.64	6.97	101.49	8.46	1.49	4.18	0.00	5.18	37.62	37.62	4.18	41.81	0.6113	25.56
2017	85.23	7.10	103.42	8.62	1.52	4.26	0.00	5.26	38.26	38.26	4.26	42.52	0.5632	23.95
2018	86.86	7.24	105.38	8.78	1.54	4.34	0.00	5.35	38.89	38.89	4.34	43.24	0.5188	22.43
2019	88.50	7.38	107.38	8.95	1.57	4.43	0.00	5.45	39.62	39.62	4.43	44.05	0.4779	21.05
2020	90.18	7.52	109.42	9.12	1.60	4.51	0.00	5.56	40.39	40.39	4.51	44.90	0.4403	19.77
2021	91.89	7.66	111.50	9.29	1.63	4.60	0.00	5.50	39.99	39.99	4.60	44.58	0.4056	18.08
2022	93.65	7.80	113.62	9.47	1.66	4.68	0.00	5.47	39.76	39.76	4.68	44.44	0.3737	16.61
2023	95.42	7.95	115.78	9.65	1.70	4.77	0.00	5.46	39.67	39.67	4.77	44.44	0.3443	15.30
2024	97.23	8.10	117.98	9.83	1.73	4.86	0.00	5.39	39.21	39.21	4.86	44.08	0.3172	13.98
2025	99.08	8.26	120.22	10.02	1.76	4.96	0.00	5.35	38.89	38.89	4.96	43.85	0.2922	12.81
2026	100.97	8.41	122.51	10.21	1.80	5.05	0.00	5.30	38.53	38.53	5.05	43.58	0.2692	11.73
2027	102.88	8.57	124.84	10.40	1.83	5.15	0.00	5.31	38.62	38.62	5.15	43.77	0.2480	10.86
2028	104.84	8.74	127.20	10.60	1.86	5.24	0.00	5.36	38.94	38.94	5.24	44.18	0.2285	10.10
2029	106.83	8.90	129.62	10.80	1.90	5.34	0.00	5.38	39.08	39.08	5.34	44.42	0.2105	9.35

				Mills / kWh
2010	1 Year -	Sum of PV Costs		40.08
2010 - 2014	5 Year -	Short Run -		
		Sum of PV Costs	@ 8.55%	166.64
		Annual Cost of Energy	@ 22.59%	37.64
2010 - 2019	10 Years -	Medium Run -		
		Sum of PV Costs	@ 8.55%	286.87
		Annual Cost of Energy	@ 13.05%	37.44
2010 - 2029	20 Years -	Long Run -		
		Sum of PV Costs	@ 8.55%	425.45
		Annual Cost of Energy	@ 8.51%	36.21

Footnote:
Source: Ore Commission Approved - AC Study (2007 08 13).xls
Column A: Total Cost of Simple Cycle: Table 8, Page 1, column (f)
Column C: Total Cost of Combined Cycle: Table 8, Page 2, column (f)
Column H: **Gas Price: (5/8) * Column H of Worksheet "Energy" (i.e., Tab: 5.1 of Exhibit PPL/907)**
Column I: Heat Rate: for CCCT: Table 8, Page 3

Table 3

STAFF SUBSTITUTE WORKSHEET -- UPDATED ENERGY COSTS

PacifiCorp
Oregon Marginal Cost Study
20 Year Costing Inputs and Customer Data
Marginal Unit Costs
December 2010 Dollars

Line	Description		(A) Residential (sec)	(B) General Service - Schedule 23 0-15 kW (sec)	(C) General Service - Schedule 23 15+ kW (sec)	(D) General Service - Schedule 23 Primary (pri)	(E) General Service - Schedule 28 0-50 kW (sec)	(F) General Service - Schedule 28 51-100 kW (sec)	(G) General Service - Schedule 28 > 101kW (sec)	(H) General Service - Schedule 28 Primary (pri)
	Billing Units									
	Demand									
1	Load Factors	System	78.75%	88.41%	74.04%	75.50%	77.67%	68.93%	75.29%	73.67%
2		Feeder	57.08%	89.84%	73.88%	75.48%	74.08%	69.79%	74.90%	73.48%
3		Transformer	30.26%	27.16%	49.98%	N/A	51.09%	57.17%	59.46%	N/A
4										
5	Peak Mw @ Generator	System	862	82	73	0	69	122	153	3
6		Feeder	1,189	81	73	0	73	120	154	3
7		Transformer	2,244	268	107	N/A	106	147	194	N/A
8										
9	Energy									
10	Energy - Annual Mwh	@ Meter	5,435,846	582,532	430,256	1,152	431,990	672,435	922,391	18,249
11	Energy Loss Factor		1.0940	1.0940	1.0940	1.0595	1.0940	1.0940	1.0940	1.0595
12	Energy - Annual Mwh	@ Generator	5,946,598	637,267	470,683	1,220	472,580	735,617	1,009,059	19,335
13										
14	Customer									
15	Annual Customers		478,485	64,649	9,372	34	4,491	3,525	2,034	50
16	Average Customers									
17										
18	Unit Costs									
19										
20	Generation	$ / System Peak Kw	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46
21	Transmission	$ / System Peak Kw	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47
22	Poles, Cond., Subst.	$ / Feeder Kw	$82.45	$86.68	$86.68	$86.68	$66.57	$66.57	$66.57	$66.57
23	Transformers	$ / Xfmr Kw	$1.51	$1.96	$1.96	$0.00	$1.96	$1.96	$1.96	$0.00
24										
25	Energy - @ Generator									
26	Generation	$ / Kwh	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621
27	Transmission	$ / Kwh	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382
28										
29	Poles	$ / Cust / Year	$95.59	$109.53	$109.53	$109.53	$46.87	$46.87	$46.87	$46.87
30	Conductor	$ / Cust / Year	$38.28	$43.86	$43.86	$43.86	$18.77	$18.77	$18.77	$18.77
31	Transformers	$ / Cust / Year	$74.20	$221.25	$496.66	$0.00	$688.85	$804.03	$883.01	$0.00
32	Service Drop	$ / Cust / Year	$70.83	$91.18	$218.20	$0.00	226.92	237.05	522.35	-
33	Meters	$ / Cust / Year	$15.54	$18.38	$38.08	$1,199.32	36.81	46.53	207.91	1,199.32
34	Meter Reading	$ / Cust / Year	$14.00	$17.36	$17.36	$17.36	16.80	16.80	16.80	16.80
35	Billing & Collections	$ / Cust / Year	$32.27	$30.49	$30.49	$30.49	32.60	32.60	32.60	32.60
36	Uncollectables	$ / Cust / Year	$10.15	$2.73	$2.73	$2.73	25.17	25.17	25.17	25.17
37	Customer Service / Other	$ / Cust / Year	$12.82	$12.11	$12.11	$12.11	15.01	15.01	15.01	15.01
38	Total Commitment & Billing	$ / Cust / Year	$363.68	$546.91	$969.04	$1,415.41	$1,107.81	$1,242.83	$1,768.49	$1,354.54

Line	Description	(I) General Service - Schedule 30 0-300 kW (sec)	(J) General Service - Schedule 30 301+ kW (sec)	(K) General Service - Schedule 30 Primary (pri)	(L) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(M) Large Power Service - Schedule 48T 1 - 4 MW (pri)	(N) Large Power Service - Schedule 48T > 4 MW (sec)	(O) Large Power Service - Schedule 48T > 4 MW (pri)	(P) Large Power Service - Schedule 48T Trans (trn)	(Q) Irrigation Sch 41 (sec)	(R) Irrigation Sch 33* (sec)
1	Load Factors - System	76.42%	77.06%	77.01%	76.07%	82.02%	92.58%	87.26%	99.33%	67.15%	67.15%
2	Feeder	76.00%	75.71%	75.73%	74.77%	79.59%	98.15%	87.10%	N/A	67.15%	67.15%
3	Transformer	64.58%	68.79%	N/A	50.73%	N/A	67.13%	N/A	N/A	32.07%	32.07%
5	Peak Mw @ Generator - System	34	175	15	98	61	7	163	48	25	22
6	Feeder	34	178	15	99	63	7	163	N/A	25	22
7	Transformer	40	196	N/A	146	N/A	10	N/A	N/A	53	46
10	Energy - Annual Mwh @ Meter	206,234	1,078,480	93,931	594,746	414,743	54,345	1,175,179	404,889	136,792	118,046
11	Energy Loss Factor	1.0940	1.0940	1.0595	1.0940	1.0595	1.0940	1.0595	1.0361	1.0940	1.0940
12	Energy - Annual Mwh @ Generator	225,612	1,179,814	99,519	650,629	439,416	59,451	1,245,090	419,485	149,645	129,138
15	Annual Customers	230	572	52	121	56	2	34	2	6,108	2,062
16	Average Customers									2,834	756
20	Generation	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46
21	Transmission	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47
22	Poles, Cond., Subst.	$68.95	$68.95	$68.95	$56.67	$56.67	$23.37	$23.37	$0.00	$149.33	$171.83
23	Transformers	$1.96	$1.96	$0.00	$1.96	$0.00	$1.96	$0.00	$0.00	$1.96	$1.96
26	Generation	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621
27	Transmission	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382
29	Poles	$55.18	$55.18	$55.18	$16.34	$16.34	$0.00	$0.00	$0.00	$294.43	$371.91
30	Conductor	$22.11	$22.11	$22.11	$6.54	$6.54	$0.00	$0.00	$0.00	$117.93	$148.96
31	Transformers	$1,070.36	$1,072.63	$0.00	$1,074.16	$0.00	$1,074.16	$0.00	$0.00	$894.11	$1,045.59
32	Service Drop	522.13	522.12	-	$937.60	$0.00	$937.60	$0.00	$0.00	$0.00	$0.00
33	Meters	209.71	209.92	1,199.32	$262.55	$1,199.32	$262.55	$1,199.32	$42,924	$37.44	$45.09
34	Meter Reading	75.73	75.73	75.73	114.93	$114.93	$114.93	$114.93	$114.93	$26.74	$26.67
35	Billing & Collections	32.60	32.60	32.60	238.20	$238.20	$238.20	$238.20	$238.20	$33.07	$33.02
36	Uncollectables	180.30	180.30	180.30	1,110.75	$1,110.75	$1,110.75	$1,110.75	$1,110.75	$12.33	$9.21
37	Customer Service / Other	40.89	40.89	40.89	182.97	$182.97	$182.97	$182.97	$182.97	$14.72	$14.32
38	Total Commitment & Billing	$2,209.01	$2,211.48	$1,606.13	$3,944.05	$2,869.07	$3,921.17	$2,846.18	$44,570	$1,430.75	$1,694.78

Sources:
Lines 1 - 3 Tab 17.4 (Cust Data 4:) 'Customer Load Factors12 Months Ended December 2010'
Lines 10 & 15 Tab 17.2 (Cust Data 2:) 'Customers and MWh's12 Months Ended December 2010 - Normalized'
Line 11 Tab 16.1 (Losses:) 'Energy Loss Factors'
Line 20 Tab 4.1 (Capacity:) 'Marginal Capacity Costs Based on Avoided Capacity Costs'
Line 21 Tab 6.1 (Transm1:) 'Marginal Transmission Investment and O&M Expenses'
Line 22 Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'
Line 26 Staff Substitute Worksheet "Energy" (Tab: Staff Energy) -- 20 Years - Long Run - Annual Cost of Energy @ 8.51%
Line 27 Tab 2.6 (Table 6:) 'Marginal Cost of Transmission Investment and Associated Expenses'
Lines 29 - 37 Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'

* Schedule 33 Cost of Service results are provided for informational purposes only.

Table 4

STAFF SUBSTITUTE WORKSHEET -- UPDATED ENERGY COSTS

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
December 2010 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg	Sch 51,53,54
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 M	> 4 MW	> 4 M	Trans	Sch 41	Sch 33*	Streetlighting
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)	(sec)
	Demand Related Marginal Cost																				
1	Generation	$148,195	$64,189	$6,127	$5,403	$14	$5,172	$9,071	$11,393	$223	$2,509	$13,014	$1,098	$7,270	$4,554	$546	$12,128	$3,590	$1,894	$1,635	
2	Transmission	$150,207	$65,060	$6,210	$5,477	$14	$5,242	$9,194	$11,547	$226	$2,544	$13,191	$1,113	$7,369	$4,616	$553	$12,293	$3,638	$1,920	$1,657	
3	Distribution																				
4	Poles	$42,784	$26,664	$1,960	$1,760	$4	$1,139	$1,882	$2,404	$48	$563	$2,955	$249	$1,132	$718	$0	$0	$0	$1,305	$1,331	
5	Conductor	$71,273	$43,588	$3,166	$2,843	$7	$2,007	$3,317	$4,239	$83	$982	$5,152	$434	$2,174	$1,380	$0	$0	$0	$1,901	$1,929	
6	Substations	$53,241	$27,798	$1,893	$1,700	$4	$1,702	$2,813	$3,595	$70	$792	$4,158	$351	$2,322	$1,473	$162	$3,814	$0	$595	$513	
7	Subtotal: Pole, Cond, Subs	$167,297	$98,050	$7,019	$6,304	$15	$4,848	$8,011	$10,238	$201	$2,338	$12,265	$1,034	$5,628	$3,571	$162	$3,814	$0	$3,800	$3,773	
8	Transformers	$5,872	$3,388	$525	$211	$0	$207	$288	$380	$0	$78	$384	$0	$287	$0	$20	$0	$0	$105	$90	
9	Distribution subtotal	$173,169	$101,438	$7,544	$6,515	$15	$5,054	$8,300	$10,617	$201	$2,415	$12,649	$1,034	$5,915	$3,571	$182	$3,814	$0	$3,905	$3,863	
10																					
11	Total Demand Related	$471,571	$230,687	$19,881	$17,395	$43	$15,468	$26,565	$33,557	$650	$7,468	$38,854	$3,245	$20,554	$12,741	$1,281	$28,235	$7,228	$7,719	$7,155	
12	(Lines 1+2+9)																				
13																					
14	Energy Related Marginal Cost																				
15	Generation Energy Related	$499,296	$215,326	$23,075	$17,043	$44	$17,112	$26,637	$36,538	$700	$8,169	$42,721	$3,604	$23,559	$15,911	$2,153	$45,085	$15,190	$5,419	$4,676	$1,009
16	Transmission Energy Related	$52,647	$22,705	$2,433	$1,797	$5	$1,804	$2,809	$3,853	$74	$861	$4,505	$380	$2,484	$1,678	$227	$4,754	$1,602	$571	$493	$106
17	Total Energy	$551,943	$238,031	$25,509	$18,841	$49	$18,916	$29,445	$40,391	$774	$9,031	$47,226	$3,984	$26,043	$17,589	$2,380	$49,839	$16,791	$5,990	$5,169	$1,116
18																					
19	Customer Related Marginal Cost																				
20	Poles	$62,289	$45,737	$7,081	$1,027	$4	$211	$165	$95	$3	$12	$31	$3	$1	$1	$0	$0	$0	$1,799	$767	$6,119
21	Conductor	$22,545	$18,319	$2,835	$411	$1	$84	$67	$38	$1	$5	$12	$1	$1	$0	$0	$0	$0	$720	$307	$48
22	Transformers	$68,752	$35,505	$14,304	$4,654	$0	$3,094	$2,834	$1,796	$0	$246	$614	$0	$131	$0	$3	$0	$0	$5,461	$2,156	$111
23	Service Drops	$45,280	$33,890	$5,895	$2,045	$0	$1,019	$835	$1,063	$0	$120	$299	$0	$113	$0	$1	$0	$0	$0	$0	
24	Meters	$10,523	$7,438	$1,188	$357	$41	$165	$164	$423	$60	$48	$120	$62	$32	$67	$1	$41	$86	$229	$93	$2
25	Meter Reading	$8,321	$6,698	$1,122	$163	$1	$75	$59	$34	$1	$17	$43	$4	$14	$6	$0	$4	$0	$76	$20	$2
26	Billing & Collections	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$32
27	Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
28	Customer Service / Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
29	Total Commitment & Billing Rel.	$248,994	$174,017	$35,358	$9,082	$48	$4,976	$4,380	$3,597	$69	$508	$1,265	$84	$477	$161	$8	$97	$89	$8,454	$3,387	$6,326
30																					
31	Total Revenue @ Full MC																				
32	Generation	$647,491	$279,515	$29,202	$22,446	$58	$22,284	$35,708	$47,931	$923	$10,678	$55,735	$4,702	$30,829	$20,465	$2,699	$57,213	$18,780	$7,313	$6,311	$1,009
33	Transmission	$202,854	$87,765	$8,643	$7,274	$19	$7,046	$12,003	$15,400	$300	$3,405	$17,696	$1,493	$9,853	$6,294	$780	$17,047	$5,240	$2,491	$2,150	$106
34	Distribution	$372,038	$234,889	$37,660	$14,652	$21	$9,462	$12,200	$13,609	$205	$2,799	$13,605	$1,038	$6,161	$3,573	$186	$3,814	$0	$11,884	$7,094	$6,279
35	Customer - Billing	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$32
36	Customer - Metering	$18,842	$14,136	$2,311	$520	$41	$241	$223	$457	$61	$66	$163	$66	$46	$74	$1	$45	$86	$304	$113	$2
37	Customer - Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
38	Revenue (less Uncollectables)	$1,266,769	$637,879	$80,571	$45,291	$140	$39,247	$60,302	$77,494	$1,491	$16,965	$87,241	$7,302	$46,940	$30,429	$3,666	$78,133	$24,106	$22,128	$15,704	$7,441
39																					
40	Customer - Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
41	Total Revenue	$1,272,508	$642,735	$80,748	$45,317	$140	$39,361	$60,390	$77,545	$1,492	$17,007	$87,345	$7,312	$47,075	$30,491	$3,669	$78,171	$24,108	$22,163	$15,711	$7,441

Source: Tab 2.3 (Table 3:) '20 Year Costing Inputs and Customer Data Marginal Unit Costs'
Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'

Line 1 Generation (Table 3, Row 5) x (Table 3, Row 20)/1000
Line 2 Transmission (Table 3, Row 5) x (Table 3, Row 21)/1000
Lines 4-6 Poles, Cond., Subst. (Table 3, Row 6) x (Table 7, Row 1 - 3) x (1 + .3605) (Dist OM, Row 32)
Line 8 Transformers (Table 3, Row 7) x (Table 7, Row 7) x (1 + .3605) (Dist OM, Row 32)
Lines 15-16 Energy Related (Table 3, Row 12) x (Table 3, Row 26 - 27)
Lines 20-29 Commitment Related (Table 3, Row 15) x (Table 7, Row 13 - 27) including O&M Adders

Streetlighting's departure from PPL's marginal energy cost attribution of $1,552 = ($543) Or -$1,552 + $1,009
Location of both energy cost figures: Cell S15 on Tab: 2.4 of original and staff substitute for Exhibit PPL/907 (Table 4)

* Schedule 33 Cost of Service results are provided for informational purposes only.

STAFF SUBSTITUTE WORKSHEET --UPDATED ENERGY COSTS
PACIFICORP STATE OF OREGON
Combined GRC and TAM
December 31, 2010 Unbundled Revenue Requirement Allocation by Rate Schedule

Line	Description	Total	(A) Residential	(B) General Service Sch 23	(C) General Service Sch 23	(D) General Service Sch 28	(E) General Service Sch 28	(F) General Service Sch 30	(G) General Service Sch 30	(H) Large Power Service Sch 48T	(I) Large Power Service Sch 48T	(J) Large Power Service Sch 48T	(K) Irrigation Sch 41	(L) Street Lgt. Sch 51, 53, 54
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	**Total Operating Revenues**	$915,181	$471,595	$90,790	$99	$124,369	$1,123	$73,370	$5,318	$35,927	$77,376	$17,402	$14,323	$3,489
2	**MWH**	12,680,407	5,435,846	1,012,789	1,152	2,026,816	18,249	$1,284,715	93,931	649,091	1,589,921	404,889	136,792	$26,217
3														
4	**Functionalized 20 Year Full Marginal Costs - Class $**													
5	Generation	$647,491	$279,515	$51,649	$58	$105,923	$923	$66,413	$4,702	$33,528	$77,678	$18,780	$7,313	$1,010
6	Transmission	$202,854	$87,765	$15,917	$19	$34,449	$300	$21,101	$1,493	$10,633	$23,341	$5,240	$2,491	$106
7	Distribution	$372,038	$234,889	$52,312	$21	$35,272	$205	$16,404	$1,038	$6,347	$7,387	$0	$11,884	$6,279
8	Customer - Billing	$18,233	$15,441	$2,257	$1	$328	$2	$26	$2	$29	$21	$0	$94	$32
9	Customer - Metering	$18,842	$14,136	$2,830	$41	$921	$61	$229	$66	$46	$118	$86	$304	$2
10	Customer - Other	$7,310	$6,133	$897	$0	$151	$1	$33	$2	$23	$16	$0	$42	$12
11	Total	$1,266,769	$637,879	$125,862	$140	$177,043	$1,491	$104,207	$7,302	$50,607	$108,562	$24,106	$22,128	$7,442
12														
13	**Functional Revenue Requirement Allocation Factors**													
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**													
15	Generation	100.00%	43.17%	7.98%	0.01%	16.36%	0.14%	10.26%	0.73%	5.18%	12.00%	2.90%	1.13%	0.16%
16	Transmission	100.00%	43.26%	7.85%	0.01%	16.98%	0.15%	10.40%	0.74%	5.24%	11.51%	2.58%	1.23%	0.05%
17	Distribution	100.00%	63.14%	14.06%	0.01%	9.48%	0.06%	4.41%	0.28%	1.71%	1.99%	0.00%	3.19%	1.69%
18	Ancillary Service	100.00%	43.17%	7.98%	0.01%	16.36%	0.14%	10.26%	0.73%	5.18%	12.00%	2.90%	1.13%	0.16%
19	Customer - Billing	100.00%	84.69%	12.38%	0.01%	1.80%	0.01%	0.14%	0.01%	0.16%	0.12%	0.00%	0.51%	0.18%
20	Customer - Metering	100.00%	75.02%	15.02%	0.22%	4.89%	0.32%	1.22%	0.35%	0.25%	0.63%	0.46%	1.62%	0.01%
21	Customer - Other	100.00%	83.90%	12.27%	0.01%	2.06%	0.01%	0.45%	0.03%	0.31%	0.23%	0.01%	0.57%	0.17%
22	Embedded DSM - (mWh)	100.00%	42.87%	7.99%	0.01%	15.98%	0.14%	10.13%	0.74%	5.12%	12.54%	3.19%	1.08%	0.21%
23	Regulatory & Franchise	100.00%	51.53%	9.92%	0.01%	13.59%	0.12%	8.02%	0.58%	3.93%	8.45%	1.90%	1.57%	0.38%
24	Taxes (Revenue)													
25														
26	**Functionalized Class Revenue Requirement - (Target)**													
27	Generation	$612,171	$264,268	$48,831	$55	$100,145	$873	$62,791	$4,445	$31,699	$73,441	$17,755	$6,914	$955
28	Transmission	$75,967	$32,867	$5,961	$7	$12,901	$112	$7,902	$559	$3,982	$8,741	$1,962	$933	$40
29	Distribution	$246,801	$155,820	$34,703	$14	$23,398	$136	$10,882	$688	$4,211	$4,900	$0	$7,884	$4,165
30	Ancillary Services	$10,758	$4,644	$858	$1	$1,760	$15	$1,103	$78	$557	$1,291	$312	$122	$17
31	Customer - Billing	$11,737	$9,940	$1,453	$1	$211	$1	$17	$1	$19	$14	$0	$60	$21
32	Customer - Metering	$28,029	$21,029	$4,210	$62	$1,370	$90	$341	$99	$69	$176	$128	$453	$3
33	Customer - Other	$13,088	$10,980	$1,605	$1	$270	$1	$59	$4	$40	$29	$1	$75	$22
34	Embedded DSM - (mWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Regulatory & Franchise T	$23,859	$12,295	$2,367	$3	$3,242	$29	$1,913	$139	$937	$2,017	$454	$373	$91
36	Total	$1,022,411	$511,843	$99,988	$142	$143,297	$1,258	$85,007	$6,013	$41,514	$90,609	$20,612	$16,813	$5,313
37														
38	**Ratio of Operating Revn to Revenue**	89.51%	92.14%	90.80%	69.74%	86.79%	89.27%	86.31%	88.45%	86.54%	85.40%	84.43%	85.19%	65.66%
39	(Line 1 / Line 36)													
40														
41	**Increase or (Decrease)**	$107,229	$40,248	$9,198	$43	$18,928	$135	$11,637	$695	$5,587	$13,233	$3,210	$2,490	$1,825
42	(Line 36 - Line 1)													
43														
44														
45	**Percent Increase (Decrease)**	11.72%	8.53%	10.13%	43.40%	15.22%	12.02%	15.86%	13.06%	15.55%	17.10%	18.45%	17.38%	52.30%
46	(Line 41 / Line 1)													

Generation Marginal Cost Source (Line 5): A straight transfer of Line 32 from Worksheet Table 4
Exception: Streetlighting is the original PPL figure adjusted by the change in those schedules' marginal energy costs shown in the Table 4 footnote.

CASE: UE 210
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1104

Generation-Related Worksheets With Staff-Augmented Capacity Costs

July 24, 2009

Table 3

STAFF SUBSTITUTE WORKSHEET -- FULL GENERATION CAPACITY COSTS

PacifiCorp
Oregon Marginal Cost Study
20 Year Costing Inputs and Customer Data
Marginal Unit Costs
December 2010 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrigation Sch 41	Irrigation Sch 33*
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans		
Line	Description		(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Billing Units																			
	Demand																			
1	Load Factors	System	78.75%	88.41%	74.04%	75.50%	77.67%	68.93%	75.29%	73.67%	76.42%	77.06%	77.01%	76.07%	82.02%	92.58%	87.26%	99.33%	67.15%	67.15%
2		Feeder	57.08%	89.84%	73.88%	75.48%	74.08%	69.79%	74.90%	73.48%	76.00%	75.71%	75.73%	74.77%	79.59%	98.15%	87.10%	N/A	67.15%	67.15%
3		Transformer	30.26%	27.16%	49.98%	N/A	51.09%	57.17%	59.46%	N/A	64.58%	68.79%	N/A	50.73%	N/A	67.13%	N/A	N/A	32.07%	32.07%
4																				
5	Peak Mw @ Generator	System	862	82	73	0.2	69	122	153	3.0	34	175	15	98	61	7.3	163	48	25	22
6		System Capacity Requirement	1047	100	88	0.2	84	148	186	3.6	41	212	18	119	74	8.9	198	59	31	27
7		Feeder	1,189	81	73	0.2	73	120	154	3.0	34	178	15	99	63	6.9	163	N/A	25	22
8		Transformer	2,244	268	107	N/A	106	147	194	N/A	40	196	N/A	146	N/A	10.1	N/A	N/A	53	46
9	Energy																			
10	Energy - Annual Mwh	@ Meter	5,435,846	582,532	430,256	1,152	431,990	672,435	922,391	18,249	206,234	1,078,480	93,931	594,746	414,743	54,345	1,175,179	404,889	136,792	118,046
11	Energy Loss Factor		1.0940	1.0940	1.0940	1.0595	1.0940	1.0940	1.0940	1.0595	1.0940	1.0940	1.0595	1.0940	1.0595	1.0940	1.0595	1.0361	1.0940	1.0940
12	Energy - Annual Mwh	@ Generator	5,946,598	637,267	470,683	1,220	472,580	735,617	1,009,059	19,335	225,612	1,179,814	99,519	650,629	439,416	59,451	1,245,090	419,485	149,645	129,138
13																				
14	Customer																			
15	Annual Customers		478,485	64,649	9,372	34	4,491	3,525	2,034	50	230	572	52	121	56	2	34	2	6,108	2,062
16	Average Customers																		2,834	756
17																				
18	Unit Costs																			
19																				
20	Generation	$ / System Peak Kw	$83.40	$83.40	$83.40	$83.40	$83.40	$83.40	$83.40	$83.40	$83.40	$83.40	$83.40	$83.40	$83.40	$83.40	$83.40	$83.40	$83.40	$83.40
21	Transmission	$ / System Peak Kw	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47
22	Poles, Cond., Subst.	$ / Feeder Kw	$82.45	$86.68	$86.68	$86.68	$66.57	$66.57	$66.57	$66.57	$68.95	$68.95	$68.95	$56.67	$56.67	$23.37	$23.37	$0.00	$149.33	$171.83
23	Transformers	$ / Xfmr Kw	$1.51	$1.96	$1.96	$0.00	$1.96	$1.96	$1.96	$0.00	$1.96	$1.96	$0.00	$1.96	$0.00	$1.96	$0.00	$0.00	$1.96	$1.96
24																				
25	Energy - @ Generator																			
26	Generation	$ / Kwh	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570
27	Transmission	$ / Kwh	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382
28																				
29	Poles	$ / Cust / Year	$95.59	$109.53	$109.53	$109.53	$46.87	$46.87	$46.87	$46.87	$55.18	$55.18	$55.18	$16.34	$16.34	$0.00	$0.00	$0.00	$294.43	$371.91
30	Conductor	$ / Cust / Year	$38.28	$43.86	$43.86	$43.86	$18.77	$18.77	$18.77	$18.77	$22.11	$22.11	$22.11	$6.54	$6.54	$0.00	$0.00	$0.00	$117.93	$148.96
31	Transformers	$ / Cust / Year	$74.20	$221.25	$496.66	$0.00	$688.85	$804.03	$883.01	$0.00	$1,070.36	$1,072.63	$0.00	$1,074.16	$0.00	$1,074.16	$0.00	$0.00	$894.11	$1,045.59
32	Service Drop	$ / Cust / Year	$70.83	$91.18	$218.20	$0.00	226.92	237.05	522.35	-	522.13	522.12	-	$937.60	$0.00	$937.60	$0.00	$0.00	$0.00	$0.00
33	Meters	$ / Cust / Year	$15.54	$18.38	$38.08	$1,199.32	36.81	46.53	207.91	1,199.32	209.71	209.92	1,199.32	$262.55	$1,199.32	$262.55	$1,199.32	$42,924	$37.44	$45.09
34	Meter Reading	$ / Cust / Year	$14.00	$17.36	$17.36	$17.36	16.80	16.80	16.80	16.80	75.73	75.73	75.73	114.93	$114.93	$114.93	$114.93	$114.93	$26.74	$26.67
35	Billing & Collections	$ / Cust / Year	$32.27	$30.49	$30.49	$30.49	32.60	32.60	32.60	32.60	32.60	32.60	32.60	238.20	$238.20	$238.20	$238.20	$238.20	$33.07	$33.02
36	Uncollectables	$ / Cust / Year	$10.15	$2.73	$2.73	$2.73	25.17	25.17	25.17	25.17	180.30	180.30	180.30	1,110.75	$1,110.75	$1,110.75	$1,110.75	$1,110.75	$12.33	$9.21
37	Customer Service / Other	$ / Cust / Year	$12.82	$12.11	$12.11	$12.11	15.01	15.01	15.01	15.01	40.89	40.89	40.89	182.97	$182.97	$182.97	$182.97	$182.97	$14.72	$14.32
38	Total Commitment & Billing	$ / Cust / Year	$363.68	$546.91	$969.04	$1,415.41	$1,107.81	$1,242.83	$1,768.49	$1,354.54	$2,209.01	$2,211.48	$1,606.13	$3,944.05	$2,869.07	$3,921.17	$2,846.18	$44,570	$1,430.75	$1,694.78

Source:
Line 20: $74.46 x 1.12 = $83.40

Calculations:
Line 5: (Line 12 / 8760)/(Line 1)
Line 6: (Line 5) * {(2417.2)/(Sum of Line 5)}

Source of 2417.2:
Oregon Load at System Peak = 2417.2 MWs   Source: Page 11.5 of Exhibit PPL/702.

* Schedule 33 Cost of Service results are provided for informational purposes only.

Table 4

STAFF SUBSTITUTE WORKSHEET -- FULL GENERATION CAPACITY COSTS

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
December 2010 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg	Sch 51,53,54
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 M	> 4 MW	> 4 M	Trans	Sch 41	Sch 33*	Streetlighting
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)	(sec)
	Demand Related Marginal Cost																				
1	Generation	$201,595	$87,318	$8,334	$7,350	$19	$7,035	$12,340	$15,498	$303	$3,414	$17,704	$1,494	$9,890	$6,195	$742	$16,499	$4,883	$2,577	$2,224	
2	Transmission	$150,207	$65,060	$6,210	$5,477	$14	$5,242	$9,194	$11,547	$226	$2,544	$13,191	$1,113	$7,369	$4,616	$553	$12,293	$3,638	$1,920	$1,657	
3	Distribution																				
4	Poles	$42,784	$26,664	$1,960	$1,760	$4	$1,139	$1,882	$2,404	$48	$563	$2,955	$249	$1,132	$718	$0	$0	$0	$1,305	$1,331	
5	Conductor	$71,273	$43,588	$3,166	$2,843	$7	$2,007	$3,317	$4,239	$83	$982	$5,152	$434	$2,174	$1,380	$0	$0	$0	$1,901	$1,929	
6	Substations	$53,241	$27,798	$1,893	$1,700	$4	$1,702	$2,813	$3,595	$70	$792	$4,158	$351	$2,322	$1,473	$162	$3,814	$0	$595	$513	
7	Subtotal: Pole, Cond, Subs	$167,297	$98,050	$7,019	$6,304	$15	$4,848	$8,011	$10,238	$201	$2,338	$12,265	$1,034	$5,628	$3,571	$162	$3,814	$0	$3,800	$3,773	
8	Transformers	$5,872	$3,388	$525	$211	$0	$207	$288	$380	$0	$78	$384	$0	$287	$0	$20	$0	$0	$105	$90	
9	Distribution subtotal	$173,169	$101,438	$7,544	$6,515	$15	$5,054	$8,300	$10,617	$201	$2,415	$12,649	$1,034	$5,915	$3,571	$182	$3,814	$0	$3,905	$3,863	
10																					
11	Total Demand Related	$524,971	$253,816	$22,088	$19,342	$48	$17,331	$29,834	$37,662	$730	$8,373	$43,544	$3,641	$23,174	$14,382	$1,477	$32,606	$8,521	$8,402	$7,744	
12	(Lines 1+2+9)																				
13																					
14	Energy Related Marginal Cost																				
15	Generation Energy Related	$768,041	$331,225	$35,496	$26,217	$68	$26,323	$40,974	$56,205	$1,077	$12,567	$65,716	$5,543	$36,240	$24,475	$3,311	$69,352	$23,365	$8,335	$7,193	$1,552
16	Transmission Energy Related	$52,647	$22,705	$2,433	$1,797	$5	$1,804	$2,809	$3,853	$74	$861	$4,505	$380	$2,484	$1,678	$227	$4,754	$1,602	$571	$493	$106
17	Total Energy	$820,689	$353,930	$37,929	$28,014	$73	$28,127	$43,783	$60,057	$1,151	$13,428	$70,220	$5,923	$38,724	$26,153	$3,538	$74,105	$24,967	$8,907	$7,686	$1,659
18																					
19	Customer Related Marginal Cost																				
20	Poles	$62,289	$45,737	$7,081	$1,027	$4	$211	$165	$95	$3	$12	$31	$3	$1	$1	$0	$0	$0	$1,799	$767	$6,119
21	Conductor	$22,545	$18,319	$2,835	$411	$1	$84	$67	$38	$1	$5	$12	$1	$1	$0	$0	$0	$0	$720	$307	$48
22	Transformers	$68,752	$35,505	$14,304	$4,654	$0	$3,094	$2,834	$1,796	$0	$246	$614	$0	$131	$0	$3	$0	$0	$5,461	$2,156	$111
23	Service Drops	$45,280	$33,890	$5,895	$2,045	$0	$1,019	$835	$1,063	$0	$120	$299	$0	$113	$0	$1	$0	$0	$0	$0	
24	Meters	$10,523	$7,438	$1,188	$357	$41	$165	$164	$423	$60	$48	$120	$62	$32	$67	$1	$41	$86	$229	$93	$2
25	Meter Reading	$8,321	$6,698	$1,122	$163	$1	$75	$59	$34	$1	$17	$43	$4	$14	$6	$0	$4	$0	$76	$20	$2
26	Billing & Collections	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$32
27	Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
28	Customer Service / Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
29	Total Commitment & Billing Rel.	$248,994	$174,017	$35,358	$9,082	$48	$4,976	$4,380	$3,597	$69	$508	$1,265	$84	$477	$161	$8	$97	$89	$8,454	$3,387	$6,326
30																					
31	Total Revenue @ Full MC																				
32	Generation	$969,636	$418,543	$43,830	$33,567	$87	$33,358	$53,314	$71,703	$1,380	$15,981	$83,420	$7,037	$46,130	$30,670	$4,053	$85,851	$28,248	$10,912	$9,417	$1,552
33	Transmission	$202,854	$87,765	$8,643	$7,274	$19	$7,046	$12,003	$15,400	$300	$3,405	$17,696	$1,493	$9,853	$6,294	$780	$17,047	$5,240	$2,491	$2,150	$106
34	Distribution	$372,038	$234,889	$37,660	$14,652	$21	$9,462	$12,200	$13,609	$205	$2,799	$13,605	$1,038	$6,161	$3,573	$186	$3,814	$0	$11,884	$7,094	$6,279
35	Customer - Billing	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$32
36	Customer - Metering	$18,842	$14,136	$2,311	$520	$41	$241	$223	$457	$61	$66	$163	$66	$46	$74	$1	$45	$86	$304	$113	$2
37	Customer - Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
38	Revenue (less Uncollectables)	$1,588,914	$776,908	$95,198	$56,412	$169	$50,321	$77,908	$101,265	$1,948	$22,267	$114,926	$9,638	$62,241	$40,634	$5,021	$106,771	$33,575	$25,728	$18,810	$7,984
39																					
40	Customer - Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
41	Total Revenue	$1,594,654	$781,763	$95,375	$56,437	$169	$50,434	$77,996	$101,317	$1,949	$22,309	$115,029	$9,647	$62,376	$40,696	$5,023	$106,808	$33,577	$25,762	$18,817	$7,984

Source:
Line 1 **Generation (Table 3, Row 6) x (Table 3, Row 20)/1000**

* Schedule 33 Cost of Service results are provided for informational purposes only.

STAFF SUBSTITUTE WORKSHEET -- FULL GENERATION CAPACITY COSTS

PACIFICORP STATE OF OREGON

Combined GRC and TAM

December 31, 2010 Unbundled Revenue Requirement Allocation by Rate Schedule

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			Residential	General Service		General Service		General Service		Large Power Service			Irrigation	Street Lgt.
		Total		Sch 23		Sch 28		Sch 30		Sch 48T			Sch 41	Sch 51, 53, 54
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	Total Operating Revenues	$915,181	$471,595	$90,790	$99	$124,369	$1,123	$73,370	$5,318	$35,927	$77,376	$17,402	$14,323	$3,489
2	MWH	12,680,407	5,435,846	1,012,789	1,152	2,026,816	18,249	$1,284,715	93,931	649,091	1,589,921	404,889	136,792	$26,217
3														
4	Functionalized 20 Year Full Marginal Costs - Class $													
5	Generation	$969,626	$418,538	$77,397	$87	$158,372	$1,380	$99,399	$7,037	$50,182	$116,520	$28,248	$10,912	$1,552
6	Transmission	$202,854	$87,765	$15,917	$19	$34,449	$300	$21,101	$1,493	$10,633	$23,341	$5,240	$2,491	$106
7	Distribution	$372,038	$234,889	$52,312	$21	$35,272	$205	$16,404	$1,038	$6,347	$7,387	$0	$11,884	$6,279
8	Customer - Billing	$18,233	$15,441	$2,257	$1	$328	$2	$26	$2	$29	$21	$0	$94	$32
9	Customer - Metering	$18,842	$14,136	$2,830	$41	$921	$61	$229	$66	$46	$118	$86	$304	$2
10	Customer - Other	$7,310	$6,133	$897	$0	$151	$1	$33	$2	$23	$16	$0	$42	$12
11	Total	$1,588,904	$776,903	$151,610	$169	$229,492	$1,948	$137,192	$9,638	$67,261	$147,404	$33,575	$25,728	$7,984
12														
13	Functional Revenue Requirement Allocation Factors													
14	Functionalized 20 Year Full Marginal Costs - Class % of Total													
15	Generation	100.00%	43.16%	7.98%	0.01%	16.33%	0.14%	10.25%	0.73%	5.18%	12.02%	2.91%	1.13%	0.16%
16	Transmission	100.00%	43.26%	7.85%	0.01%	16.98%	0.15%	10.40%	0.74%	5.24%	11.51%	2.58%	1.23%	0.05%
17	Distribution	100.00%	63.14%	14.06%	0.01%	9.48%	0.06%	4.41%	0.28%	1.71%	1.99%	0.00%	3.19%	1.69%
18	Ancillary Service	100.00%	43.16%	7.98%	0.01%	16.33%	0.14%	10.25%	0.73%	5.18%	12.02%	2.91%	1.13%	0.16%
19	Customer - Billing	100.00%	84.69%	12.38%	0.01%	1.80%	0.01%	0.14%	0.01%	0.16%	0.12%	0.00%	0.51%	0.18%
20	Customer - Metering	100.00%	75.02%	15.02%	0.22%	4.89%	0.32%	1.22%	0.35%	0.25%	0.63%	0.46%	1.62%	0.01%
21	Customer - Other	100.00%	83.90%	12.27%	0.01%	2.06%	0.01%	0.45%	0.03%	0.31%	0.23%	0.01%	0.57%	0.17%
22	Embedded DSM - (mWh)	100.00%	42.87%	7.99%	0.01%	15.98%	0.14%	10.13%	0.74%	5.12%	12.54%	3.19%	1.08%	0.21%
23	Regulatory & Franchise	100.00%	51.53%	9.92%	0.01%	13.59%	0.12%	8.02%	0.58%	3.93%	8.45%	1.90%	1.57%	0.38%
24	Taxes (Revenue)													
25														
26	Functionalized Class Revenue Requirement - (Target)													
27	Generation	$612,171	$264,243	$48,864	$55	$99,988	$871	$62,755	$4,443	$31,683	$73,565	$17,835	$6,889	$980
28	Transmission	$75,967	$32,867	$5,961	$7	$12,901	$112	$7,902	$559	$3,982	$8,741	$1,962	$933	$40
29	Distribution	$246,801	$155,820	$34,703	$14	$23,398	$136	$10,882	$688	$4,211	$4,900	$0	$7,884	$4,165
30	Ancillary Services	$10,758	$4,644	$859	$1	$1,757	$15	$1,103	$78	$557	$1,293	$313	$121	$17
31	Customer - Billing	$11,737	$9,940	$1,453	$1	$211	$1	$17	$1	$19	$14	$0	$60	$21
32	Customer - Metering	$28,029	$21,029	$4,210	$62	$1,370	$90	$341	$99	$69	$176	$128	$453	$3
33	Customer - Other	$13,088	$10,980	$1,605	$1	$270	$1	$59	$4	$40	$29	$1	$75	$22
34	Embedded DSM - (mWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Regulatory & Franchise T	$23,859	$12,295	$2,367	$3	$3,242	$29	$1,913	$139	$937	$2,017	$454	$373	$91
36	Total	$1,022,411	$511,817	$100,022	$142	$143,138	$1,257	$84,972	$6,011	$41,497	$90,735	$20,693	$16,788	$5,339
37														
38	Ratio of Operating Revn to Revenue	89.51%	92.14%	90.77%	69.79%	86.89%	89.38%	86.35%	88.48%	86.58%	85.28%	84.10%	85.32%	65.34%
39	(Line 1 / Line 36)													
40														
41	Increase or (Decrease)	$107,229	$40,223	$9,232	$43	$18,769	$133	$11,602	$692	$5,570	$13,359	$3,291	$2,465	$1,851
42	(Line 36 - Line 1)													
43														
44														
45	Percent Increase (Decrease)	11.72%	8.53%	10.17%	43.29%	15.09%	11.88%	15.81%	13.02%	15.50%	17.27%	18.91%	17.21%	53.04%
46	(Line 41 / Line 1)													

Generation Marginal Cost Source: A straight transfer of Line 32 from Worksheet Table 4

CASE: UE 210
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1105

Generation-Related Worksheets With Staff-Revised Energy and Capacity Costs

July 24, 2009

Table 3

STAFF SUBSTITUTE WORKSHEET -- Modified Energy & Capacity Costs

PacifiCorp
Oregon Marginal Cost Study
20 Year Costing Inputs and Customer Data
Marginal Unit Costs
December 2010 Dollars

Line	Description		(A) Residential (sec)	(B) General Service - Schedule 23 0-15 kW (sec)	(C) General Service - Schedule 23 15+ kW (sec)	(D) General Service - Schedule 23 Primary (pri)	(E) General Service - Schedule 28 0-50 kW (sec)	(F) General Service - Schedule 28 51-100 kW (sec)	(G) General Service - Schedule 28 > 101kW (sec)	(H) General Service - Schedule 28 Primary (pri)
	Billing Units									
	Demand									
1	Load Factors	System	78.75%	88.41%	74.04%	75.50%	77.67%	68.93%	75.29%	73.67%
2		Feeder	57.08%	89.84%	73.88%	75.48%	74.08%	69.79%	74.90%	73.48%
3		Transformer	30.26%	27.16%	49.98%	N/A	51.09%	57.17%	59.46%	N/A
4										
5	Peak Mw @ Generator	System	862	82	73	0	69	122	153	3
6		System Capacity Requirement	1173	112	99	0	94	166	208	4
7		Feeder	1,189	81	73	0	73	120	154	3
8		Transformer	2,244	268	107	N/A	106	147	194	N/A
9	Energy									
10	Energy - Annual Mwh	@ Meter	5,435,846	582,532	430,256	1,152	431,990	672,435	922,391	18,249
11	Energy Loss Factor		1.0940	1.0940	1.0940	1.0595	1.0940	1.0940	1.0940	1.0595
12	Energy - Annual Mwh	@ Generator	5,946,598	637,267	470,683	1,220	472,580	735,617	1,009,059	19,335
13										
14	Customer									
15	Annual Customers		478,485	64,649	9,372	34	4,491	3,525	2,034	50
16	Average Customers									
17										
18	Unit Costs									
19										
20	Generation	$ / System Peak Kw	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46
21	Transmission	$ / System Peak Kw	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47
22	Poles, Cond., Subst.	$ / Feeder Kw	$82.45	$86.68	$86.68	$86.68	$66.57	$66.57	$66.57	$66.57
23	Transformers	$ / Xfmr Kw	$1.51	$1.96	$1.96	$0.00	$1.96	$1.96	$1.96	$0.00
24										
25	Energy - @ Generator									
26	Generation	$ / Kwh	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621
27	Transmission	$ / Kwh	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382
28										
29	Poles	$ / Cust / Year	$95.59	$109.53	$109.53	$109.53	$46.87	$46.87	$46.87	$46.87
30	Conductor	$ / Cust / Year	$38.28	$43.86	$43.86	$43.86	$18.77	$18.77	$18.77	$18.77
31	Transformers	$ / Cust / Year	$74.20	$221.25	$496.66	$0.00	$688.85	$804.03	$883.01	$0.00
32	Service Drop	$ / Cust / Year	$70.83	$91.18	$218.20	$0.00	226.92	237.05	522.35	-
33	Meters	$ / Cust / Year	$15.54	$18.38	$38.08	$1,199.32	36.81	46.53	207.91	1,199.32
34	Meter Reading	$ / Cust / Year	$14.00	$17.36	$17.36	$17.36	16.80	16.80	16.80	16.80
35	Billing & Collections	$ / Cust / Year	$32.27	$30.49	$30.49	$30.49	32.60	32.60	32.60	32.60
36	Uncollectables	$ / Cust / Year	$10.15	$2.73	$2.73	$2.73	25.17	25.17	25.17	25.17
37	Customer Service / Other	$ / Cust / Year	$12.82	$12.11	$12.11	$12.11	15.01	15.01	15.01	15.01
38	Total Commitment & Billing	$ / Cust / Year	$363.68	$546.91	$969.04	$1,415.41	$1,107.81	$1,242.83	$1,768.49	$1,354.54

Line	Description		(I) General Service - Schedule 30 0-300 kW (sec)	(J) General Service - Schedule 30 301+ kW (sec)	(K) General Service - Schedule 30 Primary (pri)	(L) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(M) Large Power Service - Schedule 48T 1 - 4 MW (pri)	(N) Large Power Service - Schedule 48T > 4 MW (sec)	(O) Large Power Service - Schedule 48T > 4 MW (pri)	(P) Large Power Service - Schedule 48T Trans (trn)	(Q) Irrigation Sch 41 (sec)	(R) Irrigation Sch 33* (sec)
	Billing Units											
	Demand											
1	Load Factors	System	76.42%	77.06%	77.01%	76.07%	82.02%	92.58%	87.26%	99.33%	67.15%	67.15%
2		Feeder	76.00%	75.71%	75.73%	74.77%	79.59%	98.15%	87.10%	N/A	67.15%	67.15%
3		Transformer	64.58%	68.79%	N/A	50.73%	N/A	67.13%	N/A	N/A	32.07%	32.07%
4												
5	Peak Mw @ Generator	System	34	175	15	98	61	7	163	48	25	22
6		System Capacity Requirement	46	238	20	133	83	10	222	66	35	30
7		Feeder	34	178	15	99	63	7	163	N/A	25	22
8		Transformer	40	196	N/A	146	N/A	10	N/A	N/A	53	46
9	Energy											
10	Energy - Annual Mwh	@ Meter	206,234	1,078,480	93,931	594,746	414,743	54,345	1,175,179	404,889	136,792	118,046
11	Energy Loss Factor		1.0940	1.0940	1.0595	1.0940	1.0595	1.0940	1.0595	1.0361	1.0940	1.0940
12	Energy - Annual Mwh	@ Generator	225,612	1,179,814	99,519	650,629	439,416	59,451	1,245,090	419,485	149,645	129,138
13												
14	Customer											
15	Annual Customers		230	572	52	121	56	2	34	2	6,108	2,062
16	Average Customers										2,834	756
17												
18	Unit Costs											
19												
20	Generation	$ / System Peak Kw	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46
21	Transmission	$ / System Peak Kw	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47
22	Poles, Cond., Subst.	$ / Feeder Kw	$68.95	$68.95	$68.95	$56.67	$56.67	$23.37	$23.37	$0.00	$149.33	$171.83
23	Transformers	$ / Xfmr Kw	$1.96	$1.96	$0.00	$1.96	$0.00	$1.96	$0.00	$0.00	$1.96	$1.96
24												
25	Energy - @ Generator											
26	Generation	$ / Kwh	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621	$0.03621
27	Transmission	$ / Kwh	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382
28												
29	Poles	$ / Cust / Year	$55.18	$55.18	$55.18	$16.34	$16.34	$0.00	$0.00	$0.00	$294.43	$371.91
30	Conductor	$ / Cust / Year	$22.11	$22.11	$22.11	$6.54	$6.54	$0.00	$0.00	$0.00	$117.93	$148.96
31	Transformers	$ / Cust / Year	$1,070.36	$1,072.63	$0.00	$1,074.16	$0.00	$1,074.16	$0.00	$0.00	$894.11	$1,045.59
32	Service Drop	$ / Cust / Year	522.13	522.12	-	$937.60	$0.00	$937.60	$0.00	$0.00	$0.00	$0.00
33	Meters	$ / Cust / Year	209.71	209.92	1,199.32	$262.55	$1,199.32	$262.55	$1,199.32	$42,924	$37.44	$45.09
34	Meter Reading	$ / Cust / Year	75.73	75.73	75.73	114.93	$114.93	$114.93	$114.93	$114.93	$26.74	$26.67
35	Billing & Collections	$ / Cust / Year	32.60	32.60	32.60	238.20	$238.20	$238.20	$238.20	$238.20	$33.07	$33.02
36	Uncollectables	$ / Cust / Year	180.30	180.30	180.30	1,110.75	$1,110.75	$1,110.75	$1,110.75	$1,110.75	$12.33	$9.21
37	Customer Service / Other	$ / Cust / Year	40.89	40.89	40.89	182.97	$182.97	$182.97	$182.97	$182.97	$14.72	$14.32
38	Total Commitment & Billing	$ / Cust / Year	$2,209.01	$2,211.48	$1,606.13	$3,944.05	$2,869.07	$3,921.17	$2,846.18	$44,570	$1,430.75	$1,694.78

Sources:
Lines 1 - 3 Tab 17.4 (Cust Data 4:) 'Customer Load Factors12 Months Ended December 2010'
Lines 10 & 15 Tab 17.2 (Cust Data 2:) 'Customers and MWh's12 Months Ended December 2010 - Normalized'
Line 11 Tab 16.1 (Losses:) 'Energy Loss Factors'
Line 20 Tab 4.1 (Capacity:) 'Marginal Capacity Costs Based on Avoided Capacity Costs'
Line 21 Tab 6.1 (Transm1:) 'Marginal Transmission Investment and O&M Expenses'
Line 22 Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'
Line 26 Staff Substitute Worksheet "Energy" from Staff/1103, Compton/1
Line 27 Tab 2.6 (Table 6:) 'Marginal Cost of Transmission Investment and Associated Expenses'
Lines 29 - 37 Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'

Calculations:
Line 5: (Line 12 / 8760)/(Line 1)
Line 6: (Line 5) * {(2707.3)/(Sum of Line 5)}

Source of 2707.3:

Oregon Load at System Peak =	2417.2 MWs	Source: Page 11.5 of Exhibit PPL/702.
Reserve Margin =	12%	Source: PacifiCorp's recent IRPs.
Oregon Capacity requirement at System Peak =	2707.3 MWs	= 2417.2 * 1.12

* Schedule 33 Cost of Service results are provided for informational purposes only.

Table 4

STAFF SUBSTITUTE WORKSHEET -- Modified Energy & Capacity Costs

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
December 2010 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg	Sch 51,53,54
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 M	> 4 MW	> 4 M	Trans	Sch 41	Sch 33*	Streetlighting
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)	(sec)
	Demand Related Marginal Cost																				
1	Generation	$201,585	$87,313	$8,334	$7,350	$19	$7,035	$12,339	$15,497	$303	$3,414	$17,703	$1,494	$9,889	$6,195	$742	$16,498	$4,883	$2,577	$2,223	
2	Transmission	$150,207	$65,060	$6,210	$5,477	$14	$5,242	$9,194	$11,547	$226	$2,544	$13,191	$1,113	$7,369	$4,616	$553	$12,293	$3,638	$1,920	$1,657	
3	Distribution																				
4	Poles	$42,784	$26,664	$1,960	$1,760	$4	$1,139	$1,882	$2,404	$48	$563	$2,955	$249	$1,132	$718	$0	$0	$0	$1,305	$1,331	
5	Conductor	$71,273	$43,588	$3,166	$2,843	$7	$2,007	$3,317	$4,239	$83	$982	$5,152	$434	$2,174	$1,380	$0	$0	$0	$1,901	$1,929	
6	Substations	$53,241	$27,798	$1,893	$1,700	$4	$1,702	$2,813	$3,595	$70	$792	$4,158	$351	$2,322	$1,473	$162	$3,814	$0	$595	$513	
7	Subtotal: Pole, Cond, Subs	$167,297	$98,050	$7,019	$6,304	$15	$4,848	$8,011	$10,238	$201	$2,338	$12,265	$1,034	$5,628	$3,571	$162	$3,814	$0	$3,800	$3,773	
8	Transformers	$5,872	$3,388	$525	$211	$0	$207	$288	$380	$0	$78	$384	$0	$287	$0	$20	$0	$0	$105	$90	
9	Distribution subtotal	$173,169	$101,438	$7,544	$6,515	$15	$5,054	$8,300	$10,617	$201	$2,415	$12,649	$1,034	$5,915	$3,571	$182	$3,814	$0	$3,905	$3,863	
10																					
11	Total Demand Related	$524,961	$253,811	$22,088	$19,342	$48	$17,331	$29,833	$37,661	$730	$8,373	$43,543	$3,641	$23,173	$14,382	$1,477	$32,605	$8,521	$8,402	$7,743	
12	(Lines 1+2+9)																				
13																					
14	Energy Related Marginal Cost																				
15	Generation Energy Related	$499,296	$215,326	$23,075	$17,043	$44	$17,112	$26,637	$36,538	$700	$8,169	$42,721	$3,604	$23,559	$15,911	$2,153	$45,085	$15,190	$5,419	$4,676	$1,009
16	Transmission Energy Related	$52,647	$22,705	$2,433	$1,797	$5	$1,804	$2,809	$3,853	$74	$861	$4,505	$380	$2,484	$1,678	$227	$4,754	$1,602	$571	$493	$106
17	Total Energy	$551,943	$238,031	$25,509	$18,841	$49	$18,916	$29,445	$40,391	$774	$9,031	$47,226	$3,984	$26,043	$17,589	$2,380	$49,839	$16,791	$5,990	$5,169	$1,116
18																					
19	Customer Related Marginal Cost																				
20	Poles	$62,289	$45,737	$7,081	$1,027	$4	$211	$165	$95	$3	$12	$31	$3	$1	$1	$0	$0	$0	$1,799	$767	$6,119
21	Conductor	$22,545	$18,319	$2,835	$411	$1	$84	$67	$38	$1	$5	$12	$1	$1	$0	$0	$0	$0	$720	$307	$48
22	Transformers	$68,752	$35,505	$14,304	$4,654	$0	$3,094	$2,834	$1,796	$0	$246	$614	$0	$131	$0	$3	$0	$0	$5,461	$2,156	$111
23	Service Drops	$45,280	$33,890	$5,895	$2,045	$0	$1,019	$835	$1,063	$0	$120	$299	$0	$113	$0	$1	$0	$0	$0	$0	
24	Meters	$10,523	$7,438	$1,188	$357	$41	$165	$164	$423	$60	$48	$120	$62	$32	$67	$1	$41	$86	$229	$93	$2
25	Meter Reading	$8,321	$6,698	$1,122	$163	$1	$75	$59	$34	$1	$17	$43	$4	$14	$6	$0	$4	$0	$76	$20	$2
26	Billing & Collections	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$32
27	Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
28	Customer Service / Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
29	Total Commitment & Billing Rel.	$248,994	$174,017	$35,358	$9,082	$48	$4,976	$4,380	$3,597	$69	$508	$1,265	$84	$477	$161	$8	$97	$89	$8,454	$3,387	$6,326
30																					
31	Total Revenue @ Full MC																				
32	Generation	$700,881	$302,639	$31,409	$24,393	$63	$24,147	$38,976	$52,035	$1,003	$11,583	$60,424	$5,098	$33,448	$22,106	$2,895	$61,583	$20,073	$7,996	$6,899	$1,009
33	Transmission	$202,854	$87,765	$8,643	$7,274	$19	$7,046	$12,003	$15,400	$300	$3,405	$17,696	$1,493	$9,853	$6,294	$780	$17,047	$5,240	$2,491	$2,150	$106
34	Distribution	$372,038	$234,889	$37,660	$14,652	$21	$9,462	$12,200	$13,609	$205	$2,799	$13,605	$1,038	$6,161	$3,573	$186	$3,814	$0	$11,884	$7,094	$6,279
35	Customer - Billing	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$32
36	Customer - Metering	$18,842	$14,136	$2,311	$520	$41	$241	$223	$457	$61	$66	$163	$66	$46	$74	$1	$45	$86	$304	$113	$2
37	Customer - Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
38	Revenue (less Uncollectables)	$1,320,159	$661,003	$82,778	$47,238	$145	$41,110	$63,570	$81,598	$1,571	$17,870	$91,930	$7,698	$49,559	$32,070	$3,862	$82,503	$25,399	$22,811	$16,292	$7,441
39																					
40	Customer - Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
41	Total Revenue	$1,325,898	$665,859	$82,955	$47,264	$145	$41,224	$63,658	$81,649	$1,572	$17,912	$92,034	$7,708	$49,694	$32,132	$3,865	$82,541	$25,401	$22,846	$16,299	$7,441

Source: Tab 2.3 (Table 3:) '20 Year Costing Inputs and Customer Data Marginal Unit Costs'
Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'

Line 1 Generation (Table 3, Row 6) x (Table 3, Row 20)/1000
Line 2 Transmission (Table 3, Row 5) x (Table 3, Row 21)/1000
Lines 4-6 Poles, Cond., Subst. (Table 3, Row 6) x (Table 7, Row 1 - 3) x (1 + .3605) (Dist OM, Row 32)
Line 8 Transformers (Table 3, Row 7) x (Table 7, Row 7) x (1 + .3605) (Dist OM, Row 32)
Lines 15-16 Energy Related (Table 3, Row 12) x (Table 3, Row 26 - 27)
Lines 20-29 Commitment Related (Table 3, Row 15) x (Table 7, Row 13 - 27) including O&M Adders

Streetlighting's departure from PPL's marginal energy cost attribution of $1,552 = ($543) Or -$1,552 + $1,009
Location of both energy cost figures: Cell S15 on Tab: 2.4 of original and staff substitute for Exhibit PPL/907 (Table 4)

* Schedule 33 Cost of Service results are provided for informational purposes only.

STAFF SUBSTITUTE WORKSHEET -- Modified Energy & Capacity
PACIFICORP STATE OF OREGON
Combined GRC and TAM
December 31, 2010 Unbundled Revenue Requirement Allocation by Rate Schedule

Line	Description	Total	(A) Residential	(B) General Service	(C)	(D) General Service	(E)	(F) General Service	(G)	(H) Large Power Service	(I)	(J)	(K) Irrigation	(L) Street Lgt.
				Sch 23		Sch 28		Sch 30			Sch 48T		Sch 41	Sch 51, 53, 54
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(tm)		
1	**Total Operating Revenues**	$915,181	$471,595	$90,790	$99	$124,369	$1,123	$73,370	$5,318	$35,927	$77,376	$17,402	$14,323	$3,489
2	**MWH**	12,680,407	5,435,846	1,012,789	1,152	2,026,816	18,249	$1,284,715	93,931	649,091	1,589,921	404,889	136,792	$26,217
3														
4	**Functionalized 20 Year Full Marginal Costs - Class $**													
5	Generation	$700,881	$302,639	$55,803	$63	$115,158	$1,003	$72,007	$5,098	$36,343	$83,689	$20,073	$7,996	$1,010
6	Transmission	$202,854	$87,765	$15,917	$19	$34,449	$300	$21,101	$1,493	$10,633	$23,341	$5,240	$2,491	$106
7	Distribution	$372,038	$234,889	$52,312	$21	$35,272	$205	$16,404	$1,038	$6,347	$7,387	$0	$11,884	$6,279
8	Customer - Billing	$18,233	$15,441	$2,257	$1	$328	$2	$26	$2	$29	$21	$0	$94	$32
9	Customer - Metering	$18,842	$14,136	$2,830	$41	$921	$61	$229	$66	$46	$118	$86	$304	$2
10	Customer - Other	$7,310	$6,133	$897	$0	$151	$1	$33	$2	$23	$16	$0	$42	$12
11	Total	$1,320,159	$661,003	$130,016	$145	$186,278	$1,571	$109,801	$7,698	$53,422	$114,573	$25,399	$22,811	$7,442
12														
13	**Functional Revenue Requirement Allocation Factors**													
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**													
15	Generation	100.00%	43.18%	7.96%	0.01%	16.43%	0.14%	10.27%	0.73%	5.19%	11.94%	2.86%	1.14%	0.14%
16	Transmission	100.00%	43.26%	7.85%	0.01%	16.98%	0.15%	10.40%	0.74%	5.24%	11.51%	2.58%	1.23%	0.05%
17	Distribution	100.00%	63.14%	14.06%	0.01%	9.48%	0.06%	4.41%	0.28%	1.71%	1.99%	0.00%	3.19%	1.69%
18	Ancillary Service	100.00%	43.18%	7.96%	0.01%	16.43%	0.14%	10.27%	0.73%	5.19%	11.94%	2.86%	1.14%	0.14%
19	Customer - Billing	100.00%	84.69%	12.38%	0.01%	1.80%	0.01%	0.14%	0.01%	0.16%	0.12%	0.00%	0.51%	0.18%
20	Customer - Metering	100.00%	75.02%	15.02%	0.22%	4.89%	0.32%	1.22%	0.35%	0.25%	0.63%	0.46%	1.62%	0.01%
21	Customer - Other	100.00%	83.90%	12.27%	0.01%	2.06%	0.01%	0.45%	0.03%	0.31%	0.23%	0.01%	0.57%	0.17%
22	Embedded DSM - (mWh)	100.00%	42.87%	7.99%	0.01%	15.98%	0.14%	10.13%	0.74%	5.12%	12.54%	3.19%	1.08%	0.21%
23	Regulatory & Franchise	100.00%	51.53%	9.92%	0.01%	13.59%	0.12%	8.02%	0.58%	3.93%	8.45%	1.90%	1.57%	0.38%
24	Taxes (Revenue)													
25														
26	**Functionalized Class Revenue Requirement - (Target)**													
27	Generation	$612,171	$264,334	$48,740	$55	$100,582	$876	$62,894	$4,452	$31,743	$73,096	$17,532	$6,984	$882
28	Transmission	$75,967	$32,867	$5,961	$7	$12,901	$112	$7,902	$559	$3,982	$8,741	$1,962	$933	$40
29	Distribution	$246,801	$155,820	$34,703	$14	$23,398	$136	$10,882	$688	$4,211	$4,900	$0	$7,884	$4,165
30	Ancillary Services	$10,758	$4,645	$857	$1	$1,768	$15	$1,105	$78	$558	$1,285	$308	$123	$15
31	Customer - Billing	$11,737	$9,940	$1,453	$1	$211	$1	$17	$1	$19	$14	$0	$60	$21
32	Customer - Metering	$28,029	$21,028	$4,210	$62	$1,370	$90	$341	$99	$69	$176	$128	$453	$3
33	Customer - Other	$13,088	$10,980	$1,605	$1	$270	$1	$59	$4	$40	$29	$1	$75	$22
34	Embedded DSM - (mWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Regulatory & Franchise T	$23,859	$12,295	$2,367	$3	$3,242	$29	$1,913	$139	$937	$2,017	$454	$373	$91
36	Total	$1,022,411	$511,910	$99,895	$142	$143,743	$1,262	$85,112	$6,020	$41,559	$90,259	$20,385	$16,884	$5,240
37														
38	**Ratio of Operating Revn to Revenue**	89.51%	92.12%	90.89%	69.65%	86.52%	89.03%	86.20%	88.34%	86.45%	85.73%	85.37%	84.83%	66.58%
39	(Line 1 / Line 36)													
40														
41	**Increase or (Decrease)**	$107,229	$40,315	$9,105	$43	$19,374	$138	$11,742	$702	$5,632	$12,883	$2,983	$2,561	$1,751
42	(Line 36 - Line 1)													
43														
44														
45	**Percent Increase (Decrease)**	11.72%	8.55%	10.03%	43.58%	15.58%	12.33%	16.00%	13.20%	15.68%	16.65%	17.14%	17.88%	50.19%
46	(Line 41 / Line 1)													

Generation Marginal Cost Source: A straight transfer of Line 32 from Worksheet Table 4
Exception: Streetlighting is the original PPL figure adjusted by the change in those schedules' marginal energy costs shown in the Table 4 footnote.

CASE: UE 210
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1106

Distribution-Related Worksheets
With Staff-Revised Feeder Model

July 24, 2009

PC 3

STAFF SUBSTITUTE WORKSHEET
PacifiCorp

Oregon
Feeder Model Inputs

		(A)	(B)	(C)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
					Customer Location on the Hypothetical Feeder*						
Line	Customer Class	Annual mwh's	Number of Customers	Feeder Load Factor	1	2	3	4	5	6 Trunk	7 Trunk
1	Residential	5,546,125	488,139	57.08%	1.30%	1.30%	1.30%	4.01%	4.01%	4.01%	84.08%
2	GS 0-15 kW (sec) (23)	660,613	65,352	89.84%	1.62%	1.62%	1.62%	3.98%	3.98%	3.98%	83.19%
3	GS >15 kW (sec) (23)	487,926	9,474	73.88%	1.62%	1.62%	1.62%	3.98%	3.98%	3.98%	83.19%
4	GS (pri) (23)	1,278	34	75.48%	1.62%	1.62%	1.62%	3.98%	3.98%	3.98%	83.19%
5	GS < 50 kW (sec) (28)	441,213	4,459	74.08%	0.51%	0.51%	0.51%	2.54%	2.54%	2.54%	90.85%
6	GS 51-100 kW (sec) (28)	686,792	3,500	69.79%	0.51%	0.51%	0.51%	2.54%	2.54%	2.54%	90.85%
7	GS > 100 kW (sec) (28)	942,085	2,020	74.90%	0.51%	0.51%	0.51%	2.54%	2.54%	2.54%	90.85%
8	GS (pri) (28)	18,798	50	73.48%	0.51%	0.51%	0.51%	2.54%	2.54%	2.54%	90.85%
9	GS 0-300 kW (sec) (30)	210,232	240	76.00%	0.75%	0.75%	0.75%	2.30%	2.30%	2.30%	90.85%
10	GS >300 kW (sec) (30)	1,099,384	597	75.71%	0.75%	0.75%	0.75%	2.30%	2.30%	2.30%	90.85%
11	GS (pri) (30)	96,013	55	75.73%	0.75%	0.75%	0.75%	2.30%	2.30%	2.30%	90.85%
12	Irrigation	130,845	6,131	67.15%	3.81%	3.81%	3.81%	13.14%	13.14%	13.14%	49.13%
13	USBR / UKRB	104,533	2,070	67.15%	5.97%	5.97%	5.97%	11.40%	11.40%	11.40%	47.88%
14	Large GS 1 - 4 MW (sec)	649,403	123	74.77%	0.00%	0.00%	0.00%	1.68%	1.68%	1.68%	94.95%
15	Large GS 1 - 4 MW (pri)	459,309	57	79.59%	0.00%	0.00%	0.00%	1.68%	1.68%	1.68%	94.95%
16	Large GS + 4 MW (sec)	59,339	2	98.15%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
17	Large GS + 4 MW (pri)	1,301,457	34	87.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18	Total -	12,895,345	582,336								
19	Customers per mile		30.69								
20											
21	Line Statistics		Per State								
22	Pole miles		14,146								
23	Trench miles		4,831								
24	Total miles		18,977								
25											
26	Total feeders		604								
27	Total Poles		371,574								

Feeder Load Factor Source: Exhibit PPL/909 Paice/1

PACIFICORP
2010 DISTRIBUTION PEAK LOADS AT SALES
STATE OF OREGON

Month : / Peak Date : / Peak Time MST :	Jan-10 28 09:00	Feb-10 9 08:00	Mar-10 10 08:00	Apr-10 6 07:00	May-10 5 08:00	Jun-10 9 08:00	Jul-10 13 18:00	Aug-10 5 18:00	Sep-10 2 18:00	Oct-10 29 08:00	Nov-10 29 08:00	Dec-10 16 08:00	12-Month Average
Residential													
Sch 004 sec	1,542,653	1,411,878	1,209,361	1,374,572	1,081,866	828,105	862,131	717,828	704,709	933,873	1,107,283	1,286,842	1,088,425
GNSV Sch 023													
0 -15 kw Sec	73,969	120,458	62,727	61,804	65,225	63,107	74,023	67,180	69,570	71,688	73,209	88,741	74,308
GT 15 kw Sec	84,347	72,677	71,741	67,127	59,335	52,511	69,426	65,020	67,131	59,535	63,797	66,660	66,609
Pri	216	200	184	173	155	139	181	169	175	157	168	178	175
	158,532	193,335	134,652	129,104	124,715	115,757	143,630	132,369	136,876	131,380	137,174	155,579	
GNSV Sch 028													
0 -50 kw Sec	93,869	66,862	75,207	57,202	57,758	54,875	76,623	64,333	56,696	66,508	70,958	59,478	66,697
51 -100 kw Sec	129,333	116,391	108,368	107,104	98,064	86,112	102,515	103,999	113,973	116,419	117,243	122,189	110,143
GT 100 kw Sec	158,902	140,799	131,111	129,401	116,878	103,550	154,209	148,400	153,139	148,162	155,627	150,870	140,921
- Pri	3,283	2,883	2,715	2,641	2,409	2,137	2,992	2,895	3,011	2,983	3,101	3,044	2,841
	385,387	326,935	317,401	296,348	275,109	246,674	336,339	319,627	326,819	334,072	346,929	335,581	
GNSV Sch 030													
0 -300 kw Sec	35,279	33,389	30,484	30,603	28,404	27,528	30,461	30,540	29,318	31,253	32,185	33,003	31,037
GT 300 kw Sec	172,470	170,863	156,266	159,853	160,470	165,215	172,604	168,046	155,205	146,465	164,127	165,812	163,116
Pri	15,090	14,903	13,628	13,924	13,908	14,268	14,957	14,588	13,507	12,854	14,319	14,480	14,202
	222,839	219,155	200,378	204,380	202,782	207,011	218,022	213,174	198,030	190,572	210,631	213,295	
GNSV Sch 048													
1-4 MW Sec	96,723	91,402	87,448	89,740	90,478	88,513	91,161	89,942	89,508	89,440	91,825	96,673	91,071
1-4 MW Pri	64,252	58,751	59,583	57,685	60,100	61,335	60,224	57,405	60,650	52,931	61,511	61,435	59,655
GT-4 MW Sec	2,211	2,208	3,594	5,000	6,779	9,901	13,639	13,110	13,428	2,349	2,195	2,228	6,387
GT-4 MW Pri	154,030	146,719	148,060	158,286	166,632	148,112	174,493	176,292	170,139	139,648	127,021	144,359	154,483
Trans	0	0	0	0	0	0	0	0	0	0	0	0	0
	317,216	299,080	298,685	310,711	323,989	307,861	339,517	336,749	333,725	284,368	282,552	304,695	
APSV Sch 041	555	628	581	5,285	19,266	27,837	48,489	31,480	88,432	13,170	3,114	677	19,960
Total Oregon	2,627,182	2,451,011	2,161,058	2,320,400	2,027,727	1,733,245	1,948,128	1,751,227	1,788,591	1,887,435	2,087,683	2,296,669	
Breakdown By Voltage Level													
Secondary	2,390,311	2,227,555	1,936,888	2,087,691	1,784,523	1,507,254	1,695,281	1,499,878	1,541,109	1,678,862	1,881,563	2,073,173	1,858,674
Primary	236,871	223,456	224,170	232,709	243,204	225,991	252,847	251,349	247,482	208,573	206,120	223,496	231,356
Sub Trans	0	0	0	0	0	0	0	0	0	0	0	0	0
Total KW	2,627,182	2,451,011	2,161,058	2,320,400	2,027,727	1,733,245	1,948,128	1,751,227	1,788,591	1,887,435	2,087,683	2,296,669	

Source: PacifiCorp Attachment to OPUC DR 245, 1st Supplemental

PC 4

STAFF SUBSTITUTE WORKSHEET -- DISTRIBUTION LOAD FACTOR ADDED
PacifiCorp
Oregon Feeder Model Study
Feeder Model Inputs and Assumptions

Oregon

Line	Class	(A) Annual MWH	(B) Number of Customers	(C) Average MWh per Customer (A) / (B)	(D) Hours in Study Period	(E) Average kW / customer per hour (C)/(D)x1000	(F') Distribution 1 DCP Load Factor (E)/(G')	(G') Average 1 DCP kW per Customer (I')/(B)	(I') Distribution 1 DCP Average Total kW	(F) Feeder Load Factor 12CP	(G) Average 12CP kW per Customer (E)/(F)
1	Residential	5,546,125	488,139	11.36	8,760	1.30	41.04%	3.16	1,542,653	57.08%	2.27
2	GS 0-15 kW (sec) (23)	660,613	65,352	10.11	8,760	1.15	101.95%	1.13	73,969	89.84%	1.28
3	GS >15 kW (sec) (23)	487,926	9,474	51.50	8,760	5.88	66.04%	8.90	84,347	73.88%	7.96
4	GS (pri) (23)	1,278	34	37.24	8,760	4.25	67.56%	6.29	216	75.48%	5.63
5	GS < 50 kW (sec) (28)	441,213	4,459	98.95	8,760	11.30	53.66%	21.05	93,869	74.08%	15.25
6	GS 51-100 kW (sec) (28)	686,792	3,500	196.25	8,760	22.40	60.62%	36.96	129,333	69.79%	32.10
7	GS > 100 kW (sec) (28)	942,085	2,020	466.46	8,760	53.25	67.68%	78.68	158,902	74.90%	71.09
8	GS (pri) (28)	18,798	50	372.85	8,760	42.56	65.36%	65.12	3,283	73.48%	57.92
9	GS 0-300 kW (sec) (30)	210,232	240	875.96	8,760	100.00	68.03%	147.00	35,279	76.00%	131.58
10	GS >300 kW (sec) (30)	1,099,384	597	1,842.29	8,760	210.31	72.77%	289.02	172,470	75.71%	277.76
11	GS (pri) (30)	96,013	55	1,759.02	8,760	200.80	72.63%	276.46	15,090	75.73%	265.14
12	Irrigation	130,845	6,131	21.34	8,760	2.44	2691.29%	0.09	555	67.15%	3.63
13	USBR / UKRB	104,533	2,070	50.50	8,760	5.76	2691.29%	0.21	443	67.15%	8.58
14	Large GS 1 - 4 MW (sec)	649,403	123	5,276.13	8,760	602.30	76.64%	785.83	96,723	74.77%	805.56
15	Large GS 1 - 4 MW (pri)	459,309	57	8,081.68	8,760	922.57	81.60%	1,130.53	64,252	79.59%	1,159.22
16	Large GS + 4 MW (sec)	59,339	2	29,669.60	8,760	3,386.94	306.37%	1,105.50	2,211	98.15%	3,450.70
17	Large GS + 4 MW (pri)	1,301,457	34	38,278.15	8,760	4,369.65	96.45%	4,530.29	154,030	87.10%	5,016.77
18	Total -	12,895,345	582,336								

Line	Line Statistics		Per Select_State	
19	Pole miles		14,146	
20	Trench miles		4,831	
21	Total miles		18,977	
22	Total feeders		604	
23	Total Poles		371,574	
24	Branches per Feeder		7	
25	Poles per mile	(Total Poles/Pole Miles)	26.27	Poles
26	Customers per mile	(Total Customers/Total Miles)	30.69	Customers
27	Distance per Feeder	(Total miles/Feeders)	31.42	Miles
28	Distance per Branch	(Feeder miles / Branches)	4.49	Miles

Oregon Model

12 kV feeder 12 miles long has approx. 3 miles of single phase.
which is approx. 25 percent of feeder distance.
7.85 = 25 percent of typical Oregon feeder

5 divide by outer branches
1.571 distance of single phase on outer branch
35.00% equals percentage of single phase outer branch Segments

SOURCES:

(I') Last column of Tab "Attach. OPUC 245 1st Supp. (Exhibit Staff/1106 Compton/2)
(F) PC 3 (Exhibit Staff/1106 Compton/1)
(G') Line 13 Same load factor as Line 12 is assumed.

PC 5

STAFF SUBSTITUTE WORKSHEET
PacifiCorp
Oregon Feeder Model Study
Average Customers by Hypothetical Feeder Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Feeder Branch							
		1	2	3	4	5	6	7	Total
	Average Customers								
1	Residential	10.47	10.47	10.47	32.40	32.40	32.40	679.55	808.18
2	GS 0-15 kW (sec) (23)	1.75	1.75	1.75	4.31	4.31	4.31	90.01	108.20
3	GS >15 kW (sec) (23)	0.25	0.25	0.25	0.62	0.62	0.62	13.05	15.69
4	GS (pri) (23)	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.06
5	GS < 50 kW (sec) (28)	0.04	0.04	0.04	0.19	0.19	0.19	6.71	7.38
6	GS 51-100 kW (sec) (28)	0.03	0.03	0.03	0.15	0.15	0.15	5.26	5.79
7	GS > 100 kW (sec) (28)	0.02	0.02	0.02	0.09	0.09	0.09	3.04	3.34
8	GS (pri) (28)	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08
9	GS 0-300 kW (sec) (30)	0.00	0.00	0.00	0.01	0.01	0.01	0.36	0.40
10	GS >300 kW (sec) (30)	0.01	0.01	0.01	0.02	0.02	0.02	0.90	0.99
11	GS (pri) (30)	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.09
12	Irrigation	0.39	0.39	0.39	1.33	1.33	1.33	4.99	10.15
13	USBR / UKRB	0.20	0.20	0.20	0.39	0.39	0.39	1.64	3.43
14	Large GS 1 - 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.20
15	Large GS 1 - 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
16	Large GS + 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	Large GS + 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	Total	13.17	13.17	13.17	39.53	39.53	39.53	805.99	964.07

Sources: PC 3 and PC 4
Customers multiplied by Customer Distribution on the Hypothetical Feeder Branch divided by feeders in the state.
Example: Residential 10.47 = 488,139 (PC 4) x 1.30% (PC 3) / 604 (PC 4)

	Percent of Customers	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Residential	79.53%	79.53%	79.53%	81.98%	81.98%	81.98%	84.31%	83.83%
2	GS 0-15 kW (sec) (23)	13.32%	13.32%	13.32%	10.90%	10.90%	10.90%	11.17%	11.22%
3	GS >15 kW (sec) (23)	1.93%	1.93%	1.93%	1.58%	1.58%	1.58%	1.62%	1.63%
4	GS (pri) (23)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
5	GS < 50 kW (sec) (28)	0.28%	0.28%	0.28%	0.48%	0.48%	0.48%	0.83%	0.77%
6	GS 51-100 kW (sec) (28)	0.22%	0.22%	0.22%	0.37%	0.37%	0.37%	0.65%	0.60%
7	GS > 100 kW (sec) (28)	0.13%	0.13%	0.13%	0.22%	0.22%	0.22%	0.38%	0.35%
8	GS (pri) (28)	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%
9	GS 0-300 kW (sec) (30)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.04%	0.04%
10	GS >300 kW (sec) (30)	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.11%	0.10%
11	GS (pri) (30)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
12	Irrigation	2.94%	2.94%	2.94%	3.37%	3.37%	3.37%	0.62%	1.05%
13	USBR / UKRB	1.55%	1.55%	1.55%	0.99%	0.99%	0.99%	0.20%	0.36%
14	Large GS 1 - 4 MW (sec)	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.02%	0.02%
15	Large GS 1 - 4 MW (pri)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%
16	Large GS + 4 MW (sec)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
17	Large GS + 4 MW (pri)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

	Sum of Branch Loads	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
19	1,2,3,6	13.2	13.2	13.2			39.5		79.0
20	1,2,3,4,5,6,7	13.2	13.2	13.2	39.5	39.5	39.5	806.0	964.1
21									
22	1,2,3,6	16.7%	16.7%	16.7%			50.0%		100.0%
23	1,2,3,4,5,6,7	1.4%	1.4%	1.4%	4.1%	4.1%	4.1%	83.6%	100.0%

PC 6 - 12CP

ORIGINAL PACIFICORP WORKSHEET (With Clarified Title and Source Notes)

PacifiCorp
Oregon Feeder Model Study
Feeder kW Load (12CP) by Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Feeder Branch							
		1	2	3	4	5	6	7	Total
	Feeder kW Loads								
1	Residential	23.8	23.8	23.8	73.6	73.6	73.6	1,544.1	1,836.3
2	GS 0-15 kW (sec) (23)	2.3	2.3	2.3	5.5	5.5	5.5	115.6	139.0
3	GS >15 kW (sec) (23)	2.0	2.0	2.0	5.0	5.0	5.0	103.8	124.8
4	GS (pri) (23)	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3
5	GS < 50 kW (sec) (28)	0.6	0.6	0.6	2.9	2.9	2.9	102.3	112.6
6	GS 51-100 kW (sec) (28)	0.9	0.9	0.9	4.7	4.7	4.7	169.0	186.0
7	GS > 100 kW (sec) (28)	1.2	1.2	1.2	6.0	6.0	6.0	215.9	237.7
8	GS (pri) (28)	0.0	0.0	0.0	0.1	0.1	0.1	4.4	4.8
9	GS 0-300 kW (sec) (30)	0.4	0.4	0.4	1.2	1.2	1.2	47.5	52.3
10	GS >300 kW (sec) (30)	2.1	2.1	2.1	6.3	6.3	6.3	249.3	274.4
11	GS (pri) (30)	0.2	0.2	0.2	0.6	0.6	0.6	21.8	24.0
12	Irrigation	1.4	1.4	1.4	4.8	4.8	4.8	18.1	36.8
13	USBR / UKRB	1.8	1.8	1.8	3.4	3.4	3.4	14.1	29.4
14	Large GS 1 - 4 MW (sec)	-	-	-	2.8	2.8	2.8	155.9	164.2
15	Large GS 1 - 4 MW (pri)	-	-	-	1.8	1.8	1.8	103.6	109.1
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
18	Total	36.6	36.6	36.6	118.8	118.8	118.8	2,865.5	3,331.7

Sources: PC 5 and PC 4
Example: Residential 23.8 = 10.47 (PC 5) x 2.27 (PC 4)

	Percent of Branch Load								
1	Residential	64.99%	64.99%	64.99%	61.99%	61.99%	61.99%	53.88%	55.12%
2	GS 0-15 kW (sec) (23)	6.15%	6.15%	6.15%	4.66%	4.66%	4.66%	4.03%	4.17%
3	GS >15 kW (sec) (23)	5.52%	5.52%	5.52%	4.19%	4.19%	4.19%	3.62%	3.75%
4	GS (pri) (23)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
5	GS < 50 kW (sec) (28)	1.56%	1.56%	1.56%	2.41%	2.41%	2.41%	3.57%	3.38%
6	GS 51-100 kW (sec) (28)	2.57%	2.57%	2.57%	3.98%	3.98%	3.98%	5.90%	5.58%
7	GS > 100 kW (sec) (28)	3.29%	3.29%	3.29%	5.09%	5.09%	5.09%	7.54%	7.13%
8	GS (pri) (28)	0.07%	0.07%	0.07%	0.10%	0.10%	0.10%	0.15%	0.15%
9	GS 0-300 kW (sec) (30)	1.07%	1.07%	1.07%	1.01%	1.01%	1.01%	1.66%	1.57%
10	GS >300 kW (sec) (30)	5.63%	5.63%	5.63%	5.32%	5.32%	5.32%	8.70%	8.24%
11	GS (pri) (30)	0.49%	0.49%	0.49%	0.46%	0.46%	0.46%	0.76%	0.72%
12	Irrigation	3.84%	3.84%	3.84%	4.07%	4.07%	4.07%	0.63%	1.11%
13	USBR / UKRB	4.80%	4.80%	4.80%	2.82%	2.82%	2.82%	0.49%	0.88%
14	Large GS 1 - 4 MW (sec)	-	-	-	2.32%	2.32%	2.32%	5.44%	4.93%
15	Large GS 1 - 4 MW (pri)	-	-	-	1.54%	1.54%	1.54%	3.61%	3.27%
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
18	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Sum of Branch Loads

1,2,3,6	36.6	36.6	36.6			118.8		228.6
1,2,3,4,5,6,7	36.6	36.6	36.6	118.8	118.8	118.8	2,865.5	3,331.7

1,2,3,6	16.02%	16.02%	16.02%			51.95%		100.0%
1,2,3,4,5,6,7	1.10%	1.10%	1.10%	3.56%	3.56%	3.56%	86.01%	100.0%

PC 6 - 1 DCP

STAFF SUBSTITUTE WORKSHEET -- ALTERNATIVE LOAD FACTOR
PacifiCorp
Oregon Feeder Model Study
Feeder kW Load (1 DCP) by Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Feeder Branch							
		1	2	3	4	5	6	7	Total
	Feeder kW Loads								
1	Residential	33.1	33.1	33.1	102.4	102.4	102.4	2,147.6	2,554.1
2	GS 0-15 kW (sec) (23)	2.0	2.0	2.0	4.9	4.9	4.9	101.9	122.5
3	GS >15 kW (sec) (23)	2.3	2.3	2.3	5.6	5.6	5.6	116.2	139.6
4	GS (pri) (23)	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4
5	GS < 50 kW (sec) (28)	0.8	0.8	0.8	4.0	4.0	4.0	141.2	155.4
6	GS 51-100 kW (sec) (28)	1.1	1.1	1.1	5.4	5.4	5.4	194.5	214.1
7	GS > 100 kW (sec) (28)	1.3	1.3	1.3	6.7	6.7	6.7	239.0	263.1
8	GS (pri) (28)	0.0	0.0	0.0	0.1	0.1	0.1	4.9	5.4
9	GS 0-300 kW (sec) (30)	0.4	0.4	0.4	1.3	1.3	1.3	53.1	58.4
10	GS >300 kW (sec) (30)	2.1	2.1	2.1	6.6	6.6	6.6	259.4	285.5
11	GS (pri) (30)	0.2	0.2	0.2	0.6	0.6	0.6	22.7	25.0
12	Irrigation	0.04	0.04	0.04	0.12	0.12	0.12	0.45	0.92
13	USBR / UKRB	0.04	0.04	0.04	0.08	0.08	0.08	0.35	0.73
14	Large GS 1 - 4 MW (sec)	0.0	0.0	0.0	2.7	2.7	2.7	152.1	160.1
15	Large GS 1 - 4 MW (pri)	0.0	0.0	0.0	1.8	1.8	1.8	101.0	106.4
16	Large GS + 4 MW (sec)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Large GS + 4 MW (pri)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Total	43.4	43.4	43.4	142.3	142.3	142.3	3,534.6	4,091.7

Sources: PC 5 and PC 4
Customers multiplied by feeder kW per customer.
Example: Residential 33.1 = 10.47 (PC 5) x 3.16 (PC 4) .

	Percent of Branch Load	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Residential	76.20%	76.20%	76.20%	71.98%	71.98%	71.98%	60.76%	62.42%
2	GS 0-15 kW (sec) (23)	4.57%	4.57%	4.57%	3.43%	3.43%	3.43%	2.88%	2.99%
3	GS >15 kW (sec) (23)	5.21%	5.21%	5.21%	3.91%	3.91%	3.91%	3.29%	3.41%
4	GS (pri) (23)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
5	GS < 50 kW (sec) (28)	1.81%	1.81%	1.81%	2.78%	2.78%	2.78%	3.99%	3.80%
6	GS 51-100 kW (sec) (28)	2.50%	2.50%	2.50%	3.83%	3.83%	3.83%	5.50%	5.23%
7	GS > 100 kW (sec) (28)	3.07%	3.07%	3.07%	4.71%	4.71%	4.71%	6.76%	6.43%
8	GS (pri) (28)	0.06%	0.06%	0.06%	0.10%	0.10%	0.10%	0.14%	0.13%
9	GS 0-300 kW (sec) (30)	1.01%	1.01%	1.01%	0.94%	0.94%	0.94%	1.50%	1.43%
10	GS >300 kW (sec) (30)	4.94%	4.94%	4.94%	4.62%	4.62%	4.62%	7.34%	6.98%
11	GS (pri) (30)	0.43%	0.43%	0.43%	0.40%	0.40%	0.40%	0.64%	0.61%
12	Irrigation	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.01%	0.02%
13	USBR / UKRB	0.10%	0.10%	0.10%	0.06%	0.06%	0.06%	0.01%	0.02%
14	Large GS 1 - 4 MW (sec)	0.00%	0.00%	0.00%	1.89%	1.89%	1.89%	4.30%	3.91%
15	Large GS 1 - 4 MW (pri)	0.00%	0.00%	0.00%	1.26%	1.26%	1.26%	2.86%	2.60%
16	Large GS + 4 MW (sec)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
17	Large GS + 4 MW (pri)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Sum of Branch Loads	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1,2,3,6	43.4	43.4	43.4			142.3		272.6
1,2,3,4,5,6,7	43.4	43.4	43.4	142.3	142.3	142.3	3,534.6	4,091.7

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1,2,3,6	15.93%	15.93%	15.93%			52.20%		100.0%
1,2,3,4,5,6,7	1.06%	1.06%	1.06%	3.48%	3.48%	3.48%	86.38%	100.0%

PC 7 **STAFF SUBSTITUTE WORKSHEET -- RECOGNIZE COMMITMENT COSTS FOR BRANCHES 6 AND 7**

PacifiCorp
Oregon Feeder Model Study
System-wide Pole and Conductor Costs

Adjusted Oregon Line Costs per Mile

	Wire Sizes	Account 364 Pole Cost per Mile: Pole Cost per Mile	Account 364 Pole Cost per Mile: Adjustment Factor	Account 364 Pole Cost per Mile: Adjusted Pole Cost	Account 365 Conductor Cost per Mile	Total Line Construction Cost
1	1 Phase -1/0 ACSR	$ 29,819	0.990	$ 29,521	$ 11,544	$ 41,363
2	3 Phase - 1/0 ACSR 1\0 ACSR	$ 35,873	0.990	$ 35,514	$ 23,754	$ 59,627
4	3 Phase - 447 AAC & 4\0 AAC	$ 41,961	0.990	$ 41,541	$ 39,106	$ 81,067
5	3 Phase -795 AAC & 477 AAC	$ 44,996	0.990	$ 44,546	$ 92,427	$ 137,423

State	State Specific Account 364 Pole Statistics: Poles	Pole Miles	Poles / Mile	Adjustment Factor
California	55,376	2,295	24.13	0.909
Idaho	101,768	4,392	23.17	0.873
Oregon	371,574	14,146	26.27	0.990
Utah	363,003	11,505	31.55	1.189
Washington	98,596	3,545	27.81	1.048
Wyoming	154,013	7,246	21.25	0.801
Total	1,144,330	43,129	26.53	1.000

	Costs for Branches 1,2,3,4,5			
Wire Size	1 Phase -1/0 ACSI	3 Phase - 1/0 ACSR 1\0	Total	
Poles	$ 46,375	$ 103,611	$ 149,986	
Conductors	$ 18,135	$ 69,301	$ 87,436	
Total	$ 64,510	$ 172,912	$ 237,422	
	Costs for Branch 6		**Cost for Branch 7**	
Wire Size	3 Phase - 447 AAC & 4\0 AAC		3 Phase -795 AAC & 477 AAC	
Poles	$ 186,454		$ 199,940	
Conductors	$ 175,523		$ 414,847	
Total	$ 361,976		$ 614,787	

Miles per Branch	4.49
Single Phase Miles Per Branch	1.57
Three Phase Miles Per Branch	2.92

Source: Input Tab

Commitment and Demand Costs Per Branch - *Revised*

Wire Sizes	Poles: Total Cost	Poles: Commitment	Poles: Demand	Conductor: Total Cost	Conductor: Commitment	Conductor: Demand
Branches 1,2,3,4,5						
1 Phase -1/0 ACSR	$ 46,375	$ 46,375	$ -	$ 18,135	$ 18,135	$ -
3 Phase - 1/0 ACSR 1\0 ACSR	$ 103,611	$ 86,125	$ 17,486	$ 69,301	$ 33,679	$ 35,622
Total Branches 1,2,3,4,5	$ 149,986	$ 132,501	$ 17,486	$ 87,436	$ 51,814	$ 35,622
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$ 186,454	$ 132,501	$ 53,953	$ 175,523	$ 51,814	$ 123,709
Branch 7						
3 Phase -795 AAC & 477 AAC	$ 199,940	$ 132,501	$ 67,439	$ 414,847	$ 51,814	$ 363,034
Total All Branches	$ 1,136,324	$ 927,504	$ 208,820	$ 1,027,549	$ 362,697	$ 664,852

Pole and Conductor Commitment Costs for Branches 1-7 equals miles Per Branch Multiplied by 1 Phase - 1/0 ACSR Cost
Pole and Conductor Demand Costs for 3-Phase Circuits is Total Cost minus Commitment Cost

PC 8 STAFF SUBSTITUTE WORKSHEET -- RECOGNIZE COMMITMENT COSTS FOR BRANCHES 6 AND 7

PacifiCorp

Oregon Feeder Model Study

***Revised* Calculation of Hypothetical Feeder Model Branch Cost**

Conductors Type	(A)	(B)	(C)	(D)	(E)	(F)
	Total Cost		Commitment Cost		Demand Cost	
	Poles	Conductor	Poles	Conductor	Poles	Conductor
Branch 1						
1 Phase -1/0 ACSR	$ 46,375	$ 18,135	$ 46,375	$ 18,135	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 103,611	$ 69,301	$ 86,125	$ 33,679	$ 17,486	$ 35,622
Total segment	$ 149,986	$ 87,436	$ 132,501	$ 51,814	$ 17,486	$ 35,622
Branch 2						
1 Phase -1/0 ACSR	$ 46,375	$ 18,135	$ 46,375	$ 18,135	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 103,611	$ 69,301	$ 86,125	$ 33,679	$ 17,486	$ 35,622
Total Segments	$ 149,986	$ 87,436	$ 132,501	$ 51,814	$ 17,486	$ 35,622
Branch 3						
1 Phase -1/0 ACSR	$ 46,375	$ 18,135	$ 46,375	$ 18,135	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 103,611	$ 69,301	$ 86,125	$ 33,679	$ 17,486	$ 35,622
Total Segments	$ 149,986	$ 87,436	$ 132,501	$ 51,814	$ 17,486	$ 35,622
Branch 4						
1 Phase -1/0 ACSR	$ 46,375	$ 18,135	$ 46,375	$ 18,135	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 103,611	$ 69,301	$ 86,125	$ 33,679	$ 17,486	$ 35,622
Total Segments	$ 149,986	$ 87,436	$ 132,501	$ 51,814	$ 17,486	$ 35,622
Branch 5						
1 Phase -1/0 ACSR	$ 46,375	$ 18,135	$ 46,375	$ 18,135	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 103,611	$ 69,301	$ 86,125	$ 33,679	$ 17,486	$ 35,622
Total Segments	$ 149,986	$ 87,436	$ 132,501	$ 51,814	$ 17,486	$ 35,622
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$ 186,454	$ 175,523	$ 132,501	$ 51,814	$ 53,953	$ 123,709
Total Segments	$ 186,454	$ 175,523	$ 132,501	$ 51,814	$ 53,953	$ 123,709
Branch 7						
3 Phase -795 AAC & 477 AAC	$ 199,940	$ 414,847	$ 132,501	$ 51,814	$ 67,439	$ 363,034
Total segment	$ 199,940	$ 414,847	$ 132,501	$ 51,814	$ 67,439	$ 363,034

Source: PC 7

PC 9 STAFF SUBSTITUTE WORKSHEET -- RECOGNIZE COMMITMENT COSTS FOR BRANCHES 6 AND 7; JURISDICTIONAL LOAD FACTOR

PacifiCorp
Oregon Feeder Model Study
Poles Demand, per se, Cost Allocation

Line	Poles	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Branch	1	2	3	4	5	6	7		
1	% Demand	15.93%	15.93%	15.93%	NA	NA	52.20%	NA	100.00%	$ / kW
2	Branch 6 Shared Cost	$ 8,597	$ 8,597	$ 8,597	NA	NA	$ 28,162	NA	$ 53,953	
3	% Demand	1.06%	1.06%	1.06%	3.48%	3.48%	3.48%	86.38%	100.00%	
4	Branch 7 Shared Cost	$ 716	$ 716	$ 716	$ 2,345	$ 2,345	$ 2,345	$ 58,257	$ 67,439	
5	Branch's Own Demand Cost	$ 17,486	$ 17,486	$ 17,486	$ 17,486	$ 17,486	NA	NA		Average
6	Total	$ 26,798	$ 26,798	$ 26,798	$ 19,830	$ 19,830	$ 30,507	$ 58,257	$ 208,820	$ 51.04
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 20,420	$ 20,420	$ 20,420	$ 14,274	$ 14,274	$ 21,959	$ 35,396	$ 147,162	$ 57.62
11	GS 0-15 kW (sec) (23)	$ 1,225	$ 1,225	$ 1,225	$ 680	$ 680	$ 1,046	$ 1,679	$ 7,758	$ 63.35
12	GS >15 kW (sec) (23)	$ 1,396	$ 1,396	$ 1,396	$ 775	$ 775	$ 1,193	$ 1,915	$ 8,847	$ 63.35
13	GS (pri) (23)	$ 4	$ 4	$ 4	$ 2	$ 2	$ 3	$ 5	$ 23	$ 63.35
14	GS < 50 kW (sec) (28)	$ 486	$ 486	$ 486	$ 551	$ 551	$ 848	$ 2,327	$ 5,736	$ 36.91
15	GS 51-100 kW (sec) (28)	$ 670	$ 670	$ 670	$ 759	$ 759	$ 1,168	$ 3,206	$ 7,902	$ 36.91
16	GS > 100 kW (sec) (28)	$ 823	$ 823	$ 823	$ 933	$ 933	$ 1,436	$ 3,939	$ 9,709	$ 36.91
17	GS (pri) (28)	$ 17	$ 17	$ 17	$ 19	$ 19	$ 30	$ 81	$ 201	$ 36.91
18	GS 0-300 kW (sec) (30)	$ 271	$ 271	$ 271	$ 187	$ 187	$ 288	$ 875	$ 2,349	$ 40.22
19	GS >300 kW (sec) (30)	$ 1,324	$ 1,324	$ 1,324	$ 916	$ 916	$ 1,409	$ 4,275	$ 11,486	$ 40.22
20	GS (pri) (30)	$ 116	$ 116	$ 116	$ 80	$ 80	$ 123	$ 374	$ 1,005	$ 40.22
21	Irrigation	$ 22	$ 22	$ 22	$ 17	$ 17	$ 26	$ 7	$ 132	$ 143.53
22	USBR / UKRB	$ 27	$ 27	$ 27	$ 12	$ 12	$ 18	$ 6	$ 128	$ 174.69
23	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 375	$ 375	$ 578	$ 2,506	$ 3,835	$ 23.95
24	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 249	$ 249	$ 384	$ 1,665	$ 2,547	$ 23.95
25	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 26,798	$ 26,798	$ 26,798	$ 19,830	$ 19,830	$ 30,507	$ 58,257	$ 208,820	

Sources: Line 1 & 3: PC 6 - 3CP Bottom Table
Line 2(H): PC 8 Branch 6(E)
Line 2(A-G): Line 1(A-G) * Line 2(H)
Line 4(H): PC 8 Branch 7(E)
Line 4(A-G): Line 3(A-G) * Line 4(H)
Line 5: PC 8 Branches 1(E) - 5(E)
Line 10 - 26: Line 6 Totals times respective schedule branch load percentages from PC 6 - 3CP
Column (I):
Line 6: Line 6(H) divided by Line 18(H) from PC 6 - 3CP
Line 10 - 26: Lines (10-24)(H) divided by respective Lines (1-15)(H) from PC 6 - 3CP

PC 10

STAFF SUBSTITUTE WORKSHEET -- RECOGNIZE COMMITMENT COSTS FOR BRANCHES 6 AND 7; JURISDICTIONAL LOAD FACTOR

PacifiCorp

Oregon Feeder Model Study

Conductor Demand, per se, Cost Allocation

Line	Conductors	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Branch	1	2	3	4	5	6	7		
1	% Demand	15.93%	15.93%	15.93%	NA	NA	52.20%	NA	100.00%	$ / kW
2	Branch 6 Shared Cost	$ 19,712	$ 19,712	$ 19,712	NA	NA	$ 64,574	NA	$ 123,709	
3	% Demand	1.06%	1.06%	1.06%	3.48%	3.48%	3.48%	86.38%	100.00%	
4	Branch 7 Shared Cost	$ 3,853	$ 3,853	$ 3,853	$ 12,623	$ 12,623	$ 12,623	$ 313,605	$ 363,034	average
5	Branch's Own Demand Cost	$ 35,622	$ 35,622	$ 35,622	$ 35,622	$ 35,622	$ -	$ -		
6	Total	$ 59,187	$ 59,187	$ 59,187	$ 48,245	$ 48,245	$ 77,197	$ 313,605	$ 664,852	$ 162.49
7										
8									Total Demand Cost	Total Per kW
9	Class Cost per Branch(4)	1	2	3	4	5	6	7		
10	Residential	$ 45,099	$ 45,099	$ 45,099	$ 34,727	$ 34,727	$ 55,567	$ 190,541	$ 450,859	$ 176.53
11	GS 0-15 kW (sec) (23)	$ 2,704	$ 2,704	$ 2,704	$ 1,654	$ 1,654	$ 2,646	$ 9,039	$ 23,107	$ 188.68
12	GS >15 kW (sec) (23)	$ 3,084	$ 3,084	$ 3,084	$ 1,886	$ 1,886	$ 3,018	$ 10,308	$ 26,349	$ 188.68
13	GS (pri) (23)	$ 8	$ 8	$ 8	$ 5	$ 5	$ 8	$ 26	$ 67	$ 188.68
14	GS < 50 kW (sec) (28)	$ 1,073	$ 1,073	$ 1,073	$ 1,341	$ 1,341	$ 2,146	$ 12,527	$ 20,575	$ 132.39
15	GS 51-100 kW (sec) (28)	$ 1,479	$ 1,479	$ 1,479	$ 1,848	$ 1,848	$ 2,956	$ 17,259	$ 28,348	$ 132.39
16	GS > 100 kW (sec) (28)	$ 1,817	$ 1,817	$ 1,817	$ 2,270	$ 2,270	$ 3,632	$ 21,205	$ 34,829	$ 132.39
17	GS (pri) (28)	$ 38	$ 38	$ 38	$ 47	$ 47	$ 75	$ 438	$ 720	$ 132.39
18	GS 0-300 kW (sec) (30)	$ 598	$ 598	$ 598	$ 456	$ 456	$ 729	$ 4,708	$ 8,142	$ 139.40
19	GS >300 kW (sec) (30)	$ 2,923	$ 2,923	$ 2,923	$ 2,228	$ 2,228	$ 3,564	$ 23,016	$ 39,805	$ 139.40
20	GS (pri) (30)	$ 256	$ 256	$ 256	$ 195	$ 195	$ 312	$ 2,014	$ 3,483	$ 139.40
21	Irrigation	$ 48	$ 48	$ 48	$ 41	$ 41	$ 66	$ 40	$ 331	$ 359.99
22	USBR / UKRB	$ 60	$ 60	$ 60	$ 28	$ 28	$ 45	$ 31	$ 313	$ 425.87
23	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 913	$ 913	$ 1,461	$ 13,491	$ 16,779	$ 104.78
24	Large.GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 607	$ 607	$ 971	$ 8,962	$ 11,146	$ 104.78
25	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 59,187	$ 59,187	$ 59,187	$ 48,245	$ 48,245	$ 77,197	$ 313,605	$ 664,852	

Sources: Line 1 & 3: PC 6 - 3CP Bottom Table
Line 2(H): PC 8 Branch 6(F)
Line 2(A-G): Line 1(A-G) * Line 2(H)
Line 4(H): PC 8 Branch 7(F)
Line 4(A-G): Line 3(A-G) * Line 4(H)
Line 5: PC 8 Branches 1(F) - 5(F)
Line 10 - 26: Line 6 Totals times respective schedule branch load percentages from PC 6 - 3CP
Column (I):
Line 6: Line 6(H) divided by Line 18(H) from PC 6 - 3CP
Line 10 - 26: Lines (10-24)(H) divided by respective Lines (1-15)(H) from PC 6 - 3CP

PC 11

STAFF SUBSTITUTE WORKSHEET -- RECOGNIZE COMMITMENT COSTS FOR BRANCHES 6 AND 7; FEEDER LOAD FACTOR
PacifiCorp
Oregon Feeder Model Study
***Revised* Poles Commitment Cost Allocations**

	Poles	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		average
5	All Branchs' Commitment Cost	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 132,501		
6	Total	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 927,504	$ 278.39
7										
8									Total Commitment Cost	**$ Per <u>kW</u>**
9										
10	Class Cost per Branch(2)	1	2	3	4	5	6	7	$ 576,141	$ 313.75
11	Residential	$ 86,108	$ 86,108	$ 86,108	$ 82,140	$ 82,140	$ 82,140	$ 71,396	$ 48,320	$ 347.69
12	GS 0-15 kW (sec) (23)	$ 8,150	$ 8,150	$ 8,150	$ 6,174	$ 6,174	$ 6,174	$ 5,346	$ 43,396	$ 347.69
13	GS >15 kW (sec) (23)	$ 7,320	$ 7,320	$ 7,320	$ 5,545	$ 5,545	$ 5,545	$ 4,801	$ 111	$ 347.69
14	GS (pri) (23)	$ 19	$ 19	$ 19	$ 14	$ 14	$ 14	$ 12	$ 20,508	$ 182.20
15	GS < 50 kW (sec) (28)	$ 2,065	$ 2,065	$ 2,065	$ 3,195	$ 3,195	$ 3,195	$ 4,728	$ 33,888	$ 182.20
16	GS 51-100 kW (sec) (28)	$ 3,412	$ 3,412	$ 3,412	$ 5,280	$ 5,280	$ 5,280	$ 7,813	$ 43,309	$ 182.20
17	GS > 100 kW (sec) (28)	$ 4,360	$ 4,360	$ 4,360	$ 6,748	$ 6,748	$ 6,748	$ 9,985	$ 881	$ 182.20
18	GS (pri) (28)	$ 89	$ 89	$ 89	$ 137	$ 137	$ 137	$ 203	$ 10,486	$ 200.56
19	GS 0-300 kW (sec) (30)	$ 1,421	$ 1,421	$ 1,421	$ 1,342	$ 1,342	$ 1,342	$ 2,196	$ 55,038	$ 200.56
20	GS >300 kW (sec) (30)	$ 7,461	$ 7,461	$ 7,461	$ 7,043	$ 7,043	$ 7,043	$ 11,528	$ 4,805	$ 200.56
21	GS (pri) (30)	$ 651	$ 651	$ 651	$ 615	$ 615	$ 615	$ 1,007	$ 32,286	$ 876.69
22	Irrigation	$ 5,084	$ 5,084	$ 5,084	$ 5,399	$ 5,399	$ 5,399	$ 837	$ 30,957	$ 1,052.21
23	USBR / UKRB	$ 6,361	$ 6,361	$ 6,361	$ 3,741	$ 3,741	$ 3,741	$ 651	$ 16,448	$ 100.20
24	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 3,080	$ 3,080	$ 3,080	$ 7,208	$ 10,929	$ 100.20
25	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 2,047	$ 2,047	$ 2,047	$ 4,789	$ -	$ -
26	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
28	Check Total	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 132,501	$ 927,504	

Sources: Line 5: PC 8 (C)
Line 10 - 26: Line 6 Totals times respective schedule branch load percentages from PC 6 - 12CP
Column (I):
Line 6: 6(H) divided by 18(H) from PC 6 - 12CP
Line 10 - 26: Lines (10-24)(H) divided by respective Lines (1-15)(H) from PC 6 - 12CP

PC 12

STAFF SUBSTITUTE WORKSHEET -- RECOGNIZE COMMITMENT COSTS FOR BRANCHES 6 AND 7; FEEDER LOAD FACTOR

PacifiCorp
Oregon Feeder Model Study
***Revised* Conductor Commitment Cost Allocations**

Line	Conductors	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		average
5	Branch Commitment Cost	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ 51,814		$ 108.86
6	Total	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ 362,697	
7										
8									Total Commitment Cost	**$ Per** **kW**
9										
10	Class Cost per Branch(2)	1	2	3	4	5	6	7		
11	Residential	$ 33,672	$ 33,672	$ 33,672	$ 32,120	$ 32,120	$ 32,120	$ 27,919	$ 225,298	$ 122.69
12	GS 0-15 kW (sec) (23)	$ 3,187	$ 3,187	$ 3,187	$ 2,414	$ 2,414	$ 2,414	$ 2,091	$ 18,895	$ 135.96
13	GS >15 kW (sec) (23)	$ 2,862	$ 2,862	$ 2,862	$ 2,168	$ 2,168	$ 2,168	$ 1,877	$ 16,970	$ 135.96
14	GS (pri) (23)	$ 7	$ 7	$ 7	$ 6	$ 6	$ 6	$ 5	$ 44	$ 135.96
15	GS < 50 kW (sec) (28)	$ 807	$ 807	$ 807	$ 1,250	$ 1,250	$ 1,250	$ 1,849	$ 8,020	$ 71.25
16	GS 51-100 kW (sec) (28)	$ 1,334	$ 1,334	$ 1,334	$ 2,065	$ 2,065	$ 2,065	$ 3,055	$ 13,252	$ 71.25
17	GS > 100 kW (sec) (28)	$ 1,705	$ 1,705	$ 1,705	$ 2,639	$ 2,639	$ 2,639	$ 3,905	$ 16,936	$ 71.25
18	GS (pri) (28)	$ 35	$ 35	$ 35	$ 54	$ 54	$ 54	$ 79	$ 344	$ 71.25
19	GS 0-300 kW (sec) (30)	$ 556	$ 556	$ 556	$ 525	$ 525	$ 525	$ 859	$ 4,100	$ 78.43
20	GS >300 kW (sec) (30)	$ 2,917	$ 2,917	$ 2,917	$ 2,754	$ 2,754	$ 2,754	$ 4,508	$ 21,522	$ 78.43
21	GS (pri) (30)	$ 255	$ 255	$ 255	$ 240	$ 240	$ 240	$ 394	$ 1,879	$ 78.43
22	Irrigation	$ 1,988	$ 1,988	$ 1,988	$ 2,111	$ 2,111	$ 2,111	$ 327	$ 12,625	$ 342.83
23	USBR / UKRB	$ 2,487	$ 2,487	$ 2,487	$ 1,463	$ 1,463	$ 1,463	$ 255	$ 12,106	$ 411.46
24	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 1,205	$ 1,205	$ 1,205	$ 2,818	$ 6,432	$ 39.18
25	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 800	$ 800	$ 800	$ 1,873	$ 4,274	$ 39.18
26	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Check Total	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ 51,814	$ 362,697	

Sources: Line 5: PC 8 (C)
Line 10 - 26: Line 6 Totals times respective schedule branch load percentages from PC 6 - 12CP
Column (I):
Line 6: 6(H) divided by 29(H) from Tab 8.6
Line 10 - 26: Lines (10-24)(H) divided by respective Lines (1-15)(H) from PC 6 - 12CP

PC 2 STAFF SUBSTITUTE WORKSHEET -- ALTERNATIVE DEMANDLOAD FACTOR; COMMITMENT COSTS IN BRANCHES 6 AND 7

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors
Poles and Conductor -- ***Revised***
Three Phase Costs as Demand

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Demand		Commitment		2010 Demand		2010 Commitment	
Line	Poles Cost/kW	Conductor Cost/kW	Poles Cost/kW	Conductor Cost/kW	Poles Cost/kW	Conductor Cost/kW	Poles Cost/kW	Conductor Cost/kW
					(D) x 0.9867	(C) x 1.0106	(B) x 0.9867	(A) x 1.0106
1	Res - Schedule 4							
2	$ 57.62	$ 176.53	$313.75	$122.69	$56.85	$178.40	$309.57	$123.99
3								
4	GS - Schedule 23							
5	$ 63.35	$ 188.68	$347.69	$135.96	$62.51	$190.68	$343.06	$137.40
6	$ 63.35	$ 188.68	$347.69	$135.96	$62.51	$190.68	$343.06	$137.40
7	$ 63.35	$ 188.68	$347.69	$135.96	$62.51	$190.68	$343.06	$137.40
8								
9	GS - Schedule 28							
10	$ 36.91	$ 132.39	$182.20	$71.25	$36.41	$133.79	$179.77	$72.00
11	$ 36.91	$ 132.39	$182.20	$71.25	$36.41	$133.79	$179.77	$72.00
12	$ 36.91	$ 132.39	$182.20	$71.25	$36.41	$133.79	$179.77	$72.00
13	$ 36.91	$ 132.39	$182.20	$71.25	$36.41	$133.79	$179.77	$72.00
13	$ 36.91	$ 132.39	$182.20	$71.25	$36.41	$133.79	$179.77	$72.00
14								
15	GS - Schedule 30							
16	$ 40.22	$ 139.40	$200.56	$78.43	$39.69	$140.88	$197.89	$79.26
17	$ 40.22	$ 139.40	$200.56	$78.43	$39.69	$140.88	$197.89	$79.26
18	$ 40.22	$ 139.40	$200.56	$78.43	$39.69	$140.88	$197.89	$79.26
19								
20	LPS - Schedule 48T							
21	$ 23.95	$ 104.78	$100.20	$39.18	$23.63	$105.89	$98.86	$39.60
22	$ 23.95	$ 104.78	$100.20	$39.18	$23.63	$105.89	$98.86	$39.60
23	$ -	$ -	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
24	$ -	$ -	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
25								
26	Irrigation - Schedule 41							
27	$ 143.53	$ 359.99	$876.69	$342.83	$141.62	$363.80	$865.03	$346.46
28								
29	Irrigation - Schedule 33*							
30	$ 174.69	$ 425.87	$1,052.21	$411.46	$172.37	$430.39	$1,038.21	$415.82

Pacific Region			
	Index		Escalation Factor
	2008	2010	2008 - 2010
Poles	527.2	520.2	0.9867
Conductors	686.9	694.2	1.0106

Sources:
Column (A): PC 9 (I)
Column (B): PC 10 (I)
Column (C): PC 11 (I)
Column (D): PC 12 (I)

Footnotes:
Escalation Factors: Cost Trends of Electric Utility Construction, Table A14
Pole and conductor costs from Distribution Feeder Model.

* Schedule 33 Cost of Service results are provided for informational purposes only.

PC 1 STAFF SUBSTITUTE WORKSHEET -- ALTERNATIVE LOAD FACTOR; COMMITMENT COSTS IN BRANCHES 6 AND 7

PacifiCorp
Oregon Marginal Cost Study
Hypothetical Feeder Study Results
Annual Demand and Commitment Costs -- ***Revised***
December 2010 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			Demand				Commitment			
			Investment $/kW		Annual $/kW		Investment $/kW		Annual $/kW	
Line	Load Class		Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor
					(A) x 10.79%	(B) x 10.79%			(E) x 10.79%	(F) x 10.79%
1	Res - Schedule 4	(sec)	$56.85	$178.40	$6.13	$19.25	$309.57	$123.99	$33.40	$13.38
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	$62.51	$190.68	$6.74	$20.57	$343.06	$137.40	$37.02	$14.83
5	15+ kW	(sec)	$62.51	$190.68	$6.74	$20.57	$343.06	$137.40	$37.02	$14.83
6	Primary	(pri)	$62.51	$190.68	$6.74	$20.57	$343.06	$137.40	$37.02	$14.83
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	$36.41	$133.79	$3.93	$14.44	$179.77	$72.00	$19.40	$7.77
10	51-100 kW	(sec)	$36.41	$133.79	$3.93	$14.44	$179.77	$72.00	$19.40	$7.77
11	> 101kW	(sec)	$36.41	$133.79	$3.93	$14.44	$179.77	$72.00	$19.40	$7.77
12	Primary	(pri)	$36.41	$133.79	$3.93	$14.44	$179.77	$72.00	$19.40	$7.77
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	$39.69	$140.88	$4.28	$15.20	$197.89	$79.26	$21.35	$8.55
16	301+ kW	(sec)	$39.69	$140.88	$4.28	$15.20	$197.89	$79.26	$21.35	$8.55
17	Primary	(pri)	$39.69	$140.88	$4.28	$15.20	$197.89	$79.26	$21.35	$8.55
18										
19	LPS - Schedule 48T									
20	1 - 4 MW	(sec)	$23.63	$105.89	$2.55	$11.43	$98.86	$39.60	$10.67	$4.27
21	1 - 4 MW	(pri)	$23.63	$105.89	$2.55	$11.43	$98.86	$39.60	$10.67	$4.27
22	> 4 MW	(sec)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
23	> 4 MW	(pri)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
24										
25	Irrigation - Schedule 41	(sec)	$141.62	$363.80	$15.28	$39.25	$865.03	$346.46	$93.34	$37.38
26	Irrigation - Schedule 33*	(sec)	$172.37	$430.39	$18.60	$46.44	$1,038.21	$415.82	$112.02	$44.87
27										
28	The $/kW are in terms of "Feeder" kW's.									

* Schedule 33 Cost of Service results are provided for informational purposes only.

Sources:
Column (A): PC 2 (E)
Column (B): PC 2 (F)
Column (E): PC 2 (G)
Column (F): PC 2 (H)

Table 7

STAFF SUBSTITUTE WORKSHEET -- ALTERNATIVE LOAD FACTOR; COMMITMENT COSTS IN BRANCHES 6 AND 7

PacifiCorp
Oregon Marginal Cost Study
Marginal Distribution & Billing Costs By Load Size
December 2010 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg Sch 41	Irrg Sch 33*
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans		
Line	Description		(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Demand, per se, Related Costs ($/kW-1DCP)																			
1	Poles		$6.13	$6.74	$6.74	$6.74	$3.93	$3.93	$3.93	$3.93	$4.28	$4.28	$4.28	$2.55	$2.55	-	-	NA	$15.28	$18.60
2	Conductors		$19.25	$20.57	$20.57	$20.57	$14.44	$14.44	$14.44	$14.44	$15.20	$15.20	$15.20	$11.43	$11.43	-	-	NA	$39.25	$46.44
3	Substation		17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	NA	17.18	17.18
4	Dist. O&M @ of Total Investment	36.05%	15.34	16.04	16.04	16.04	12.82	12.82	12.82	12.82	13.22	13.22	13.22	11.23	11.23	6.19	6.19	NA	25.85	29.64
5	Total $/ Feeder kW-3CP		$57.90	$60.53	$60.53	$60.53	$48.37	$48.37	$48.37	$48.37	$49.88	$49.88	$49.88	$42.39	$42.39	$23.37	$23.37	-	$97.56	$111.86
6	Transformers		1.11	1.44	1.44	NA	1.44	1.44	1.44	NA	1.44	1.44	NA	1.44	NA	1.44	NA	NA	1.44	1.44
7	Dist. O&M @ of Total Investment	36.05%	0.40	0.52	0.52	NA	0.52	0.52	0.52	NA	0.52	0.52	NA	0.52	NA	0.52	NA	NA	0.52	0.52
8	Total $/ Transformer kW		$1.51	$1.96	$1.96	$0.00	$1.96	$1.96	$1.96	$0.00	$1.96	$1.96	$0.00	$1.96	$0.00	$1.96	$0.00	$0.00	$1.96	$1.96
9																				
10	Commitment Related Costs ($/kW-12CP)																			
11	Poles		$33.40	$37.02	$37.02	$37.02	$19.40	$19.40	$19.40	$19.40	$21.35	$21.35	$21.35	$10.67	$10.67				$93.34	$112.02
12	Conductors		$13.38	$14.83	$14.83	$14.83	$7.77	$7.77	$7.77	$7.77	$8.55	$8.55	$8.55	$4.27	$4.27				$37.38	$44.87
13	Dist. O&M @ of Total Investment	36.05%	16.86	18.69	18.69	18.69	9.79	9.79	9.79	9.79	10.78	10.78	10.78	5.39	5.39	-	-	-	47.12	56.56
14	Total $/ Feeder kW-1CP		$63.64	$70.54	$70.54	$70.54	$36.96	$36.96	$36.96	$36.96	$40.68	$40.68	$40.68	$20.33	$20.33	$0.00	$0.00	$0.00	$177.84	$213.45
15																				
16	Commitment Related Costs ($/Customer)																			
17	Transformers		54.54	162.63	365.06	NA	506.32	590.98	649.03	NA	786.74	788.41	NA	789.53	NA	789.53	NA	NA	657.19	768.53
18	Dist. O&M @ of Total Investment	36.05%	42.60	58.63	131.60	-	182.53	213.05	233.98	-	283.62	284.22	-	284.63	-	284.63	-	NA	236.92	277.06
19	Total Commitment Related		$160.78	$221.26	$496.66	$0.00	$688.85	$804.03	$883.01	$0.00	$1,070.36	$1,072.63	$0.00	$1,074.16	$0.00	$1,074.16	$0.00	$0.00	$894.11	$1,045.59
20																				
21	Billing Related Costs ($/Customer/Yr)																			
22	Service Drop		52.06	67.02	160.38	NA	166.79	174.24	383.94	NA	383.78	383.77	NA	689.16	NA	689.16	NA	NA	NA	NA
23	Service Drop O&M @	36.05%	18.77	24.16	57.82	NA	60.13	62.81	138.41	NA	138.35	138.35	NA	248.44	NA	248.44	NA	NA	NA	NA
24	Meter		10.90	12.89	26.70	$840.98	25.81	32.63	145.79	840.98	147.05	147.20	840.98	184.10	840.98	184.10	840.98	30,098.54	26.25	31.62
25	Meter O&M at	42.61%	4.64	5.49	11.38	358.34	11.00	13.90	62.12	358.34	62.66	62.72	358.34	78.45	358.34	78.45	358.34	12,824.99	11.19	13.47
26	Meter Reading		14.00	17.36	17.36	17.36	16.80	16.80	16.80	16.80	$75.73	$75.73	$75.73	114.93	114.93	114.93	114.93	114.93	26.74	26.67
27	Billing & Collections		32.27	30.49	30.49	30.49	32.60	32.60	32.60	32.60	$32.60	$32.60	$32.60	238.20	238.20	238.20	238.20	238.20	33.07	33.02
28	Uncollectables		10.15	2.73	2.73	2.73	25.17	25.17	25.17	25.17	$180.30	$180.30	$180.30	1,110.75	1,110.75	1,110.75	1,110.75	1,110.75	12.33	9.21
29	Customer Service / Other		12.82	12.11	12.11	12.11	15.01	15.01	15.01	15.01	40.89	40.89	40.89	182.97	182.97	182.97	182.97	182.97	14.72	14.32
30	Total Billing Related		$155.60	$172.26	$318.98	$1,262.02	$353.31	$373.16	$819.84	$1,288.90	$1,061.36	$1,061.56	$1,528.84	$2,847.01	$2,846.18	$2,847.01	$2,846.18	$44,570.39	$124.29	$128.32
31																				
32																				
33	Monthly Billing Related (Line 28 / 12)		$12.97	$14.35	$26.58	$105.17	$29.44	$31.10	$68.32	$107.41	$88.45	$88.46	$127.40	$237.25	$237.18	$237.25	$237.18	$3,714.20	$10.36	$10.69
34																				
35	Total Distribution (Comm & Billing Costs)		$316.38	$393.51	$815.64	$1,262.02	$1,042.16	$1,177.19	$1,702.85	$1,288.90	$2,131.72	$2,134.19	$1,528.84	$3,921.17	$2,846.18	$3,921.17	$2,846.18	$44,570.39	$1,018.40	$1,173.91
36	Line 17 + Line 28																			
37	Monthly Commitment & Bill (Line 33 / 12)		$26.37	$32.79	$67.97	$105.17	$86.85	$98.10	$141.90	$107.41	$177.64	$177.85	$127.40	$326.76	$237.18	$326.76	$237.18	$3,714.20	$84.87	$97.83

Sources: Lines
Line 1 PC 1 (C)
Line 2 PC 1 (D)
Line 10 PC 1 (G)
Line 11 PC 1 (H)
Note: Substations (Line 3) are now to be allocated on a jurisdictional (3 CP) basis rather than the Company's feeder (12 CP) basis.

* Schedule 33 Cost of Service results are provided for informational purposes only.

Table 3

STAFF SUBSTITUTE WORKSHEET -- ALTERNATIVE LOAD FACTOR; COMMITMENT COSTS IN BRANCHES 6 AND 7

PacifiCorp
Oregon Marginal Cost Study
20 Year Costing Inputs and Customer Data
Marginal Unit Costs
December 2010 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q) Irrigation Sch 41	(R) Irrigation Sch 33*
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T						
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans		
Line	Description		(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Billing Units																			
	Demand																			
1	Load Factors	System	78.75%	88.41%	74.04%	75.50%	77.67%	68.93%	75.29%	73.67%	76.42%	77.06%	77.01%	76.07%	82.02%	92.58%	87.26%	99.33%	67.15%	67.15%
2		Distribution (1DCP)	44.78%	79.90%	74.70%	73.71%	68.62%	63.93%	71.61%	69.90%	70.81%	73.95%	73.94%	78.09%	85.28%	305.73%	100.13%	N/A	2409.14%	2409.14%
3		Feeder (12CP)	57.08%	89.84%	73.88%	75.48%	74.08%	69.79%	74.90%	73.48%	76.00%	75.71%	75.73%	74.77%	79.59%	98.15%	87.10%	N/A	67.15%	67.15%
4		Transformer	30.26%	27.16%	49.98%	N/A	51.09%	57.17%	59.46%	N/A	64.58%	68.79%	N/A	50.73%	N/A	67.13%	N/A	N/A	32.07%	32.07%
5																				
6	Peak Mw @ Generator	System	862	82	73	0	69	122	153	3	34	175	15	98	61	7	163	48	25	22
7		Distribution (1DCP)	1,516	91	72	0	79	131	161	3	36	182	15	95	59	2	142	N/A	2409.14%	2409.14%
8		Feeder (12CP)	1,189	81	73	0	73	120	154	3	34	178	15	99	63	7	163	N/A	25	22
9		Transformer	2,244	268	107	N/A	106	147	194	N/A	40	196	N/A	146	N/A	10	N/A	N/A	53	46
10	Energy																			
11	Energy - Annual Mwh	@ Meter	5,435,846	582,532	430,256	1,152	431,990	672,435	922,391	18,249	206,234	1,078,480	93,931	594,746	414,743	54,345	1,175,179	404,889	136,792	118,046
12	Energy Loss Factor		1.0940	1.0940	1.0940	1.0595	1.0940	1.0940	1.0940	1.0595	1.0940	1.0940	1.0595	1.0940	1.0595	1.0940	1.0595	1.0361	1.0940	1.0940
13	Energy - Annual Mwh	@ Generator	5,946,598	637,267	470,683	1,220	472,580	735,617	1,009,059	19,335	225,612	1,179,814	99,519	650,629	439,416	59,451	1,245,090	419,485	149,645	129,138
14																				
15	Customer																			
16	Annual Customers		478,485	64,649	9,372	34	4,491	3,525	2,034	50	230	572	52	121	56	2	34	2	6,108	2,062
17	Average Customers																		2,834	756
18																				
19	Unit Costs																			
20	Generation	$ / System Peak Kw	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46
21	Transmission	$ / System Peak Kw	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47
22	Poles, Cond., Subst.	$ / Feeder Kw-1DCP	$57.90	$60.53	$60.53	$60.53	$48.37	$48.37	$48.37	$48.37	$49.88	$49.88	$49.88	$42.39	$42.39	$23.37	$23.37	$0.00	$97.56	$111.86
23	Poles, Cond.	$ / Feeder Kw-12CP	$63.64	$70.54	$70.54	$70.54	$36.96	$36.96	$36.96	$36.96	$40.68	$40.68	$40.68	$20.33	$20.33	$0.00	$0.00	$0.00	$177.84	$213.45
24	Transformers	$ / Xfmr Kw	$1.51	$1.96	$1.96	$0.00	$1.96	$1.96	$1.96	$0.00	$1.96	$1.96	$0.00	$1.96	$0.00	$1.96	$0.00	$0.00	$1.96	$1.96
25																				
26	Energy - @ Generator																			
27	Generation	$ / Kwh	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570
28	Transmission	$ / Kwh	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382
29																				
30	Poles	$ / Cust / Year	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
31	Conductor	$ / Cust / Year	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
32	Transformers	$ / Cust / Year	$74.20	$221.25	$496.66	$0.00	$688.85	$804.03	$883.01	$0.00	$1,070.36	$1,072.63	$0.00	$1,074.16	$0.00	$1,074.16	$0.00	$0.00	$894.11	$1,045.59
33	Service Drop	$ / Cust / Year	$70.83	$91.18	$218.20	$0.00	226.92	237.05	522.35	-	522.13	522.12	-	$937.60	$0.00	$937.60	$0.00	$0.00	$0.00	$0.00
34	Meters	$ / Cust / Year	$15.54	$18.38	$38.08	$1,199.32	36.81	46.53	207.91	1,199.32	209.71	209.92	1,199.32	$262.55	$1,199.32	$262.55	$1,199.32	$42,924	$37.44	$45.09
35	Meter Reading	$ / Cust / Year	$14.00	$17.36	$17.36	$17.36	16.80	16.80	16.80	16.80	75.73	75.73	75.73	114.93	$114.93	$114.93	$114.93	$114.93	$26.74	$26.67
36	Billing & Collections	$ / Cust / Year	$32.27	$30.49	$30.49	$30.49	32.60	32.60	32.60	32.60	32.60	32.60	32.60	238.20	$238.20	$238.20	$238.20	$238.20	$33.07	$33.02
37	Uncollectables	$ / Cust / Year	$10.15	$2.73	$2.73	$2.73	25.17	25.17	25.17	25.17	180.30	180.30	180.30	1,110.75	$1,110.75	$1,110.75	$1,110.75	$1,110.75	$12.33	$9.21
38	Customer Service / Other	$ / Cust / Year	$12.82	$12.11	$12.11	$12.11	15.01	15.01	15.01	15.01	40.89	40.89	40.89	182.97	$182.97	$182.97	$182.97	$182.97	$14.72	$14.32
39	Total Commitment & Billing	$ / Cust / Year	$229.81	$393.51	$815.64	$1,262.02	$1,042.16	$1,177.18	$1,702.85	$1,288.90	$2,131.72	$2,134.19	$1,528.84	$3,921.17	$2,846.18	$3,921.17	$2,846.18	$44,570	$1,018.40	$1,173.91

Sources:

Line 22: Line 5 of Table 7
Line 23: Line 14 of Table 7
Line 30 - 31: Zeros since none of the Poles' and Conductors' costs are classified as "Customer."

* Schedule 33 Cost of Service results are provided for informational purposes only.

Table 4

STAFF SUBSTITUTE WORKSHEET -- ALTERNATIVE LOAD FACTOR; COMMITMENT COSTS IN BRANCHES 6 AND 7

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
December 2010 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg Sch 41	Irrg Sch 33*	Sch 51,53,54 Streetlighting
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 M	> 4 MW	> 4 M	Trans			
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)	(sec)
	Demand Related Marginal Cost																				
1	Generation	$148,195	$64,189	$6,127	$5,403	$14	$5,172	$9,071	$11,393	$223	$2,509	$13,014	$1,098	$7,270	$4,554	$546	$12,128	$3,590	$1,894	$1,635	
2	Transmission	$150,207	$65,060	$6,210	$5,477	$14	$5,242	$9,194	$11,547	$226	$2,544	$13,191	$1,113	$7,369	$4,616	$553	$12,293	$3,638	$1,920	$1,657	
3																					
4	Distribution																				
5	Poles, Conductor, Sub @ 1DCP	$139,651	$87,774	$5,511	$4,354	$11	$3,803	$6,354	$7,781	$153	$1,814	$9,085	$766	$4,032	$2,493	$52	$3,317	$0	$2,350	$2,695	
6	Poles and Conductor @ 12CP	$116,525	$75,685	$5,712	$5,130	$13	$2,692	$4,447	$5,684	$111	$1,379	$7,237	$610	$2,019	$1,281	$0	$0	$0	$4,524	$4,686	
7	Subtotal: Pole, Cond, Subs	$256,175	$163,459	$11,223	$9,484	$24	$6,494	$10,801	$13,465	$264	$3,193	$16,321	$1,377	$6,051	$3,775	$52	$3,317	$0	$6,875	$7,381	
8	Transformers	$5,872	$3,388	$525	$211	$0	$207	$288	$380	$0	$78	$384	$0	$287	$0	$20	$0	$0	$105	$90	
9	Distribution subtotal	$262,047	$166,847	$11,748	$9,695	$24	$6,701	$11,089	$13,844	$264	$3,270	$16,705	$1,377	$6,338	$3,775	$72	$3,317	$0	$6,979	$7,471	
10	Total Demand Related	$560,449	$296,096	$24,085	$20,575	$52	$17,115	$29,354	$36,784	$713	$8,323	$42,910	$3,588	$20,977	$12,945	$1,171	$27,738	$7,228	$10,793	$10,763	
11	(Lines 1+2+9)																				
12																					
13																					
14	Energy Related Marginal Cost																				
15	Generation Energy Related	$768,041	$331,225	$35,496	$26,217	$68	$26,323	$40,974	$56,205	$1,077	$12,567	$65,716	$5,543	$36,240	$24,475	$3,311	$69,352	$23,365	$8,335	$7,193	$1,552
16	Transmission Energy Related	$52,647	$22,705	$2,433	$1,797	$5	$1,804	$2,809	$3,853	$74	$861	$4,505	$380	$2,484	$1,678	$227	$4,754	$1,602	$571	$493	$106
17	Total Energy	$820,689	$353,930	$37,929	$28,014	$73	$28,127	$43,783	$60,057	$1,151	$13,428	$70,220	$5,923	$38,724	$26,153	$3,538	$74,105	$24,967	$8,907	$7,686	$1,659
18																					
19	Customer Related Marginal Cost																				
20	Poles	$6,054	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,054
21	Conductor	$22	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$22
22	Transformers	$68,752	$35,505	$14,304	$4,654	$0	$3,094	$2,834	$1,796	$0	$246	$614	$0	$131	$0	$3	$0	$0	$5,461	$2,156	$111
23	Service Drops	$45,280	$33,890	$5,895	$2,045	$0	$1,019	$835	$1,063	$0	$120	$299	$0	$113	$0	$1	$0	$0	$0	$0	
24	Meters	$10,523	$7,438	$1,188	$357	$41	$165	$164	$423	$60	$48	$120	$62	$32	$67	$1	$41	$86	$229	$93	$2
25	Meter Reading	$8,321	$6,698	$1,122	$163	$1	$75	$59	$34	$1	$17	$43	$4	$14	$6	$0	$4	$0	$76	$20	$2
26	Billing & Collections	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$32
27	Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
28	Customer Service / Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
29	Total Commitment & Billing Rel.	$170,236	$109,961	$25,441	$7,644	$43	$4,680	$4,149	$3,464	$64	$490	$1,221	$79	$475	$159	$8	$97	$89	$5,936	$2,312	$6,236
30																					
31	Total Revenue @ Full MC																				
32	Generation	$916,236	$395,414	$41,623	$31,620	$82	$31,495	$50,045	$67,598	$1,300	$15,076	$78,730	$6,641	$43,510	$29,029	$3,857	$81,480	$26,955	$10,229	$8,828	$1,552
33	Transmission	$202,854	$87,765	$8,643	$7,274	$19	$7,046	$12,003	$15,400	$300	$3,405	$17,696	$1,493	$9,853	$6,294	$780	$17,047	$5,240	$2,491	$2,150	$106
34	Distribution	$382,158	$236,242	$31,948	$16,394	$24	$10,814	$14,759	$16,703	$264	$3,636	$17,618	$1,377	$6,582	$3,775	$76	$3,317	$0	$12,440	$9,627	$6,189
35	Customer - Billing	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$32
36	Customer - Metering	$18,842	$14,136	$2,311	$520	$41	$241	$223	$457	$61	$66	$163	$66	$46	$74	$1	$45	$86	$304	$113	$2
37	Customer - Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
38	Revenue (less Uncollectables)	$1,545,634	$755,131	$87,279	$56,207	$168	$49,810	$77,197	$100,254	$1,927	$22,200	$114,249	$9,581	$60,042	$39,195	$4,715	$101,903	$32,282	$25,601	$20,754	$7,895
39																					
40	Customer - Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
41	Total Revenue	$1,551,374	$759,987	$87,455	$56,233	$168	$49,923	$77,286	$100,305	$1,928	$22,241	$114,352	$9,590	$60,176	$39,257	$4,718	$101,941	$32,284	$25,636	$20,761	$7,895

Sources:

Line 5 Table 3 {Line 22 X Line 7}
Line 6 Table 3 {Line 23 X Line 8}

Streetlighting (Column S): PacifiCorp's original formulas preserved.

* Schedule 33 Cost of Service results are provided for informational purposes only.

STAFF SUBSTITUTE WORKSHEET -- ALTERNATIVE LOAD FACTOR; COMMITMENT COSTS IN BRANCHES 6 AND 7

PACIFICORP – STATE OF OREGON
Combined GRC and TAM
December 31, 2010 Unbundled Revenue Requirement Allocation by Rate Schedule

Line	Description	Total	(A) Residential	(B) General Service Sch 23	(C) General Service Sch 23	(D) General Service Sch 28	(E) General Service Sch 28	(F) General Service Sch 30	(G) General Service Sch 30	(H) Large Power Service Sch 48T	(I) Large Power Service Sch 48T	(J) Large Power Service Sch 48T	(K) Irrigation Sch 41	(L) Street Lgt. Sch 51, 53, 54
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	**Total Operating Revenues**	$915,181	$471,595	$90,790	$99	$124,369	$1,123	$73,370	$5,318	$35,927	$77,376	$17,402	$14,323	$3,489
2	**MWH**	12,680,407	5,435,846	1,012,789	1,152	2,026,816	18,249	$1,284,715	93,931	649,091	1,589,921	404,889	136,792	$26,217
3														
4	**Functionalized 20 Year Full Marginal Costs - Class $**													
5	Generation	$916,236	$395,414	$73,243	$82	$149,137	$1,300	$93,805	$6,641	$47,367	$110,509	$26,955	$10,229	$1,552
6	Transmission	$202,854	$87,765	$15,917	$19	$34,449	$300	$21,101	$1,493	$10,633	$23,341	$5,240	$2,491	$106
7	Distribution	$382,248	$236,242	$48,342	$24	$42,275	$264	$21,254	$1,377	$6,658	$7,092	$0	$12,440	$6,279
8	Customer - Billing	$18,233	$15,441	$2,257	$1	$328	$2	$26	$2	$29	$21	$0	$94	$32
9	Customer - Metering	$18,842	$14,136	$2,830	$41	$921	$61	$229	$66	$46	$118	$86	$304	$2
10	Customer - Other	$7,310	$6,133	$897	$0	$151	$1	$33	$2	$23	$16	$0	$42	$12
11	Total	$1,545,724	$755,131	$143,486	$168	$227,261	$1,927	$136,448	$9,581	$64,757	$141,098	$32,282	$25,601	$7,984
12														
13	**Functional Revenue Requirement Allocation Factors**													
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**													
15	Generation	100.00%	43.16%	7.99%	0.01%	16.28%	0.14%	10.24%	0.72%	5.17%	12.06%	2.94%	1.12%	0.17%
16	Transmission	100.00%	43.26%	7.85%	0.01%	16.98%	0.15%	10.40%	0.74%	5.24%	11.51%	2.58%	1.23%	0.05%
17	Distribution	100.00%	61.80%	12.65%	0.01%	11.06%	0.07%	5.56%	0.36%	1.74%	1.86%	0.00%	3.25%	1.64%
18	Ancillary Service	100.00%	43.16%	7.99%	0.01%	16.28%	0.14%	10.24%	0.72%	5.17%	12.06%	2.94%	1.12%	0.17%
19	Customer - Billing	100.00%	84.69%	12.38%	0.01%	1.80%	0.01%	0.14%	0.01%	0.16%	0.12%	0.00%	0.51%	0.18%
20	Customer - Metering	100.00%	75.02%	15.02%	0.22%	4.89%	0.32%	1.22%	0.35%	0.25%	0.63%	0.46%	1.62%	0.01%
21	Customer - Other	100.00%	83.90%	12.27%	0.01%	2.06%	0.01%	0.45%	0.03%	0.31%	0.23%	0.01%	0.57%	0.17%
22	Embedded DSM - (mWh)	100.00%	42.87%	7.99%	0.01%	15.98%	0.14%	10.13%	0.74%	5.12%	12.54%	3.19%	1.08%	0.21%
23	Regulatory & Franchise	100.00%	51.53%	9.92%	0.01%	13.59%	0.12%	8.02%	0.58%	3.93%	8.45%	1.90%	1.57%	0.38%
24	Taxes (Revenue)													
25														
26	**Functionalized Class Revenue Requirement - (Target)**													
27	Generation	$612,171	$264,191	$48,936	$55	$99,644	$869	$62,675	$4,437	$31,648	$73,835	$18,010	$6,835	$1,037
28	Transmission	$75,967	$32,867	$5,961	$7	$12,901	$112	$7,902	$559	$3,982	$8,741	$1,962	$933	$40
29	Distribution	$246,801	$152,531	$31,212	$16	$27,295	$170	$13,723	$889	$4,299	$4,579	$0	$8,032	$4,054
30	Ancillary Services	$10,758	$4,643	$860	$1	$1,751	$15	$1,101	$78	$556	$1,298	$316	$120	$18
31	Customer - Billing	$11,737	$9,940	$1,453	$1	$211	$1	$17	$1	$19	$14	$0	$60	$21
32	Customer - Metering	$28,029	$21,029	$4,210	$62	$1,370	$90	$341	$99	$69	$176	$128	$453	$3
33	Customer - Other	$13,088	$10,980	$1,605	$1	$270	$1	$59	$4	$40	$29	$1	$75	$22
34	Embedded DSM - (mWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Regulatory & Franchise T	$23,859	$12,295	$2,367	$3	$3,242	$29	$1,913	$139	$937	$2,017	$454	$373	$91
36	Total	$1,022,411	$508,476	$96,604	$144	$146,685	$1,289	$87,730	$6,205	$41,550	$90,689	$20,871	$16,881	$5,286
37														
38	**Ratio of Operating Revn to Reven**	89.51%	92.75%	93.98%	68.84%	84.79%	87.19%	83.63%	85.70%	86.47%	85.32%	83.38%	84.85%	66.00%
39	(Line 1 / Line 36)													
40														
41	**Increase or (Decrease)**	$107,229	$36,881	$5,815	$45	$22,316	$165	$14,360	$887	$5,623	$13,313	$3,469	$2,558	$1,797
42	(Line 36 - Line 1)													
43														
44														
45	**Percent Increase (Decrease)**	11.72%	7.82%	6.40%	45.26%	17.94%	14.70%	19.57%	16.68%	15.65%	17.21%	19.94%	17.86%	51.52%
46	(Line 41 / Line 1)													

Source:

Line 7: Respective values from Line 34 of Table 4. Secondary and Primary figures, respectively, are aggregated within Schedules.

CASE: UE 210
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1107

Cost-of-Service Results
Incorporating All of Staff's Revisions

July 24, 2009

STAFF SUBSTITUTE WORKSHEET -- MODIFIED GENERATION ENERGY & CAPACITY PLUS REFORMULATED FEEDER MODEL

PACIFICORP – STATE OF OREGON
Combined GRC and TAM
December 31, 2010 Unbundled Revenue Requirement Allocation by Rate Schedule

Line	Description	Total	(A) Residential	(B) General Service	(C)	(D) General Service	(E)	(F) General Service	(G)	(H)	(I) Large Power Service	(J)	(K) Irrigation	(L) Street Lgt.
				Sch 23		Sch 28		Sch 30			Sch 48T		Sch 41	Sch 51, 53, 54
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	**Total Operating Revenues**	$915,181	$471,595	$90,790	$99	$124,369	$1,123	$73,370	$5,318	$35,927	$77,376	$17,402	$14,323	$3,489
2	**MWH**	12,680,407	5,435,846	1,012,789	1,152	2,026,816	18,249	$1,284,715	93,931	649,091	1,589,921	404,889	136,792	$26,217
3														
4	**Functionalized 20 Year Full Marginal Costs - Class $**													
5	Generation	$700,881	$302,639	$55,803	$63	$115,158	$1,003	$72,007	$5,098	$36,343	$83,689	$20,073	$7,996	$1,010
6	Transmission	$202,854	$87,765	$15,917	$19	$34,449	$300	$21,101	$1,493	$10,633	$23,341	$5,240	$2,491	$106
7	Distribution	$382,248	$236,242	$48,342	$24	$42,275	$264	$21,254	$1,377	$6,658	$7,092	$0	$12,440	$6,279
8	Customer - Billing	$18,233	$15,441	$2,257	$1	$328	$2	$26	$2	$29	$21	$0	$94	$32
9	Customer - Metering	$18,842	$14,136	$2,830	$41	$921	$61	$229	$66	$46	$118	$86	$304	$2
10	Customer - Other	$7,310	$6,133	$897	$0	$151	$1	$33	$2	$23	$16	$0	$42	$12
11	Total	$1,330,369	$662,356	$126,046	$149	$193,281	$1,630	$114,651	$8,037	$53,733	$114,278	$25,399	$23,367	$7,442
12														
13	**Functional Revenue Requirement Allocation Factors**													
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**													
15	Generation	100.00%	43.18%	7.96%	0.01%	16.43%	0.14%	10.27%	0.73%	5.19%	11.94%	2.86%	1.14%	0.14%
16	Transmission	100.00%	43.26%	7.85%	0.01%	16.98%	0.15%	10.40%	0.74%	5.24%	11.51%	2.58%	1.23%	0.05%
17	Distribution	100.00%	61.80%	12.65%	0.01%	11.06%	0.07%	5.56%	0.36%	1.74%	1.86%	0.00%	3.25%	1.64%
18	Ancillary Service	100.00%	43.18%	7.96%	0.01%	16.43%	0.14%	10.27%	0.73%	5.19%	11.94%	2.86%	1.14%	0.14%
19	Customer - Billing	100.00%	84.69%	12.38%	0.01%	1.80%	0.01%	0.14%	0.01%	0.16%	0.12%	0.00%	0.51%	0.18%
20	Customer - Metering	100.00%	75.02%	15.02%	0.22%	4.89%	0.32%	1.22%	0.35%	0.25%	0.63%	0.46%	1.62%	0.01%
21	Customer - Other	100.00%	83.90%	12.27%	0.01%	2.06%	0.01%	0.45%	0.03%	0.31%	0.23%	0.01%	0.57%	0.17%
22	Embedded DSM - (mWh)	100.00%	42.87%	7.99%	0.01%	15.98%	0.14%	10.13%	0.74%	5.12%	12.54%	3.19%	1.08%	0.21%
23	Regulatory & Franchise	100.00%	51.53%	9.92%	0.01%	13.59%	0.12%	8.02%	0.58%	3.93%	8.45%	1.90%	1.57%	0.38%
24	Taxes (Revenue)													
25														
26	**Functionalized Class Revenue Requirement - (Target)**													
27	Generation	$612,171	$264,334	$48,740	$55	$100,582	$876	$62,894	$4,452	$31,743	$73,096	$17,532	$6,984	$882
28	Transmission	$75,967	$32,867	$5,961	$7	$12,901	$112	$7,902	$559	$3,982	$8,741	$1,962	$933	$40
29	Distribution	$246,801	$152,531	$31,212	$16	$27,295	$170	$13,723	$889	$4,299	$4,579	$0	$8,032	$4,054
30	Ancillary Services	$10,758	$4,645	$857	$1	$1,768	$15	$1,105	$78	$558	$1,285	$308	$123	$15
31	Customer - Billing	$11,737	$9,940	$1,453	$1	$211	$1	$17	$1	$19	$14	$0	$60	$21
32	Customer - Metering	$28,029	$21,029	$4,210	$62	$1,370	$90	$341	$99	$69	$176	$128	$453	$3
33	Customer - Other	$13,088	$10,980	$1,605	$1	$270	$1	$59	$4	$40	$29	$1	$75	$22
34	Embedded DSM - (mWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Regulatory & Franchise T	$23,859	$12,295	$2,367	$3	$3,242	$29	$1,913	$139	$937	$2,017	$454	$373	$91
36	Total	$1,022,411	$508,622	$96,405	$144	$147,640	$1,296	$87,953	$6,221	$41,647	$89,937	$20,385	$17,033	$5,128
37														
38	**Ratio of Operating Revn to Reven**	89.51%	92.72%	94.18%	68.64%	84.24%	86.67%	83.42%	85.49%	86.27%	86.03%	85.37%	84.09%	68.03%
39	(Line 1 / Line 36)													
40														
41	**Increase or (Decrease)**	$107,229	$37,027	$5,615	$45	$23,270	$173	$14,583	$903	$5,720	$12,562	$2,983	$2,710	$1,639
42	(Line 36 - Line 1)													
43														
44														
45	**Percent Increase (Decrease)**	11.72%	7.85%	6.18%	45.70%	18.71%	15.39%	19.88%	16.97%	15.92%	16.23%	17.14%	18.92%	46.99%
46	(Line 41 / Line 1)													

Source: Same worksheet as Staff/1105 Compton/18 except substitution of Line 7 from Staff/1106 Compton/18

CASE: UE 210
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1108

Transitioning from Cost-of-Service Results to the Rate Designs: PGE and PacifiCorp Contrasted

July 24, 2009

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2009

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 32						
General Service <30 kW						
Theoretic						
Functional Costs						
Basic Charge						
Single-Phase	$7,368	52,679	Customers	$11.66	per cust. per mo.	$7,371
Three-Phase	$5,668	30,977	Customers	$15.25	per cust. per mo.	$5,669
Trans. & Rel. Serv. Charge	$2,767	1,500,066	MWh	1.84	mills/kWh	$2,760
Distribution Charge	$37,243	1,500,066	MWh	24.83	mills/kWh	$37,247
Franchise Fees & Other	$3,955	1,500,066	MWh	2.64	mills/kWh	$3,960
Energy Charge	$95,343	1,500,066	MWh	63.56	mills/kWh	$95,344
Subtotal	$152,344					$152,351
Proposed						
Functional Costs						
Basic Charge						
Single-Phase		52,679	Customers	$12.00	per cust. per mo.	$7,586
Three-Phase		30,977	Customers	$16.00	per cust. per mo.	$5,948
Trans. & Rel. Serv. Charge		1,500,066	MWh	1.84	mills/kWh	$2,760
Distribution Charge						
First 5 MWh		1,337,428	MWh	27.11	mills/kWh	$36,258
Over 5 MWh		162,637	MWh	3.00	mills/kWh	$488
System Usage Charge Calc						
Franchise Fees & Other		1,500,066	MWh	2.64	mills/kWh	$3,960
Cust Impact Offset		1,500,066	MWh	0.12	mills/kWh	$180
System Usage Charge		1,500,066	MWh	2.76	mills/kWh	$4,140
Energy Charge		1,500,066	MWh	63.56	mills/kWh	$95,344
Subtotal						$152,524
					w/o CIO	$152,344
SCHEDULE 38						
Time-of-Day G.S. >30 kW						
Theoretic						
Functional Costs						
Basic						
Single-Phase	$17	61	Customers	$23.61	per cust. per mo.	$17
Three-Phase	$173	524	Customers	$27.41	per cust. per mo.	$172
Trans. & Rel. Serv. Charge	$65	65,998	MWh	0.99	per cust. per mo.	$65
Distribution Charges	$2,387	65,998	MWh	36.16	per cust. per mo.	$2,386
Franchise Fees & Other	$176	65,998	MWh	2.66	mills/kWh	$176
Energy Charge	$4,185	65,998	MWh	63.41	mills/kWh	$4,185
Subtotal	$7,002					$7,002
Proposed						
Functional Costs						
Basic						
Single-Phase		61	Customers	$20.00	per cust. per mo.	$15
Three-Phase		524	Customers	$25.00	per cust. per mo.	$157
Trans. & Rel. Serv. Charge		65,998	MWh	0.99	mills/kWh	$65
Distribution Charges		65,998	MWh	35.97	mills/kWh	$2,374
System Usage Charge						
Franchise Fees & Other		65,998	MWh	2.66	mills/kWh	$176
Cust Impact Offset		65,998	MWh	0.12	mills/kWh	$8
System Usage Charge		65,998	MWh	2.78	mills/kWh	$183
Energy Charge Calc						
On-Peak (special)		31,815	MWh	70.97	mills/kWh	$2,258
Off-Peak		34,183	MWh	56.37	mills/kWh	$1,927
Reactive Demand Charge		61,602	kVar	$0.50	kVar	$31
Subtotal						$7,010
					w/o CIO	$7,002

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2008
Forecast 12 Months Ended December 31, 2010

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price		Present Rates Effective 3/31/09 Dollars	Proposed Price		Proposed Dollars
Schedule No. 23/723								
General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	1,012,788,782	kWh	0.455	¢	$4,608,189	0.374	¢	$3,787,830
Distribution Charge								
Basic Charge								
Single Phase, per month	695,056	bill	$16.15		$11,225,154	$18.65		$12,962,794
Three Phase, per month	193,187	bill	$24.10		$4,655,807	$27.85		$5,380,258
Load Size Charge								
≤ 15 kW		kW	No Charge			No Charge		
per kW for all kW in excess of 15 kW	767,514	kW	$1.10		$844,265	$1.25		$959,393
Demand Charge, the first 15 kW of demand		kW	No Charge			No Charge		
Demand Charge, per kW for all kW in excess of 15 kW	419,716	kW	$3.77		$1,582,329	$4.36		$1,829,962
Reactive Power Charge, per kvar	54,155	kvar	65.00	¢	$35,201	65.00	¢	$35,201
Distribution Energy Charge, per kWh	1,012,788,782	kWh	2.252	¢	$22,808,003	2.591	¢	$26,241,357
Energy Charge								
Schedule 200								
1st 3,000 kWh, per kWh	778,802,018	kWh	4.502	¢	$35,061,667	2.942	¢	$22,912,355
All additional kWh, per kWh	233,986,764	kWh	3.343	¢	$7,822,178	2.185	¢	$5,112,611
Schedule 201								
1st 3,000 kWh, per kWh	778,802,018	kWh				2.195	¢	$17,094,704
All additional kWh, per kWh	233,986,764	kWh				1.630	¢	$3,813,984
Subtotal					$88,642,793			$100,130,449
Renewable Adjustment Clause, per kWh	1,012,788,782	kWh	0.229	¢	$2,319,286	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	1,012,788,782	kWh	(0.017)	¢	($172,174)	0.000	¢	$0
Total	1,012,788,782	kWh			$90,789,905			$100,130,449
						Change		$9,340,544

Schedule	Forecast 1/10 - 12/10 Units		Present Rates Effective 3/31/09 Price		Present Rates Effective 3/31/09 Dollars	Proposed Price		Proposed Dollars
Schedule No. 23/723								
General Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	1,151,715	kWh	0.442	¢	$5,091	0.362	¢	$4,169
Distribution Charge								
Basic Charge								
Single Phase, per month	228	bill	$16.15		$3,682	$18.65		$4,252
Three Phase, per month	190	bill	$24.10		$4,579	$27.85		$5,292
Load Size Charge								
≤ 15 kW		kW	No Charge			No Charge		
per kW for all kW in excess of 15 kW	2,989	kW	$1.10		$3,288	$1.25		$3,736
Demand Charge, the first 15 kW of demand		kW	No Charge			No Charge		
Demand Charge, per kW for all kW in excess of 15 kW	2,440	kW	$3.67		$8,955	$4.24		$10,346
Reactive Power Charge, per kvar	3,872	kvar	60.00	¢	$2,323	60.00	¢	$2,323
Distribution Energy Charge, per kWh	1,151,715	kWh	2.190	¢	$25,223	2.509	¢	$28,897
Energy Charge								
Schedule 200								
1st 3,000 kWh, per kWh	535,677	kWh	4.386	¢	$23,495	2.849	¢	$15,261
All additional kWh, per kWh	616,038	kWh	3.259	¢	$20,077	2.116	¢	$13,035
Schedule 201								
1st 3,000 kWh, per kWh	535,677	kWh				2.126	¢	$11,388
All additional kWh, per kWh	616,038	kWh				1.579	¢	$9,727
Subtotal					$96,713			$108,426
Renewable Adjustment Clause, per kWh	1,151,715	kWh	0.229	¢	$2,637	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	1,151,715	kWh	(0.017)	¢	($196)	0.000	¢	$0
Total	1,151,715	kWh			$99,154			$108,426
						Change		$9,272

CASE: UE 210
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1109

Contrasting PacifiCorp's Large Industrial Rate Designs for Utah and Oregon

July 24, 2009

PACIFIC POWER & LIGHT COMPANY
LARGE GENERAL SERVICE - 1,000 KW AND OVER
DELIVERY SERVICE

OREGON
SCHEDULE 48

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until the Consumer fails to exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 47.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
	Secondary	**Primary**	**Transmission**	
Distribution Charge				
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$310.00	$270.00	$260.00	(I)
Facility Capacity > 4000 kW, per month	$580.00	$480.00	$480.00	
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$ 1.75	$ 0.85	$ 0.45	
> 4000 kW, per kW Facility Capacity	$ 1.60	$ 0.80	$ 0.45	
On-Peak Demand Charge, per kW	$ 1.31	$ 1.43	$ 0.78	(I)(R)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	$ 0.55	
Transmission & Ancillary Services Charge				
Per kW of On-Peak demand	$ 1.51	$ 1.59	$ 1.94	(R)

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period, which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the maximum measured kilowatt demand for the same month.

(continued)

PACIFIC POWER & LIGHT COMPANY
COST-BASED
SUPPLY SERVICE

RECEIVED
DEC 02 2008
PUC
Utility Program

OREGON
SCHEDULE 200

Energy Charge *(continued)*

Delivery Service Schedule No.		Delivery Voltage: Secondary	Primary	Transmission	
41	Summer, all kWh, per kWh	4.112 ¢	4.007¢		(I)

For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30.

		Secondary	Primary	Transmission	
47/48	Per kWh On-Peak	3.976¢	3.797¢	3.630¢	(I)
	Per kWh, Off-Peak	3.876¢	3.697¢	3.530¢	(I)

For Schedule 47 and Schedule 48, On-Peak hours are from 6:00 a.m. to 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-Peak hours are remaining hours.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

		Secondary	
52	For dusk to dawn operation, per kWh	2.289¢	(I)
	For dusk to midnight operation, per kWh	2.289¢	(I)
54	Per kWh	1.683¢	(I)

15	Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire	
	Mercury Vapor	7,000	76	$1.73	(I)
	Mercury Vapor	21,000	172	$3.91	
	Mercury Vapor	55,000	412	$9.38	
	High Pressure Sodium	5,800	31	$0.71	
	High Pressure Sodium	22,000	85	$1.93	
	High Pressure Sodium	50,000	176	$4.01	(I)

50 **A. Company-owned Overhead System**
Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
Horizontal, per lamp	$1.44	$3.26	$7.80	(I)
Vertical, per lamp	$1.44	$3.26		(I)

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.44			(I)
On 26-foot poles, vertical, per lamp	$1.44			
On 30-foot poles, horizontal , per lamp		$3.26		
On 30-foot poles, vertical, per lamp		$3.26		
On 33-foot poles, horizontal , per lamp			$7.80	(I)

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 8

STATE OF UTAH

Large General Service – 1,000 kW and Over – Distribution Voltage

AVAILABILITY: At any point on the Company's interconnected system where there are facilities of adequate capacity.

APPLICATION: This Schedule is for alternating current, single or three-phase, electric service supplied at Company's available voltage, but less than 46,000 volts through a single point of delivery, for all service required on the Customer's premises. This Schedule is applicable to electric service loads which have registered 1,000 kW or more, more than once in the preceding 18-month period. This Schedule will remain applicable until the Customer fails to exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. This Schedule is for general nonresidential service, except for multi-unit residential complexes master metered in accordance with the Utah Administrative Code, Section R746-210. Service under this Schedule is also available to common areas associated with residential complexes.

MONTHLY BILL:

Customer Service Charge:
$25.00 per Customer

Facilities Charge:
$3.47 per kW

Power Charge:

Billing Months - May through September inclusive
On-Peak: $11.34 per kW
Off-Peak: None

Billing Months - October through April inclusive
On-Peak: $8.18 per kW
Off-Peak: None

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 8 - Continued

MONTHLY BILL: (continued)

Energy Charge:

Billing Months - May through September inclusive
3.6832¢ per kWh for all On-Peak kWh
2.4832¢ per kWh for all Off-Peak kWh

Billing Months - October through April inclusive
2.8832¢ per kWh for all On-Peak kWh
2.4832¢ per kWh for all Off-Peak kWh

Voltage Discount: Where Customer takes service from Company's available lines of 2,300 volts or higher and provides and maintains all transformers and other necessary equipment, the Voltage Discount based on measured On-Peak Power will be:

$0.83 per kW

SURCHARGE ADJUSTMENT: All monthly bills shall be adjusted in accordance with Schedule 193.

FACILITIES KW: All kW as shown by or computed from the reading of Company's Power meter for the 15-minute period of Customer's greatest use at any time during the month, adjusted for Power Factor to the nearest kW.

POWER: The kW as shown by or computed from the readings of Company's Power meter for the 15-minute On-Peak period of Customer's greatest use during the month, adjusted for Power Factor to the nearest kW.

POWER FACTOR: The On-Peak Power Charge is based on the Customer maintaining at all times a Power Factor of 90% lagging, or higher, as determined by measurement. If the average Power Factor is found to be less than 90% lagging, the On-Peak Power, as recorded by the Company's meter, will be increased by 3/4 of 1% for every 1% that the Power Factor is less than 90%.

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P.S.C.U. No. 47

First Revision of Sheet No. 8.3
Canceling Original Sheet No. 8.3

ELECTRIC SERVICE SCHEDULE NO. 8 - Continued

TIME PERIODS:

On-Peak:	October through April inclusive 7:00 a.m. to 11:00 p.m., Monday thru Friday, except holidays. May through September inclusive 1:00 p.m. to 9:00 p.m., Monday thru Friday, except holidays.
Off-Peak:	All other times.

Holidays include only New Year's Day, President's Day, Memorial Day, Independence Day, Pioneer Day, Labor Day, Thanksgiving Day, and Christmas Day. When a holiday falls on a Saturday or Sunday, the Friday before the holiday (if the holiday falls on a Saturday) or the Monday following the holiday (if the holiday falls on a Sunday) will be considered a holiday and consequently Off-Peak.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005 the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

FORCE MAJEURE: Neither Company nor Customer shall be subject to any liability or damages for inability to provide or receive service to the extent that such failure shall be due to causes beyond the control of either Company or Customer, including but not limited to the following: (a) operation and effect of any rules, regulations and orders promulgated by any Commission, municipality, or governmental agency of the United States, or subdivision thereof; (b) restraining order, injunction, or similar decree of any court; (c) war; (d) flood; (e) earthquake; (f) act of God; (g) sabotage; or (h) strikes or boycotts. Should any of the foregoing occur, the minimum Billing Demand that would otherwise be applicable under this Schedule shall be waived and the Customer will have no liability for service until such time as the Customer is able to resume service, except for any term minimum guarantees designed to cover special facilities extension costs. The party claiming Force Majeure under this provision shall make every reasonable attempt to remedy the cause thereof as diligently and expeditiously as possible.

ELECTRIC SERVICE REGULATIONS: Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Public Service Commission of the State of Utah, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.

Issued by authority of Report and Order of the Public Service Commission of Utah in Advice No. 06-12

FILED: October 9, 2006 **EFFECTIVE:** March 1, 2007

CASE: UE 210
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1110

The Time-of-Day Sensitive Nature of Summertime Spot Market Prices

July 24, 2009

STAFF EXHIBIT 1110

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 09-120. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 210 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 210
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1111

Some Alternative Time-of-Use Rate Designs for Large Industrial Customers

July 24, 2009

SOME ALTERNATIVE ENERGY CHARGES

Schedule 48: July and August.

2010 Predicted Load Aggregates

	Secondary	Primary	Transmission
Super-Peak (Mon-Sat: Noon-8pm)	41,419,517	95,736,398	21,693,374
Shoulder-Peak (Mon-Sat: 6am-Noon, 8pm-10pm)	41,075,108	93,199,361	21,808,843
Peak (Super-Peak plus Shoulder-Peak)	82,494,625	188,935,759	43,502,217
Off-Peak (Sundays, Holidays and all non-Peak hours)	46,655,823	122,217,359	33,160,244
Non-Super-Peak (Shoulder-Peak plus Off-Peak)	87,730,931	215,416,720	54,969,087

Prices (i.e., Sched. 200 + Sched. 201) and Revenues (for July & August)

	Secondary	Primary	Transmission	
PacifiCorp Proposal				
On-Peak Price (¢/kWh)	4.915	4.682	4.492	
Off-Peak Price (¢/kWh)	4.815	4.582	4.392	Grand Total
Total Revenues ($)	6,301,089	14,445,972	3,410,517	24,157,578
Total Sales	129,150,448	311,153,118	76,662,461	516,966,027
Alternative 1				
On-Peak Price (¢/kWh)	5.200	5.000	4.900	
Off-Peak Price (¢/kWh)	4.311	4.090	3.857	Grand Total
Total Revenues ($)	6,301,089	14,445,972	3,410,517	24,157,578
Total Sales	129,150,448	311,153,118	76,662,461	516,966,027
Alternative 2				
Super-Peak Price (¢/kWh)	5.900	5.700	5.500	
Non-Super-Peak Price (¢/kWh)	4.397	4.173	4.034	Grand Total
Total Revenues ($)	6,301,089	14,445,972	3,410,517	24,157,578
Total Sales	129,150,448	311,153,118	76,662,461	516,966,027
Alternative 3				
Super-Peak Price (¢/kWh)	6.000	5.800	5.600	
Shoulder-Peak Price (¢/kWh)	4.747	4.559	4.594	
Off-Peak Price (¢/kWh)	4.000	3.800	3.600	Grand Total
Total Revenues ($)	6,301,089	14,445,972	3,410,517	24,157,578
Total Sales	129,150,448	311,153,118	76,662,461	516,966,027

CASE: UE 210
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Opening Testimony

July 24, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Matt Muldoon. I am employed by the Public Utility Commission of Oregon as a Senior Economist in the Economic Research and Financial Analysis Division. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

My Witness Qualifications Statement is found in Staff/1201

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony examines PacifiCorp's long-run incremental cost (LRIC) model integrity. In this case long-run refers to 20-year data and calculations. Within this context the terms "incremental cost" and "marginal cost" are used interchangeably. My efforts focused on model verification, primarily of two spreadsheet models sponsered by Company witness C. Craig Paice:

A. Feeder Model OR 2010; and

B. MC Oregon 2010.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/1202, consisting of one page.

Q. WHICH PACIFICORP TESTIMONY AND EXHIBITS DID YOU REVIEW?

A. Regarding PacifiCorp's long-run marginal cost model, I reviewed PacifiCorp's LRIC models filed primarily in the direct testimony of C. Craig Paice as Exhibits PPL/900 through 907, and also reviewed Exhibit PPL/701 of R. Bryce Dalley and Exhibit PPL/1003 accompanying the direct testimony of William R. Griffith with respect to billing determinants.

Q. WHAT ARE YOUR SUMMARY FINDINGS?

A. I detected no inconsistencies or unreasonable constructs not addressed in Staff witness George Compton's Exhibit Staff/1100 testimony. However, I do think that future reviews would benefit if PacifiCorp developed and implemented three enhancements to the Company's LRIC model prior to the Company's filing of a subsequent general rate case:

1. A graphical representation of model data flows, with each element identified by both hard copy and spreadsheet tab references;
2. A comprehensive set of definitions and translations for all acronyms and abbreviations used in testimony, exhibits, and work papers;
3. Common and consistently placed worksheet and hard copy references;

Q. DID YOU FIND ANY CURRENT PRACTICES BY PACIFICORP PARTICULARLY HELPFUL?

A. Yes. The workshops PacifiCorp held on marginal costs were very helpful.

Q. DO YOU BELIEVE PACIFICORP'S LRIC MODEL IS CONSISTENT WITH THE COMMISSION'S APPROACH FOR DEVELOPING MARGINAL COST OF ELECTRICITY STUDIES?

A. Yes. In Order No. 98-374 entered Sept 11, 1998, the Commission "allowed utilities to address the issue of calculating marginal costs in different ways," which "has led to significant and productive new approaches to efficient pricing and costing of electrical service." I believe the Company's Exhibits PPL/900-906 LRIC elements are consistent with the Commission's aforementioned finding that "utilities should be allowed to best fit the particular circumstances of their systems and nature of their customers." Inherent within that finding is the expectation that LRIC models will be refined over time to best reflect the operations of the Company and the evolving needs of its customers and stakeholders.

Q. HOW IS the REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony describes this review processes as follows:

GENERAL APPROACH

Q. WHAT WAS YOUR GENERAL APPROACH IN EXAMINING LRIC MODEL INTEGRITY?

A. I generally used the following approach:

1. Exhibit PPL/906 provided unbundled results of operations and current rates. I looked for Oregon normalized revenues and then functionalized revenues leading to return on rate base.
2. Exhibit PPL/902 summarized this information.
3. Exhibit PPL/701 gave me target overall revenue requirements.
4. Exhibit PPL/901 then drew on the prior cost and rate base assets from PacifiCorp's Oregon Results of Operations report to functionalize target revenue requirements.
5. Exhibit PPL/905 allowed derivation of functionalized target revenue requirement by class and schedule. As per Exhibit PPL/900 Paice/4, I looked for consistency in the allocation of full long-run marginal cost for

each customer class by function, primarily focusing on generation, transmission and distribution functions. (Across this analysis generation and production are interchangeable terms.) Total revenue requirement for a given function was allocated to a given customer class at the same percentage rate as that class' share of that function's total marginal cost.

6. Exhibit PPL/906 provided breakout to FERC accounts or rather into functionalized buckets. My focus was monitoring allocations to buckets.
7. Exhibit PPL/907, in general, PacifiCorp's marginal cost study, found in Exhibit PPL/907, looks at the marginal cost of resources by customer class to produce a single additional unit of electricity or add one additional customer. My focus was on long-run 20-year marginal costs on either a mills per kilowatt-hour (kWh) or dollars per customer basis, largely summarized in Tab 2, Tables 3 and 4. Long-run unit costs are broken out by function in Table 3 inclusive of the cost of expanding facilities. Table 4 then calculates long-run marginal costs by class.

Q. WERE INCONSISTENCIES OR ERRORS DETECTED THAT ARE NOT ADDRESSED BY STAFF IN SEPARATE TESTIMONY?

A. No. In examining functionalization between production, transmission and distribution; classification and allocation to customer classes, the Company's spreadsheet models worked and performed as expected. To the extent that models were interlinked, spreadsheets had consistent cell references and calculated as described in hard copy testimony.

EXAMPLE of SPECIFIC DATA FLOWS

Q. DID YOU EXAMINE EXHIBIT PPL/907 MARGINAL TRANSMISSION AND DISTRIBUTION COSTS AND OTHER SPECIFIC DATA FLOWS?

A. Yes, PPL/907 afforded me an opportunity to study the PacifiCorp Distribution Feeder model for poles and wires. When PacifiCorp builds a new branch line segment (other than a trunk), this model presumes that there is a commitment to a given cost of poles, conductor and transformers required just to connect incremental customer points of delivery.

Within this construct, the commitment cost (stated in terms of levelized dollars per customer per year) is the minimal construction cost for a branch with smallest single-phase conductor and matching poles. Costs in excess of that amount (stated in terms of levelized dollars per kW per year) are assigned to demand. This hypothetical feeder model, consisting of five branches and two trunks (all of equal length), is used to approximate Oregon composite line statistics in lieu of developing a LRIC model based on a statistical sampling of actual embedded costs.

Q. DID YOU CONSIDER STAFF'S PROPOSED DISTRIBUTION FEEDER POLE AND WIRES MODEL REVISION (AS IS DOCUMENTED IN EXHIBIT STAFF/1100) AS YOU REVIEWED THE INTEGRITY OF PACIFICORP'S DISTRIBUTION FEEDER MODEL?

A. Yes, I followed Staff witness Dr. George Compton's proposed distribution feeder pole and wires model revision. Therein Dr. Compton proposes to consistently ascribe commitment costs to all seven segments of the "fishbone" feeder model, (to both the five branches and its two trunks) and to allocate these costs on the basis of the same twelve coincidental peak (12-CP) methodology that the Company used to allocate its feeder model's demand costs.. In contrast, the current PacifiCorp feeder model, as depicted in Exhibit PPL/907, Tab 1.2 page 5, assigns commitment costs to only the five branches of the feeder model.

Both the original and Staff's proposed adjustment maintain model integrity. Because this is a conceptual model, one expects it to be improved over time. Assignment of commitment to all segments trunk and branch alike makes for a simpler and more elegant model with more consistent handling of components.

Q. DID THIS TESTIMONY ARTICULATE ALL OF DR. COMPTON'S ADJUSTMENTS TO THE PACIFICORP FEEDER MODEL.

A. No, This testimony does not address all the differences between the PaciCorp feeder model and Dr. George Compton's proposals.

EX: This testimony does not examine Dr. George Compton's proposed use of a three winter jurisdictional demand methodology (3-CP).

Q. PLEASE PROVIDE AN EXAMPLE OF DATA FLOW THEREIN.

A. Exhibit Staff/1202 Muldoon/1 displays the interaction of models encountered while following data flows through PacifiCorp's 7-Segment (poles and wires) Feeder Model. It also shows the plethora of electronic and hard copy markings one encounters following data flows across models.

Q. WERE ANY INCONSISTENCIES OR ERRORS DETECTED THAT ARE NOT ADDRESSED ELSEWHERE?

A. No.

Q. DID YOU ENCOUNTER ANY OPPORTUNITIES TO IMPROVE FUTURE REVIEW OF LRIC DATA FLOWS?

A. Yes. Working through long-run incremental cost data flows demonstrated that both hard copy and spreadsheet model data could be more uniformly and consistently labeled. When moving between models, this effort may speed future analysis yielding subsequent improvements. Moreover, participating parties may then more rapidly match hard copy and electronic spreadsheet materials.

Q. ARE THERE OTHER OPPORTUNITIES FOR PROCESS IMPROVEMENT?

A. Yes. A graphical representation of the model data flows with each element identified by both hard copy and spreadsheet tab references would similarly orient reviewing parties.

In addition, a comprehensive set of definitions for all acronyms and abbreviations used is an essential element of rate cases and compilations.

Within the electrical industry multiple definitions are in aggregate assigned to short abbreviations. Three and four character abbreviations can save space and time when so defined. However, different meanings are assigned to the same short abbreviations in different contexts. Because PacifiCorp operates in multiple states and Staff reviews materials from different entities, this self contained translation is important. Further, maintaining that information online with a link thereto can keep information current and reduce paper consumption. As an example, three-character abbreviations in UE 210 may differ in meaning from that same abbreviation in a Bonneville Power Administration rate case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 210
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Witness Qualification Statement

July 24, 2009

WITNESS QUALIFICATION STATEMENT

NAME: Matthew Muldoon

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist, Economic Research and Financial Analysis

ADDRESS: 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

EDUCATION: Masters of Business Administration with Finance Certificate
Portland State University

Bachelor of Arts
University of Chicago

EXPERIENCE: I have been employed by the OPUC from April of 2008 to the present. My current responsibilities include financial and rate analysis in the Economic Research and Financial Analysis Division of the OPUC's Utility Program, with a focus on transmission and wind integration. I participate in regional and sub-regional planning including the Western Electricity Coordinating Council (WECC) Variable Generation Subcommittee (VGS) and the joint Columbia Grid and Northern Tier Transmission Group (NTTG) Wind Integration Study Team (WIST).

From 2002 to 2008 I was Executive Director of the Acceleration Transportation Rate Bureau, Inc. (ARB), where I developed new rate structures for surface transportation and created metrics to ensure program success within regulated processes.

I was Vice President of Operations for Willamette Traffic Bureau, Inc. from 1993 to 2002, where I managed tariff rate compilation and analysis. I also developed new information systems and did sensitivity analysis for transportation rate modeling.

I have prepared, presented, and defended formal testimony in contested hearings before the ICC, STB, WUTC and ODOT, and most recently prepared and presented Staff testimony in the BPA WP-10 transmission and generation rate cases.

CASE: UE 210
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1202

Exhibits in Support
Of Opening Testimony

July 24, 2009

Flow of examination in PacifiCorp 7-Segment (poles and wires) Feeder Model

HC = Hard Copy Exhibits

	Worksheet	Excel Tab	Top Left Ref	Table	HC Tab
1	**Feeder Model** OR 2010	Line Cost	PC 7	8.7	**Paice 907 8.7**
2	**Feeder Model** OR 2010	BR Cost	PC 8	8.8	**Paice 907 8.8**
3	**Feeder Model** OR 2010	BR Demand P	PC 9	8.9	**Paice 907 8.9**
	Feeder Model OR 2010	BR Demand C	PC 10	8.10	**Paice 907 8.10**
	Feeder Model OR 2010	BR Commit P	PC 11	8.11	**Paice 907 8.11**
	Feeder Model OR 2010	BR Commit C	PC 12	8.12	**Paice 907 8.12**
	Feeder Model OR 2010	kW	PC 6	8.6	**Paice 907 8.2**
4	**MC** Oregon 2010	PC 2	PC 2	8.2	**Paice 907 8.2**
5	**MC** Oregon 2010	PC 1	PC 1	8.1	**Paice 907 8.1**
6	**MC** Oregon 2010	Table 7	Table 7	7	**Paice 907 2.7**
7	**MC** Oregon 2010	Table 3	Table 3	3	**Paice 907 2.3**
8	**MC** Oregon 2010	Table 4	Table 4	4	**Paice 907 2.4**
9	**MC** Oregon 2010	Exhibit 905, P.1	Blank	Blank	**Paice 905 pg 1**

Working through LRIC also identified an opportunity to improve document and spreadsheet reference consistency.

Consistent placement of references on hardcopy and spreadsheets may speed future reviews, affording more time for incremental model improvement.

CASE: UE 210
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Opening Testimony

July 24, 2009

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 1300

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 09-120. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 210 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Kelcey Brown. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I am a Senior Economist in the Electric and Natural Gas Division of the Utility Program of the Public Utility Commission of Oregon.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/1301.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss the prudency of four wind-powered generation resources: Seven Mile Hill II, Glenrock III, High Plains, and Three Buttes. In addition, I will respond to Greg Duvall's second supplemental direct testimony associated with two issues: changes in methodologies utilized in the calculation of net power costs, and whether a stand-alone Transition Adjustment Mechanism (TAM) should include the variable power costs of new generation resources if the fixed costs of the generation resources are not included in rates.

Q. DO YOU PROPOSE ANY ADJUSTMENTS IN YOUR TESTIMONY?

A. No.

Q. PLEASE SUMMARIZE YOUR POSITION ON THE PRUDENCY OF THE FOUR WIND-POWERED GENERATION RESOURCES: SEVEN MILE HILL II, GLENROCK III, HIGH PLAINS, AND THREE BUTTES.

A. Staff believes the four wind-powered generation resources are prudent based on favorable comparisons to the recently acknowledged short-list of bids in the 2008R-1 request for proposal (RFP) proceeding (UM 1368) and previously built wind resources.

Q. PLEASE SUMMARIZE YOUR POSITION ON METHODOLOGY CHANGES IN STAND-ALONE TAM PROCEEDINGS.

A. Staff supports PacifiCorp's position to have no changes in methodologies in stand-alone TAM proceedings, however this would not preclude Staff and Intervenors from proposing adjustments or changes to existing methodologies that were adopted in the most recent general rate case (GRC). The TAM proceeding is intended to be a streamlined narrow proceeding in which the Company has the ability to update its costs, but in the past it has also taken the opportunity to update its modeling methodologies. Staff does not support the Company making these types of changes in stand-alone TAM proceedings.

Q. PLEASE SUMMARIZE YOUR POSITION ON INCLUDING VARIABLE POWER COSTS IN THE TAM PROCEEDING WITHOUT THE INCLUSION OF THE FIXED COSTS IN BASE RATES.

A. Staff does not support the Company's position, that the dispatch benefit of new resources should not be reflected in variable power costs and included in rates until the fixed costs are also included in effective rates. The TAM is an automatic adjustment clause that allows the company to update its variable power costs, which provides significant benefit for the company on a year-to-year basis. Staff position is that the TAM update should include all resources available by the beginning of the test period. A utility has complete discretion when to file a general rate case for recovery of fixed capital costs; therefore, customers should not be denied the dispatch benefit of new resources and incur higher variable power costs due to the timing of the Company's GRC.

Prudency Review

Q. PLEASE DISCUSS THE WIND POWERED RESOURCES PACIFICORP IS SEEKING COST RECOVERY FOR IN THIS PROCEEDING.

A. PacifiCorp is seeking cost recovery for Seven Mile Hill II, Glenrock III, High Plains, and the Three Buttes power purchase agreement (PPA).[1] The four wind resources are all located in the state of Wyoming, and are all relatively close to existing PacifiCorp wind resources; e.g. Seven Mile Hill, Glenrock, and Foote Creek.

Q. ARE THESE WIND RESOURCES CONSISTENT WITH PACIFICORP'S CURRENTLY ACKNOWLEGED INTEGRATED RESOURCE PLAN (IRP)?

A. Yes. PacifiCorp's 2007 IRP identified a renewable acquisition target of 1,400 MW by 2010, with an additional commitment to acquire up to 2,000 MW by 2013. The combined 256.5 MW, of the four wind powered resources identified above, are in-line with the Company's 1,400 MW renewable acquisition target that was acknowledged by the Commission.[2]

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[1] Seven Mile Hill II is a 19.5 MW resource with an expected 40.3 percent capacity factor, Glenrock III is a 39 MW resource with an expected 36.4 percent capacity factor, High Plains is a 99 MW resource with an expected 35.7 percent capacity factor, and Three Buttes is a 99 MW resource with an expected capacity factor of [redacted].

[2] See Order No. 08-232 (Docket LC 42).

Q. DID THE COMPANY ACQUIRE THE FOUR RESOURCES THROUGH A COMMISSION APPROVED RFP PROCEEDING?

A. No. The Commissions Competitive Bidding Guidelines[3] only require an RFP process for facilities that are greater than 100 MW and the term is greater than five years. All four of the wind-powered resources are below the 100 MW threshold. However, the Company did acquire the Three Buttes PPA through a Company RFP process termed “2008R.”

Q. DID THE COMPANY CONSIDER OTHER RESOURCES FROM THE 2008R?

A. Yes. According to the Company, it did consider and entered into negotiations for a 49.5 MW facility in early summer 2008. However, after months of negotiations the counterparty was unwilling to agree to PacifiCorp’s terms and conditions and negotiations were terminated in late 2008.

Q. HAS STAFF COMPARED THE FOUR WIND-POWERED RESOURCES TO THE 2008R BIDS OR THE RECENTLY ACKNOWLEDGED SHORT-LIST OF BIDS IN THE 2008R-1 RFP?

A. Yes. In Staff Data Request No. 290[4] the Company provided a comparison of the four new resources to seven bids from the 2008R-1 and four existing resources. The following criteria were used in the comparison: levelized $/MWh over the life of the resource, $/MW expected capital cost, interconnection cost, estimated or actual capacity factor, and projected wind integration costs.

[3] See Guideline 1 Order No. 06-446 (at 3).
[4] See Confidential Exhibit Staff/1302, Brown/1.

Q. DID THE FOUR WIND-POWERED RESOURCES COMPARE FAVORABLY TO THE EXISTING RESOURCES AND RECENTLY APPROVED SHORT-LIST OF BIDS IN THE 2008R-1 RFP?

A. Yes. The highest cost resource, on a $/MWh basis, was the [redacted]. This resource is approximately [redacted] than the next highest Company built resource, and is approximately [redacted] than [redacted]. However, the [redacted] resource is comparable to the recently approved 2008R-1 short list of bids.

Q. IS THE COMPANY CURRENTLY ACTIVE IN CONTINUING ITS SOLICITATION PROCESS FOR RENEWABLE RESOURCES?

A. Yes. As stated above, the Company has received acknowledgment of its short-list of bids in the 2008R-1 RFP process and on July 2, 2009 the Commission approved the 2009R RFP for new renewable resources.

<u>Methodological Changes in the TAM</u>

Q. PLEASE PROVIDE THE BACKGROUND TO STAFF'S POSITION ON CHANGES IN METHODOLOGIES USED TO CALCULATE NET POWER COSTS IN STAND-ALONE TAM PROCEEDINGS.

A. In a prior proceeding, UE 199, Staff testified[5] that PacifiCorp's change in methodology with regard to forced outage rates on hydroelectric facilities was more appropriate for a GRC proceeding than a TAM proceeding. The TAM is intended to provide the Company with the ability to update its fuel prices,

[5] See UE 199, Staff/100, Brown/11, Lines 12-23.

power purchase costs, loads, new resources and contracts. Instead, the Company has taken the opportunity to make significant changes in its modeling methodologies that are difficult for Staff and Intervenors to fully review the ramifications of in a shortened period of time.

Q. IS IT APPROPRIATE FOR THE COMPANY TO CONTINUE TO CORRECT METHODOLOGIES ASSOCIATED WITH AN ERROR IN THE MODEL?

A. Yes. If the Company can sufficiently demonstrate to parties that a change in methodology is necessary due to an error that the Company has discovered in its modeling, this is an appropriate change to make in either a TAM or GRC proceeding.

Q. IS THE COMPANY CURRENTLY ALLOWED TO CHANGE ITS LEAST COST DISPATCH MODEL (GRID) WITHOUT PRIOR CONSENT FROM STAFF AND INTERVENORS?

A. No. Prior to filing its annual TAM filing the Company must get the consent of Staff and Intervenors before filing net variable power costs using a new version of the GRID model. There is no reason the same criteria cannot be applied to changes in methodologies that the Company believes are necessary due to the finding of an error or a needed correction.

Q. WOULD THIS PRECLUDE STAFF OR INTERVENORS FROM SUGGESTING CHANGES OR ADJUSTMENTS ASSOCIATED WITH EXISTING MODELING METHDOLOGIES?

A. No. To only allow Staff and Intervenors a single year (GRC year) in which to propose changes to the model is inappropriate. These models are extremely complex and take a significant amount of time to fully evaluate and understand. With changing power prices or fuel contracts a change in methodology may not be fully isolated or understood for several years. Staff and Intervenors should not be precluded from proposing adjustments in a TAM proceeding.

Q. HAS THE COMMISSION EVER RAISED CONCERNS ABOUT THE ABILITY OF STAFF AND INTERVENORS TO PROPOSE ADJUSTMENTS IN THE TAM PROCEEDING?

A. Yes. In the original order establishing the TAM procedure the Commission recognized this very concern in the following statement, “We are somewhat concerned about establishing the TAM with its annual update because there is a certain amount of one-sidedness to PacifiCorp’s annual updates without concomitant adjustments by intervenors and Staff. We will continue to look at the TAM and investigate to whatever extent we believe is necessary.”[6]

New Resources

Q. PLEASE SUMMARIZE STAFF’S RECOMMENDATION WITH REGARD TO NEW RESOURCES AND THE ANNUAL TAM PROCEEDING.

A. Including new facilities that are used and useful as of January 1 of the test year into net power costs is reflective of the actual variable power costs that PacifiCorp will incur, and therefore appropriate for ratemaking.

Q. IS THIS THE FIRST TIME THAT STAFF OR INTERVENORS HAS MADE THIS TYPE OF RECOMMENDATION?

[6] See Order No. 05-1050, at 21.

A. No. In UE 170, Staff recommended that PacifiCorp include all new resources and their impact on net variable power costs in rates, regardless of whether the fixed costs of those resources were also included in rates. Staff argued that including all new resources in the power cost modeling would provide a better representation of the actual costs that PacifiCorp would incur in the test period. PacifiCorp accepted this recommendation within its sursurrebuttal testimony in UE 170.[7] , PacifiCorp indicated that changing the mechanism to incorporate new resources would address CUB's concern about "phantom costs" and eliminate reliance on proxy market purchases.

Q. WHEN CAN A UTILITY FILE A GENERAL RATE CASE IN ORDER TO RECOVER THE FIXED COSTS OF NEW RESOURCES?

A. A utility has complete discretion when to file a general rate case for recovery of fixed capital costs.

Q. PLEASE DISCUSS PACIFICORP'S ARGUMENT THAT THE COMMISSION ENDORSED A POLICY OF MATCHING THE RECOVERY OF FIXED AND VARIABLE COSTS FOR RENEWABLE RESOURCES AND THEREFORE SHOULD APPLY THE SAME STANDARD TO NON-RENEWABLE RESOURCES.

A. Section 13 of Senate Bill 838 required the Commission to establish an automatic adjustment clause that would allow timely recovery of prudently incurred costs. Therefore, the Commission approved a stipulation in which the parties agreed to allow the utility to recover the fixed costs of renewable

[7] See PPL/702, Omohundro/2.

resources if the dispatch benefits associated with those resources are also included in rates. Senate Bill 838 requires certain utilities to meet renewable portfolio standard obligations and aggressive renewable acquisition targets. The legislature likely included the automatic adjustment mechanism to mitigate the "regulatory lag" associated with its RPS requirements. Similar mandates do not apply to the acquisition of non-renewable resources.

Q. WAS PGE ABLE TO SYNCHORONIZE THE FIXED AND VARIABLE COST RECOVERY OF ITS PORT WESTWARD GENERATING FACILITY?

A. Yes. PGE filed a GRC proceeding before the facility was completed in order to recoup fixed costs from customers at the same time that customers recognized the variable costs of the resource.

Q. DOES PACIFICORP HAVE THE SAME OPTION, TO FILE A GRC PROCEEDING IN ORDER TO RECOUP FIXED COSTS AT THE SAME TIME THAT CUSTOMERS WOULD REALIZE THE DISPATCH BENEFIT OF THE RESOURCE?

A. Yes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 210
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1301

Witness Qualification Statement

July 24, 2009

WITNESS QUALIFICATION STATEMENT

NAME:	Kelcey Brown
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist, Electric and Natural Gas Division, Electric Rates and Planning
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.
EDUCATION:	All course work towards Masters in Economics University of Wyoming B.S. University of Wyoming Major: Business Economics Minor: Finance
EXPERIENCE:	Since November 2007 I have been employed by the Public Utility Commission of Oregon. Responsibilities include research, analysis and recommendations on a wide range of cost, revenue and policy issues for electric utilities. I have provided testimony in UE 199, UE 200, UE 204, UE 207 and UM 1355 and have actively participated in regulatory proceedings in Oregon, including UE 195, UE 198, LC 47 and UM 1429. From June 2003 to November 2007 I worked as the Economic Analyst for Blackfoot Telecommunications Group, a competitive and incumbent telephone provider in Missoula, Montana. I conducted all long and short term sales and revenue forecasts, resource acquisition cost-benefit analysis, business case analysis on new products and build-outs, pricing, regulatory support, market research, and strategic planning support. From May 2002 to August 2002 I worked as an intern at the Illinois Commerce Commission in Springfield, Illinois. I performed competitive market analysis, spot market monitoring and pricing review, and extensive research on locational marginal pricing and transmission system incentives for development. My course work, towards a Master's degree at the University of Wyoming, focused heavily on the regulatory economics of network industries such as electricity, natural gas, and telecommunications.

CASE: UE 210
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1302

Exhibits in Support Of Opening Testimony

July 24, 2009

STAFF EXHIBIT 1302

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ORDER NO. 09-120. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 210 TO RECEIVE THE

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OF THIS EXHIBIT.

UE 210
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CERTIFICATE OF SERVICE

UE 210

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 24th day of July, 2009.

Kay Barnes

Kay Barnes
Public Utility Commission
Regulatory Operations
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