BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

RE: THE INVESTIGATION AND SUSPENSION)
OF TARIFF SHEETS FILED BY PUBLIC SERVICE)
COMPANY OF COLORADO ADVICE LETTER NO.) DOCKET NO. 02S – 315 EG
1373 – ELECTRIC, ADVICE LETTER NO. 593 –)
GAS AND ADVICE LETTER NO. 80 – STEAM)

SETTLEMENT AGREEMENT

April 4, 2003

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OF THE STATE OF COLORADO**

RE: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO ADVICE LETTER NO. 1373 – ELECTRIC, ADVICE LETTER NO. 593 – GAS AND ADVICE LETTER NO. 80 – STEAM	)))))	DOCKET NO. 02S – 315 EG

SETTLEMENT AGREEMENT

Public Service Company of Colorado, the Staff of the Colorado Public Utilities Commission, the Office of Consumer Counsel, the Colorado Governor's Office of Energy Management and Conservation, the City and County of Denver, the Colorado Energy Consumers, The Kroger Company, the Federal Executive Agencies, the Land and Water Fund of the Rockies, the Colorado Energy Assistance Foundation, and the Colorado Business Alliance for Cooperative Utility Practices (collectively, the "Parties") hereby enter into this Settlement Agreement.

INTRODUCTION[1]

On May 31, 2002, Public Service Company of Colorado ("Public Service" or the "Company") filed Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, and Advice Letter No. 80 – Steam with the Colorado Public Utilities Commission ("Commission" or "CPUC"), tendering revised tariff sheets in which the Company proposed comprehensive rate and tariff changes. The Company also filed Direct Testimony and Exhibits in support of the proposed rate and tariff changes. The

[1] Attachment A is a spreadsheet showing the adjustments to the Company's original case as a result of the corrections and stipulations identified in this Settlement Agreement.

Company requested the following changes in rate revenue (as summarized in Table No. FCS-1, filed with the Direct Testimony of Fredric C. Stoffel):

Table No. FCS-1
Summary Chart of 2002 Rate Case Impact

	A	B	C	D	E	F
Department	Base Rate Revenue (No Riders)	Revenue From Existing Riders	Proposed Revenue Increases Compared To Base Revenue	Net Change to Annual Revenue (C-B)	Net Change Annual Percent (D/A)	Percent Rider (C/A)
Gas	$ 285,411,606	$ 15,483,440	$ 2,581,416	$(12,902,024)	-4.52%	0.90%
Electric						
Base	$ 1,427,853,011	$(32,678,899)	$ 74,404,991	$107,083,890	7.50%	5.21%
ECA	$ -	$ -	$ 113,003,685	$113,003,685	7.91%	7.91%
	$ 1,427,853,011	$(32,678,899)	$ 187,408,676	$220,087,575	15.41%	
Steam	$ 7,524,464	$ 906,698	$ 1,360,827	$ 454,129	6.04%	18.09%
Total	$ 1,720,789,081	$(16,288,761)	$ 191,350,919	$207,639,680	12.07%	

As Column C of the table above shows, in its direct case Public Service proposed revenue increases as compared to base rate revenue as follows: Gas $2,581,416; Electric $74,404,991; and Steam $1,360,827. In its Direct Testimony, the Company proposed an Electric Commodity Adjustment ("ECA") that would recover $113,003,685 in 2003.[2]

On August 7, 2002, the Company filed Supplemental Direct Testimony, Corrected Testimony and Revised Exhibits, primarily as a result of the Commission-approved restructuring of two power purchase agreements between the Company and the Thermo companies. This filing reduced the Company's requested increases in base rate revenue for the electric and gas departments but increased projected ECA revenue. The Company's Supplemental Direct filing requested the following revenue increases to base rate revenue: Gas $2,249,166; Electric $60,257,656; and Steam

[2] As explained *infra* at Section XII.A., the Company's proposed ECA has been replaced by the Interim Adjustment Clause ("IAC") for 2003.

$1,360,827. The Company projected 2003 ECA revenue to be $127,256,402 (Exhibit No. RND-4 (Revised 8/07/02)).

Contemporaneous with the preparation of Answer Testimony and Exhibits, the Staff and the OCC engaged in negotiations with the Company concerning depreciation issues and corrections to the Company's filed position. These negotiations resulted in the execution of two stipulations that were filed on November 22, 2002.

The first Stipulation and Agreement Regarding Depreciation Issues ("Depreciation Stipulation," attached as Attachment B) was entered into between Public Service, Staff and the OCC and dealt with the details of calculating the Company's depreciation expense. The effect of the Depreciation Stipulation changed the Company's requests for base rate revenue increases by the following amounts: Gas $609,935; Electric ($29,266,852)[3]; and Steam ($4,658). The Depreciation Stipulation did not affect the projected 2003 ECA.

The second Stipulation Regarding Corrections to the Direct Case Filed by Public Service Company of Colorado ("Stipulation on Corrections," attached as Attachment C) was entered into between Public Service and Staff and reflected an agreement on numerous changes and acknowledged errors in the Company's Direct and Supplemental Direct Testimony and Exhibits. The seven issues addressed in the Stipulation on Corrections were primarily identified through Staff's audit of the Company's Direct Case. The corrections changed the Company's revenue requirement request with respect to: (1) the cash working capital allowance resulting from a revision of certain lead/lag factors in the Company's lead/lag study; (2) the proper accounting of

[3] Numbers in brackets denote negative numbers or decreases in expense.

Other Comprehensive Income in the common equity portion of the capital structure; (3) the *pro forma* adjustment to firm wheeling service for a reclassification of the revenue credit for autotransformer capacity charges; (4) the rent expense to reflect the correct utility allocators; 5) the calculation of the thermal department cash working capital; (6) the proper elimination of the amortization of gas rate case expenses; and (7) the correct allocation of common deferred tax expenses.

The Stipulation on Corrections contemplated certain further corrections to calculations, which corrections were agreed to between Staff and the Company and set forth in a Supplemental Stipulation Regarding Corrections to the Direct Case Filed By Public Service Company of Colorado ("Supplemental Stipulation Regarding Corrections," attached as Attachment D) dated January 23, 2003. The three issues addressed in the Supplemental Stipulation Regarding Corrections reflect additional corrections to the Company's revenue requirement request with respect to: (1) the correct labor overheads and Administrative and General ("A&G") Engineering and Supervision overheads used to develop the loaded labor rates for the Company's proposed non-gratuitous charges; (2) the income tax expense to remove the amount of Allowance for Funds Used During Construction ("AFUDC") multiplied by the composite tax rate; and (3) reallocation of certain bad debt expenses to the Federal Energy Regulatory Commission ("FERC") jurisdiction.

The changes reflected in these three Stipulations are summarized in spreadsheet form in Attachment A to this Settlement Agreement. Incorporating the cumulative result of the three Stipulations, the Company's direct case reflected increases (or decreases) to base rate revenue in the following amounts: Gas ($6,891,919); Electric $18,945,647; and Steam $1,144,393.

On November 22, 2002, many parties filed Answer Testimony and Exhibits objecting to aspects of the Company's requested rate changes. Some parties objected primarily to the Company's proposed ECA and raised issues with respect to the Company's electric trading operation.[4] Other parties concentrated their objections on issues that were reflected in the changes that the Company proposed to Base Rate Revenue Requirements for the electric, gas and thermal departments.

Staff and the OCC each summarized their Answer testimonies using tables similar to the Company's Table FCS-1. Staff's case in Answer Testimony is summarized by the following table presented in the updated Answer Testimony of Dr. Gary E. Schmitz[5]:

4 Among the parties filing Answer Testimony addressing the ECA were CF&I Steel, LLP ("CF&I") and Climax Molybdenum Company ("Climax"). CF&I and Climax take no position with respect to the Settlement Agreement.

5 Dr. Schmitz filed corrections to his Answer Testimony on February 18, 2003, to reflect the Company's direct case revenue change request as of January 23, 2003. Table GES-1 presented in this Settlement Agreement is the corrected Table GES-1.

Table No. GES-1

Summary Chart of Staff View of PSCo's 2002 Rate Case Impact[6]

	A	B	C	D	E	F
Department	Pro Forma 2001 Base Rate Revenues	Revenue from Existing Riders	Proposed Revenue Increases Compared to Base Revenue	Net Change to Annual Revenue	Net Change Annual Percent	Percent Rider
				(C-B)	(D/A)	(C/A)
Gas	$ 290,226,216	$ 15,483,440	$ (30,056,558)	$ (45,539,998)	-15.6912%	-10.3563%
Electric						
Base	$ 1,427,501,814	$ (32,678,899)	$ (51,024,042)	$ (18,345,143)	-1.2851%	-3.5744%
ECA			$ 111,738,600	$ 111,738,600	7.83%	7.8276%
SubTotal	$ 1,427,501,814	$ (32,678,899)	$ 60,714,558	$ 93,393,457	6.5424%	
Thermal	$ 7,524,464	$ 906,698	$ 771,263	$ (135,435)	-1.7999%	10.2501%
Total	$ 1,725,252,494	$ (16,288,761)	$ 31,429,263	$ 47,718,024	2.7659%	

The OCC's case is summarized in the Answer Testimony of Kenneth V. Reif[7]:

Department	Base Rate Revenue (No Riders)	Revenue From Existing Riders	Proposed Revenue Increases Compared Base Revenue	Net Change To Annual Revenue	Net Change Annual Percent	Proposed Percent Rider
Gas	$285,411,606	$15,483,440	($16,666,246)	($32,149,686)	-11.26%	-5.84%
Electric						
Base	$1,427,853,011	($32,678,899)	($47,974,605)	($15,295,706)	-1.07%	-3.40%
ECA	$0	$0	$113,003,685	$113,003,685	7.91%	7.91%
	$1,427,853,011	($32,678,899)	$65,029,080	$97,707,979	6.84%	
PSCo Total	$1,713,264,617	($17,195,459)	$48,362,834	$65,558,293	3.83%	

6 The table included in the updated Answer Testimony of Dr. Schmitz did not reflect the impact of expiration of a portion of the negative electric base rate rider on August 1, 2002. After August 1, 2002, revenues from the existing base rate electric rider changed from ($32,678,899) to ($20,852,893).

7 The table included in the Answer Testimony of Kenneth V. Reif did not reflect the corrections agreed to in the Stipulation on Corrections or the Supplemental Stipulation Regarding Corrections, nor did it reflect the expiration of a portion of the negative electric base rate rider on August 1, 2002.

On January 24, 2003, the Company filed its Rebuttal Testimony and Exhibits. In its Rebuttal Testimony, the Company accepted some of the issues or positions raised in the Answer Testimony and defended the Company's position against other issues. After the filing of the Company's Rebuttal Case and the three stipulations discussed above, the Company's requested changes to base rate revenue were as follows: Gas ($6,387,191); Electric $16,193,383; and Steam $1,089,092.

In its Rebuttal Case filed on January 24, 2003, the Company updated its projected 2003 ECA to reflect an updated sales forecast, an updated jurisdictional split and an updated gas commodity cost forecast. Based upon this updated information, the Company projected the 2003 ECA to be $152,448,122.[8] However, a portion of the 2003 ECA revenue is already being collected through the Interim Adjustment Clause ("IAC") that went into effect January 1, 2003 pursuant to Commission Decision No. C02-609 (May 24, 2002) in Docket No. 02A-158E. The Company projected that the revenues that would be collected under its proposed 2003 ECA would exceed the revenue currently collected under the IAC by $29,772,639 (Exhibit No. RND-4 (Revised 1/24/03), line 17).

On February 12, 2003, the Company filed Supplemental Rebuttal Testimony and Exhibits to correct errors found in its Rebuttal Testimony and Exhibits, to concede the issue of the production capacity adjustment related to Windsource which had been opposed by the Staff and the Land and Water Fund of the Rockies ("LAW Fund"), to allocate an appropriate share of plant associated with the Company's Customer

[8] Although not set forth on Exhibit No. RND-4, page 1 (Revised 1/24/03), this updated ECA projection may be derived by netting the ECA Factors on line 9 and the ECA Credits on line 10, and then multiplying the net amount by the jurisdictional sales by delivery level on line 14.

Information System ("CIS") to its non-regulated business activities, and to correct the interest expense on customer deposits for the gas department. After these filings, the Company's proposed case stood as follows: Gas ($5,984,401); Electric $14,503,382; and Steam $1,089,084.[9] The Company further updated its projections of 2003 ECA revenue, projecting the 2003 ECA revenue to be $186,473,283. The Company projected that the revenue it would collect under its proposed 2003 ECA would exceed the revenue currently collected under the IAC by $63,899,985. (Exhibit No. RND-4 (Revised 2/12/03)). These are the requests for base rate revenue changes that the Company would have sought had this matter proceeded to a fully contested hearing.

Subsequent to the filing of its Rebuttal testimony, the Company has been in settlement discussions with opposing parties regarding all issues. These settlement discussions have been successful. The Parties have reached compromise and settlement on all contested issues in this case. The resolutions of all contested issues are set forth in this Settlement Agreement. For the purpose of determining Phase I revenue requirements~~ and for purposes of Earnings Test filings until the next general rate case~~, to the extent an issue is not specifically addressed in this Settlement Agreement or detailed in the supporting cost of service in Attachment E, the Parties have accepted the Company's last filed position on that issue.

As a result of this Settlement Agreement, the Parties have agreed to the following changes to the base rate revenues of the Company: Gas ($17,843,528); Electric ($21,082,702); and Steam $880,653. When the revenues from expiring rate

[9] These amounts are set forth in the Supplemental Rebuttal Testimony (2/12/03) of Timothy L. Willemsen at page 4. They differ from those set forth in Table FCS-1 to the Supplemental Rebuttal Testimony (2/12/03) of Fredric C. Stoffel at page 2 because of the exclusion of Street Light Maintenance revenue.

riders are taken into account, the net result of this settlement on base rate revenue is as follows: Gas ($33,326,968); Electric ($229,809)[10]; and Steam ($26,045) (compare to Column D of the above summary charts). The following table sets forth the results of this Settlement Agreement:

	A	B	C	D	E	F
Department	Base Rate Revenue (No Riders)	Revenue From Riders as of May, 2003	Proposed Revenue Increases Compared To Base Revenue	Net Change to Annual Revenue (C-B)	Net Change Annual Percent (D/A)	Percent Rider (C/A)
Gas	$ 288,019,186	$ 15,483,440	$ (17,843,528)	$ (33,326,968)	-11.57%	(1)
Electric						
Base	$ 1,427,853,011	$ (20,852,893)	$ (21,082,702)	$ (229,809)	-0.02%	(1)
IAC	$ -	$ -	$ 215,508,934	$ 215,508,934	15.09%	
	$ 1,427,853,011	$ (20,852,893)	$ 194,426,232	$ 215,279,125	15.08%	
Steam	$ 7,524,464	$ 906,698	$ 880,653	$ (26,045)	-0.35%	(1)
Total	$ 1,723,396,661	$ (4,462,755)	$ 177,463,357	$ 181,926,112	10.56%	

'(1) See Attachment E, Schedule 2 for the rider calculations.

The Parties have also agreed to the mechanism that the Company shall use for recovery of fuel, purchased energy and purchased wheeling expense incurred by the electric department beginning January 1, 2003[11] and the sharing of margins from the Company's trading operations.

REVENUE REQUIREMENTS MODEL AND PHASE II

As a part of this Settlement Agreement, the Parties have agreed that the Company shall modify its revenue requirements model to reflect the jurisdictional cost of service, without functionalization, and including jurisdictional revenues, expenses and

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[10] The net change to the electric base rate revenue does not reflect the full impact of the ($32,678,899) rider identified in Column B of the above tables because a portion of that negative rider expired on August 1, 2002. Instead, the net change to the electric base rate revenue of ($229,809) reflects a rider of only ($20,852,893).

[11] Pursuant to the Settlement Agreement approved by Commission Decision No. C02-609 in Docket No. 02A-158E, the Company's fuel, purchased energy and purchased wheeling expenses incurred by the electric department beginning January 1, 2003, which are currently recovered through the Interim Adjustment Clause or IAC is to be recalculated and trued up to the recovery mechanism approved by the Commission in this general rate case.

rate base. The revised cost of service presentation is similar to the Company's cost of service presentation contained in its Earnings Test Reports. A summary of the Company's CPUC jurisdictional cost of service incorporating the results of this Settlement Agreement, including an income statement and rate base, the percent rider calculations, and the calculation of cash working capital, is attached to this Settlement Agreement as Attachment E. An electronic version of the cost of service model is filed contemporaneously with the filing of this Settlement Agreement.

As required by the Stipulation and Agreement, dated January 31, 2000, entered in Docket No. 99A-377EG and approved by the Commission in Decision No. C00-393 (the "Merger Stipulation"), Public Service will file an electric Phase II (cost allocation/rate design) case for its electric department within 120 days following the entry of the final order in this docket. In addition to the electric Phase II, Public Service plans to file a Phase II for its thermal department at that time. Given that the cost allocations and rate design underlying Public Service's current gas rates were approved by the Commission in July 2000 in Docket No. 99S-609G, the Parties agree that Public Service should not be required to file a Phase II case for its gas department until its next comprehensive gas base rate change.

The Company's revised cost of service model establishes the Company's CPUC jurisdictional cost of service and the resulting total jurisdictional revenue requirements for the Company's gas, electric and thermal departments. With the exception of certain adjustments to jurisdictional revenue requirements that are expressly permitted under Section VII of this Settlement Agreement (Reclassification of Substation Plant and Treatment of Radial Transmission Lines) concerning a change in the classification of high voltage facilities within distribution substations from transmission to distribution and/or the direct assignment of radial transmission facilities during Phase II, the Parties agree that the total jurisdictional revenue requirement amounts established by this Settlement Agreement shall be the revenue requirement amounts intended to be collected as a result of the allocation of costs among rate classes in Phase II. All Parties have reserved all rights to advocate any position regarding the design of rates and the means of allocating of costs among the customer classes for purposes of Phase II of the Company's rate proceeding.

EARNINGS TEST AND EARNINGS SHARING

It is the Parties' intent that, consistent with the Merger Stipulation, the outcome of this proceeding shall establish the ratemaking principles to be applied in the electric Earnings Tests for calendar years 2004, 2005 and 2006. Except as expressly modified by this Settlement Agreement, the Earnings Test and sharing mechanism described in the Merger Stipulation shall continue in effect and all Parties retain all rights with respect to the Earnings Test and sharing mechanism that are afforded under the Merger Stipulation. Section XVI *infra* identifies the revised sharing percentages and the ratemaking principles resulting from this Settlement Agreement that the Parties agree shall be applied in the 2004, 2005 and 2006 Earnings Tests unless altered by further order of the Commission entered in a subsequent rate case, or in an Earnings Test proceeding based on the Commission's finding of a "material change of circumstances" warranting such change as set forth at page 12 of the Merger Stipulation.

TERM OF THE SETTLEMENT AGREEMENT

This Settlement Agreement shall take effect upon its approval by the Commission. Nothing in this Settlement Agreement shall be construed to prevent the Company from filing a general rate case for its electric, gas or steam operations at any time. Nothing in this Settlement Agreement shall be construed to limit the Company from applying to the Commission for adjustment clauses or for any other change to the Company's electric, gas and steam rates. Nothing in this Settlement Agreement shall be construed to prevent the Staff of the Commission (by seeking an Order to Show Cause) or any other party (by filing a Complaint) from seeking review by the Commission of the justness and reasonableness of the Company's electric, gas or steam rates.

Where reference is made in the Settlement Agreement to provisions that apply for a period of time (for example the references to the 2004-2006 Energy Cost Adjustment), all such time period provisions of this Settlement Agreement may be modified by a subsequent filing with the Commission. Where references are made to settled principles for purposes of Earnings Tests, these settled principles shall only be deemed settled for Earnings Tests that apply to periods before the conclusion of a subsequent general rate case proceeding, whether initiated by the Company or by any other party.

PUBLIC INTEREST

The Parties to this Settlement Agreement state that reaching agreement as set forth herein by means of a negotiated settlement rather than through a formal adversarial process is in the public interest and, therefore, the compromises and settlements reflected in this Settlement Agreement are in the public interest. The Parties further state that approval and implementation of the compromises and settlements reflected in this Settlement Agreement constitute a just and reasonable resolution of this proceeding.

EXECUTIVE SUMMARY OF SETTLEMENT

Cost of Service

Public Service's original filing on May 31, 2002 requested the following revenue increases: $2.58 million for gas, $74.40 million for electric, and $1.36 million for thermal. These were increases above the levels included in the Company's base rates at the time of the filing and therefore did not reflect the revenue impact of the existing negative electric revenue riders associated with the mergers or the positive gas and thermal energy revenue riders from the Company's prior rate cases. On the electric side, the Company was also showing an increase in the ECA of $113 million due to higher purchased fuel and energy costs.

The Company's final rebuttal case, filed February 12, 2003, proposed a $5.98 million decrease for gas, a $14.50 million increase for electric operations, and a $1.09 million increase for thermal. The rebuttal case filing incorporated the correction of certain errors to the original filing, the restructured cost of a purchased power agreement (Thermo), reductions associated with the settlement of depreciation rates, and certain allocation issues.

This settlement proposes a cost of service decrease for gas operations of $17.84 million, a decrease of $21.08 million for electric operations, and a $0.88 million increase for thermal operations. These amounts are measured against the Company's original filing. After taking into account the elimination of existing riders and the current IAC, the electric base rates will decrease $229,809, and the IAC will recover an additional $93.1 million. The gas base rates will decrease $33.3 million and the thermal energy base rates will decrease $26,045.

Taken as a whole, typical residential natural gas customers will see a decrease of $1.74 on monthly bills, while typical small business natural gas customers will see a decrease of $5.55 a month. Typical residential electric customers will see an increase of $4.34 on their monthly bills, while typical small business electric customers will see an increase of $8.80 per month.[12]

Key aspects of the cost of service settlement are:

- Depreciation expense decreased from current levels for the electric and thermal departments, and increased from current levels for the gas department.
- Agreement to a 10.75% return on equity for electric and 11.0% for gas and thermal.
- Use of average rate base instead of year-end rate base.
- Amortization of the full Plant Held for Future Use balance of the Pawnee 2 Pre-engineering costs over four years.
- Agreement that the revenue requirement allowance for gas stored underground inventory will be based on test year period volumes using a three-year average price based on the Last In, First Out method (“LIFO”).

[12] These customer impacts are calculated as of July 1, 2003. Attachment L hereto sets forth the customer impacts of the rate changes that would result from this Settlement Agreement if approved by the Commission.

- Inclusion of actual 2002 property and casualty insurance expense levels.
- Adjustment of purchased capacity costs to reflect 2002 actual payments.
- Elimination of $2.74 million of A&G and non-production Operations and Maintenance ("O&M") expense associated with the Company's electric trading operations from the CPUC jurisdictional cost of service.
- Inclusion of oil and gas royalties and related administrative expenses in the determination of retail revenue requirements.
- Recognition of a portion of the anticipated increase in pension costs in 2003.
- Acceptance of the Company's *pro forma* adjustment relating to the discontinuation of operations at PS Colorado Credit Corporation ("PSCCC").
- Agreement to accept the Company's allocation and assignment of costs to its non-regulated business activities as reflected in its Rebuttal case; and that the Parties will engage in workshops to evaluate the form of the Company's Fully Distributed Cost ("FDC") study and endeavor to arrive at fair and reasonable assignments and allocations of costs to and between Public Service's regulated and non-regulated business activities.
- The Company agrees to phase out the use of FERC allocations in its JD Edwards general ledger accounting system as defined in the Company's 2002 Cost Allocation Manual.
- Agreement, pending the conclusion of the Phase II rate case, that the Company's base rates shall continue to recover energy costs in the

amount of $12.78 per MWh; the Company's fuel clause (first the IAC and then the ECA) shall recover Energy Costs in excess of $12.78 per MWh; and the Company shall withdraw its proposed Base Energy Credit.

- The Company agrees to file by June 1, 2007 to reduce base rates to eliminate the amortizations for the Pawnee 2 Pre-engineering costs and the Metro Ash Disposal Site option.

Electric Commodity Adjustment & Trading

Key aspects of the electric commodity adjustment (ECA) and trading issues are:

- 100% pass-through of CPUC fuel and purchased energy expense during 2003. Change existing rates using 2003 forecast beginning July 1, 2003. This would increase electric rates by $93.1 million above the amount being collected through the Interim Adjustment Clause that became effective January 1, 2003.
- Implementation of a new ECA based on the Company's formula on January 1, 2004. The formula will use as a test year the 12-month period ending August 31, 2003. The new ECA will remain in effect through calendar year 2006.
- The costs recovered through the ECA will be bounded as follows: The first $15 million above and $15 million below the ECA base is shared 50% to retail customers and 50% to shareholders. The next $15 million above and $15 million below is shared 75% to retail customers and 25% to shareholders. Beyond $30 million, 100% of the CPUC jurisdictional cost increases or decreases will be passed on to retail customers.

- The Company will file an application on April 1, 2006 addressing the regulatory treatment of fuel and purchased energy expenses beyond December 31, 2006.
- The 100% pass-through IAC that is in effect in 2003 and the incentive ECA rate that is in effect in each year generally will be modified annually, but shall be subject to more frequent modification within certain constraints.
- Within certain limits, the Company will be permitted to sell gas which was purchased for electric system operation, but which is not needed for certain months or certain days.
- Margin sharing shall be calculated separately for each of the Generation Book margins and Proprietary Book margins.[13] Within each book, the CPUC jurisdictional Gross Margins shall be aggregated annually. If these aggregated margins from either book are negative, the negative margin shall not be passed on to retail customers.

[13] *See* discussion of Trading, *infra* at Section XIII, in which further definition is supplied concerning the Company's Generation and Proprietary Book trading operations.

- For 2003 and 2004, positive Gross Margins shall be treated as follows:
  - Generation Book: customers get the first $1.74 million. The Company will retain the next $1.74 million. The remainder is shared on a 60%/40% (retail customer/shareholder) basis.
  - Proprietary Book: the Company receives the first $1 million and the remainder is shared on a 40%/60% (retail customer/shareholder) basis.
- The definition of short-term wholesale sales shall be modified to include sales of up to two years in term length.
- Agreement to use the Company's current Business Rules as the basis of the operation of trading and sharing during 2003 and 2004. If the Company operates by these rules for transactions made prior to January 1, 2005, its actions shall be deemed prudent.
- The Company shall arrange for a procedures audit of its Generation and Proprietary book trading operations. The audit shall be conducted and completed by October 1, 2003. The cost of the audit shall be deemed an allowable expense in the 2004 Earnings Test.
- In January 2004, the Company shall file an application for Commission review of its trading operation, including its Business Rules and cost allocation procedures related to costing short-term wholesale sales. The expectation would be that this new case would be completed by October 15, 2004. Any change in cost allocation procedures or in the Business Rules would apply prospectively only beginning January 1, 2005.

- Within ~~two~~ one months of the effective date of this Settlement Agreement, the Company shall provide funds to hire a consultant selected by the trial Staff and OCC to provide Staff and the OCC with technical advice and consulting regarding prospective changes that should be made, if any, to the Company's trading activities. The Company's expenditures for this consultant shall be recoverable through the 2003 or 2004 fuel and purchased energy adjustment clause.

SETTLEMENT OF DISPUTED ISSUES

I. Rate Of Return and Capital Structure

A. Rate of Return on Equity

Background. Five witnesses presented testimony regarding the proper rate of return on equity ("ROE"). Their recommendations are summarized in the table below:

Witness	Recommendation
Dr. Olson (PSCo)	12% (electric) 12.25% (gas and thermal)
Mr. Trogonoski (Staff)	10.75%
Mr. Copeland (OCC)	9.90%
Mr. Kahal (FEA)	10.70% (electric) 11% (gas)
Mr. Gorman (CEC)	10.50%

All of the witnesses who addressed the issue of ROE derived their estimates using a Discounted Cash Flow ("DCF") approach, supplemented, in some cases, by analyses using the Capital Asset Pricing Model, risk premium approach, or Dividend Discount Model. The pre-filed testimony of these witnesses reflects a variety of opinions regarding the selection of the appropriate group of comparable companies to use in the DCF analysis, and the determination of dividend yields and growth rates. In addition, Staff witness Mr. Trogonoski stated his opinion that the Commission should not allow the Company to earn a higher rate of return because of Xcel Energy's decision to expand into unregulated businesses, such as NRG Energy, Inc. ("NRG"). The Company disputes that Xcel Energy's participation in unregulated businesses, including NRG, during the test year should have any impact on the determination of its rate of return on equity. As Dr. Olson explained in his Direct Testimony, he purposefully excluded consideration of Xcel Energy and other large diversified holding companies from his DCF analysis in order to determine an appropriate return on equity unaffected by the risk associated with the merchant generation business.

Resolution. For purposes of settlement, the Parties agree that a fair and reasonable ROE for the electric utility is 10.75% and for the gas and thermal utilities is 11.00%.

B. Cost of Debt

Background. Staff witness, Mr. Trogonoski, recommended reducing the Company's embedded cost of debt from 7.31% to 7.20% to reflect an assumed refinancing of a $147,840,000 debt issue during 2002 at a lower coupon rate than that included in the Company's embedded cost of debt. As grounds for imputing to the Company a lower cost of debt than its embedded cost, Mr. Trogonoski suggested that, but for the fact that the Company's credit rating was under review by rating agencies, the Company would have refinanced this 8.75% debt at 7.63% during the summer of 2002. In her Rebuttal Testimony, the Company's witness, Ms. Schell, refuted Mr.

Trogonoski's assertion that the Company would have refinanced this high coupon rate debt during 2002 had its credit rating been higher. Ms. Schell contended that if all costs associated with such a refinancing were taken into consideration, refinancing the $147,840,000 debt issue at 7.63% would have resulted in an increase to the Company's embedded cost of debt rather than decreasing it as Mr. Trogonoski claimed. Ms. Schell challenged the adjustment on the basis that it was out-of-period and failed to reflect a known and measurable change.

Resolution. For purposes of settlement, the Parties agree that the Company's proposed cost of debt of 7.31% shall be used to determine the weighted average cost of capital. This 7.31% equals the Company's embedded cost of debt as of the end of the 2001 test year.

C. Capital Structure and Weighted Average Cost of Capital

Background. Public Service recommended that the Commission use its capital structure as of the end of the 2001 test year, excluding short-term debt, adjusted to include notes payable to subsidiaries as a part of long-term debt and to reflect the discontinuance of operations at PSCCC. CEC's witness, Mr. Gorman, found the Company's proposed capital structure to be reasonable for ratemaking purposes. Staff concurred with the Company's Direct Case as corrected on January 23, 2003. OCC's witness Mr. Copeland accepted the Company's proposal to use an historic year-end capital structure, excluding short-term debt, but opposed the Company's adjustments for PSCCC and for notes payable to subsidiaries. Kroger's witness, Mr. Higgins, proposed that the Commission include in the regulated capital structure $562.8 million of short-term debt on the Company's books as of the end of the test year.

The following table summarizes the Parties' final, as filed, recommendations with respect to capital structure ratios:

Party	**Short-Term Debt**	**Long-Term Debt**	**Equity**
Public Service		48.60%	51.40%
CEC		48.72 %	51.28 %
FEA		48.72%	51.28%
Staff		48.60%	51.40%
OCC		45.72%	54.28%
Kroger	13.575%	39.525%	46.90%

Resolution. For purposes of settlement, the Parties have agreed to the Company's and Staff's proposed capital structure of 48.60% long-term debt and 51.40% common equity. The Parties agree that Public Service's proposed capital structure is reasonable and should be used to establish the Company's revenue requirement in this proceeding. The Parties further agree that for purpose of the earnings sharing calculation in 2004, 2005 and 2006, the Company shall use year-end capital structure adjusted to include notes payable to subsidiaries as long-term debt. In addition, an adjustment will be made to remove any Earnings Test accruals from the common equity balance. The Parties also agree that the Commission should exclude short-term debt from the regulatory capital structure. The following tables reflect the weighted average cost of capital for the Company's electric, gas and thermal utility operations, respectively, that has been agreed to by the Parties:

Electric Utility

	Weight	Rate	Wtd Cost
Long-Term Debt	48.60%	7.31%	3.55%
Equity	51.40%	10.75%	5.53%

Total Cost:			9.08%

Gas and Thermal Utilities

	Weight	Rate	Wtd Cost
Long-Term Debt	48.60%	7.31%	3.55%
Equity	51.40%	11.00%	5.65%
Total Cost:			9.20%

II. Rate Base

A. Average Rate Base

Background. In its direct case, Public Service used year-end rate base in developing its proposed revenue requirements in accordance with the rate base calculation method approved by the Commission for Public Service in Colorado rate cases over the past 30 years.

In their Answer Testimony, Staff and the OCC recommended that the revenue requirement be developed based on an average rate base method. Staff and the OCC argued that the continued calculation of rate base using a year-end rate method rather than an average method is no longer warranted. Staff's and the OCC's position is that the factors justifying the use of year-end rate base including continued significant investment in non-revenue producing plant; upward-spiraling capital costs; sustained and continued customer growth that requires additional plant investment; and a high general inflation rate, are no longer present. Staff presented data to support its position that inflation rates since 1993 have been relatively stable at near record low levels and the rate of growth in the Company's gross plant has decreased since 1996. In addition, Staff and the OCC argued that any attrition has been mitigated by special tariff riders, such as the Gas Cost Adjustment, the electric cost adjustment as it existed prior to 1996, and the Y2K and air quality improvement riders.

In its Rebuttal Testimony, Public Service disputed Staff's and OCC's contention that the conditions relied upon by the Commission in adopting year-end rate base for Public Service have changed materially since that time, and asserted that, to the extent they have, other equally important factors have taken their place to justify the continued use of year-end rate base. In particular, Public Service argued that the sustained effect of earnings attrition, inflation and investment to meet rapid system growth is at least as significant today as the combination of factors relied upon 30 years ago, and the impact of regulatory lag is even more pronounced.

Resolution. In resolution of this issue, the Parties agree that an average rate base method should be employed for purposes of determining the revenue requirements in this case. Under this method, the 13-month average of month-end balances shall be used for all rate base items except cash working capital. Cash working capital is calculated using *pro forma* expenses multiplied by the appropriate working capital factors as reflected in Attachment E. The AFUDC addition to earnings shall be based upon actual test-period expenses, not annualized, and related adjustments for deferred taxes.~~[14]~~

To the extent possible, *pro forma* adjustments and unusual items occurring during the test year[15] will also be made using a 13-month average of month-end

~~14 The Parties acknowledge that the proposed treatment of AFUDC for purposes of this Settlement Agreement constitutes a modification of the principles approved by the Commission in Decision No. C95-52, mailed January 17, 1995, in Docket No. 94A-679EG.~~ [footnote intentionally deleted]

15 One example where it may not be possible to determine the thirteen-month average is if an adjustment to rate base is required to be made during the calendar year and the Company does not have thirteen

balances. In cases where the 13-month data is not available for *pro forma* adjustments, the sum of the prior year-end balance and the test year-end balance divided by two will be used. Specific assignment of plant to either the CPUC or FERC jurisdiction will use year-end balances. The use of average rate base for determining cost of service shall not be considered a settled principle for purposes of the 2004, 2005 and 2006 Earnings Tests.

B. Plant Held for Future Use

1. Southeast Water Rights

Background. In its direct case, Public Service proposed to continue the current rate treatment established in Docket No. 93S-001EG for the amount booked in Plant Held For Future Use associated with the water rights purchased for a prospective power plant in southeast Colorado; *i.e.*, the debt cost portion of the Company's carrying costs of these water rights is included in revenue requirements. Public Service argued that, since there is a potential use for these water rights in the future, including their potential sale, the Company should at a minimum be allowed to continue the current partial recovery rate treatment. OCC and CEC in their Answer Testimony objected to this proposed rate treatment, disputing the customer benefits of these water rights and whether they are used and useful.

Resolution. In settlement of this issue, the Parties agree that the Company should continue to include in the revenue requirement the debt cost portion of the Company's carrying costs for the Southeast Water Rights as long as and to the extent

months of data from which to calculate the thirteen-month average. The adjustment to rate base ordered as a result of Docket No. 94I-264E, the Pawnee Turbine Blade proceeding, is such an example.

that the Company continues to own such water rights. To reflect this rate treatment in the cost of service study, the balance associated with the water rights is eliminated from rate base and a negative amount is added to Miscellaneous Other Revenue, as originally proposed by the Company. This rate treatment shall continue through the 2004, 2005 and 2006 electric Earnings Tests, unless the water rights are sold during the applicable Earnings Test year, at which time the rate treatment of the Plant Held For Future Use balance and any proceeds resulting from the sale or transfer of the water rights shall be a new item identified in the Company's Earnings Test Report.[16] The Parties also reserve the right to argue the appropriate treatment of any gain or loss related to such a sale.

2. Pawnee 2 Pre-engineering Costs

Background. In its direct case, Public Service proposed to amortize the Pawnee 2 Pre-engineering Costs over a four-year period (2003 through 2006) and to include one year's amortized expense in the revenue requirement. The Company explained in its Direct Testimony that these engineering and study costs were incurred between 1982 and 1993 in connection with the development of a new power plant, the construction of which was delayed and ultimately obviated by Public Service's acquisition of the Colorado Ute generating resources as part of the resolution of the Colorado Ute bankruptcy. OCC and CEC in their Answer Testimony objected to this proposed rate treatment, disputing the customer benefits of these costs and recommending disallowance of the amortized expense. In its Answer Testimony, Staff did not oppose

[16] This Settlement Agreement does not address the question of whether and to what extent Commission approval may be required to transfer these assets under C.R.S. § 40-5-105 or Rule 55 of Commission Rules of Practice and Procedure.

the Company's proposed amortization, but proposed to offset some of the Pawnee 2 Pre-engineering costs by the amount of the gain on the sale of the Boulder Canyon Hydro Project and to amortize the difference over four years.

Resolution. In settlement of this issue, the Parties agree that the Company should be permitted to amortize the full Plant Held For Future Use balance of the Pawnee 2 Pre-engineering Costs through a straight-line amortization over four years, without any offset, and to include one year's amortization expense in the revenue requirement. The amortization will commence in the first full month after the effective date of rates from this case and continue for four years. This rate treatment shall continue through the 2004, 2005 and 2006 electric Earnings Tests.

3. Metro Ash Disposal Site

Background. In its direct case, Public Service proposed to amortize 100% of the book costs associated with the metro ash disposal site, which were incurred in 1993 to secure and improve a site for disposal of fly ash from the Arapahoe, Cherokee and potentially the Valmont coal-fired generating plants; these costs were incurred due to then anticipated changes in environmental regulations declaring fly ash to be a hazardous substance. The Company proposed to amortize over four years the original book cost of this 88-acre site, along with the cost of an option to purchase an additional 105 acres on an adjacent parcel of land, and to include one year's amortization expense in the revenue requirement. OCC and CEC in their Answer Testimony objected to this proposed rate treatment, disputing the customer benefits of these costs and recommending disallowance of the amortized expense. In its Answer Testimony, Staff concurred with the proposed amortization and rate treatment of the costs associated with the option for the 105-acre parcel, but believed amortizing the cost of the 88-acre Metro Ash Disposal Site was premature.

Resolution. In resolution of this issue, the Parties agree that the cost of the 88-acre Metro Ash Disposal Site should remain in Plant Held For Future Use, without amortization, and be included in the determination of rate base (full debt and equity return), and that Public Service should be permitted to amortize the costs associated with the option for the 105-acre parcel over four years and to include one year's amortization expense in the revenue requirement. The amortization will commence in the first full month after the effective date of rates resulting from this case and continue for four years.[17] This rate treatment shall continue through the 2004, 2005 and 2006 electric Earnings Tests, unless the 88-acre Metro Ash Disposal Site is sold during the applicable Earnings Test year, at which time the rate treatment of the Plant Held For Future Use balance, and any proceeds resulting from the sale or transfer of the site shall be a new item identified in the Company's Earnings Test Report.[18] The Parties reserve the right to argue the appropriate treatment of any gain or loss related to such a sale.

C. Underground Gas Storage Inventory Adjustment

Background. In its direct case, Public Service proposed a *pro forma* adjustment to gas stored underground (FERC Accounts 117 and 164) to reflect the gas storage inventory level on the basis of the weighted average cost method ("Average Cost")

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[17] If the option were to be sold, any net proceeds from the sale shall be netted against the balance to be amortized.

[18] This Settlement Agreement does not address the question of whether and to what extent Commission approval may be required to transfer this asset under C.R.S. § 40-5-105 or Rule 55 of Commission Rules of Practice and Procedure.

versus its current pricing method of LIFO. Public Service noted that in a separate application filed with the Commission in Docket No. 02A-267G, the Company was seeking Commission authorization to change its method of accounting for the cost of stored natural gas from the current LIFO pricing method to the Average Cost method. In its Answer Testimony, Staff objected to the Company's proposed adjustment citing its disagreement expressed in Docket No. 02A-267G over the Company's approach for calculating the Average Cost inventory amounts to accomplish this change in accounting. In addition, Staff disagreed with the Company's asserted basis for the proposed *pro forma* adjustment. In its Answer Testimony, OCC advocated that the Commission incorporate the same method of calculating gas stored underground as is approved in Docket 02A-267G. The Parties acknowledge that the proceeding in Docket No. 02A-267G is not concluded and that the Commission has not issued any final orders in that docket. The Company, the Staff, and the OCC additionally acknowledge their agreement to treat this rate case rate base issue separate and apart from the proceeding in Docket No. 02A-267G.

Resolution. In resolution of this issue, the Parties agree that the gas stored underground inventory allowance for inclusion in the gas revenue requirement should be calculated using test period volumes for all storage fields (excluding inventory amounts associated with the Leyden Gas Storage Facility and the Electric Department's portion of inventory in Young Gas Storage, Ltd.), multiplied by the average per Dth inventory price for the 36-month period beginning with the January 1, 2000 per book LIFO balance through the period ended December 31, 2002. In future gas revenue requirement filings, the Company will use the same inventory pricing method to value gas stored underground inventory that has been approved by the Commission for regulatory accounting purposes and will determine the value based on the 13-month average of month-end balances calculation method reflected in the Average Rate Base discussion in Section II.A. of this Settlement Agreement.

III. Income Statement

A. Insurance Expense

Background. In its direct case, Public Service proposed a *pro forma* adjustment to test period insurance expenses to reflect anticipated increases in property and casualty insurance premiums to be incurred by Public Service during and after 2002, citing the 9/11 terrorist attacks and other factors contributing to the general increase in property and casualty insurance costs. In Answer Testimony, Staff and OCC opposed the Company's adjustment on the ground that the Company's estimate was in excess of the actual 2002 insurance premiums. Staff and OCC recommended that the actual 2002 insurance cost levels be used in computing test year revenue requirements. In its Rebuttal Testimony, the Company reemphasized that, even though its estimate did not turn out to be accurate in hindsight, it was based on the best information available at the time the case was filed, and that these types of "true-up to actual" adjustments are inconsistent with the test period ratemaking principles historically followed by the Commission.

Resolution. For purposes of settlement, the Parties agree that the actual 2002 insurance expense levels are more representative of insurance expense during the period the new rates will be in effect and should be included in the revenue requirement.

The 2004, 2005 and 2006 Earnings Tests will reflect actual insurance expense incurred during the applicable calendar year.

B. Purchased Capacity Costs

Background. In its direct case, Public Service proposed a *pro forma* adjustment to test period expenses to reflect projected increases in electric purchased capacity costs for calendar year 2002. In fact, the projected dollars upon which the *pro forma* adjustment was based fell short of the actual 2002 electric purchased capacity cost level.

Resolution. In conjunction with the Parties' comprehensive agreement of all of the other issues in this rate case, the Parties agree that the actual 2002 electric purchased capacity costs are more representative of purchased capacity costs during the period the new rates will be in effect and should be included in the revenue requirement.

C. Trading A&G and Non-Production O&M Expense

Background. In its Answer Testimony, Staff questioned the Company's accounting for its short-term wholesale energy sales activities. Staff expressed concern that Public Service's retail customers may be improperly subsidizing the Company's Proprietary Book trading operations and argued that the Company's Proprietary trading operations should be eliminated as a regulated activity.[19] Staff, through the use of an energy ratio, recommended excluding $8,661,947, its estimate of the A&G and non-production O&M expense associated with the Company's Proprietary Book trading operations, from the Colorado jurisdictional revenue requirement. Public Service

[19] See discussion of Trading, below, in which further definition is supplied concerning the Company's Generation Book and Proprietary Book trading operations.

offered Rebuttal Testimony refuting Staff's contention that retail customers have subsidized any portion of the Company's Proprietary Book trading operations. Public Service's Rebuttal Testimony acknowledged that the Company did not record A&G and Non-Production O&M Expense associated with the Generation Book and the Proprietary Book transactions separately in the 2001 test year. The Company had implemented a change in 2002 to record time spent by traders in performing Generation Book and Proprietary Book transactions. Relying on this data and other information, the Company argued that Staff's estimate of the non-production O&M expenses associated with the Proprietary Book trading operations was overstated.

Resolution. For purposes of settlement, the Company agrees that, where practicable, it will continue to separately record time spent by traders in performing Generation Book and Proprietary Book transactions. The Parties agree, given other provisions of this Settlement Agreement discussed later in the section entitled "Trading," that Public Service shall exclude $2.74 million from the calculation of its Colorado jurisdictional base rate revenue requirements: $1.74 million associated with Generation Book trading activities and $1 million associated with Proprietary Book trading activities. The Parties agree that $2.74 million reflects a reasonable estimate of the assigned and allocated A&G and non-production O&M expense incurred by the Company's trading operation beyond what would be incurred if the Company ceased Proprietary Book trading and if the Company's only Generation Book trading activities were intra-day energy transactions[20] and day-ahead energy transactions on the Company's system.

[20] Intra-day transactions are transactions entered into on the same day as the energy flows. In the trading business rules, attached to this Settlement Agreement as Attachment J, intra-day transactions are also referred to as "real time" and "hourly".

Public Service shall also make the same $2.74 million adjustment to test-year expenses for the purpose of calculating earnings sharing for the calendar year 2004.

As discussed later, the Parties have agreed that the Company shall file an application in January 2004 to initiate review of the Company's trading activities. If as a result of that docket the Commission determines that no material changes should be made to the scope of the Company's trading activity, then the Company shall make the same $2.74 million adjustment to test-year expenses for purposes of calculating earnings sharing in the Earnings Tests for calendar years 2005 and 2006. If the Commission determines that the Company should discontinue Proprietary Book trading and also discontinue Generation Book energy trading beyond intra-day energy transactions and day-ahead energy transactions on the Company's system, then no *pro forma* adjustment shall be made to test year expenses for the purposes of calculating earnings sharing from the Earnings Tests for calendar years 2005 and 2006. If the Commission determines that the Company's trading activities should be materially reduced in scope from the trading activities undertaken by the Company at the time of this Settlement Agreement, but not reduced to the level discussed in the prior sentence, then the Company shall propose in the applicable Earnings Test filing an adjustment to test year expenses that reflects the Company's reduced trading operations from those assumed in this general rate case.

Nothing in this Agreement shall require the Company to continue with its current scope of energy trading activity. The Company reserves the right to discontinue or reduce its energy trading activity at any time. Should the Company discontinue Proprietary Book trading and also discontinue Generation Book energy trading beyond intra-day energy transactions and day-ahead energy transactions on the Company's system, then no *pro forma* adjustment shall be made to test year expenses in any applicable Earning Test period. Should the Company otherwise reduce the scope of its energy trading activity, the Company shall propose in the applicable Earnings Test an adjustment to test year expenses that reflects the Company's reduced trading operations from those assumed in this general rate case.

In connection with the docket reviewing the Company's trading operations, this Settlement Agreement provides for the funding of an expert consultant to assist Staff and the OCC. That consultant may inquire of the Company, and advise the Staff and OCC, with respect to the A&G and Non-Production O&M expense associated with the Company's trading activity, among other things. However, in making such inquiry, the Staff/OCC consultant shall first utilize the information provided by the Company to Staff and OCC through discovery and audit in this general rate case. The issue of the appropriate adjustment to revenue requirements associated with trading A&G and Non-Production O&M expense shall not be an issue in the trading docket initiated by the Company's application in January 2004; that issue is deemed settled by this Settlement Agreement. However, should the Commission decide to restrict the scope of the Company's trading operations as a result of the 2004 inquiry, or should the Company decide to reduce the scope of its trading operation, the Staff and the OCC may use information provided by this consultant, as well as other information, in the appropriate Earnings Test proceedings to determine the appropriate reduction in the $2.74 million *pro forma* adjustment to trading A&G and non-production O&M expense associated with the change in scope of the Company's energy trading activity.

D. Oil and Gas Royalty Revenues

Background. In its Direct Case, Public Service excluded revenues received from oil and gas production royalties from the determination of the revenue requirement. In its Answer Testimony, Staff opposed this exclusion on the basis that the Company had not demonstrated that it had allocated associated assets to non-regulated activities. In its Rebuttal Testimony, the Company pointed out that for the past 30 years, the Commission's practice has been to treat the costs and revenues attributable to the oil and gas production segment of the Company's business as non-regulated. The Company further explained that much of the oil and gas royalties currently received are the result of efforts and business dealings of its former unregulated subsidiary, Fuel Resources Development Co. ("Fuelco"), which was incorporated in 1970 and dissolved in 1996. Moreover, the Company pointed out that the original land and land rights costs associated with the mineral rights associated with these revenues are negligible and likely cannot be traced on the Company's books. Finally, the Company asserted that the dissolution of Fuelco and the cessation of the Company's oil and gas production activities do not warrant a change in the regulatory treatment of these revenues.

Resolution. In settlement of this issue, the Parties agree that the full amount of oil and gas royalty revenues and any related administrative expenses shall be included in the determination of the revenue requirements. Such treatment shall similarly apply in the 2004, 2005 and 2006 electric Earnings Tests, unless such treatment is changed by order of the Commission. The Company shall be free to advocate in the Earnings Test and other future proceedings that certain oil and gas revenues and costs, including asset-based costs related thereto, should not be included as regulated utility revenues and costs.[21]

E. Pension Expense

Background. The Parties acknowledge information presented by Public Service indicating, based on actuarial calculations performed in the ordinary course of business, that the Statement of Financial Accounting Standard ("SFAS") No. 87 net periodic pension credit for the 2001 test year is not reflective of the SFAS 87 net periodic pension costs for the period in which the rates in this rate case will be in effect. The Company's actual 2003 pension expense will be substantially higher than the pension expense included in its cost of service for the 2001 test year. The Company, Staff, and the OCC are concerned that, if the Company is not permitted to recover this increase in pension expense in the rates that are approved as part of this proceeding, such an increase, in combination with other known increases in expense, could put the Company in the position of having to file a second Phase I rate case shortly after the conclusion of this proceeding.

Resolution. In order to accommodate this concern and as part of the overall settlement of the issues in this case, the Parties agree that a *pro forma* adjustment for pension costs should be made to reflect an increase in pension expense anticipated in 2003. This increases the revenue requirement for the ~~electric~~ gas department by $2,675,802, for the ~~gas~~ electric department by $4,950,196, and for the thermal

[21] The Company's demonstration that oil and gas royalties should not be considered regulated utility revenues may consist of a showing that any associated expenses or investments were not included as part of the cost of service used to determine base rates in this proceeding.

department by $102,211. The 2004, 2005 and 2006 Earnings Tests shall reflect actual pension expense incurred during the applicable calendar year.

F. Allocation of Labor – A&G and Other Corrections

Background In its Rebuttal Testimony, the Company changed the jurisdictional allocation factor for five administrative and general expense accounts from net plant in service to gross plant in service. Inadvertently, the Company did not change the labor allocation in these same accounts.

Resolution. The Parties agree that a correction should be made to labor in the following FERC accounts based on the gross plant in service allocation factor: Account 924 – Property Insurance; Account 929 – Duplicate Charges; Account 930 – Miscellaneous; Account 931 – Rents; and Account 935 – Maintenance of General Plant.

G. Dark Fiber

Background. In Docket No. 98A-262EG, the Commission approved the transfer of all of Public Service's dark fiber assets to NCE Communications, Inc. ("NCEC") and a lease back of the portion of those assets Public Service was using at the time of transfer. The Commission approved the transfer following consideration of the October 8, 1998, Stipulation and Agreement ("Dark Fiber S&A") between Staff and the Company that was filed to resolve all issues in Docket No. 98A-262EG. The Dark Fiber S&A contained a "Favored Nations Clause" that provided that Public Service and its customers would be entitled to the lowest rate at which NCEC leased a similar fiber optic route segment.

In August 1999, NCEC contributed the dark fiber to Northern Colorado Telecommunications, LLC d/b/a Touch America Colorado LLC, a partnership between

NCEC and Touch America, Inc. In its Answer Testimony, Staff expressed concern whether the level of the lease rate paid by Public Service continues to be reasonable and whether the Favored Nations Clause under the Dark Fiber S&A could operate in full force and effect following the contribution of assets to Touch America Colorado.

Resolution. For purposes of settlement, the Parties agree to the amount of lease expense and pole attachment fees included in the Company's original filed case; however, the Parties do not agree that the Company's filed position should reflect a settled ratemaking principle for purposes of the Earnings Test. Staff and Public Service reserve their rights to advocate in the Earnings Test or in any other appropriate proceeding any position regarding the level of expenses and revenues to be recognized for Colorado regulatory purposes relating to dark fiber, pole attachment fees and conduit rental and whether the Favored Nations Clause applies to the contribution.

H. Regulatory Treatment of § 40-3-104.3(2)(a) Discounts

Background. For contracts involving electric and steam service C.R.S. § 40-3-104.3(2)(a) requires that the Commission specify a fully distributed cost allocation method to be used to segregate rate base, expenses, and revenues associated with utility service provided by contract from other regulated utility operations. The Company in its Direct Case made an adjustment to miscellaneous revenues to add to booked revenues the discounts given to certain contract customers.

Resolution. The Parties agree that the Company's treatment in its Direct Case was acceptable for purposes of this Phase I proceeding and should be continued for purposes of the Earnings Tests for calendar years 2004, 2005, and 2006. The Parties further agree that for purposes of Phase II the Company shall perform and file a fully distributed cost study separating revenues, assets, liabilities, reserves and expenses and will specifically identify the class in which each customer receiving a discount resides. Further, at the time of the Phase II filing, for purposes of Phase II, the Company shall provide to Staff and OCC on a confidential basis consistent with the requirements of C.R.S. § 40-3-104.3, all available customer specific load information.

IV. PSCCC

Background. In December 2001, Public Service discontinued the operations of PSCCC. Subsequently, the Company dissolved PSCCC effective April 6, 2002. In its rate case filing, the Company made a number of *pro forma* adjustments to test-year rate base and capital structure to reflect the discontinuation of PSCCC. In their Answer Testimony, the Staff and the OCC objected to the Company's *pro-forma* adjustments related to PSCCC and recommended treating PSCCC as if its operations had not been discontinued. Staff also argued that, under Decision No. C86-1392, Application No. 37781, the Company should have applied to the Commission for approval prior to discontinuing operations at PSCCC. The Company disputed that such an application was necessary. In Supplemental Answer Testimony, filed on Februray 18, 2003 after Staff had had the opportunity to conduct a more thorough analysis of the impact of the dissolution of PSCCC on Public Service's cost of service, Staff observed that, due to the interrelationship of various inputs to the Company's cost of service, the impact of dissolving PSCCC can swing from negative to positive depending upon the lead/lag factors, return on equity and rate base used as inputs to the cost of service model.

Resolution. As part of the overall settlement of issues in this docket, which includes the resolution of issues relating to cash working capital and the rate of return on equity, the Parties agree to accept the Company's *pro forma* adjustments related to the discontinuation of PSCCC as appropriate out-of-period adjustments reflecting known and measurable changes in the Company's rate base and capital structure.[22] Now that PSCCC has been dissolved, no additional adjustments associated with this entity will be required for purposes of future Earnings Tests.

V. Cost Allocation Between Regulated and Non-Regulated Business Activities

Background. In their Answer Testimony, the Staff and the Colorado Business Alliance for Cooperative Utility Practices ("CBA") challenged the sufficiency of the Company's fully distributed cost study used to allocate and assign costs to its non-regulated business activities. In particular, Staff disagreed with the revenue-based allocator used by Public Service to allocate A&G and Customer Accounting expenses to its non-regulated products and services. In the alternative, Staff recommended using an O&M-based allocator to calculate the A&G load and using a modified revenue-based allocator to calculate the Customer Accounting load. Staff also questioned the Company's failure to have allocated any investment in common plant or associated expenses, including return on such investment, to the non-regulated products and services. CBA's witness, Mr. Keating, was concerned that Public Service had not made a sufficient showing that its allocation of costs to the non-regulated business activities was consistent with the Commission's Cost Allocation Rules. OEMC raised a general issue of customer's access to historical data contained in the CIS regarding the customer's own account. OEMC recommended disallowance of a portion of the

[22] The Company's test-year cost of service did not reflect an adjustment to eliminate the fees Public Service paid to PSCCC during 2001 because the fees had been booked below-the-line as interest expense.

expense associated with the investment in CIS in the event that the Company did not make the historical data available to the customer.

In its Rebuttal Testimony, the Company agreed with Staff that the revenue-based allocator used to calculate the A&G load may not be the only reasonable approach for allocating costs. Accordingly, the Company proposed an alternative labor-based allocator, which resulted in a higher level of A&G cost allocation to the non-regulated products and services, compared to what the Company originally filed, and a lower level of cost allocation compared to what Staff proposed. In addition, the Company modified the method it used to develop the allocation factor for Customer Accounting costs. Public Service also conceded that certain expenses associated with investment in common plant, including CIS, should have been allocated to the non-regulated products and services.

Resolution. For purposes of this settlement, the Parties have agreed to accept the Company's allocation and assignment of costs to its non-regulated business activities as reflected in Public Service's Rebuttal case. Specifically, the Parties agree that the Company's proposed labor-based allocation factor shall be used to allocate A&G costs to the non-regulated products and services and further agree that the Company's proposed revenue-based allocation factor, excluding revenues associated with off-system energy sales, shall be used to allocate Customer Accounting costs. In addition, the Parties agree to the revised common plant allocations, including CIS, reflected in the Company's Rebuttal and Supplemental Rebuttal Testimony and Exhibits.

In resolution of the issues raised by OEMC, Public Service agrees to provide OEMC with access to twelve months of historical data for its metered accounts for which it does not currently have EDI.

The Parties agree to engage in good faith workshops to analyze cost allocation/assignments to and between Public Service's regulated and non-regulated business activities. The Company shall provide to all workshop participants who have executed an appropriate Non-Disclosure Agreement, its FDC study in the form of an income statement and balance sheet, supplemented by schedules in the form of Confidential Exhibit No. JSSP-3. The format for the Company's FDC study is shown in Attachment F to this Settlement Agreement, which attachment is an interim format subject to modification during the workshop process. All supporting workpapers and calculations, in electronic spreadsheet format to the extent available, will be provided concurrent with the Company's FDC study. The Company shall also make available to the participants its subject matter experts to explain the Company's position as well as supporting documentation.

The purpose of the workshops is for the workshop participants to evaluate the form of the FDC study attached as Attachment F and arrive at fair and reasonable assignments and allocations of costs to and between the Company's regulated and non-regulated business activities consistent with the requirements of C.R.S. § 40-3-114 and the Commission's Cost Allocation Rules, including the requirements of Rule 4 CCR 723-47-5 relating to transactions between the utility and non-regulated divisions, subsidiaries or affiliates. The participants shall have reasonable access to relevant information, subject to an appropriate non-disclosure agreement, concerning the

Company's costs that could be assigned between and among regulated and non-regulated services. In the event the participants do not receive such information in a timely fashion, the participants may formally seek assistance from the Commission including, as necessary, a request to employ formal discovery processes. The workshop participants will endeavor in good faith to complete the workshop process within four months following Commission approval of this Settlement Agreement. Within 30 days following completion of the workshop process or at such later time as the Parties may agree or the Commission may permit upon a showing that the Company requires greater than 30 days, Public Service will file any appropriate modifications to its Cost Allocation Manual ("CAM"). If the participants in the workshop process are not able to agree on an approach to accomplish a fair and reasonable allocation of costs to and between the Company's regulated and non-regulated business activities, the participants agree to submit the unresolved issue(s) to the Commission by no later than six (6) months following Commission approval of this Settlement Agreement.

The Company shall file its FDC study and CAM, updated to reflect the results of the workshop process, with its annual Earnings Test report commencing with the 2004 Earnings Test year filed in 2005.

VI. Depreciation Issues

Background. On November 22, 2002, Public Service, the Staff, and OCC entered into a Depreciation Stipulation resolving most of the issues raised by the Parties with respect to depreciation. As identified previously in this document, the Depreciation Stipulation is attached as Attachment B. With respect to the amortization period applicable to future computer software purchases (which was not included as part of the

November 22, 2002 Depreciation Stipulation), the Company and Staff, through the testimonies of Company witness Ms. Perkett and Staff witness Ms. Fischhaber, agree to 1) a three-year amortization period for a rollout of workstation operating systems where the rollout for the entire Company is completed in a 12-month period; and, 2) a five-year amortization period for all software purchases that qualify for capital treatment, but do not fit in the three-year or the large base systems software category that is discussed below.

Staff and the Company disagreed as to how large base computer software systems, such as accounting, human resources, billing and property accounting systems should be amortized. In its Direct Case, the Company proposed that the cost of these large base computer software systems be amortized over seven years to reflect an appropriate matching of system benefits and expenses. In its Answer Testimony, Staff proposed a 10-year amortization period for such large base computer software systems. In its Rebuttal Case, the Company modified its original proposal to state that the original installation as well as any subsequent modules of such large base computer software systems should be amortized over seven years. However, the Company stated that it would be willing to agree with Staff's proposal for a 10-year amortization period of the original large base computer system software provided that all subsequent large base computer system software upgrades would be amortized such that they would be retired at the end of this 10-year life.

Staff's and the Company's witnesses on depreciation also discussed the appropriate interval for filing updated depreciation studies, recognizing the need for periodic updates and the substantial work requirements on behalf of both Staff and the

Company. The Company expressed a desire to implement a Remaining Life Model applicable to its steam production facilities in this proceeding. Staff expressed concern that the Company's proposal may not be consistent with the Revision to Supplemental Settlement Agreement approved in Docket No. 94S-670EG that required the Company use the same depreciation methods as approved in that order through June 30, 2005. Staff recommended that the on-going review of the Remaining Life Model applicable to electric and thermal production facilities be performed at the same time as the Company's Least Cost Resource Planning ("LCRP") applications because similar information is needed and required for both activities.

Finally, Staff witness Ms. Fischhaber expressed concern regarding the Company's continued use of "black box" software programs for its depreciation studies. Public Service disputed Staff's characterization of its Power Plant software system as a "black box".

Resolution. For purposes of settlement, the Staff and the Company agree that Public Service shall amortize large base computer software systems over a 10-year life and shall amortize all software upgrades to such systems such that the upgrades are retired at the end of this same 10-year life. The Company agrees to exercise prudent judgment regarding upgrades of these systems towards the end of the useful life of the software. This treatment shall be reflected in the Company's Earnings Tests for 2004, 2005 and 2006.

Staff and the Company also agree that on a going-forward basis, after June 30, 2005, the Company shall revise its depreciation model applicable to its steam and other production facilities to a Remaining Life Model. These parties further agree that the

Company shall submit either to the Chief of Fixed Utilities for Staff review, or to the Commission as part of a proceeding where approval of depreciation rates is an issue, no later than October 2007, and thereafter at least every four years, its Remaining Life Model applicable to its electric and thermal production facilities. Unless the Remaining Life Model is submitted earlier, it is the intent of Staff and Public Service that the Company shall submit its Remaining Life Model at the same time as its LCRP applications starting in 2007.

Staff and the Company also agree that on a going-forward basis, the Company will submit either to the Chief of Fixed Utilities for the Staff, in accordance with an appropriate review schedule to be established jointly by the Company and the Staff within three (3) months following approval of this Settlement Agreement, or to the Commission as part of a proceeding where approval of depreciation rates is an issue, depreciation studies such that every aspect of the Company's plant shall be addressed in a depreciation study on an interval at least every five years. The Staff and the Company agree that every aspect of the Company's plant shall be the subject of at least one depreciation study submitted on or before December 31, 2007. The Parties recognize that any Commission approval of the depreciation studies (including the Remaining Life Model discussed in the previous paragraph) shall occur only in proceedings seeking approval of a change in depreciation rates.

Finally, Staff agrees that, in this proceeding, it will not pursue the issue of the Company's continued use of proprietary software programs for its depreciation studies that Staff asserts its cannot evaluate. Staff reserves the right to pursue this issue in any future Commission proceedings in which any of the Company's depreciation rates, net salvages, survivor curves, remaining lives, etc. are at issue.

VII. Reclassification of Substation Plant and Treatment of Radial Transmission Lines

Background. In its Direct Testimony, Public Service proposed to reclassify certain high voltage facilities within its distribution substations from distribution plant to transmission plant. The Company also proposed to eliminate the direct assignment of radial transmission lines and to treat all of these lines as part of the central transmission system. The impact of these proposals is reflected in the cost of service and in the associated revenue requirement developed for each of the affected functional categories in the Company's Cost of Service Model. Staff disagreed with the Company's proposed reclassification of high-voltage facilities in the distribution substations as transmission plant and with the Company's proposal to roll-in its radial transmission lines with its central system transmission.

Resolution. For purposes of settlement, the Parties agree that they may address the proper classification of the Company's high voltage facilities in distribution substations and its treatment of radial lines as part of Phase II of the Company's rate case. The Parties acknowledge that such changes will result in a change in the Company's retail revenue requirement from what is reflected in the Company's Cost of Service study approved as a part of this Settlement Agreement. Accordingly, the Parties agree that to the extent a change to the classification or allocation of these facilities is approved in Phase II, the Company shall be permitted to put into effect base rates that reflect the revised revenue requirement determined as a result of Phase II.

The maximum impact of a change in the classification of the Company's high voltage facilities in the distribution substations from transmission to distribution plant will be to increase the Company's jurisdictional revenue requirement by $505,013. The maximum impact of directly assigning radial transmission lines rather than treating them as central system is to increase the Company's jurisdictional revenue requirement by $159,070. The maximum cumulative impact of both these changes is to increase the Company's jurisdictional revenue by $639,448. The Parties agree that the 2004, 2005 and 2006 Earnings Tests shall reflect the outcome of these issues in the Commission's order in Phase II.

VIII. JD Edwards General Ledger Accounting System

Background. Effective October 1, 2001, Xcel Energy Inc. replaced Public Service's Walker general ledger accounting system ("Walker") and the general ledger accounting system used by other subsidiaries with a single general ledger accounting and financial reporting system. The new system uses JD Edwards ("JDE") software. The JDE general ledger accounting system was the basis for recording the financial transactions that underlie the Company's cost of service filed in this proceeding.

In recognition of Staff's and other Parties' need for additional time to review the major general ledger accounting system change, to establish confidence in the integrity of the Company's financial information underlying the Company's JDE general ledger accounting system, and to ensure that the new system continues to provide information consistent with the regulatory needs of the Commission, Public Service agreed to extend the effective date of its tariffs and the dates for hearing in this matter. In order to facilitate a greater understanding of the new general ledger system on the part of the

Parties, the Company conducted technical conferences on August 9 and 12, 2002 in which it provided detailed explanations of the accounting processes within JDE. As early as April 2002, the Company shared with the Staff and OCC an analysis comparing the electric department revenues and costs under Walker with those reflected under JDE for the first nine months of 2001. Beginning in August 2002, the Company made arrangements for Staff to have access to its general ledger system for the purpose of tracing transactions from Walker to JDE and from JDE back to source transactions. The Company engaged the services of the consultants who had assisted with the JDE implementation and made these people as well as Company personnel available to Staff for purposes of answering questions about the general ledger processing and track back of expenses and revenues. The Company also created a special model in JDE to allow the Staff and OCC to model “what if” scenarios so that they could see the impact of specified changes in allocation methods or other accounting processes upon the results of the cost of service.

As part of its review of the JDE general ledger accounting system, Staff performed studies tracking dollars step by step from Walker through to JDE. Through the audit and discovery process Staff identified the processes, calculations and formulas that were applied to the basic accounting information for purposes of performing multi-level allocations of costs. In its Answer Testimony, Staff identified concerns with the Company’s FERC allocations, questioned whether some of the Company’s accounting and recording methods, practices and procedures complied with state and federal regulatory requirements, and questioned whether the transition to the new system accurately mapped financial information from Walker to JDE accounts.

Staff argued that the Company's FERC allocations resulted in a misallocation and misclassification of expenses by FERC Account. Staff also raised questions about the Company's practices, policies and procedures for recording O&M and A&G expenses.

In Rebuttal, the Company disputed Staff's claim that ~~the~~ some of its accounting and recording methods, practices and procedures were inconsistent with state or federal regulatory requirements. Public Service also contested Staff's assertions that the FERC Allocations resulted in any misclassification of expenses by FERC account by explaining that the basis for the FERC allocations was detailed information regarding the nature of the Company's expenses contained in its work management systems. The Company also addressed Staff's concerns regarding the mapping of financial information from Walker to JDE and the level of A&G and O&M expenses.

Resolution. For purposes of settlement, Public Service agrees to phase out the use of FERC allocations in its JDE general ledger accounting system, as defined in the Company's 2002 CAM[23], by January 1, 2004, except in those instances in which the Company demonstrates that the elimination of a particular FERC allocation would be impracticable. The purpose of phasing out the FERC allocations is to achieve, to the fullest extent possible, the effect of a direct recording of costs to FERC accounts in the Company's general ledger accounting system.

Public Service also agrees that, during 2003, it shall take steps to improve its policies, procedures and oversight of O&M expense classification to achieve a greater level of accounting consistency. Specifically, a greater emphasis will be placed on the consistent recognition of O&M expenses by functional class (production, transmission,

[23] The Company revised its 2002 CAM with the filing of Janet Schmidt-Petree's Rebuttal Testimony and Exhibits on January 24, 2003. See Exhibit JSSP-2.

distribution, A&G, and customer operations). The Parties acknowledge that the phase out of the FERC allocations, the efforts to improve policies and procedures relating to the classification of O&M, and the cost workshops addressed in Section V may result in modification of the assignment/allocation methods from those that were used to develop the Company's cost of service in this proceeding. The Parties agree that any such modification in assignment/allocation methods resulting from the above described activities shall not constitute a violation of the Merger Stipulation.

Public Service agrees further that on or before June 30, 2003, September 30, 2003 and December 31, 2003, it shall provide Staff with a quarterly report describing its progress in phasing out the FERC allocations and any other significant changes in its general ledger accounting system being implemented to improve the regulatory accounting and reporting of the Company's retail cost of service. The Company agrees to meet with Staff following the submittal of each quarterly report to answer any questions Staff may have regarding the substance of the report.

Lastly, the Company agrees that it shall submit to Staff and to OCC annually, with its February surveillance report, a list of any material changes in Company accounting policies, practices or procedures. The Company shall provide a copy of the list submitted with its most recent February surveillance report with its annual Earnings Test Report. In addition, Public Service agrees that, if there are significant unusual or non-recurring expenses within a calendar year, such as a several million-dollar severance expense associated with a downsizing, it shall separately identify such non-recurring expenses within its general ledger accounting system.

IX. Sterling Correctional Facility

On September 12, 2002, Administrative Law Judge Isley approved a Stipulation ("Sterling Stipulation") between Public Service and the State of Colorado for the benefit of the Department of Corrections regarding the primary electric distribution plant to be used at the Sterling Correctional Facility ("SCF"). Staff joined in the agreement. As part of the Stipulation, the Company agreed to hold retail customers harmless with respect to the investments that the Company made at SCF that were the subject of the Stipulation. In Answer Testimony, Staff identified the adjustments to electric distribution plant in service, reserve for distribution plant depreciation, and electric distribution maintenance expense necessary under the Sterling Stipulation. In its Rebuttal Testimony, the Company accepted all of Staff's adjustments as appropriate. This treatment shall continue in the 2004, 2005 and 2006 Earnings Tests.

X. Leyden Decommissioning Costs

As indicated in its Rebuttal Testimony and Exhibits, in response to objections raised by Staff and OCC, Public Service agreed to withdraw its proposal to hold its gas rates fixed and to credit any excess revenues from the gas department operations against the deferred Leyden decommissioning costs. The Company reserves its right to seek recovery of its decommissioning costs at a later date once those costs are known with reasonable certainty.

XI. Compliance With Commission Decision No. C97-168, Docket No. 94I-264E

Staff argued in Answer Testimony that the Company had failed to conduct certain analyses related to Company power plants as required by Commission Decision No. C97-168, Docket No. 94I-264E. In Rebuttal Testimony, the Company acknowledged that unfortunately it had lost track of these study and reporting requirements. The Company agrees to fully comply with Commission Decision No. C97-168 by January 1, 2004.

XII. Electric Commodity Adjustment

Background. The Company in its Direct Testimony proposed a new adjustment clause to recover fuel, purchased energy and purchased wheeling expense (hereinafter referred to as "Energy Costs"[24]) called the Electric Commodity Adjustment. The Company argued that its proposed ECA employs the same concept of incentives as did the Company's ICA. Both the ICA and the ECA set a base amount per megawatt hour of Energy Costs and compare that base amount with the actual Energy Costs incurred by the Company each year. Fifty percent of the difference between the base amount and the actual Energy Costs (positive or negative) is shared between the Company and the customers. For example, if the base amount were $20 per MWH and the actual Energy Costs were $22 per MWH, then the ECA (or ICA) would recover from retail customers $21 per MWH; conversely, if the actual Energy Costs in any one year were $18 per MWH, the ECA (or ICA) would recover $19.

The primary difference between the Company's proposed ECA and the former ICA is that the ICA contained a fixed dollar per megawatt hour base amount. The Company's proposed ECA would have a base that is determined by a formula that would vary with gas commodity prices and the level of PUC jurisdictional sales. The Company explained in its filed testimony that natural gas-fired generation has become a larger portion of its resource mix, that gas prices are volatile and hard to predict, and

[24] The term "Energy Costs" in this Settlement Agreement shall have the same meaning as the term Energy Costs has in the Company's ICA tariff.

that the Company is a "price-taker" on gas commodity prices. Consequently, the Company can no longer accept an incentive clause with a fixed Energy Costs per megawatt hour base. The Company further explained in its filed testimony that it derived its ECA formulaic base from 2001 test year Energy Costs, with certain stated *pro forma* adjustments due to the unusual Western United States market conditions in the 2001 test year. The Company proposed that if the ECA were not acceptable, the Company would accept an adjustment clause that passed through 100% of Energy Costs, without an opportunity to earn an incentive from cost reduction.

Staff, the OCC, CEC, CF&I Steel, L.P. ("CF&I"), Climax Molybdenum Company ("Climax"), and the City and County of Denver ("CCOD") all contested the Company's proposed ECA. CF&I, Climax and CEC argued that the ECA should be differentiated by service delivery voltage. Public Service agreed and provided this differentiation in its Rebuttal Testimony. Numerous parties objected to the Company's proposal to calculate and change the ECA rate monthly. In its Rebuttal Testimony, the Company agreed to only change the ECA rate annually, unless the deferred balance (positive or negative) exceeded $50 million, in which case a change to the ECA rate would be made prior to the annual change in the ECA rate.

Staff, OCC, CEC, and CCOD raised numerous other issues with respect to the Company's proposed ECA, including assertions of the following positions:[25] the use of the 2001 test year to develop the ECA base created "baked-in-value" for the Company; it is not wise to use a complicated formula with numerous benchmarks that could

[25] Several technical objections were raised to the tariff formula itself by CEC and by CCOD. The Company agreed with many of these technical criticisms and adopted the proposed changes in its Rebuttal Testimony.

provide the opportunity for the Company to “game” the adjustment clause; the Company’s *pro forma* adjustments to 2001 test year coal plant availabilities should not be accepted; and separate treatment of gas and non-gas resources could bias future resource selection. The Staff, the OCC, and CCOD generally favored a 100% pass-through mechanism for Energy Costs in lieu of the Company’s proposed ECA incentive mechanism. CEC generally favored an incentive mechanism and offered an alternative incentive mechanism based upon CEC’s projection of gas prices.

Lengthy settlement discussions were held among the Parties on this issue and on the issue of the Company’s trading operations (discussed below). In the course of discussions, at the request of the Parties objecting to the ECA, the Company projected (by using its PROSYM model) the Company’s fuel and purchased energy costs to serve retail customer load under a prescribed set of gas prices and compared these costs to the revenue that the Company would collect under the Company’s proposed ECA for the same retail load and gas prices. Sensitivity runs were performed that varied the availability of the coal plants, water use restrictions and higher gas prices. As a result of these analyses, the Parties opposing the ECA became more familiar with the operation of this incentive mechanism. However, many Parties still had concerns about adopting any adjustment clause that used 2001 test year Energy Costs, because of the undisputed anomalies in the operation of the Company’s system in that year. In general, the Parties agreed that if the Company were to have an incentive fuel clause, the base needed to be determined from a test year other than 2001.

Further, the Company stated that it needed to have a viable trading organization with acceptable margin sharing to provide coverage against the risks to the Company inherent in any incentive Energy Costs mechanism. As explained in the Company's testimony, during the tenure of the ICA, the Company covered its increasing Energy Costs with the profits from its trading activity. In addition, various details of the Company's system operations were discussed that went beyond the issues raised in the filed testimony.

Resolution. As a result of these settlement discussions, the Parties have agreed to the following mechanisms for the recovery of the Company's Energy Costs for the calendar years 2003 through 2006.

A. 2003 Energy Costs

The 2003 Energy Costs shall be recovered through an adjustment clause that passes through to retail customers 100% of the CPUC jurisdictional share of 2003 Energy Costs. The Company shall project total 2003 CPUC jurisdictional Energy Costs and total 2003 retail sales (from January 1 through December 31) and shall design a rate that recovers these costs, taking into account the revenues already collected under the Company's Interim Adjustment Clause that has been in effect since January 1, 2003. [26] To avoid customer confusion, the 2003 clause shall continue to be called the

[26] Commission Decision No. C02-609 in Docket No. 02A-158E approved a Settlement Agreement, which provided for an Interim Adjustment Clause or IAC to recover the Company's Energy Costs beginning January 1, 2003. The Settlement Agreement provided that the IAC would take effect on January 1, 2003 and would remain in effect until the new rates from the Company's general rate case (this Docket No. 02S-315EG) go into effect. The Settlement Agreement in Docket No. 02A-158E provides as follows:

> At the time that the new rates from the Company's May, 2002, general rate filing go into effect, the Company shall recalculate, for the period the 2003 interim adjustment clause was in effect, the level of Energy Costs (as defined in the current ICA tariff) and level of margins that would have been charged and credited to retail customers according to whatever method of allowing recovery for the Company's energy costs is adopted in the final order on the Company's May, 2002, rate filing. To the extent there is any discrepancy between the amounts charged and credited through the 2003 interim adjustment clause and the amounts thus recalculated, the difference (positive or negative) shall be returned or charged to customers through an appropriate rate mechanism.

Interim Adjustment Clause or "IAC"; the new rates under the IAC shall take effect July 1, 2003 and shall be calculated as described in Attachment G. The rates shall be as follows: $0.01125 per kWh for transmission service; $0.01151 per kWh for primary service; and $0.01178 per kWh for secondary service.[27] The Parties agree that, following the Commission's approval of this Settlement Agreement, Public Service shall file an advice letter to put the revised IAC rates into effect on July 1, 2003.[28]

Any difference between actual 2003 Energy Costs and billed IAC revenues shall be accumulated in a deferred account. Whenever the Company has accumulated in the deferred account a balance (taking into account unbilled revenue)[29] of $20 million of over-recovery, the Company shall file to prospectively change the IAC rate. Whenever the Company has accumulated in the deferred account a balance (taking into account

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[27] These rates have been calculated to recover the Company's total projected 2003 Energy Costs by December 31, 2003, assuming that the new IAC rate goes into effect on July 1, 2003. Because these rates were calculated based upon the prehearing conference held on April 3, 2003, all Parties reserve the right to review and verify prior to April 21, 2003, the specific components and computations contained in the Attachment G and to suggest any changes required to meet the agreed goal of recovering projected 2003 Energy Costs by December 31, 2003. If the Parties agree that changes should be made to these proposed rates, the Parties will file on or before April 21, 2003, a Supplement to this Settlement Agreement.

[28] The Company shall also file with the Commission on or before April 9 an application to increase the IAC on May 1. The Company shall request that the IAC be revised on May 1 to provide for the following IAC rates: Transmission Level - $ 0.00968/kwh; Primary Level - $0.00990/kwh; Secondary Level - $0.01015/kwh. These rates have been calculated to recover the Company's total projected 2003 Energy Costs by December 31, 2003, assuming the new IAC rate goes into effect on May 1, 2003. These rates would remain in effect until the new rates go into effect as a result of the Commission's order in this Docket No. 02S-315EG. Attachment L reflects the customer impacts of implementing a revised IAC on May 1, 2003. The Parties agree not to oppose the Company's application to increase the IAC on May 1 to recover by December 31, 2003 the Company's projected 2003 Energy Costs. However, all Parties reserve the right to review and verify the specific components and computations contained in the Company's application and to suggest any changes required to meet the agreed goal of recovering projected 2003 Energy Costs by December 31, 2003. If the Company's application is approved, then no additional change to the IAC rates should be necessary on July 1, 2003, unless the other provisions of this Settlement Agreement require such a change.

[29] Unbilled revenue results from cycle billing and recognizes that revenues associated with usage in a given month are not billed (hence unbilled revenue) until subsequent months.

unbilled revenue) of $30 million of under-recovery, the Company shall have the option of filing to prospectively change the IAC rate. Any prospective change to the IAC rate shall be recalculated to forecast the 2003 Energy Costs for the remainder of calendar year 2003 and to recover (or reduce to zero) over the next 12 months the accumulated deferred balance. No interest shall be paid on the balance in the deferred account. The IAC rate will terminate after December 31, 2003 and any remaining deferred balance resulting from the IAC shall be transferred to the deferred account of the ECA, discussed next.

B. 2004 - 2006 Energy Costs

The 2004-2006 Energy Costs shall be recovered through an incentive adjustment clause that is designed generally in the same manner as the Company's proposed ECA, but the test year for the amounts in the ECA base shall be the twelve-month period ending August 31, 2003, instead of calendar year 2001. By using this different test year, the Parties hope to eliminate any problems associated with the anomalous 2001 test year. This clause shall be called the Electric Commodity Adjustment or "ECA" and shall take effect January 1, 2004. Except as specifically noted in this Settlement Agreement, the 2004 through 2006 ECA shall be calculated using the method described in the testimony filed by Public Service.[30]

In its testimony, the Company described several *pro forma* adjustments that were made to 2001 test year costs in developing the ECA base formula. With the agreed change in the ECA test year, instead of the *pro forma* adjustments in the Company's

[30] To the extent that the Company's Rebuttal or Supplemental Rebuttal testimonies revise the Company's Direct Testimony on the ECA, those revisions shall be used in calculating the ECA for 2004 through 2006.

filed testimony, the following two *pro forma* adjustments to new test year numbers shall be made:

- Adjustments shall be made based upon the known and measurable contract changes with respect to gas transport costs; and
- The monthly Fixed kWh used in calculating the Fixed Energy Cost ("FEC") shall be derived by taking the total annual Fixed kWh from the new test year and spreading the test year Fixed kWh to each of the twelve calendar months based upon the average percentage of the total annual coal-based energy generated in that specific month over the years 2000 through 2002.

In addition, the incentive sharing of the differences between CPUC jurisdictional actual Energy Costs and the ECA base formula shall be changed. These changes reflect a compromise among the Parties. Many Parties filed testimony urging the Commission to adopt a 100% pass-through mechanism; other Parties urged the adoption of some form of incentive mechanism, where not all cost increases and cost savings were passed on to customers. The agreed incentive sharing mechanism is as follows. The first $15 million difference (positive or negative) in any calendar year between the ECA base formula and actual CPUC jurisdictional Energy Costs shall be shared 50/50 between retail customers and the Company. The next $15 million difference (positive or negative) shall be shared 75% retail customers and 25% Company. If the difference (positive or negative) in any calendar year exceeds $30 million, the excess amount of such difference beyond $30 million shall be passed through to retail customers. This means that the maximum "profit" or "loss" with respect to Energy Costs that will be absorbed by the Company in any one year through this incentive mechanism will be $11.25 million. The remainder of any cost savings or cost increases shall be passed through to retail customers. This mechanism insures that the difference between ECA revenue paid by customers and prudently-incurred CPUC jurisdictional energy costs will never vary more that $11.25 million, either positive or negative.

The Company shall file on or before December 1, 2003, and on or before December 1 of 2004 and 2005, the Company's proposed ECA for the subsequent year, to take effect on January 1 of the subsequent year. As described in the Company's testimony, the ECA will be based upon a forecast of the costs that the Company is entitled to recover under the ECA formula rate over the next calendar year. In addition to the forecast ECA formula costs, the ECA rates will recover (or reduce to zero) over the next 12 months any accumulated deferred balance (including unbilled revenues) in the IAC or ECA as of the prior September 30.

The ECA rates will generally be modified only on an annual basis; however, a deferred account shall track the difference between the revenues billed under the ECA and the actual ECA-recoverable costs. Whenever the deferred account (including unbilled revenues) exceeds (positive or negative) $40 million, the Company shall file to change the ECA rates prospectively. The new ECA rates shall be recalculated to forecast the ECA-recoverable costs for the remainder of the then calendar year and to recover (or reduce to zero) over the next 12 months the accumulated deferred balance. No interest shall be paid on the balance in the deferred account.

The Company shall conduct a workshop with interested Parties to explain its calculation of the 2004 – 2006 ECA as soon as the new test year data becomes available and the ECA equation is developed. The Company shall file its new ECA on or before December 1, 2003 for an effective date of January 1, 2004. At the Company's option, the Company may elect to discontinue the ECA and put into effect a 100% pass-through clause to recover Energy Costs if, in the Company's opinion, the results of the trading investigation (described below) do not provide the Company with sufficient opportunity to cover risks inherent in the ECA incentive clause. If the Company makes such election, it shall file a pass-through clause like that specified for the year 2003 with 30 days notice, no later than 60 days after the final Commission order with respect to trading.

The Company shall make an application with the Commission by April 1, 2006 addressing the Company's proposed regulatory treatment of Energy Costs incurred after December 31, 2006.[31] Until the Commission rules on the Company's application, the Company shall be entitled to a 100% pass-through of its 2007 Energy Costs; however, once the Commission issues its decision on the appropriate regulatory treatment for 2007 Energy Costs, the Company shall recalculate, for the period beginning January 1, 2007, the Energy Costs that would have been charged and credited to retail customers under the recovery mechanism ultimately adopted by the Commission in its final order with respect to the Company's April 1, 2006 application. Any differences created by this recalculation shall be factored into the calculation of the recovery mechanism approved by the Commission.

[31] The Company's application shall also address the mechanism for returning the customers' share, if any, of the trading margins earned in calendar year 2006.

C. Conditions that Apply to both the IAC and the ECA

In addition, the Parties agree that there shall be certain other conditions that shall apply to both the 2003 IAC and the 2004 – 2006 ECA. First, both the IAC and ECA rates shall be differentiated by service voltage delivery level to reflect transformation losses between delivery levels.

Second, for purposes of both the IAC and the ECA, it is agreed that it shall be considered prudent[32] for the Company to sell gas which was purchased for electric system operation, but which is not needed for certain months or certain days. Revenues from the sale of this gas will be used to offset fuel expense otherwise recovered through the IAC or ECA. This agreement on prudence is subject to the following restrictions:

- Monthly gas sales may be made for a period no greater than 31 days and may be made no earlier than 31 days in advance of the first day of delivery.
- Daily gas sales may be made only within the current calendar month.
- No more than 20,000 Dth per day of monthly gas supplies may be sold for the month.
- Monthly sales will be based on market index prices.
- No more than 50,000 Dth of daily gas may be sold per day.

Any gas sales made in connection with electric system operation that do not comply with the restrictions in this paragraph may be challenged for prudence and the Company shall bear the burden of demonstrating that such sales were prudently made.

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[32] For purposes of this section, the Company's gas sales decisions shall not be considered imprudent based solely on the decision to sell gas. A specific Company gas sales decision could be challenged based upon other factors that would suggest that the specific gas sale transaction was not conducted in a prudent manner.

Third, CPUC jurisdictional gas hedging expense shall be separately identified and recorded in an appropriate FERC account and supported by original invoice and transaction documentation. In all regulatory filings made for the IAC and the ECA, CPUC jurisdictional net gas hedging costs shall be separately identified. Unless otherwise specifically approved by the Commission, the net gas hedging costs passed through to retail customers shall be capped at $15 million for each period of May 1 through April 30.[33] The calculation for determining the net gas hedging costs applicable to the gas hedging cost cap shall include all premium costs, all settlement costs in excess of the Commission-approved floor price,[34] and all gains from gas hedging transactions. The Parties agree that the purpose of hedging is to reduce the exposure of Public Service's electric sales customers to fluctuations in the price of gas used to generate electricity. Under this hedging activity, Public Service purchases and holds the financial derivative contracts only through the expiration date of the hedging transaction. Selling financial derivatives associated with the gas hedging program shall

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[33] The gas price volatility mitigation plan for electric and the related cap of $15 million described herein is intended to apply solely to the CPUC jurisdictional retail electric customers of Public Service. The Company retains the right to: (1) implement the proposed gas price volatility mitigation plan to only the CPUC jurisdictional retail customers; (2) implement the same hedging plan to both the CPUC jurisdictional retail customers and the FERC jurisdictional wholesale electric customers; or (3) implement separate hedging plans for the CPUC jurisdictional retail customers and for the FERC jurisdictional wholesale customers. In option (2) above, to the extent that the Company elects to implement the same proposed gas price volatility mitigation plan for its CPUC jurisdictional retail customers and its FERC jurisdictional wholesale customers, the net gas hedging costs from such plan will be allocated using the Company's jurisdictional allocations. If Public Service elects to implement option (3), the net gas hedging costs from the CPUC jurisdictional retail customers' gas price volatility mitigation plan will be kept separate from, and not consolidated with, those of the FERC jurisdictional wholesale gas hedging program. In doing so, Public Service will separate the hedging transactions and net gas hedging costs as between the two price volatility mitigation plans. Under any of the proposed options, the $15 million cap described in this Settlement Agreement will apply only to the net gas hedging costs allocated to the CPUC jurisdictional retail customers.

[34] If at any time during an annual period the applicable index price of the gas associated with a hedge transaction is below the Commission-approved floor price, then settlement costs during such time that represent the difference between that index price and the floor price shall not be used in calculating the $15 million gas hedging cap for that annual period.

be prohibited; the effects of any such sales should they occur shall be eliminated from the IAC and the ECA. CPUC jurisdictional net gas hedging costs under both the IAC and the ECA shall be passed through to customers, dollar for dollar. For the year 2003 and through April 30, 2004, the Parties agree that the Commission should approve a floor price of $2.75 per Dth for purposes of the gas hedging cap.[35]

Public Service shall file an annual application with the Commission for approval of its gas hedging plan. The annual filing with the Commission shall include the following information: the volume of gas to be hedged, the timing of the hedges, a description of the types of hedging instruments that the Company may use in implementing the proposed hedging plan, the floor price for determining the costs related to the gas hedging cost cap and the Company's rationale in support of its floor price, a discussion of the hedging strategy for the upcoming year including an implementation plan and the proposed hedging instruments to be used to accomplish said plan, and a proposed format[36] for reporting on the Company's use of hedging instruments. The Commission will not be requested to approve the precise hedging instruments to be employed at various gas price levels as contained in the Company's implementation plan. The annual filing shall also include, for informational purposes, the Company's projections for the calendar year of the following: the Company's gas fuel requirements for electric production; megawatt hours of electric generation; total fuel

[35] Gas supply agreements that were assigned to the Company as part of the restructuring of the Company's power purchase contracts with the Thermo Companies, approved by the Commission in Docket No. 01A-181E, shall not be included in the calculation of any annual gas hedging cap.

[36] At a minimum, the proposed format should include information identifying contract date, counter party, transaction number, strike month, contract volume, contract price, settlement amount, NYMEX natural gas contract price for the month of delivery at the time of entering into the hedge, basis at the time of entering into the hedge and relevant remarks/exceptions.

cost by fuel type including gas price forecast; and purchased energy requirements and costs. The Company shall file its gas hedging plan by January 15 of each year, to be effective March 15. For calendar year 2003, the Company shall file its gas hedging plan as soon as practicable after a final Commission order in this docket, to be effective 30 days after the filing of the plan[37].

XIII. Trading

Background. The Company described in its testimony its electric commodity trading activities. The Xcel Energy Markets business unit ("XEM") of Xcel Energy Services Inc. has developed a sophisticated trading business that purchases on the wholesale market, on behalf of Public Service,[38] short term electric energy to reduce the overall cost of serving the Company's "native load" customers.[39] The costs of these short term purchases are reflected in the Energy Costs that have been recovered from retail customers through the ICA and IAC, and in the future will be recovered in accordance with this Settlement Agreement through the IAC and then the ECA.

In addition, XEM sells on the wholesale market, on behalf of Public Service, short term electric energy that is generated from generation units owned by Public Service, that is available to Public Service under long term contracts, or that is acquired in a short term market purchase. The margins earned on these short term sales have been shared for many years between the Company and its Colorado retail customers, with

[37] Electric Department gas hedging cost documentation shall be included with the annual IAC and ECA prudence filing which shall be made no later than August 1 of each year. The prudence filing shall include Energy Cost information from the prior calendar year and the results of the gas hedging plan from the period May 1 through April 30.

[38] XEM also purchases and sells short term electric energy on behalf of the other operating companies that are owned by Xcel Energy Inc.

[39] "Native load" customers refers to the Company's retail customers and the Company's wholesale customers served under long term contracts.

the margin sharing reflected in the Company's Energy Cost recovery mechanism, most recently the ICA. In the filed testimony, these transactions are referred to as "generation book" sales or "gen book" sales. In practice, the Company is limited in the amount of Generation Book sales that it can make due to limited transmission capacity in the neighborhood of the Company's electric system and the limited spread between the Company's production costs and the production costs of other market participants.

In addition, XEM buys and sells electric energy on the wholesale market from and to entities that are not related to Public Service or to any other Xcel Energy operating company. These purchases and sales are referred to in the testimony as "proprietary" transactions or "prop" transactions. Certain transactions are undertaken on behalf of Public Service and are recorded in what is known as the Company's "prop book"; other transactions are undertaken on behalf of other Xcel Energy operating companies. Irrespective of the operating company engaged in the trading and executing the transactions, the margins earned from these "prop" transactions are shared among the Xcel Energy operating companies in accordance with the provisions of the Joint Operating Agreement[40] approved by the Federal Energy Regulatory Commission. Public Service's share of these "prop" margins have been shared with retail customers through the Company's ICA.

The accounting for these short term transactions has been governed by a Stipulation and Agreement, dated May 31, 2000, filed in Docket No, 99A-557E (the "2000 Trading Stipulation") and approved by the Commission by Decision No. R00-830

[40] The Joint Operating Agreement was filed in this docket as Exhibit MEM-6 to the Rebuttal Testimony of Marvin E. McDaniel. The Joint Operating Agreement refers to Proprietary Book transactions as "off-system marketing."

(August 1, 2000), attached as Attachment H. The 2000 Trading Stipulation, by its terms, applies to transactions conducted through December 31, 2002. It was anticipated that transactions conducted after that date would be governed by the outcome of this general rate case. Under the 2000 Trading Stipulation, Public Service aggregated all Generation and Proprietary book gross margins[41] earned by the Company over each calendar year. Fifty percent of the annual aggregated gross margins, if positive, were provided to the retail customers through the ICA; if the annual aggregated margin were negative, no additional costs were passed through to retail customers.

The Company initially proposed in this Docket No. 02S-315EG to continue to account for its short term transactions and to share margins generally in the same manner as set forth in the 2000 Trading Stipulation but to make two changes. First the Company requested that the definition of short-term electric energy transactions under the 2000 Trading Stipulation be expanded from transactions of 12 months or less in term length, to transactions of two years or less in term length. Second, the Company requested that there be symmetrical sharing of aggregated margins, with fifty percent of the annual aggregated trading margin, positive or negative, flowing to retail customers. In Rebuttal Testimony, the Company retracted its request for the sharing of annual aggregated negative margins and agreed to continue to absorb any net negative loss from its electric commodity trading operations.

Many Parties objected to the Company's proposal. The Answer Testimony primarily focused on concerns about the Company's initial proposal to share aggregated

[41] See definition of gross margins in footnote below.

negative margins with customers. Many Parties questioned whether it is appropriate for a regulated utility to engage in proprietary transactions at all, some alleging that the Company may be "gambling" with customer money in an enterprise they asserted provided no benefits to the customers. Others questioned whether the sharing levels of the Generation book and Proprietary book margins were appropriate. Some Parties questioned whether the Company's trading operations were adversely affecting the accounting for Energy Costs in the Company's ICA. Questions were raised by Staff concerning the effects of the Joint Operating Agreement and the dynamic recent changes in the electric industry, on the accounting of the Company's short-term energy trading activities. The Company in its Rebuttal Testimony addressed the concerns raised in the Answer Testimony.

The Parties have been engaged in extensive settlement discussions on the issue of trading. The major issues discussed have been the Company's accounting for short term transactions, the types of short term transactions made by the Company, the risks associated with the Company's trading activity, and the Business Rules employed by the Company to assign costs and calculate margins. It became clear through these discussions that more time would be needed than could be provided in the procedural schedule governing this general rate case to communicate with the Parties about the Company's trading operations and the Company's accounting for short term transactions. Consequently, the Parties agree that the terms and conditions of the 2000 Trading Stipulation shall be extended through December 31, 2004, with some important changes set forth below, while the Parties are given more time to study the Company's trading operations.

Resolution. Specifically, the Parties agree to the procedures set forth next. First, as discussed above, the Parties agree that *pro forma* adjustments will be made for CPUC jurisdictional ratemaking purposes to reduce A&G/non-production O&M expense associated with the Company's trading business in the setting of base rates in this case. The reductions shall be $1.74 million related to Generation Book A&G/non-production O&M expense and $1 million related to Proprietary book A&G/non-production O&M expense. The same respective *pro forma* adjustments shall be made to Earnings Tests revenue requirements in years 2004 through 2006, unless modified as discussed earlier in Section III.C. of this Settlement Agreement.

Second, the Parties agree to extend all of the terms and conditions of the 2000 Trading Stipulation[42] through December 31, 2004, except that the 2000 Trading Stipulation shall be modified as set forth in this Settlement Agreement. The modifications from the 2000 Trading Stipulation for the calendar years 2003 and 2004 shall be as follows:

- Margin sharing shall be calculated separately for each of the Generation Book margins and Proprietary Book margins. Proprietary Book margins shall be calculated from Public Service's share of margins under the Joint Operating Agreement. Within each of these books, the CPUC jurisdictional Gross Margin[43] shall be aggregated annually. If the aggregated Gross Margin from

[42] The 2000 Trading Stipulation addresses several issues in addition to the sharing of margins. Except as expressly modified by this Settlement Agreement, all terms and conditions in the 2000 Trading Stipulation are extended through December 31, 2004.

[43] Gross Margins shall be defined as follows:

either book is negative, the negative margin shall not be passed on to retail customers.

- If the annual CPUC jurisdictional aggregated Gross Margin in either book is positive, then such positive annual CPUC jurisdictional Gross Margin shall be shared annually with retail customers through the ECA as follows:
  - Positive Annual Generation Book Gross Margin: Retail customers will receive the first $1.74 million; the Company will retain the next $1.74 million; and the remaining Gross Margin will be shared 60% retail customers/ 40% Company.
  - Positive Annual Proprietary Book Gross Margin: The Company shall retain the first $1 million; the remaining Gross Margin will be shared 40% retail customers/ 60% Company.
  - Timing of Margin Sharing: The Company shall file on or before April 1 of 2004, 2005 and 2006 a change to the ECA rates, to go into effect on May 1 of each year, to reflect the customer share of margins from the prior calendar year. In calculating these prospective rate changes, the Company shall first apply the customer share of margins to reduce any balance (of under recovery) in the deferred account; then the ECA

Generation Book Gross Margins = (Revenues + Option Premium Received) - (Incremental fuel costs + variable O&M costs + Purchased Energy Costs + Transmission Costs + Option Premium Purchased + Financial Penalties)

Proprietary Book Gross Margins = (Revenues + Option Premiums received) - (Purchased Energy Costs + Transmission Costs + Broker Fees + Option Premiums Purchased + Financial Penalties)

In calculating both the Generation Book Gross Margins and the Proprietary Book Gross Margins, the Company shall adjust each book for Internal Trades. The CPUC jurisdictional Gross Margin refers to the Public Service Company Gross Margin times the retail jurisdictional allocator, which is the percentage of total energy sold by Public Service that is sold to retail customers.

rates shall be reduced to return to customers any remaining customer margins over a twelve month period.

- The Company agrees that it will not request approval from the Commission to share all or a portion of any net aggregated losses from either the Generation Book or the Proprietary Book with retail customers.

The definition of short-term electric energy transaction shall be modified to include transactions of up to two years in term length. The Company agrees that the Value at Risk limits for the Generation Book and the Proprietary Book will not be increased, in whole or in part, to specifically accommodate longer term trading. The regulatory treatment set forth in this Settlement Agreement for the Generation Book shall apply to all transactions with trade dates prior to January 1, 2005, irrespective of the future delivery date.[44] There shall be no Proprietary Book trades made on behalf of Public Service with delivery dates after December 31, 2004, absent CPUC approval. The regulatory treatment set forth in this Settlement Agreement for Proprietary Book trades applies only for deliveries through December 31, 2004.

Third, by July 1, 2003, the Company shall establish and use separate general ledger accounts to track the Generation Book and Proprietary Book costs and revenues that are used to calculate the Gross Margins in each of the Generation and Proprietary Books.

Fourth, in discussions with the Staff, the OCC and CEC, the Company has reduced to writing the trading Business Rules that the Company will follow from the

[44] This means that the regulatory treatment described in this Settlement Agreement would apply to realized gains or losses from the settlement of these transactions through December 31, 2006.

effective date of this Settlement Agreement through December 31, 2004. These trading Business Rules are entitled "Public Service Company of Colorado Policy for Resource Management and Cost Assignment for Short Term Electric Energy Transactions" and are attached as Attachment J. It is understood and agreed by the Parties that the trading Business Rules set forth in Attachment J are forward-looking and may not reflect in all respects the practices used by the Company prior to the effective date of this Settlement Agreement. The Parties further agree that any departure by the Company from the specific trading business rules set forth in Attachment J is insufficient, in and of itself, to establish imprudence by the Company in connection with its trading activity prior to the effective date of this Settlement Agreement.

In following these trading Business Rules, Public Service shall use at all times prudent utility practices to make capacity and energy available to serve its firm native load obligations. All Generation Book short term sales shall be subordinate to the Company's firm native load obligations. Generation Book short term sales and Proprietary Book short-term sales (to the extent feasible) shall be interrupted if the energy is needed for the reliability of the Company's system.[45]

To the extent that the Company follows the specific trading Business Rules in Attachment J for transactions made prior to January 1, 2005, the Company's actions shall be deemed prudent. The burden of proof shall shift to any party opposing specific

[45] In today's wholesale energy market, many short term sales are made on a "financially firm" basis. The Company can interrupt the sale if the energy is needed for its native load. However, a financial penalty could be incurred to cover the buyer's increased cost of replacing the energy not delivered by the Company. Any financial penalty incurred shall be reflected in the calculation of Gross Margins for the appropriate trading book. The Company shall track and report the circumstances under which the Proprietary Book makes an internal trade to the Generation Book for system reliability purposes and a financial penalty was incurred.

Company actions to show either that 1) the specific Company actions were not materially consistent with the trading Business Rules in Attachment J, or 2) due to changed circumstances timely known to the Company or that should have been known to a prudent utility, the specific Company actions were not prudent.[46]

Fifth, the Company shall arrange for an agreed-upon procedures audit of its Generation Book and Proprietary Book electric commodity trading operations. The intention of the procedures audit is to demonstrate that the Company has established a clear and verifiable process from transaction initiation to final accounting with respect to its energy trading activities. The audit will use standard statistical sampling procedures, and whatever other procedures are deemed necessary by the auditor, to verify whether the Company is in substantial compliance with its established policies, practices, and procedures for the period under review. The audit shall be performed in accordance with generally accepted auditing standards by a licensed CPA accounting firm selected by the Staff and the OCC but approved by the Company under a scope of work acceptable to the Company. The Staff and the OCC shall have input into the scope of the audit, but the Company shall direct the audit. The maximum amount paid for the audit shall be the amount set forth on Confidential Attachment I[47] and such monies shall be treated as an allowable expense through the 2004 Earnings Test.

The accounting firm shall be hired by the Company and all information obtained by the auditors and the audit report shall remain the property of the Company and shall

[46] The trading business rules in Attachment J provide for an exception that allows the Company to depart from the specific business rules to provide a benefit to Public Service's customers. If the Company relies on this exception for a transaction, the Company shall bear the burden of proof that its actions were prudent with respect to the Company's deviation from the trading business rules.

[47] The amounts to be provided for the audit shall be placed under seal to avoid improperly biasing competitive procurement procedures.

be afforded Confidential protection as commercially-sensitive information. If required by the auditor, the audit work papers produced by the auditor for this procedures audit shall remain the sole property of the auditor and shall not be requested for distribution by any Party. Unless otherwise agreed by the auditor, the sole output of this procedures audit that will be available to the Parties will be the audit report. The Company reserves the right to ask the Commission that portions of the audit report and/or auditor work papers (if applicable) that contain specific highly competitively sensitive information shall be afforded Extraordinary Confidential protection, with access to the information limited to the Staff and the OCC. Other Parties reserve the right to contest whether the information in the audit report and/or the auditor work papers (if applicable) to be protected should be afforded Extraordinary Confidential Protection. The audit shall cover the period of January 1, 2003 through June 30, 2003 and shall be conducted and completed by October 1, 2003.

The audit report shall contain the following information: a description of Xcel Energy Market's Front, Middle and Back Offices; a description of transaction flow through the various Offices; a description of the controls established to ensure deal and data integrity; a description of audit tests used to validate transaction cost accounting and record keeping; any substantive findings of non-compliance from the Company's policies, practices and procedures for the period under review; and any differences in the Company's policies, practices and procedures for the period under review from the Company's policies, practices and procedures set forth on Attachment J. The audit report shall be supplied to interested persons who have executed non-disclosure agreements in this Docket No. 02S-315EG, so long as each such person is qualified under the Commission's Confidentiality Rules to receive confidential information. The audit report may be used in connection with the Commission proceedings on the Company's application for review of its trading operation described next.

Sixth, in January 2004 the Company shall file an application for Commission review of its electric commodity trading operation, including the Company's proposal as to the Colorado regulatory treatment to be afforded the Company's trading operations, the Company's trading business rules and the Company's cost assignment and cost allocation procedures related to short term wholesale transactions. To facilitate review of the Company's fuel cost allocations to short term wholesale transactions, the Company agrees to retain records, beginning with the effective date of this Settlement Agreement, of the following daily information: 1) the day-ahead estimated gas prices by generation plant that the Company currently uses to dispatch its generation and to assign costs to wholesales sales; 2) the estimated gas price worksheet updated using actual gas commodity indices published for the gas day corresponding to the electric trading day; and 3) the gas commodity indices for the gas day.

The Parties expect that this trading investigation case would be completed prior to October 15, 2004.[48] The Commission Order resulting from the Company's application will govern the Colorado regulatory treatment of the Company's trading operation post December 2004. Any change in cost assignment, cost allocation or in the trading Business Rules ordered by the Commission would apply prospectively only, beginning January 1, 2005. As previously discussed, the Company reserves the right to terminate

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[48] On November 1 of each year the Company must commit whether it wishes to continue to reserve firm transmission paths. In order to do so, the Company must know the Commission's decision with respect to the Colorado regulatory treatment to be afforded its trading operations.

the ECA and implement instead an adjustment mechanism for 100% pass-through of Energy Costs, should the Company believe that the Commission Order does not afford the Company with sufficient opportunity to cover the risks inherent in an incentive adjustment mechanism.

Seventh, within one month~~s~~ of the effective date of this Settlement Agreement, the Company shall provide funds (up to the amount set forth on Confidential Attachment I)[49] to hire a consultant selected by the trial Staff and OCC, who shall be, at all times, under the personal direction of the Chief of Fixed Utilities for the Staff, in consultation with the Director of the OCC. The consultant shall provide the trial Staff and OCC with technical advice and consulting services regarding prospective changes that should be made, if any, to the Colorado regulatory treatment of the Company's trading activities. Staff and the OCC shall determine the scope and nature of the investigative and consulting services provided by the consultant. Such consultant shall act as an advisor to the trial Staff and OCC during the Commission's review of the Company's trading application, described above. Such consultant may be advising or testifying as directed by the trial Staff and OCC in response to the Company's application. The Company's expenditures for this consultant shall be fully recoverable, dollar for dollar, as a separate expense through the Company's IAC and/or ECA, depending upon the year in which all or part of these expenditures are made.

XIV. Windsource and the Base Energy Credit

<u>Background</u>. Public Service proposed as part of its Phase I filing to recover all Energy Costs through its proposed ECA clause. However, until rates are redesigned in

[49] The amounts to be provided for the consultant shall be placed under seal to avoid improperly biasing competitive procurement procedures.

Phase II, the Company's current base rates contain recovery of $12.78 per MWh of Energy Costs. To avoid double recovery of this expense pending the completion of Phase II, the Company proposed a Base Energy Credit for all customers who were paying both a base rate and the ECA for their energy consumption. The Company excluded Windsource energy from receipt of the Base Energy Credit because Windsource customers would not pay the ECA for Windsource energy purchases.

The LAW Fund opposed the exclusion of Windsource energy from receipt of the Base Energy Credit because it argued it would violate the rate cap on the Windsource premium and the market-based pricing principles established by the Stipulation and Agreement in Docket No. 96A-401E (the "Windsource Stipulation"). Without agreeing with the LAW Fund's interpretation of the Windsource Stipulation, the Company does agree that the Base Energy Credit mechanism may give the wrong impression to Windsource customers as to the relative cost of wind energy vis-à-vis non-wind energy.

<u>Resolution</u>. The Company proposes, and all Parties agree, that pending the conclusion of the Phase II rate case, the Company's base rates shall continue to recover $12.78 per MWh, the Company's fuel clause (first the IAC and then the ECA) shall recover Energy Costs in excess of $12.78 per MWH, and the Company shall withdraw its proposed Base Energy Credit. The Company reserves the right in Phase II to remove Energy Costs from base rates and to recover all of this expense through an adjustment clause and the LAW Fund and other Parties reserve the right to respond to the Company's proposal. The Company agrees to work informally with the LAW Fund and other interested Parties to evaluate the costs of service for the Windsource program. The Company, the LAW Fund and the other Parties further reserve the right

to propose a stand-alone rate for Windsource energy in lieu of the rate rider mechanism in the current tariffs.

Further the Parties agree that the Company's proposal in its Supplemental Rebuttal testimony to withdraw its proposed Windsource Production Capacity Adjustment should be accepted. As a result, the Company does not propose in this Docket a Windsource-related adjustment to revenue requirements.

XV. Special Amortizations

Background. Historically, the Commission has not generally adjusted tariffs for amortizations that occur between rate cases. However, in the last decade, amortizations have assumed a greater importance to Parties in their calculations to synchronize revenues and expenses. In its Answer Testimony, Staff recommended that certain amortized costs be recovered via a rider that is placed on a "preface page" of the Company's tariff, that the Company track the amounts collected by the rider, and that the Company file with the Commission for reduction (or elimination) of the rider at the time such amortized costs are recovered. In Rebuttal Testimony, Public Service objected to this specialized rate treatment for such a small increment of costs as excessively burdensome and unnecessary and inconsistent with test period ratemaking.

Resolution. In resolution of this issue, the Parties agree that the Company shall file by June 1, 2007, an advice letter on 30 days' notice to place into effect a negative general rate schedule adjustment rider that reduces base rates to eliminate the amortizations for the Pawnee 2 Pre-engineering costs and the Metro Ash Disposal Site option, as provided herein.[50] The negative rider shall be calculated using (1) twelve full months of amortization expense related to the amortization of Pawnee 2 Pre-engineering costs and the Metro Ash Disposal Site option and (2) a test year ending not earlier than seven months prior to June 30, 2007. If the rate changes resulting from this Settlement Agreement are delayed to the extent they become effective after July 1, 2003, then the date on which Public Service is required by this section to file an advice letter to implement a negative rider to eliminate the referenced amortizations shall be delayed by an equal number of days.

XVI. Transmission Reliability

Background**.** In Answer Testimony, Staff raised concerns about the Company's transmission planning criteria, the Company's ranking of projects, and the timeliness of Company investment in transmission additions. The Company responded with Rebuttal Testimony explaining its planning criteria and its commitment to make timely and sufficient investment in transmission facilities to maintain system reliability.

Resolution. Due to the complexity of these issues, the Company, Staff and the OCC agree that the issues need not be resolved as part of this proceeding. Public Service commits to meet with Staff and the OCC by April 15, 2003 and thereafter as necessary to address and resolve, if possible, Staff's and the OCC's concerns raised in this proceeding concerning transmission planning and reliability criteria. The Company, Staff and the OCC agree to engage in good faith discussions to resolve these issues in a reasonable manner and on a reasonable timeline that shall not exceed six months

[50] The Parties intent is to eliminate from base rates the amortization expense associated with the Pawnee 2 pre-engineering costs and the Metro Ash Disposal Site option following the 48-month amortization period. The Parties agree that in the event that an intervening rate proceeding prior to the expiration of the four-year amortization period, this aspect of the Settlement Agreement will need to be revisited so as to accomplish the Parties' intent.

from the effective date of this Settlement Agreement. As part of the process, the Company's subject matter experts will be available to explain the Company's position with respect to its interpretation and its use of transmission planning criteria.

To assist the discussions, the Company shall provide updates, as applicable, on all transmission projects identified in the N-1 filings pursuant to Decision No. C01-67, Docket No. 00A-067E. The Company also agrees to make available for Staff's and the OCC's review all existing supporting data it has available that demonstrate how the Company performs studies and plans its facilities to meet the N-1 performance standard. These data shall include but are not limited to: data with respect to the Company's as-constructed loading capabilities of transmission lines and associated priority assessment processes related thereto; the impact on generation redispatch; the potential for loss of load; and switching alternatives the Company uses in prioritizing transmission investment.

This Settlement Agreement does not intend to require the Company to generate any new documentation or studies. This Settlement Agreement shall not be construed to limit Staff's or the OCC's ability to request or receive the data necessary to perform their own studies or analyses if either Staff or the OCC ultimately determines that such analyses are necessary. In the event the issues are not resolved, the Company, the Staff and the OCC reserve their rights to pursue these issues in future Commission proceedings.

XVII. Ratemaking Principles for Future Earnings Test Filings

For the 2004 through 2006 Earnings Tests the electric earnings sharing shall be measured on the basis of an Earnings Test that uses the ratemaking principles and treatments specified in the following sections of this Settlement Agreement:

- Rate of Return and Capital Structure;
- Plant Held for Future Use;
- Insurance Expense;
- Pension Expense;
- Trading A&G and Non Production O&M Expense;
- Oil and Gas Royalty Revenues;
- Dark Fiber;
- Regulatory Treatment of C.R.S. § 40-3-104.3(2)(a) discounts;
- Cost Allocation Between Regulated and Non-Regulated Business Activities; and
- Reclassification of Substation Plant and Treatment of Radial Transmission Lines
- Sterling Correctional Facility

In addition, the Parties agree that the 2004 through 2006 Earnings Tests shall reflect the jurisdictional allocation methods used in developing the electric revenue requirement approved as a part of this Settlement Agreement and all other cost assignment/allocation methods identified in the Company's then current CAM on file with the Commission.

For the test periods 2004 through 2006, sharing percentages for earnings over 10.75 percent return on equity shall be as follows:

Measured Return on Equity	Sharing Percentages	
(10.75)	Customers	Company
>10.75% ≤ 11.75%	65%	35%
>11.75% ≤ 13.75%	50%	50%
>13.75% ≤ 14.75%	35%	65%
over 14.75%	100%	

XVIII. QFCCA

Background. In its Direct Case filed on May 31, 2002, the Company proposed to eliminate its current tariff with respect to the Qualifying Facility Capacity Cost Adjustment (“QFCCA”). The new base rates proposed by the Company would recover the Company’s capacity cost associated with purchases from Qualifying Facilities (QFs) going forward. On March 29, 2002, the Company had set the QFCCA rate at 0.00% in order to work off a projected deferred balance of over-recovery of the QF capacity costs by January 1, 2003. However, the delay in the establishment of new rates from the rate case from January 1, 2003 until potentially July 1, 2003 has caused the QFCCA deferred account to go from an over-recovery balance to an under-recovery balance. The recovery of the remaining QFCCA deferred balance needs to be addressed.

Resolution. The Parties agree that the Company shall file an advice letter requesting authorization to terminate the QFCCA effective April 30, 2003. At that time, the Company shall stop accumulating costs in the QFCCA deferred account. The account shall remain open to reflect revenues associated with electric usage occurring prior to April 30, 2003, which will be booked into subsequent months due to cycle billing. The Company shall restate the federal/state jurisdictional split of the QF capacity costs for the 12 months ending June 30, 2003 in order to reflect the actual jurisdictional split for that period. The Parties agree that the Company shall be entitled to recover the remaining QFCCA deferred balance if under-recovered, or shall be required to return the remaining QFCCA deferred balance if over-recovered, over a period of not more than twelve months. Once the deferred balance is known, the Company shall file with the Commission an application setting forth the mechanism that shall be used to recover (or return) the deferred balance. The Parties reserve the right to suggest alternatives to the Company's proposed mechanism.

IMPLEMENTATION

The Parties hereto agree that the rate and tariff changes resulting from this Settlement Agreement should be approved by the Commission to become effective July 1, 2003. Attached as Attachment K are *pro forma* tariff sheets reflecting the rate and tariff changes resulting from this Settlement Agreement. The Parties hereto agree that upon a final Commission order approving this Settlement Agreement in all material respects, Public Service will file with the Commission amended advice letters on not less than one days' notice to the place into effect revised tariff sheets in the form reflected in Attachment K hereto to become effective July 1, 2003.

GENERAL TERMS AND CONDITIONS

The Parties hereby agree that all pre-filed testimony and exhibits shall be admitted into evidence in this docket without cross-examination. This Settlement Agreement reflects compromise and settlement of all issues raised or that could have been raised in this Docket. This Settlement Agreement shall be filed as soon as possible with the Commission for Commission approval.

This Settlement Agreement shall not become effective until the issuance of a final Commission Order approving the Settlement Agreement, which Order does not contain any modification of the terms and conditions of this Settlement Agreement which is unacceptable to any of the Parties. In the event the Commission modifies this Settlement Agreement in a manner unacceptable to any Party, that Party shall have the right to withdraw from this Agreement and proceed to hearing on the issues that may be appropriately raised by that Party in this docket. The withdrawing Party shall notify the Commission and the Parties to this Agreement by e-mail within three business days of the Commission modification that the Party is withdrawing from the Settlement Agreement and that the Party is ready to proceed to hearing; the e-mail notice shall designate the precise issue or issues on which the Party desires to proceed to hearing (the “Hearing Notice”).

The withdrawal of a Party shall not automatically terminate this Agreement as to the withdrawing Party or any other Party. However, within three business days of the date of the Hearing Notice from the first withdrawing Party, all Parties shall confer to arrive at a comprehensive list of issues that shall proceed to hearing and a list of issues that remain settled as a result of the first Party’s withdrawal from this Settlement Agreement. Within five business days of the date of the Hearing Notice, the Parties shall file with the Commission a formal notice containing the list of issues that shall proceed to hearing and those issues that remain settled. The Parties who proceed to hearing shall have and be entitled to exercise all rights with respect to the issues that are heard that theywould have had in the absence of this Settlement Agreement.

Hearing shall be scheduled on all of the issues designated in the formal notice filed with the Commission as soon as practicable. In the event that this Agreement is not approved, or is approved with conditions that are unacceptable to any Party who subsequently withdraws, the negotiations or discussions undertaken in conjunction with the Agreement shall not be admissible into evidence in this or any other proceeding, except as may be necessary in any proceeding to enforce this Settlement Agreement.

Approval by the Commission of this Agreement shall constitute a determination that the Agreement represents a just, equitable and reasonable resolution of all issues that were or could have been contested among the Parties in this proceeding.

All Parties specifically agree and understand that this Settlement represents a negotiated settlement in the public interest with respect to the various Public Service rate matters and terms and conditions of service for the sole purpose of the settlement of the matters agreed to in this Settlement. Neither Public Service, the Commission, its Staff or any other party or person shall be deemed to have approved, accepted, agreed to or consented to any concept, theory or principle underlying or supposed to underlie any of the matters provided for in this Settlement, other than as specifically provided for herein with respect to the 2004, 2005 and 2006 Earnings Tests. Notwithstanding the resolution of the issues set forth in this Stipulation, none of the methods or ratemaking principles herein contained shall be deemed by the Parties to constitute a settled practice or precedent in any future proceeding (other than the aforementioned electric Earnings Test proceedings). Nothing in this Settlement Agreement shall preclude the Company from seeking prospective changes in its electric, gas or steam rates by an appropriate filing with the Commission. Nothing in this Settlement Agreement shall preclude any other party from filing a Complaint or seeking an Order to Show Cause to obtain prospective changes in the Company's electric, gas or steam rates.

The Parties to this Agreement state that reaching agreement in this docket as set forth in this Agreement by means of a negotiated settlement is in the public interest and that the results of the compromises and settlements reflected by this Agreement are just, reasonable and in the public interest.

This Agreement may be executed in counterparts, all of which when taken together shall constitute the entire Agreement with respect to the issues addressed by this Agreement.

Dated this 4th day of April, 2003.

Respectfully submitted,