Decision No. C06-0086

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 05S-264G

RE: THE TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO WITH ADVICE LETTER NO. 647 - GAS.

COMMISSION DECISION
APPROVING SETTLEMENT WITH MODIFICATIONS

Mailed Date: February 3, 2006
Adopted Date: January 19, 2006

TABLE OF CONTENTS

I. BY THE COMMISSION

A. Statement

1. This matter comes before the Commission for consideration of amended advice letter 647-Gas filed by Public Service Company of Colorado (Public Service or Company) on July 8, 2005 and the related settlement agreement filed by the Parties to this matter on December 20, 2005 (Settlement, attached as Appendix A). The Settlement is comprehensive in nature and resolves all matters for the purposes of this docket.

2. On May 27, 2005, Public Service filed Advice Letter No. 647-Gas, proposing to implement revised base rates for all of its gas sales and transportation services, along with certain other changes to its gas sales and transportation tariffs, to be effective June 27, 2005. The Company proposed that the new base rates would supersede the current base rates and eliminate all existing General Rate Schedule Adjustment (GRSA) riders. On July 8, 2005, Public Service filed its first Amended Advice Letter No. 647-Gas, correcting and supplementing its original filing, and extending the proposed effective date to July 11, 2005. Both filings contained a combined "Phase I" and "Phase II" case. Thus, not only was Public Service's revenue requirement to be determined, but the appropriate rate design as well. The proposed base rates reflected in the filing, as amended, would have increased base rate revenues by $34,545,332, or 12.46% on an annual basis. The Company's proposed revenue requirement of $311,827,757 was developed based on a test year of the 12 months ending December 31, 2004, and reflected a proposed 9.01% overall return on the Company's rate base determined as of the end of the test year. This overall return was calculated using a proposed return on common equity of 11.00% and an adjusted capital structure consisting of 55.49% equity and 44.51% long-term debt.

3. As part of the Settlement, the Parties[1] agreed upon a revenue requirement of $300,345,671 based upon the test year of twelve months ended December 31, 2004, resulting in an increase in jurisdictional base rate revenues of $22,492,993, or 8.10%.

[1] With regard to the settlement of issues concerning Revenue Requirements, as set forth in Section II.A of this Stipulation, the Earnings Cap, as set forth in Section II.E, and Gas Storage Facilities, as set forth in Section II.G, the agreements and compromises reflected therein are those by and among Public Service, Staff and the OCC. EOC/AARP join in the resolution of the average rate base issue, as described in Section II.A.4. While Climax, Atmos, Seminole and EOC/AARP support the Commission's adoption of all of the terms and conditions of this Stipulation without modification, these parties (except EOC/AARP with respect to the average rate base issue) took no position on these particular issues and take no position on the particular resolution of these issues herein. Accordingly, the use of the term "Parties" with respect to these sections of the Stipulation should be construed to mean that Climax, Atmos, Seminole and EOC/AARP (except with respect to the average rate base issue) have no objection to the resolution specified therein. Otherwise, the term Party or Parties should generally be construed to mean parties to the Settlement.

B. Procedural History

4. On May 27, 2005, Public Service Company of Colorado (Public Service or Company) filed Advice Letter No. 647 – Gas, along with pre-filed testimony in support of the Advice Letter. By Decision No. C05-0749 the Commission suspended the proposed tariffs. On July 8, 2005, Public Service filed a first Amended Advice Letter No. 647 – Gas. The Commission by Decision No. C05-0952 suspended the effective date of the amended tariffs, and by Decision No. C05-1301 suspended the effective date for another 90 days.

5. In Decision No. C05-0749, the Commission established a 30-day intervention period, which expired on July 17, 2005, and, in Decision No. C05-0952, the Commission extended the intervention deadline to September 2, 2005, recognizing that in its Supplemental Direct Testimony Public Service expanded the possible rate changes from its direct testimony.

6. The Commission held a prehearing conference on August 3, 2005 during which it ruled on petitions for intervention, proposed procedural dates, proposed discovery procedures, and other procedural issues. The Commission granted the requests for intervention by: Atmos Energy Corporation (Atmos); Climax Molybdenum Company (Climax); Colorado Business Alliance for Cooperative Utility Practices (CBA); Colorado Natural Gas, Inc. (CNG); Energy Outreach Colorado (EOC); Kinder Morgan, Inc. (KMI); Seminole Energy Services, LLC (Seminole); United States Department of Defense -- Federal Executive Agencies (USDoD); and AARP. Staff of the Commission (Staff) and the Colorado Office of Consumer Counsel (OCC) filed timely notices of intervention by right.

7. Staff and Intervenor Answer testimony and Exhibits and Rebuttal and Cross-answer Testimony and Exhibits were timely filed, and two technical conferences were held on September 16 and November 30, 2005.

8. Pursuant to Commission Decision No. C05-1010 which established the procedural schedule for this matter, public comment hearings were held in Denver, Colorado on December 5, 2005. Pursuant to Commission Decision No. C05-1268, additional public hearings were held in Pueblo and Grand Junction on November 9, 2005 and November 17, 2005 respectively. The Commission appreciates the comments provided during these hearings, and found them helpful in considering the Parties' Settlement.

9. A notice of settlement was filed on December 6, 2005 indicating that all issues in this matter had been resolved, and a settlement agreement and stipulation was then filed on December 20, 2005. All Parties save CNG, KMI, and USDoD actively support the terms and conditions of the Settlement. While CNG, KMI, and USDoD do not join the Settlement, they do not oppose it. Parties specifically reserved their right to litigate positions different than those outlined in the Settlement in future proceedings.

10. In Decision C05-1510, the Commission issued a list of questions which the Parties addressed at hearings on the Settlement held on January 3 and 4, 2006. We believe that the record as developed through the filed testimony admitted into evidence, and the oral testimony at hearing supports the Commission's decision in this matter.

11. We believe the rates established by the Settlement are just and reasonable, and that the Settlement is in the public interest. We approve virtually all provisions of the Settlement, modify it in some areas, and appreciate the Parties efforts in reaching agreement when their original positions were so far apart.

II. SETTLEMENT OF PHASE I ISSUES

A. Rate of Return on Equity and Earnings Cap

12. Public Service Company currently is authorized a return on equity of 11.00% for its gas department by Commission Decision No. C03-0670. In this docket, three witnesses presented testimony regarding the proper rate of return on equity (ROE). Their recommendations are summarized in the table below:

Witness	Recommendation
Mr. Hevert (Public Service)	11.0%[2]
Mr. Trogonoski (Staff)	9.5%[3]
Mr. Copeland (OCC)	8.5%[4]

All of the witnesses derived their estimates using a Discounted Cash Flow ("DCF") approach, supplemented, in some cases, by analyses using the Risk Premium Approach, Capital Asset Pricing Model 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. Staff's and the OCC's willingness to reach a compromise regarding ROE and capital structure as set forth below is based upon the Company's concessions on other important issues including, but not limited to, a reduction in the proposed Service and Facilities charge for residential customers, an increase in the proposed time period for determining weather normalization factors, the

[2] Mr. Hevert's recommendation of 11.00% ROE was based on a range for ROE of 10.25% to 11.25%.

[3] Mr. Trogonoski's range for ROE was 8.75% to 9.50%. His recommendation for an ROE of 9.50% was contingent on the Commission rejecting the Company's proposal to increase the Service and Facilities Charge. If the Commission allowed the Company's proposal, then Staff would recommend an ROE of 9.25%.

[4] Mr. Copeland's range for an ROE was 7.50% to 8.50%. Mr. Copeland recommended an 8.50% ROE, but it was contingent on the Commission adopting the capital structure which he had recommended. However, if the Commission adopted the capital structure requested by the Company, then his recommendation for an ROE would be at the bottom of his range, 7.50%.

acceptance of average rate base rather than year-end rate base, and the agreement to use the *Reverse-United United* method to allocate costs among customer classes.

13. As part of the settlement the Parties have agreed to implement an earnings cap of 10.50% return on equity. The earnings cap as testified to by Mr. Stoffel is an aspect of the settlement that was part of the overall compromise. Mr. Stoffel states that the company agrees to perform an annual Earnings Test for its gas business similar to the one it has been using in its electric department.5 Mr. Stoffel indicates that Public Service wanted to settle on a cost of service that included rates that would permit it an opportunity to earn its allowed rate of return. It was Mr. Stoffel's testimony that the cost of service and the rates contained in the Settlement will give the company a real opportunity to earn its allowed return. In addition, Mr. Stoffel testified that it was not the Company's goal to earn a higher return than the allowed return for the Company's gas business.

14. It is the Commission's finding that since all ROE testimony and exhibits have been admitted into evidence in this case, a range of 7.50% to 11.00% has been established for determining an appropriate return on equity. For purposes of settlement, the Parties agree that a fair and reasonable ROE for the Company's gas department is 10.50%. The Commission believes based on the testimony submitted by all Parties that the 10.50% ROE, taken in isolation from the rest of the Settlement, could be considered high, since it exceeds the range recommended by Staff by 100 basis points and by that of OCC by 200 basis points. This

[5] Beginning with the calendar year ending December 31, 2006 and thereafter for each subsequent calendar year in which the terms of this Stipulation remain effective through at least October 31, Public Service agrees to calculate its earned ROE and to reduce its base rates for gas services by means of a negative rate rider for any earnings in excess of 10.5%. Public Service shall file its annual ROE calculation for the preceding calendar year with the Commission on or before April 1 of each year, beginning on April 1, 2007.

difference in basis points is significant because each increase of 100 basis points in the ROE would increase the revenue requirement by $8.6 million.

15. However, the Commission finds based on the evidence in the record, including the testimony of Mr. Stoffel and Dr. Langland in support of the Settlement, that 10.50% is a reasonable ROE given that the Settlement should be viewed as a whole, and compromises were made by all parties, including Public Service (*e.g.*, average rate base). In addition, the Commission takes comfort from the Earnings Cap implemented in relation to the 10.50% ROE. Therefore, the Commission approves the 10.50% ROE as the authorized ROE for the Company as well as the Earnings Cap provision of the agreement without modification.

B. Cost of Debt

16. In its direct testimony, the Company's witness Mr. Tyson proposed a cost of debt of 6.54%, reflecting a reduction in the Company's embedded cost of debt, assuming the retirement of $134.5 million of long-term debt on November 1, 2005. In his Rebuttal Testimony filed on November 9, 2005, Mr. Tyson updated his recommendation and proposed using the actual embedded cost of debt of 6.44% as of November 1, 2005. The actual embedded cost of debt as of November 1, 2005 reflected both the $134.5 million debt retirement that occurred on November 1, 2005 and the refinancing of certain pollution control bonds during September 2005. In his answer testimony filed on October 10, 2005, Staff witness Mr. Trogonoski expressed reservations about the Company's proposed capital structure and cost of debt because at that time there was not yet certainty that the planned $134.5 million debt retirement would occur as scheduled on November 1, 2005. OCC witness Mr. Copeland recommended using the actual embedded cost of debt as of December 31, 2004.

17. For purposes of settlement, the Parties agree that the Company's actual embedded cost of debt of 6.44 % as of November 1, 2005 shall be used to determine the weighted average cost of capital.

18. At the hearing on January 3, 2006, Mr. Stoffel testified that the Company's actual embedded cost of debt as of November 1, 2005 is 6.44 %. In the Settlement, the Parties propose this 6.44% be used to determine the weighted average cost of capital. According to Mr. Stoffel, the 6.44% embedded cost of debt reflects the compromise from the position of both Staff and the OCC on this issue. Therefore, the Commission approves the 6.44% as the embedded cost of debt, without modification to the Settlement.

C. Capital Structure and Weighted Average Cost of Capital

19. In its original testimony, Public Service recommended that the Commission use its projected capital structure as of November 1, 2005 excluding short-term debt, and adjusted to eliminate notes between Public Service and its subsidiaries, 1480 Welton, Inc. and PSR Investments, Inc. The Company argued that use of the projected capital structure was necessary in order to enable it to meet its goal of strengthening the Company's balance sheet and improving Public Service's financial integrity. Staff witness Mr. Trogonoski recommended adjusting the Company's capital structure as of the end of the 2004 test year to reflect the early retirement of $110 million first collateral trust bonds in February 2005, but was reluctant to accept the Company's proposed additional adjustment to its year-end capital structure without certainty that the planned November 1, 2005 $134.5 million debt retirement would occur.

20. In his rebuttal testimony, Company's witness Mr. Tyson confirmed that the Company completed the additional $134.5 million debt retirement as planned on November 1, 2005. OCC witnesses Mr. Copeland and Dr. Schechter advocated using the Company's capital

structure as of the end of the test year, December 31, 2004. The following table summarizes the Parties' final, as filed, recommendations with respect to capital structure ratios:

Party	Long-Term Debt	Equity
Public Service	44.51%	55.49%
Staff	47.47%	52.53%
OCC	49.89%	50.11%

21. For purposes of settlement, the Parties have agreed to the use of the Company's proposed capital structure of 44.51% long-term debt and 55.49% common equity. The Parties agree that Public Service's proposed capital structure is reasonable given the circumstances of this case, and should be used to establish the Company's revenue requirement in this proceeding. The Parties also agree that the Commission should exclude short-term debt from the regulatory capital structure. The following table reflects the weighted average cost of capital that has been agreed to by the Parties:

	Weight	Rate	Wtd Avg.Cost
Long-Term Debt	44.51%	6.44%	2.87%
Equity	55.49%	10.5%	5.83%
Total Cost:			8.70%

22. At the January 3, 2006 hearing on the Settlement, Mr. Stoffel testified that the Company was able to compromise with Staff and that settlement of this issue was part of the trade-offs made in the Settlement as a whole. Based on the evidence in the record as well as Mr. Stoffel's testimony, the Commission finds that the capital structure proposed in the S&A is reasonable and approves this provision of the S&A without modification.

D. Average Rate Base

23. In its application and rebuttal testimony, Public Service proposed the use of a year-end rate base in developing its proposed revenue requirements. Given that calendar year

2004 was selected as the test year for setting rates in this proceeding, a year-end rate base would have generally reflected plant values as of December 31, 2004.

24. The Company defended the use of a year end-rate base as a means of partially addressing the earnings attrition that it claimed its gas department was experiencing. The Company argued that the use of year-end rate base would help counter earnings attrition caused by declining use per customer, the need for significant capital investment to meet continued growth, and regulatory lag.

25. In addition, the Company pointed out in its direct case that the year end method of valuing rate base had been used for setting gas rates for the past 31 years. However, as part of a comprehensive settlement that resolved the issues in the Company's last rate case, Docket No. 02S-315EG, the Parties including the Company agreed that the settled rates were to be calculated based on an average rate base.

26. Staff and the OCC recommended that the revenue requirement be developed based on a thirteen-month average rate base instead of the Company's proposed year-end rate base. EOC/AARP also advocated the use of average rate base. Staff, the OCC and EOC/AARP each argued that the use of year-end rate base violates the matching principle and presented testimony disputing that Public Service's gas department was actually experiencing earnings attrition. Staff pointed out that the majority of the Company's gas plant additions are of the type that immediately produce revenues and therefore are not subject to regulatory lag. In addition, Staff and OCC witnesses argued that the conditions that prompted the Commission to adopt year-end rate base in the past no longer exist.

27. In the Settlement, the Parties agreed on an average rate base method for purposes of determining the Company's revenue requirements and establishing rates. Under this method,

the thirteen-month average of month-end balances is used for all rate base items. However, there were some exceptions: (1) in cases where thirteen months of data were not available for a rate base item, the sum of the prior year-end balance and the test year-end balance divided by two was used; (2) specific assignments of plant to either the CPUC or FERC jurisdiction used year-end balances; (3) cash working capital was calculated using pro forma expenses consistent with the application of the working capital factors proposed by the Company in its application; (4) gas stored underground was reflected as an average of the twelve monthly average balances in 2004; and, (5) the Allowance for Funds Used During Construction (AFUDC) addition to earnings was an annualized amount consistent with the *pro forma* adjustment proposed by the Company in its application.

28. The rate base agreed to by the Parties is valued at $1,004,185,109. Given the settled rate of return of 8.7%, the target operating income on this rate base equals $87,364,105.

29. We accept the proposal in the Settlement to value the Company's rate base using the thirteen-month average method.

E. Amortization of Environmental Clean-up Costs, Leyden Gas Storage Costs, and Rate Case Expenses

30. In its application, Public Service proposed to amortize three categories of costs that had been deferred for accounting purposes and to include an annual amortized amount in its revenue requirement to recover these costs in rates. The three categories of costs relate to: (1) the environmental clean-up of a former Manufactured Gas Plant (MGP) site in Fort Collins, Colorado; (2) the Leyden Gas Storage Facility (Leyden) that is in its final stages of closure and abandonment; and, (3) rate case expenses.

31. With respect to the MGP clean-up costs, the Company proposed to recover $6,237,099 over four years with an annual amortization allowance in base rates of $1,559,275. With respect to Leyden, the Company proposed to recover $4,818,862 over four years with an annual amortization allowance of $1,204,716. With respect to rate case expenses, the Company proposed to recover $1,009,241, including approximately $419,740 of unamortized expenses from the 2002 rate case, over two years with an annual amortization allowance of $504,621.

32. The Company proposed a rolling balance concept for amortization balances to solve the issues surrounding the timing of amortizations and an amortization period that is longer than the time between the effective dates of the rates established through rate cases. That is, if the amortization period were shorter than the time between effective dates of new and old rates, the Company would place a negative rider in place to reduce rates by the amount of the annual amortization expense that had expired. The rider would be in place until the effective date of the rates resulting from the next rate case. This approach was approved by the Commission in Docket No. 00S-422G.

33. Concerning the amortization of MGP clean-up and Leyden decommissioning expenses, Staff recommended separate riders to recover such costs with amortization over four years. Under this plan, the Company would establish revenue sub-accounts to track actual revenues against the amortization schedules. Staff recommended that the riders appear on customers' bills with an explanation that the adjustment was for MGP clean-up costs or for Leyden decommissioning. Further, Staff recommended that the Commission order the Company to file tariff pages reflecting the riders and their terms.

34. Concerning the amortization of rate case expenses, Staff took issue with the Company's proposal to amortize such expenses over two years. Staff stated that the Commission

has historically used amortization periods of three to five years for rate case expenses and that a deviation to two years was not appropriate. Staff instead proposed an amortization of rate case expenses over three years consistent with the combined electric and gas case Docket 02S-315EG.

35. While the OCC did not object to the Company's proposal to amortize rate case expenses associated with this proceeding over two years, it took issue with the Company's cost estimate of $260,000 for outside legal counsel. The OCC argued that the Company's estimate was based on prior cases and that it included an assumption that one-half of the Phase I issues would be appealed to the Supreme Court. Because such estimate was based on speculation and did not reflect a known and measurable cost, the OCC recommended a $60,000 rate case expense allowance for outside counsel.

36. In its rebuttal, Public Service explained that its persistent need to file rate cases was based on the earnings attrition that has faced its gas department. It further argued that its proposal to deal with amortization using rolling balances and negative riders, if necessary, would satisfy concerns in regarding the protection for both the Company and its customers against any over or under recovery of amortizations. The Company further explained that it uses outside counsel more in the later stages of the case through court appeals, and, as such, the majority of such costs had not been incurred in this proceeding.

37. In settling this matter, the Parties agreed to the Company's proposal to amortize the MGP clean-up costs and the Leyden decommissioning costs over four years using an annual allowance in base rate revenue requirements. As such, no separate rate riders would be placed into effect to collect these amortizations. However, if the amortization periods applicable to these costs expires prior to the effective date of rates resulting from the Company's next base rate case, the Company agrees to file an application on less than statutory notice to place into effect a

negative rider that will reduce rates by the amount of the annual amortization expense for the amortization that had expired. Such negative riders would go into effect on February 1, 2010 for both the MGP clean-up and Leyden decommissioning amortizations and would remain in place until the effective date of the rates resulting from the Company's next gas rate case in which revenue requirements are determined.

38. In addition, the Parties agreed to allow the Company to amortize over two years the $498,426 of actual booked rate case expenses associated with this proceeding as of November 30, 2005. In conjunction with the remaining unamortized portion of the 2002 rate case expenses, the resulting annual amortized amount for rate case expense would be $459,083. This annual amortized expense would be included in the settled revenue requirement and in the development of the settled base rates. However, if the amortization period applicable to this expense expired prior to the effective date of rates resulting from the Company's next base rate case, the Company agrees to file an application on less than statutory notice to place into effect a negative rider that would reduce rates by the amount of the annual amortization expense for the amortization that had expired. Such a negative rider would go into effect on February 1, 2008 and would remain in place until the effective date of the rates resulting from the Company's next gas rate case in which revenue requirements are determined.

39. We accept the proposals in the Settlement concerning the amortization of MGP clean-up costs, Leyden closure costs, and rate case expenses.

F. Pipeline Integrity Management Costs

40. Public Service in its application proposed to include one-third of the estimated $8,351,700 it expects to spend to implement its Pipeline Integrity Management Plan. The Company completed this plan in December 2004 to comply with federal pipeline safety laws and

U.S. Department of Transportation Office of Pipeline Safety regulations. The regulations require that 50 percent of the Company's pipeline risk assessment work, as outlined in the plan, be completed by 2007. Accordingly, the Company proposed to recover the three-year average of the total amount, or $2,783,900, as an annual allowance in its base rates.

41. Both Staff and the OCC challenged these estimated costs based on the relatively high degree of uncertainty regarding the amount and timing of the necessary expenditures, and whether they qualified under the known and measurable standard. OCC witness Mr. Peterson recommended that the Commission approve the amount Public Service had budgeted for 2005, or $735,000.

42. In its rebuttal case, the Company put forward a revised three-year program cost estimate of $5,220,139 based on updated information. The Company also disputed that its proposed adjustments for program implementation expenses violate the known and measurable principle. The Company further argued that if it did not file a rate case using a 2006 or 2007 test-year, there would be no opportunity for it to request recovery of the costs that were necessary to comply with the federal mandated requirements. Public Service suggested that at a minimum the Commission should allow for deferred accounting treatment of these costs as they are material and certain to occur during a three-year period even if the distribution of these costs over the period is currently uncertain.

43. In the Settlement, the Parties agreed that the Company should be permitted to include $735,000 in its revenue requirement for recovery of Pipeline Integrity Management Costs. For regulatory accounting purposes, the Company shall be permitted to defer in a regulatory asset account the actual amounts incurred during 2005, 2006 and 2007 under the Pipeline Integrity Management Plan that are in excess of $735,000 per year.

44. Given the Company's revised estimate in its rebuttal case that it will spend approximately $5.2 million over the three years 2005 to 2007, the terms of the Settlement could result in a balance of approximately $3 million in the regulatory asset account. The issues surrounding the recovery of these additional costs, including potentially interest-related or other carrying costs, are anticipated to be addressed in the Company's next base rate case.

45. While we believe that it may be appropriate for the Company to recover more than the $735,000 per year for recovery of its Pipeline Integrity Management Costs, we approve this component of the Settlement without modification.

G. American Gas Association Dues

46. In its application, Public Service proposed to recover through its base rates an annual allowance of $206,615 which represents a fraction of the dues it paid to the American Gas Association (AGA) in the 2004 test year. The allowance amount in the Company's revenue requirement reflects a reduction of $10,331 in the amount of AGA dues actually incurred by the Company to account for the representative amount of AGA dues associated with the AGA's lobbying activities.

47. OCC witness David Peterson recommended that the proposed amount of recoverable test year AGA dues be further reduced by the representative amounts associated with AGA's governmental relations and media communications (excluding environmental communications) activities. The OCC argued that these reductions would be consistent with past Commission practice concerning the ratemaking treatment of similar expenses incurred by the Company and with an audit of AGA expenditures completed by the National Association of Regulatory Utility Commissioners. The OCC advocated that expenses related to AGA dues be reduced by an additional $44,000.

48. In the Settlement, the Parties agreed to the exclusion of AGA dues related to governmental relations and media communications activities. Dues associated with environmental communications activities would not be excluded. Therefore, the resulting test year allowance for AGA dues included in the settled revenue requirement is $162,432, or approximately $44,000 less than the Company had requested in its application.

49. The Commission accepts the proposal in the Settlement concerning the recovery of AGA dues. Commissioner Miller dissents separately on this issue.

H. GCA Recovery of Certain Costs

50. In its filed case, Public Service proposed to transfer three items that would normally be in base rates into the Gas Cost Adjustment (GCA) recovery mechanism. Staff and OCC opposed this proposal, preferring that recovery remain in base rates. The items are Kansas property taxes on gas inventory of $505,895 (Kansas Taxes), Yosemite compressor costs of $135,258, and net gas shrinkage costs of $2,358,676. In the Settlement the Parties agreed to recover all three of these items in base rates, and agreed that these costs shall not be recovered through the Company's GCA mechanism at this time.

51. The Commission is concerned about the proposed treatment of the Kansas Taxes. Under the Settlement, Public Service would collect through base rates the amounts necessary to pay the Kansas Taxes. Public Service, along with numerous other Parties, has challenged the legality of these taxes, and the case is currently on appeal in Kansas at the state administrative level. Under the Settlement terms Public Service would recover the costs of the Kansas Taxes from ratepayers regardless of whether these taxes are actually paid (Public Service has not yet paid any taxes, but has accrued a liability on its balance sheet). Given that the question of the legality of the taxes could not be resolved for several years, Public Service could collect millions

of dollars. If Public service's court challenge is successful, it would receive a windfall as the base rates would be set artificially high by the amount of the taxes.

52. Since the tax is on the value of gas in storage, we believe it logical to recover the amounts through the GCA mechanism. The GCA also provides an administratively efficient means of reversing the recovery of costs from ratepayers, should the court challenge be successful. We therefore remove the cost of the Kansas Taxes from base rates, and direct Public Service to address these costs in a GCA filing. It is possible that Public Service will be successful in challenging the Kansas taxes, in which case we direct Public Service to refund amounts collected to pay the taxes through the GCA mechanism. This issue is unique, and our ruling here should not be taken as Commission policy for other such costs.

53. In direct testimony, Public Service states that $505,895 should be eliminated from account 40811 in Taxes Other Than Income to remove the Kansas Taxes from the CCOSS model. We direct Public Service to file a revised Settlement CCOSS model with the Kansas Taxes removed, as appropriate, in order to calculate the precise base rates without the Kansas Taxes. In order to honor the overall intent of the Settlement we approve the dollar amounts proposed in the Settlement for rate mitigation, and we approve the fixed rate components as proposed in the Settlement, as discussed below. The variable rate components of base rates will then be changed to reflect the removal of the Kansas Taxes.

54. Base rates will be reduced to reflect the removal of the Kansas Taxes, but sales classes (*e.g.,* Residential and Commercial) will pay increased GCA costs. We recognize that in shifting the Kansas Taxes to the GCA, the amount that transportation customers would have paid in base rates will be included in GCA charges to sales customers. However, we find that this is a

very small amount compared to the cost shifting due to rate mitigation, and these GCA costs would eventually be eliminated if Public Service succeeds in its court challenge of the taxes.

55. The Commission approves base-rate recovery of the Yosemite compressor costs and net gas shrinkage costs, as proposed in the Settlement.

I. Weather Normalization

56. In its filed case, Public Service proposed to change the adjustment made to weather normalize test year sales revenues and quantities. Rather than using the 30-year standardization method approved by the Commission in Decision No. C99-579, the Company proposed to adjust test year revenues and quantities for weather based on average conditions in its service territory over the past ten years.

57. Staff and the OCC opposed Public Service's proposal to include only ten years of heating degree day data in the calculation of the weather normalization adjustments. Staff and the OCC argued in favor of using the National Oceanic and Atmospheric Administration (NOAA) thirty-year normal, adjusted to reflect updated data, according to the methods previously approved by the Commission. Staff and the OCC further argued that using 30 years of data provides a more accurate indication of normal weather and that Public Service's proposed ten-year average lacked proper statistical support.

58. In the Settlement, the Parties agreed to calculate the weather normalization adjustments used in determining revenue requirements and the settled rates based on the adjusted NOAA 30-year normal method as approved by the Commission in Decision No. C99-579. We accept the proposal in the Settlement concerning weather normalization without modification.

J. Lead-Lag Study and Cash Working Capital

59. In its application, Public Service included cash working capital in its rate base for the purpose of determining the Company's revenue requirements. Cash working capital reflects the cash balances the Company retains to meet the cash flow requirements of its gas operations. Cash working capital requirements are typically associated with no commodity gas costs, operations and maintenance expenses, vacation liabilities, and taxes.

60. Cash working capital amounts are typically calculated by multiplying cash flow oriented expense amounts by factors that reflect the time between when Public Service is required to pay an expense and when the Company collects revenues from customers to cover the expense. An analysis of this time difference is generally called a lead-lag study.

61. Staff challenged the methodology used by the Company to develop its cash working capital factors, questioning the validity of the underlying statistical methods of its lead-lag study. Furthermore, Staff advocated that the Company should be required to perform an appropriate lead-lag study based on test-year data in conjunction with every rate case.

62. In its rebuttal case, Public Service disputed Staff's claims that the lead-lag study used to derive the Company's proposed cash working capital factors was flawed. The Company also complained that the completion of a lead-lag study was time-consuming and labor-intensive and usually did not produce large variances in results.

63. To resolve this issue, the Parties agreed to the determination of the Company's cash working capital amounts based on the cash working capital factors proposed by the Company in its application. Accordingly, the cash working capital balances were determined using the lead-lag factors approved by the Commission in the Company's most recent combined rate case, Docket No. 02S-315EG.

64. In addition, Public Service, Staff, and the OCC agreed to engage in discussions to determine the statistical methods and data collection processes, including the availability and access of data, to be used in performing future lead-lag studies, including the lead-lag study that will be performed in connection with the Company's next electric rate case. The Company has agreed to provide Staff and the OCC with all information and data necessary within 30 days of such request in order to conduct their own lead-lag studies, should they wish to complete such analyses for the upcoming electric rate case. The Company has also agreed to provide all data and supporting information as well as access to the personnel, equipment and software necessary to verify such data.

65. We accept the proposed cash working capital amounts to be recovered pursuant to the Settlement as well as the proposals concerning the statistical methods to be used in future lead-lag studies. We also agree with the provision of information, in native and electronic executable format, to Staff and the OCC for the purpose of enabling them or their experts to conduct their own studies.

K. Customer Resource System (CRS)

66. In its filed case, Public Service requested cost allowances associated with the implementation of its new Customer Resource System (CRS) that is used for billing and customer care. As of the end of the test year, the total cost of the CRS to Xcel Energy was approximately $131.6 million, including an allowance for funds used during construction. Of that amount, Public Service's allocated share was approximately 47 percent, or $61.8 million.

67. Staff raised issues about a significant rise in billing complaints that Staff categorizes as non-compliant with filed tariffs or Commission rules associated with billing. For

instance, Staff provided evidence of the rise in non-compliant customer complaints relating to the Company's Sync Bill product (formerly One-Bill).

68. EOC and AARP raised concerns about the number of vendor defect reports concerning CRS and the possibility of unwarranted secondary "excess" costs in CRS implementation. EOC and AARP recommended a separate Commission inquiry on the propriety of CRS investment and expenses.

69. In its rebuttal case, the Company responded to Staff's concerns by explaining that the Company expected to experience some increase in complaints to the Commission's External Affairs section with the implementation of CRS. The Company further explained that it had put in place various processes to track and address CRS related complaints and began to see a decrease in such complaints, including complaints regarding the Sync Bill product, within a year following implementation of the new system.

70. In its rebuttal case, Public Service addressed the suggestions put forward by EOC and AARP concerning the CRS, explaining that, while the CRS project was a very difficult one, the system as implemented was a success. The Company further argued that the secondary costs associated with the implementation of CRS were of short duration and reasonable.

71. In the Settlement, the Parties have agreed to use the cost information and accounting treatments proposed in the Company's application concerning the implementation of its CRS during the 2004 test year. In terms of rate base, the costs of the CRS would be based on a 13-month average. The CRS would be amortized on a full-year basis and would be represented, in part, with amounts included in the Company's Construction Work in Progress. Furthermore, the Parties accepted a *pro forma* adjustment to the revenues used for determining

the settled revenue requirements and the rates to reflect a change to a calendar month billing approach using the CRS.

72. In addition, the Company has agreed to continue to work closely with the Commission's External Affairs Section to address and resolve informal complaints as completely and quickly as possible consistent with Commission rules.

73. We accept the proposal in the Settlement concerning the CRS without modification.

L. Phase I Issues Not Addressed by Stipulation but Agreed to for Implementation as Proposed by the Company in its Rate Case Application

74. In the Settlement, the Parties agreed to implement the proposals contained in the Company's application as originally filed on May 27, 2005 (as corrected on July 8, 2005) concerning all issues raised but not expressly dealt with in the Settlement. With respect to Phase I issues that were not specifically addressed in the Settlement, a number of items were raised by the Parties in their filed cases.

75. Concerning the Company's rate base, the Parties accept: (1) the 2004 calendar year as a suitable test year; (2) no eliminations made to Accumulated Deferred Income Taxes with respect to "catch up amounts" to account for additional deferred taxes that would have accrued had full normalization been used during past periods of time; (3) the exclusion of contractor retentions from Construction Work in Progress; and, (4) the exclusion of capital lease assets from rate base.

76. Concerning revenues, the Parties accept a *pro forma* adjustment to test-year revenues to account for late payment revenues, customer connections, return check charges, and miscellaneous service revenues that correct for charges incorrectly credited to the wrong utility

department. As previously discussed, the Parties also accept a *pro forma* adjustment made to revenues to reflect a change to a calendar month billing approach using the CRS.

77. Concerning expenses, the Parties accept: (1) the removal of per book purchased gas costs of $789,031,198 that are collected through the Company's Gas Cost Adjustment from base rate calculations consistent with the last gas Phase II rate case in Docket No. 99S-609G; (2) the inclusion of interest on customer deposits as a Customer Operations expense; (3) *pro forma* adjustments to reflect the 2005 level of pension and benefit costs, including estimates for costs associated with pension expenses, health benefits, and retiree health benefit costs directly incurred either directly by the Company or by the service company and then allocated to the Company; (4) no *pro forma* adjustments to depreciation expenses; (5) the Company's Uncollectible Accounts expense set at $4,099,506; and, (6) no *pro forma* adjustment to reflect recently increased postage expense.

78. Concerning cost allocators, the Parties accept: (1) Public Service's Cost Assignment and Allocation Manual (CAAM) as filed in the Company's application; (2) the Company's proposed FERC Jurisdictional Allocators for line-by-line allocation of rate base and earnings between Commission and FERC jurisdictions; (3) the service company allocations for costs from Xcel Energy, Inc., associated with executive management, finance, accounting, human resources, information technology, environmental, engineering, and customer services as filed by the Company in its application; and, (4) the inclusion of only those costs identified as common in FERC accounts 920-935 in the pool of administrative and general costs used to determine the Company's overhead calculation.

79. In its rebuttal testimony, the Company agreed to file a report on the results of the workshops relating to the CAAM within 30 days of an order in this case. At the hearings on

January 3, 2006, Mr. Stoffel acknowledged that Public Service would keep its pledge to file the report consistent with its proposal in its rebuttal case. Mr. Stoffel explained that this report would be filed in the docket of the Company's last rate case, Docket No. 02S-315EG.

80. We accept the provision in the Settlement concerning the adoption of the Company's proposal for the Phase I issues listed above as set forth in the Company's application. We also direct Public Service to file a report on the results of the workshops relating to the CAAM within 30 days of this decision.

III. SETTLEMENT OF PHASE II ISSUES

A. Cost Classification and Allocations

81. In its filed case Public Service proposed to use a "minimum system" approach to allocate distribution system costs to the different customer classes. Under this approach, Public Service developed the cost of the minimum system that is necessary to connect its customers. Public Service allocated the estimated cost of this hypothetical minimum distribution system to the customer classes based on number of customers in each class. It then allocated the remaining cost difference between the hypothetical minimum system and the book amounts for the actual distribution system based on demand.[6]

82. Staff and OCC proposed the "Seaboard" allocation method, which allocates 50 percent of the common distribution system costs to customer classes based on average commodity usage, and 50 percent based on demand. EOC and AARP proposed to allocate costs

[6] We note that under this approach nearly all distribution system costs were allocated based on number of customers, and no costs were allocated based on average commodity usage.

based on the "Reverse-United" method, which allocates 75 percent of costs to demand and 25 percent to commodity.[7]

83. In the Settlement, the Parties propose to allocate costs to customer classes based largely on the Reverse-United method. The Settlement Class Cost Of Service Study (CCOSS) model, provided as Attachment D to the Settlement, allocates all fixed costs not classified as customer-related on the basis of 75 percent demand and 25 percent annual usage.

84. The Settlement demand allocation factors for the residential (RG) and commercial (CG) classes are derived by applying a 20% load factor to the classes' respective test-year weather-normalized throughput, rather than applying the actual load factor. No Party proposed any such variation from actual load factor prior to the Settlement.

85. The demand allocation factors for the industrial (IG) and transportation interruptible (TI) classes are derived by applying a 100% load factor to the classes' respective test-year throughput. The demand factors for IG and TI remain the same as proposed in Public Service's filed case, and were not disputed by Parties.

86. The demand allocation factor for the transportation firm (TF) class is the sum of individual customers' Peak Daily Quantities (PDQ), as proposed by Public Service in its filed case. Seminole had recommended using actual measured demand for the TF class in its answer testimony, but agrees to the sum of PDQs for the purpose of Settlement.

87. This settled allocation method eliminates the minimum system proposed by Public Service, and instead adopts the Reverse-United approach. The Reverse-United method is

[7] We note that under the Seaboard and Reverse-United methods no distribution system costs were allocated on the basis of number of customers, other than costs classified as customer-related. Items such as meters and service laterals, which are used only by one customer, are classified as customer-related.

proposed with only a few changes for the purpose of cost allocation to the customer classes, but the Settlement contains major changes to the application of the Reverse-United cost basis in Rate Design, as discussed below, which alters the amounts recovered through the fixed rate component and shifts costs between classes.

88. Though the settled 20% load factor for RG and CG classes is slightly lower than the actual load factor used in all Parties filed models, the Commission finds that the CCOSS properly allocates costs to the various customer classes. Though the Commission would like to investigate other approaches in the future, we approve this component of the Settlement without modification.

B. Transportation Discounts and Mitigation of Rate Impacts

89. In its direct case, Public Service incorporated the revenue deficiency of transportation discounts of $5,503,926 in its calculation of class-allocated revenue requirements, adjusting the revenue deficiency for taxes and allocating the pre-tax costs to all classes on the basis of total revenue requirements. In the first step of this process, the Company reduced the revenue requirement to be collected from Transportation Firm (TF) customers by approximately $4.1 million and reduced the revenue requirement to be collected from Transportation Interruptible (TI) customers by approximately $1.4 million. In the second step, the Company reallocated the pre-tax costs of the discounts of approximately $3.1 million, calculated as the full revenue discounts of $5.5 million times the difference of one less the Company's marginal tax rate, to all customer classes (including the non-discounted transportation customers) based on total revenue requirements. The net effect of this allocation of costs and tax effects was a reduction in the Company's total revenue requirement of approximately $2.4 million, reflecting the income taxes that do not need to be paid due to lower level of revenues collected from the

transportation customers on discounted rates, but that were included in the class-allocated revenue requirements allocated to the TF and TI classes.

90. According to this method of allocating the pre-tax costs and tax effects associated with the transportation discounts, the total revenue requirements assigned to the TF rate class would be approximately $3.8 million less and the revenue requirements assigned to the TI class would be approximately $1.3 million less. To balance these revenue requirement offsets, customers on the RG rate would collectively pay approximately $2.2 million of the pre-tax costs that would have otherwise been assigned to the non-discounted customers in the TG and TI rate classes. Similarly, the customers on the CG rate would pay approximately $567,000 of such costs.

91. Staff recommended that the Commission deny Public Service full recovery of the revenue deficiencies associated with the transportation discounts. Staff further argued that the discounts had not lowered rates for non-discounted customers, that the discounts had not proven to be cost effective, that the discounts were not proven to result in a more efficient use of the Company's assets, and that the revenue deficiencies from the discounts were being improperly recouped from customers in rate classes other than the transportation classes.

92. In its rebuttal case, Public Service defended the re-allocation of pre-tax costs associated with the transportation discounts to other rate classes as well as to the non-discounted transportation customers arguing that customers would leave the Company's system if it did not offer discounts. The Company explained that discounts were extended only in cases where an alternate pipeline or an alternate fuel was available to a transportation customer at a lower price or for a better value. The Company further stated that Commission had specifically addressed

the issue of transportation discount cost recovery in Docket No. 96S-290G, Decision No. C97-478.

93. In the Settlement, the Parties agreed to spread the pre-tax costs associated with transportation discounts to all customer classes in a manner similar to that used in the Company's application. According to the model filed with the Settlement and the testimony of Mr. John P. Kundert at the hearing on January 3, 2006, the transportation discounts of approximately $5.5 million were addressed in a two-step process. First, the $3.1 million of pre-tax costs were reassigned to the Company's major rate classes using a set of allocation factors accepted by the Parties that deviates from the Company's cost-based approach in its application, such that the customers in the (RG) class would pay roughly $1.6 million of the pre-tax costs and the customers in the (CG) would pay roughly $800,000 more of such costs. Second, the full revenue discount was subtracted from the TF and TI classes in the amounts of $2.8 million and $2.1 million, respectively. As in the Company's application, the net effect was a reduction in the Company's overall revenue requirement of about $2.4 million, a value equal to taxes that do not need to be paid as a result of the lower revenues collected from the transportation customers on discounted rates. Due to the approach used to address the tax effects of the discounts in the Settlement, the net reduction in the class allocated revenue requirement for the TF class was approximately $2.3 million, while the net reduction in the class allocated revenue requirement for the TI class was approximately $2.5 million.

94. In the Settlement, the Parties also agreed to limit the overall revenue requirement increase to the CG class to 18 percent, down from of a 19.29 percent increase that would have otherwise resulted after the reallocation of pre-tax transportation discount costs. The net shortfall in test-year revenue of approximately $660,000 to achieve this rate mitigation would be

recovered from TI and RG rate classes as follows: First, the increase to TI customers not receiving rate discounts would be raised to the system average increase of 8.10 percent, or an increase in allocated revenue requirements of approximately $413,000. Second, the remaining revenue deficiency was eliminated by raising the RG class increase from 4.72 percent to 4.84 percent, or an increase in allocated revenue requirements of approximately $247,000. At the hearing on the Settlement on January 3, 2006, Mr. Stoffel confirmed that this proposed rate mitigation would not be phased out over time but would instead remain in place until new rates took effect pursuant to the Company's next Phase II rate case.

95. Although the Settlement presents the allocation of transportation discount revenue deficiencies and tax effects as distinct from the rate impact mitigation, we find the two issues to be linked. Moreover, we find the Settlement's discussion of the allocation of the costs and tax effects associated with gas transportation discounts to fall far short of what should have been presented in light of its significance as a settled term in the agreement.

96. On one hand, the proposed allocation of $1.6 million of costs to the RG class and the $800,000 of costs to the CG class affords the non-discounted transportation customers substantial relief from the full cost responsibilities that come from the application of the Reverse-United method for cost allocation. On the other hand, the need for rate mitigation for the CG class stemmed largely from this method for allocating the costs of transportation discounts to other rate classes. Indeed, we estimate that the rate increase to the CG class prior to the allocation of the transportation discounts would have been slightly less than 18 percent.

97. From a total costs perspective, we conclude, however, that the shifting of some $3 million of costs between rate classes is not an unreasonable level of rate mitigation when compared to a total revenue requirement of some $300 million. As such, we adopt the

transportation discount allocations and rate mitigation provisions in the Settlement. Nevertheless, as discussed below, we instruct the Parties to examine the appropriateness and fairness of the allocation of transportation discounts as part of the rate design workshops.

98. In light of our decision to move the recovery of costs associated with the Kansas Taxes from base rates to the GCA, the dollar amount of rate mitigation that is needed bring the overall increase to the CG class to 18 percent could be reduced due to the removal of these costs from base rate revenue requirements. However, the CG class will become subject to a somewhat higher level of cost responsibility associated with the Kansas Taxes because the CG customers pay the GCA. Therefore, we instruct Public Service to maintain the same rate mitigation dollar amounts agreed to by the Parties in the Settlement, such that the revenue requirements assigned to the CG class is reduced by the same dollar amount as in the Settlement and the revenue deficiency caused by this mitigation is addressed by the same dollar increases in revenue requirements allocated to the TI customers not receiving rate discounts and to the RG class.

99. As discussed below, we also require a future Phase II rate case to be filed by the Company during which we expect the Parties to more fully address these rate mitigation issues.

100. The commission nearly rejected this key provision of the Settlement, because only after significant investigation were we able to comprehend all of the mitigation involved. This stems from an absence of discussion of this issue in the Settlement and the fact that the Parties did not explain during the hearing how the transportation discount and associated taxes were allocated, and instead relied on a late-filed exhibit to provide the required information. We accepted this procedural imperfection because it allowed the Parties to take the time necessary to provide a thorough and accurate response. However, this compromised the Commission’s ability

to ask follow-up questions related to the exhibit. In the future, we expect Parties to fully explain the underpinnings of their case, whether the matter is litigated in full, or settled.

C. Rate Design

101. In Direct and answer testimony, Parties proposed a wide range of fixed-component rates. For example, for residential service Public Service proposed a fixed rate component of $13.00 per month and OCC proposed $7.72 per month. In its filed case Public Service states that it needs to increase the fixed monthly component of rates in order to address revenue attrition. Public Service argues that increased gas prices have resulted in significant conservation, which erodes its ability to recover its costs when base rate costs are recovered through a variable usage charge. In response, other Parties argue that in its last rate case Public Service actually reduced its gas rates, demonstrating that continued earnings attrition is not an issue that the Commission needs to address here. The Settlement proposes rates that are within the range of rates proposed in testimony. The Settlement rates generally recover an increased amount of costs through fixed rate components, but variable rates are still used to recover some of the base-rate costs.

102. The fixed rate components as proposed in the Settlement of $10 for RG and $20 for CG are significantly higher than would be established through a cost-based application of the Reverse-United allocation method. Further, the fixed components of rates for other classes appear to vary based on settled terms. For example, the IG fixed component decreases from $90 to $70; the TF fixed component increases from $60 to $70, and the TI fixed component decreases from $195 to $140.[8] These fixed rate components are not consistent with the direct application of the proposed Reverse-United allocation method. However, the fixed components of the rates

[8] Excluding base-rate riders.

are generally within the range of proposed rates contained in the record. Through the different allocation methods proposed in direct and answer testimony, the Parties established a wide range of rates based on established allocation methods. Since the fixed components of the Settlement rates are generally within the rates proposed in the record, we find them to be reasonable. We approve the fixed rate components as proposed in the Settlement. We also approve the Firm Capacity Charge for TF as proposed in the Settlement.

103. As discussed in the GCA section, the Commission modified the Settlement to move the Kansas Taxes from base rates to the GCA. We therefore approve the Settlement rate design with respect to the variable rate components with the modifications to remove the Kansas Taxes, as discussed above.

D. Rate Nomenclature

104. In its application, Public Service proposed to change the rates and billing term "Commodity" to "Volumetric Distribution" to clarify delivery charges based on dekatherms of natural gas usage.

105. Staff argued that the Company's proposed name change for the "Commodity Charge" would create confusion, since the billing determinant is an energy measurement (*i.e.*, therms) and not a volumetric measurement (*e.g.*, cubic feet).

106. In the Settlement, the Parties agreed that the "Commodity Charge" currently applicable to its RG, CG and IG rate schedules and the "Transportation Commodity Charge" applicable to its TF and TI rate schedules would be renamed to "Volumetric Charge," so that it may be better understood as applying to usage and recovering delivery costs, not gas commodity costs.

107. As demonstrated by the comments of several participants in the Public Hearings in this case, the "Metering and Billing" charge is already a source of customer confusion and discontent. However, the Settlement is largely silent on the term "Metering and Billing" charge that appears on customer bills, although this rate nomenclature is used in the tariffs filed with the Settlement on December 20, 2005.

108. We find that the term "Volumetric Charge" may not be understood by many customers, particularly those in RG and CG rate classes. Given that one cannot see natural gas, the notion of "volumes" is rather abstract. Further, we agree with Staff that the term "volumetric" is inconsistent with the Company's change from volumetric to energy (therm) billing. We further find that the "use" of natural gas and the corresponding "use" of the Company's distribution system are less abstract and more intuitive to customers. We therefore modify the Settlement by ordering the Company to use the term "Usage Charge" in place of the "Commodity Charge" currently applicable to its RG, CG, and IG rate schedules and for the "Transportation Commodity Charge" applicable to its TF and TI rate schedules. Likewise, "Distribution System" charges per therm should no longer be described in the tariff as "Commodity Costs."

109. We also find that the continued use of the "Metering and Billing" label for the "Service and Facilities Charge" should be reconsidered. We are concerned that the proposed increase of the "Service and Facilities Charge" for RG customers to $10 per month and the proposed increase in the "Service and Facilities Charge" for CG customers to $20 per month will cause even more confusion and discontent if they continue to be identified as "Metering and Billing" charges on customer bills.

110. We therefore order the Company to discontinue the use of "Metering and Billing" charge in its tariffs and on customer bills within six months and to develop, in consultation with a designated member of the Commission's External Affairs group, a new term to replace the "Metering and Billing" charge as it appears in the Company's tariffs and on customer bills.

E. Phase II Issues Raised But Not Expressly Dealt With In This Stipulation

111. Consistent with the resolution of certain Phase I issues, the Parties agreed to implement the proposals contained in the Company's application as originally filed on May 27, 2005, and as corrected on July 8, 2005, concerning all Phase II issues raised by the Parties in this proceeding but not expressly dealt with in the Settlement.

112. First, the Parties accept the meter weighting factors for the TF class as proposed by the Company in its application. Second, the Parties agree to no change in the classification of service laterals and transmission plant from the FERC plant accounts as filed by the Company in it application. Finally, the Parties agree that the Company shall make no change to its line extension policies and tariffs except that it shall file updated construction allowances consistent with the allocated costs and charges established by the Settlement.

113. We accept the provision in the Settlement concerning the adoption of the Company's proposal for the three Phase II issues listed above. We also direct Public Service to file new construction allowances pursuant to Sheet No. R34 of its line extension tariff within 30 days from this decision based on the appropriate revenue and commodity amounts established here. The Company shall file the revised construction allowance based on the method approved in Docket No. 02S-574G and will provide work papers supporting the revised construction allowances. The Company shall file an advice letter with accompanying tariffs to become effective on not less than one business day's notice to the Commission.

F. Workshops to Explore Rate Design Approaches

114. In order to further investigate the important rate design, interclass rate comparability and class composition issues that were raised in this proceeding, the Company agrees to convene and to invite all Parties to a series of workshops. The intent of these workshops is to develop and, if possible, to come to a consensus regarding the workshop issues. The Parties agree that the workshops will commence within one month after the rates in this case become effective. Further, the Parties electing to participate in the workshops agree to file a written report with the Commission informing it of the results of the workshop no later than September 1, 2006. The Parties agree that simulation runs with alternative rate designs will use the settled revenue requirements and cost allocations from this proceeding and will be provided as part of the report. If a consensus is reached by all workshop participants, the Company will file an application, prior to or as part of its next gas rate case, to implement the agreed to changes. If a consensus cannot be reached by all workshop participants, a participant is free to use any information from the workshops, other than information designated as confidential or proprietary, to advocate positions in the Company's next rate case filing.

115. We agree that a workshop approach can potentially provide the best overall resolution to these complex issues, in a timely and efficient manner. The commission directs the Parties to address the following issues, at a minimum, through the workshops:

a. Decoupling or other method to remove temperature sensitivity from utility revenue recovery.

b. The estimation and application of individual customer demands (residential and commercial) for ratemaking and billing purposes to help address intraclass subsidies, and to potentially be used for decoupling.

c. Additional commercial and/or transportation rates classes, to address customer migration between CG and TF classes, and to reduce customer disparity within classes (*e.g.,* load factor or other differences).

d. Additional transportation rates for delivery to other utilities.

e. Cost adjustment mechanisms analogous to the GCA, but for certain distribution-related costs that are collected from both sales and transportation customers (*e.g.,* environmental clean-up costs, facility closure costs, rate case expenses, pipeline integrity management costs).

f. The proper application of transportation discounts and taxes in cost models.

116. In the Settlement hearing, Parties indicated that it may be difficult to achieve consensus on the additional CG/TF rate class issue, as some Parties will likely gain and some will lose with any new rate structure. Further, the Commission is concerned that we are not resolving these issues in this case, and if not resolved in the workshops, the CG/TF rate class issue will likely resurface in the next rate proceeding. Therefore we find it appropriate to implement an additional requirement related to this issue. If the Parties cannot achieve consensus on the CG/TF rate class issue, we require Public Service to include a proposal for additional CG and/or TF rate classes to address the issue as a part of its next Phase II rate case.

G. New Phase II Filing Requirements

117. Parties propose that the Commission adopt the Settlement without modification. However, the Commission has several concerns about the rates proposed in the Settlement. Therefore we find it appropriate to require Public Service to file an additional Phase II rate case within a specific timeframe.

118. Though the Settlement is described as being based on a Reverse-United cost allocation, we are concerned that the Settlement contains many modifications that diverge from a conventional “cost-based” modeling methodology. The Settlement rates are generally within the range of “cost-based” rates proposed by the Parties. However, the Settlement percentage

increases for each class are quite different and not based on the Reverse-United allocation method which was used in this matter. The Settlement rates also propose fixed rate components (*e.g.,* $10 for RG, and $20 for CG) that are substantially higher than those developed from a Reverse-United cost allocation methodology. Further, we are concerned that the Settlement contains explicit and implicit rate mitigation, as a divergence from cost-based rates, without any proposal to transition the rates to a non-mitigated level. As rates diverge from a cost-based standard over time, a subsequent rate realignment can result in substantial rate shock.

119. The record in this case provides a wide range of "cost-based" rates. The minimum system allocation method produces rates that result in most of the increase being applied to classes with smaller customers such as the residential class, while Seaboard and Reverse-United allocation methods result in more if not most of the rate increase being applied to classes with larger customers such as the industrial class. The Settlement cost allocation, with mitigation and other modifications discussed above, provides rates that are generally within this wide range.

120. In response to Commission questions, Public Service provided a comparison of the rates developed by EOC/AARP witness Binz and the proposed Settlement rates. Both of these rate proposals were based on cost modeling using the Reverse-United allocation method, but the resulting rates were substantially different. Public Service's comparison, along with an exhibit filed by Staff after hearings were concluded, demonstrates that a large portion of the difference is caused by the treatment of cost recovery of transportation discounts and associated taxes. A statement in the Settlement indicates Staff's concern with the treatment of transportation discounts. In hearing, Public Service stated that it will work with Staff and other Parties to resolve the transportation tax issue for future cases.

121. The Settlement proposes fixed rate components that are higher than the Reverse-United allocation, but lower than proposed by Public Service in its minimum-system approach for most classes. Again the rates are generally within the range proposed in the record. However, the Settlement adjustments to fixed rate components are not derived from a cost-based methodology, and the application of fixed billing component adjustments does not appear to be consistent between customer classes, as discussed in the Rate Design section.

122. We are confident that the Parties adequately represent the interests of the classes at issue, and that the Settlement rates fall within a reasonable range of rates as proposed in the record. However, our concerns warrant a Commission requirement for Public Service to file another Phase II rate case by date certain. Further, if Public Service is correct that conservation is impacting customer usage characteristics, it would be appropriate to file another Phase II rate case in the near future to respond to these changes.

123. The Commission requires Public Service to file a Phase II rate case within three years of the final decision in this docket. This could be a combined Phase I and Phase II filing, a Phase II filed after its next Phase I filing, or a stand-alone Phase II filing.

124. We also find it appropriate to provide input regarding cost allocation methodologies as proposed in this case, in an effort to encourage Parties to narrow the range of proposals in the next case. In Public Service's filed case, its minimum system proposal allocated nearly all distribution main costs based on number of customers, without any recognition of commodity allocation. Other Parties raised substantial concerns about Public Service's proposal, and provided a thorough discussion related to the merits of using a commodity allocator. On the other end of the spectrum, several Parties proposed Seaboard and Reverse-United allocation proposals. These methods allocated distribution main costs based on demand and commodity,

without any recognition of number of customers. Public Service responded with numerous arguments about the merits of using customer connection as an allocator. We find that the record contains solid arguments that being connected to the utility system and day-to-day commodity usage are both important factors.

125. In the next Phase II rate case we encourage Parties to present cost-based allocation methodologies that better represent all such cost characteristics in proposed allocation methodologies. A "trybrid" allocation combining demand, commodity, and customer connection appears to have the potential to produce rates that would fall within the general range of the settled rates, and could potentially result in a more direct cost-based approach. The last two Phase II cases have resulted in settlements using the Reverse-United allocation method, but both have required substantial modification or mitigation in order to achieve reasonable rates. We encourage Parties to explore a more rigorous cost-based approach, focusing on all aspects of cost causation.

126. We also encourage Parties to present methods to eliminate subsidies between high and low-volume customers within a class. This should be addressed in the workshops, as well as in the next Phase II case.

IV. TRANSPORTATION

A. Revised Fuel Reimbursement Percentage

127. For purposes of settlement, the Parties agree that the Fuel Reimbursement Percentage shall be changed from 1.46% to 0.86 % upon the effective date of the base rates approved by the Commission as part of this Stipulation. In addition, within 30 days following the date of the Commission's order approving the Settlement, Public Service shall file an advice letter proposing to implement new tariff provisions that require Public Service to file separate

annual filings to update the Fuel Reimbursement Percentage. The first such filing would be submitted for implementation no later than one-year from the effective date of the new Fuel Reimbursement Percentage resulting from the Settlement.

128. We agree that a more frequent revision of the Fuel Reimbursement Percentage is appropriate. The Commission approves this component of the Settlement without modification.

B. Imbalance Cashouts Related to Prior Period Adjustments

129. In answer testimony, Atmos and Seminole raised concerns about imbalance cashouts from a prior period that required transportation customers to pay substantially higher prices to Public Service for gas than would have been paid at the time the imbalance occurred, due to gas prices increasing over time. To resolve this issue, Public Service, Atmos, Seminole and Staff agree to address this issue in two different ways: (1) pending and currently unresolved imbalances resulting from prior period adjustments due to Measurement Errors, and (2) those imbalances resulting from such prior period adjustments which occur on and after the effective date of the Settlement. The agreed modifications to the gas transportation terms and conditions are reflected in tariff sheet Nos. T1, T3 through T6, T11, T13 through T14, as presented in Settlement Attachment A.

130. For all pending and currently unresolved imbalances resulting from prior period adjustments (*i.e.*, still within the six-month imbalance make-up period) as of the effective date of the Commission's order approving this Stipulation, Public Service, Staff, Atmos and Seminole agree that such imbalance shall be immediately cashed out at an amount equal to the weighted average commodity cost of gas, as has been calculated by the Company for the applicable month. This treatment shall apply immediately to all such prior period adjustment imbalances existing for Atmos's and Seminole's accounts and shall apply to any other Shipper with pending prior

period adjustment imbalances that advises Public Service within 20 days of the effective date of the Commission's order approving this Stipulation that it elects such one-time treatment. Any such Shipper shall have the right to opt out of such one-time treatment and to have such imbalances treated as ordinary gas transportation imbalances subject to the Shipper's right to make up the gas in-kind or be cashed out at the standard cashout rates.

131. The Settlement requires Public Service to provide notice to all such other Shippers having pending prior period adjustment imbalances of their right to elect such one-time treatment within three days of the effective date of the Commission's order herein. Public Service is required to maintain documentation in order to facilitate Staff's audit on any unresolved imbalance that qualifies for this one-time treatment. Public Service, Staff, Atmos and Seminole clarify that this is not a reclassification of unresolved imbalances into prior period adjustments and no reclassification is contemplated in the future.

132. Prior period adjustments resulting from the Company's Measurement Errors (as these errors are clarified in the revised language of the tariff) occurring on and after the effective date of this Stipulation shall be resolved by implementing billing adjustments to reflect the sale or purchase, as the case may be, of the additional or reduced quantities at prices based on the higher or the lower of the Colorado Interstate Gas Company Rocky Mountain spot gas price index or the Panhandle Eastern Pipeline Company spot gas price index or the weighted average commodity cost of gas as calculated by the Company for each month of the prior period and in the amounts in which the corrected quantities were applied.

133. To the extent that the weighted average commodity cost of gas is not defined in the tariff, the Company will clarify the method for such calculation as part of its general gas transportation tariff filing to be filed on or before February 28, 2006. Also in that filing, the

Company shall make a proposal as to a reasonable amount of costs, if any, that should be included in the imbalance cashout rates to account for upstream pipeline services.

134. The Commission finds that the proposed treatment of imbalance cashouts is appropriate, and we approve this component of the Settlement without modification.

C. Remaining Issues Concerning Transportation Terms and Conditions

135. In order to provide a forum in which these and similar types of issues concerning transportation terms and conditions may be resolved, to the extent they cannot otherwise be resolved through informal discussions, Public Service, Staff, Atmos and Seminole agree that, on or before February 28, 2006, Public Service shall file an advice letter proposing changes to its gas transportation terms and conditions which will provide a forum in which Staff's, Atmos' and Seminole's issues concerning the terms and conditions of the Company's gas transportation services may be raised and considered by the Commission. Public Service agrees that Parties may raise any issue relating to the Company's gas transportation terms and conditions in that proceeding. Public Service agrees to meet informally with Atmos, Staff and Seminole in advance of such filing in order to advise them of the general nature of changes that Public Service intends to propose in such filing before it is made.

136. We agree that a separate filing to resolve these issues is appropriate. However, we do not intend for this issue to continue to be put off to subsequent proceedings. Therefore the Commission approves this component of the Settlement with the understanding that Public Service will file the necessary information in subsequent Phase II or GCA proceedings, as dictated by the outcome of the February 28, 2006 filing. In addition, we clarify that back-up services will continue unless addressed otherwise in the outcome of the February 28, 2006 proceeding.

V. MISCELLANEOUS

A. Future Gas Storage Facilities

137. As a part of the Settlement, Staff and Public Service agree to discuss options for additional gas storage facilities. We agree that storage is an important factor in reducing volatility and helping overall market stability, particularly in light of recent gas price trends. We encourage Parties to work out a proposal to provide additional storage in an economical manner.

B. Venue Issues

138. In its testimony, Staff raised the question of what is the proper venue to resolve certain issues affecting GCA rates. Staff argues that a GCA prudence review hearing is the proper venue to determine whether rates are just and reasonable for costs recovered through the GCA mechanism. Staff believes that such a prudence review is akin to a Phase I and Phase II rate case for gas commodity costs. Public Service argues for a narrower view of a GCA prudence review. It believes that only those gas costs for which it obtains expedited recovery and which are collected through the GCA are subject to review and disallowance in a GCA prudence review. For purposes of resolving the question of what is the appropriate venue, a rate case, a prudency review, or other GCA docket, to raise these issues, the Parties have agreed to file on or before February 6, 2006 a joint petition for declaratory judgment. The pleadings will frame the dispute so that the Commission may consider the positions of the Parties and issue an order resolving the dispute. The petition will be served on all Parties to this docket and all other Commission regulated gas utilities in Colorado having GCA mechanisms in their tariffs. The Parties agree that this argument is essentially legal in nature, and that a full trial-type hearing will not be required.

139. We accept this provision of the Settlement without modification. Resolution of these issues is important to all utilities in the state. Parties need to know what types of proceedings should be used to address what issues. We agree that a separate filing to resolve these issues is appropriate. However, we do not intend for this issue to continue to be put off to subsequent proceedings. Therefore the Commission approves this component of the Settlement with the understanding that Public Service will file all necessary information in subsequent Phase II or GCA proceedings, as dictated by the Commission's determination in the February 6, 2006 joint petition for declaratory judgment.

C. No Settled Practice

140. We recognize that the Parties have reserved their rights to argue their original or other positions should the issues in this docket arise in subsequent dockets. It is a risk inherent in settlements that issues that could have been resolved are perhaps left to a future proceeding. We note that the issue of earnings attrition, for example, is not new to this docket. Where possible we urge the Parties to resolve their differences, and not reargue in the future points made during this proceeding.

D. Effective Date of Settlement Rates, Terms and Conditions

141. The Commission has 210 days in which to consider Public Service's suspended advice letter, and issue its order. The Parties advocate that the rates proposed in the Settlement go into effect as soon as possible. Because Commission Staff will need time to review Public Service's tariff complying with this order, Public Service shall file a tariff incorporating the above modifications to be effective on not less than one business day's notice.

VI. CONCLUSION

A. Acceptance of Settlement Agreement

142. Because we believe that the rates, terms and conditions of the Settlement Agreement filed by the Parties on December 20, 2005 as modified in this order are just and reasonable, we approve the Settlement as modified above.

VII. ORDER

A. The Commission Orders That:

1. Public Service Company of Colorado's first amended Advice Letter 647 – Gas is permanently suspended.

2. The Settlement Agreement entered into by the Parties to this docket is approved with the modifications ordered above.

3. Public Service shall file a tariff, along with a revised CCOSS model, incorporating the above modifications to be effective on not less than one business day's notice.

4. The 20-day time period provided by § 40-6-114(1), C.R.S., to file an application for rehearing, reargument, or reconsideration shall begin on the first day after the mailed date of this Order.

5. This Order is effective on its Mailed Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING January 19, 2006.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

GREGORY E. SOPKIN

POLLY PAGE

CARL MILLER

Commissioners

COMMISSIONER CARL MILLER
CONCURRING, IN PART,
DISSENTING, IN PART.

VIII. COMMISSIONER MILLER CONCURRING IN PART AND DISSENTING IN PART

1. I agree with my fellow Commissioners but for one issue on which I respectfully dissent:

A. American Gas Association Dues

2. I disagree with the settling Parties' recommendation as it pertains to expenses for American Gas Association dues. I believe membership, expenditures and active participation in such organizations benefit customers as well as shareholders. My specific objection is the Settlement's recommendation to deny costs associated with government relations and media communications (excluding environmental communications). I oppose the "pick and choose" practice allowing selected media communications (i.e. environmental) while disallowing other media communications that may benefit the majority of ratepayers. If such "pick and choose" practices are allowed then I suggest that only carefully selected environmental communications be approved that are least cost and benefit the majority of customers.

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

CARL MILLER

Commissioners

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * * *

RE: THE TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO WITH ADVICE LETTER NO. 647- GAS.	**))))**	**DOCKET NO. 05S-264G**

STIPULATION AND AGREEMENT IN RESOLUTION OF PROCEEDING

TABLE OF CONTENTS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

RE: THE TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO WITH ADVICE LETTER NO. 647- GAS.	**))))**	**DOCKET NO. 05S-264G**

STIPULATION AND AGREEMENT
IN RESOLUTION OF PROCEEDING

This Stipulation and Agreement in Resolution of Proceeding ("Stipulation") is entered into by and among Public Service Company of Colorado ("Public Service" or "Company"), the Staff of the Public Utilities Commission of the State of Colorado ("Staff"), the Colorado Office of Consumer Counsel ("OCC"), Energy Outreach Colorado and AARP (collectively, "EOC/AARP"), Atmos Energy Corporation ("Atmos"), Climax Molybdenum Company ("Climax"), Colorado Business Alliance for Cooperative Utility Practices ("CBA"), and Seminole Energy Services, LLC ("Seminole"), collectively referred to herein as the "Parties." Colorado Natural Gas, Inc. ("CNG"), Kinder Morgan, Inc. ("KMI") and the United States Department of Defense - Federal Executive Agencies are not joining in the Stipulation, but do not oppose its approval. This Stipulation sets forth the terms and conditions by which the Parties have agreed to resolve all outstanding issues presented by the Company's gas rate case filing that have or could have been contested in this proceeding.

The Parties state that the results of the compromises reflected herein are a just and reasonable resolution of this gas rate case proceeding, that reaching agreement as set forth and implementation of the compromises and settlements reflected in this Stipulation will result in substantial savings to all concerned by establishing certainty and avoiding litigation. Each party hereto pledges its support of this Stipulation and states that each will defend the settlement reached. The Parties respectfully request that the Public Utilities Commission of the State of Colorado ("Commission") approve this Stipulation, without modification. For those Parties for whom this Stipulation is executed by counsel, such counsel states that (s)he has authority to execute this Stipulation on behalf of his/her client.

I. BACKGROUND

On May 27, 2005, Public Service filed Advice Letter No. 647-Gas, proposing to implement revised base rates for all of its gas sales and transportation services, along with certain other changes to its gas sales and transportation tariffs, to be effective June 27, 2005. The Company proposed that the new base rates would supersede the current base rates and eliminate all existing General Rate Schedule Adjustment ("GRSA") riders. The Company's filing represented a departure from the recent tradition of the Company making two separate rate filings (referred to as "Phase I" and "Phase II") to effect the implementation of revised base rates. Instead of proposing to recover its revenue deficiency through a General Rate Schedule Adjustment rider, and waiting to make a separate filing to allocate its cost of service to the various customer classes and to design its rates, Public Service combined these two steps into one rate filing. On July 8, 2005, Public Service filed its first Amended Advice Letter No. 647-Gas, correcting and supplementing its original filing, and extending the proposed effective date to July 11, 2005. The proposed base rates reflected in the filing, as amended, would have increased base rate revenues by $34,545,332, or 12.46% on an annual basis. The

Company's proposed revenue requirement of $311,827,757 was developed based on a test year of the 12 months ending December 31, 2004, and reflected a proposed 9.01% overall return on the Company's rate base determined as of the end of the test year. This overall return was calculated using a proposed return on common equity of 11.00% and an adjusted capital structure consisting of 55.49% equity and 44.51% long-term debt.

The proposed base rates also reflected changes in the Company's methodology in cost allocation among customer classes and associated rate design, the most significant of which was the Company's classification of costs associated with a "minimum distribution system" as customer-related, rather than capacity-related. Consistent with these changes, Public Service proposed to increase the monthly Service and Facility Charge applicable to residential sales customers from the current $8.44 ($9.00 less 6.20% negative general rate schedule adjustment) to $13.00. Public Service's proposed rates would have resulted in an average increase in the average monthly bill for the average residential customer of $2.02 or a 13.58% increase in non-gas costs as stated in the Notice of Filing by the Company dated August 31, 2005. The filing, as amended, included the Company's direct testimony and exhibits in support of the proposed changes.

By Decision No. C05-0749 (Mailed Date: June 17, 2005), as corrected by Errata Notice, Decision No. C05-0749-E, the Commission set for hearing the tariff sheets filed with Advice Letter No. 647 – Gas, and suspended their effective date for 120 days, or until October 25, 2005. By Decision No. C05-0952 (Mailed Date: August 3, 2005), the Commission set the proposed tariffs contained in the first Amended Advice Letter No. 647 – Gas for hearing, and suspended the effective date 120 days from the revised proposed effective date of July 11, 2005, or until November 8, 2005. By Decision No. C05-1301 (Mailed Date: October 28, 2005), the Commission further suspended the effective date of the tariff sheets filed on July 8, 2005, under its first Amended Advice Letter No. 647-Gas, for an additional 90 days, or until February 6, 2006.

In Decision No. C05-0749, the Commission also prescribed a date for interventions by interested persons and scheduled a pre-hearing conference for August 3, 2005. Petitions to intervene were filed by Atmos, EOC, AARP, CBA, Federal Executive Agencies, Climax, Seminole, KMI and CNG. Staff and the OCC filed timely notices of intervention on June 22, 2005 and June 20, 2005, respectively. The pre-hearing conference was held as scheduled on August 3, 2005, pursuant to which the Commission issued its Procedural Order, Decision No. C05-1010 (Mailed Date: August 24, 2005), in which the Commission granted all petitions to intervene, set the hearing for December 5 through December 16, 2005, set dates for the filing of answer, rebuttal and cross-answer testimony, and established discovery and other procedures.

Staff, the OCC, EOC/AARP, Atmos, CBA and Seminole filed answer testimony on October 5, 2005. The principal issues of Staff and the OCC were the Company's proposed return on equity; its use of year-end, rather than average, rate base; the Company's weather normalization method; the effects of the Service and Facility charges; and the Company's proposed minimum system approach and the resulting impact of the rate design on customer classes. The Staff and the OCC proposed to allocate costs among customer classes based on the *Atlantic-Seaboard*[1] method. In addition, Staff raised a number of other issues including, but not limited to, recovery of upstream storage costs in base rates as a result of Leyden decommissioning; recovery of revenue deficiency associated with transportation discounts; applicability of rate riders to recover certain amortized costs; re-functionalization of service laterals to mains; elimination of the carry-forward of gas transportation imbalances; the proper venue for cost allocation, rate design and tariff issues, and the resulting revenue recovery issues for costs recovered through the Gas Cost Adjustment; potential rate case for the Front Range Pipeline; change in terminology for billing units from commodity to volume; alternative fuel requirement for interruptible customers; elimination of gas light rate schedules; elimination of on-peak service; records for converted customers; proper Fuel Reimbursement Percentage; elimination of backup supply; and applicability of the line extension policy. EOC/AARP challenged several aspects of the Company's cost allocation, including Public Service's use of the minimum system approach. Atmos proposed a separate, transmission-only service, and raised several other specific issues concerning gas transportation service terms and conditions. Atmos did not take any position (either in testimony or in subsequent settlement negotiations) on the variety of Phase I issues surrounding Public Service's proposed revenue requirement. Seminole objected to Public Service's proposed rates on the basis that they made the CG class and TF class less comparable with respect to low load factor customers, and also raised several issues concerning gas transportation service terms and conditions. Other transportation issues

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[1] 11 FPC 43 (1953). Under the *Atlantic-Seaboard* method, 50% of non-customer fixed costs are allocated based on demand and the remaining 50% are allocated based on annual

included recommendations concerning reductions to customer Peak Day Quantities to avoid unfairly penalizing customers who had made operational changes resulting in gas conservation, and modifications to procedures for settling imbalances resulting from prior period measurement corrections caused by Public Service billing or measurement errors and which were now, under the current process and market-pricing, unduly penalizing transportation customers who did not cause the errors. Additional recommendations were made by Atmos or Seminole concerning resolution of disputed measurement, communication line outages, access to measurement signals, and the Company's mishandling of emergency calls received from transportation customers. The CBA acknowledged Public Service's use of the fully distributed cost study methodology developed in workshops arising out of the settlement of the Company's prior Phase I case and Public Service's implementation of two procedures, effective January 1, 2005 (outside the test year), for charging non-regulated affiliates for the use of Public Service's utility customer list as part of their stand alone bill stuffers or as part of their joint advertising in the Company's stuffer *Update*. The CBA requested that in the next proceeding in which Public Service's revenue requirement or earnings are at issue, it reflect the revenues from these two procedures.

On November 10, 2005, Public Service filed the rebuttal testimony and exhibits of 14 witnesses responding to the various positions of the parties in answer testimony and further supporting its direct case. In addition, Company witness Fredric Stoffel described in his rebuttal testimony several developments occurring since the filing of the Company's direct case that were further contributing to the financial needs of the Company and for increased

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usage.

rates. These developments included the large and sustained increase in the commodity price of natural gas, higher interest rates as reflected in several increases in the federal funds rate, an increase in postage rates announced by the U.S. Postal Service, and increased difficulties in obtaining permits to site natural gas facilities. With respect to the high gas costs, Mr. Stoffel explained that Public Service must secure additional lines of credit necessary to manage the higher cost gas portfolio on behalf its customers, that the higher gas costs appear to be causing increased conservation which is accelerating the decline in gas consumption per customer, and that the Company is experiencing increased exposure and costs associated with late payment and nonpayment of utility bills. The Company continued to argue that its gas department was suffering from earnings attrition.

Also on November 10, 2005, the Staff, the OCC, Climax, Atmos and Seminole filed cross-answer testimony. Atmos' cross-answer testimony opposed Staff's and the OCC's proposal to allocate costs among customer classes based on the *Atlantic-Seaboard* method, arguing instead for use of the Public Service's minimum system approach or, in the alternative, the Straight Fixed-Variable method of allocating such costs. In addition, Atmos disputed Staff's proposal to "re-functionalize" certain distribution costs as transmission costs. Seminole's cross-answer testimony responded to the rate design and certain other proposals of the other parties insofar as they pertain to firm transportation customers. One of Seminole's concern was that the rate design proposals of the other parties would further increase the lack of comparability between CG and TF service for low load factor customers. Staff did not oppose Atmos' proposal for a separate transmission-only transportation rate if high pressure distribution mains could be properly re-classified as transmission. Staff also addressed, *inter alia*, issues raised by Atmos and Seminole on prior period adjustments caused by meter or billing errors.

After several preliminary conversations between Public Service, Staff and the OCC, the Company made an offer of settlement to Staff and the OCC during the week of November 23, 2005. On November 9 and 30, 2005, the OCC filed corrected testimony. EOC/AARP filed corrected testimony on November 29, 2005. On November 30, 2005, Staff late filed corrected testimony.

After several exchanges of offers of settlement on major principles, Public Service, Staff and the OCC came to agreement in principle on several major principles. On December 1, 2005, Public Service invited all parties to attend a settlement conference on December 2, 2005, opening the negotiations to all other active parties in the proceeding. Extensive settlement negotiations occurred on December 2, 5 and 6, 2005, at which time a comprehensive settlement on all major principles was achieved. This Stipulation represents the results of those negotiations.

This Stipulation incorporates by this reference the S&A Attachments A through G, appended hereto, which are identified as follows:

S&A Attachment A - Settled Revisions to Colorado PUC No. 6 – Gas Tariff

S&A Attachment B - Summary of Settled Revenue Requirements Issues

S&A Attachment C - Settled Revenue Requirements Study

S&A Attachment D - Settled Class Cost of Service Study

S&A Attachment E - Settled Rate Design and Price Out

S&A Attachment F - Rate Comparisons – Present and Settled

S&A Attachment G - Bill Impacts

II. TERMS OF SETTLEMENT

A. Revenue Requirements

The Parties[2] have agreed upon a settled revenue requirement of $300,345,671 based upon the test year of twelve months ended December 31, 2004, resulting in an increase in jurisdictional base rate revenues of $22,492,993, or 8.10%. The Parties have agreed to the specific resolution of the disputed issues concerning revenue requirements, as set forth in Sections II.A.1 through II.A.10 below. A summary of the revenue requirements effect of the specific settled issues are reflected in S&A Attachment B. For the purpose of determining revenue requirements, to the extent an issue is not specifically addressed in this Stipulation or detailed in the supporting cost of service in S&A Attachment C, the Parties agree to implementation of the Company's proposal as to that issue, as reflected in the Company's rate case application originally filed on May 27, 2005, and corrected on July 8, 2005.

1. Rate of Return on Equity

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

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[2] With regard to the settlement of issues concerning Revenue Requirements, as set forth in Section II.A of this Stipulation, the Earnings Cap, as set forth in Section II.E, and Gas Storage Facilities, as set forth in Section II.G, the agreements and compromises reflected therein are those by and among Public Service, Staff and the OCC. EOC/AARP join in the resolution of the average rate base issue, as described in Section II.A.4. While Climax, Atmos, Seminole and EOC/AARP support the Commission's adoption of all of the terms and conditions of this Stipulation without modification, these parties (except EOC/AARP with respect to the average rate base issue) took no position on these particular issues and take no position on the particular resolution of these issues herein. Accordingly, the use of the term "Parties" with respect to these sections of the Stipulation should be construed to mean that Climax, Atmos, Seminole and EOC/AARP (except with respect to the average rate base issue) have no objection to the resolution specified therein.

Witness	Recommendation
Mr. Hevert (Public Service)	11.0%
Mr. Trogonoski (Staff)	9.5%
Mr. Copeland (OCC)	8.5%

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 Risk Premium Approach, Capital Asset Pricing Model 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 made an alternative ROE recommendation depending upon the outcome of the Company's proposal regarding rate design and OCC witness Mr. Copeland made an alternative ROE recommendation depending upon the outcome of the Company's proposed capital structure. Staff's and the OCC's willingness to reach the compromise regarding ROE and capital structure as set forth below is based upon the Company's compromises on other important issues including, but not limited to, a reduction in the proposed Service and Facilities charge for residential customers, an increase in the proposed time period for determining weather normalization factors, the acceptance of average rate base rather than year-end rate base, and the agreement to use the *Reverse United* method to allocate costs among customer classes.

Resolution. For purposes of settlement, the Parties agree that a fair and reasonable ROE for the Company's gas department is 10.5%.

2. Cost of Debt

Background. In its direct testimony, the Company's witness Mr. Tyson proposed a cost of debt of 6.54%, reflecting the reduction of the Company's embedded cost of debt assuming the retirement of $134.5 million of long-term debt on November 1, 2005. In his Rebuttal Testimony filed on November 9, 2005, Mr. Tyson updated his recommendation and proposed using the actual embedded cost of debt of 6.44% as of November 1, 2005. The actual embedded cost of debt as of November 1, 2005 reflected both the $134.5 million debt retirement that occurred on November 1, 2005 and the refinancing of certain pollution control bonds during September 2005. In his answer testimony filed on October 10, 2005, Staff witness Mr. Trogonoski expressed reservations about the Company's proposed capital structure and cost of debt because at that time there was not yet certainty that the planned $134.5 million debt retirement would occur as scheduled on November 1, 2005. OCC witness Mr. Copeland recommended using the actual embedded cost of debt as of December 31, 2004.

Resolution. For purposes of settlement, the Parties agree that the Company's actual embedded cost of debt of 6.44 % as of November 1, 2005 shall be used to determine the weighted average cost of capital.

3. Capital Structure and Weighted Average Cost of Capital

Background. Public Service recommended that the Commission use its projected capital structure as of November 1, 2005, excluding short-term debt, and adjusted to eliminate notes between Public Service and its subsidiaries, 1480 Welton, Inc. and PSR Investments, Inc. The Company argued that use of the projected capital structure was necessary in order to enable it to meet its goals to strengthen the Company's balance sheet and improve Public Service's financial integrity. Staff witness Mr. Trogonoski recommended adjusting the Company's capital structure as of the end of the 2004 test year to reflect the early retirement of $110 million first collateral trust bonds in February 2005, but was reluctant to accept the Company's proposed additional adjustment to its year-end capital structure without certainty that the planned November 1, 2005 $134.5 million debt retirement would occur. In his rebuttal testimony, Company's witness Mr. Tyson confirmed that the Company completed the additional $134.5 million debt retirement as planned on November 1, 2005. OCC witnesses Mr. Copeland and Dr. Schechter advocated using the Company's capital structure as of the end of the test year, December 31, 2004.

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

Party	**Long-Term Debt**	**Equity**
Public Service	44.51%	55.49%
Staff	47.47%	52.53%
OCC	49.89%	50.11%

Resolution. For purposes of settlement, the Parties have agreed to the use of the Company's proposed capital structure of 44.51% long-term debt and 55.49% common equity. The Parties agree that Public Service's proposed capital structure is reasonable, given the circumstances of this case, and should be used to establish the Company's revenue requirement in this proceeding. The Parties also agree that the Commission should exclude short-term debt from the regulatory capital structure. The following table reflects the weighted average cost of capital that has been agreed to by the Parties:

	Weight	Rate	Wtd Avg.Cost
Long-Term Debt	44.51%	6.44%	2.87%
Equity	55.49%	10.5%	5.83%
Total Cost:			8.70%

4. Average Rate Base

Background. In both its direct and rebuttal cases, Public Service advocated the use of year-end rate base in developing its proposed revenue requirements as a means of partially addressing earnings attrition that Company stated that its gas department has been experiencing. In particular, the Company claimed that the use of year-end rate base was necessary to counter the effects on its revenues of declining use per customer, the need for significant capital investment to meet significant continued growth in its service territory, and pronounced regulatory lag.

In their answer testimony, Staff and the OCC recommended that the revenue requirement be developed based on 13-month average rate base. EOC/AARP also advocated the use of average rate base. Staff, the OCC and EOC/AARP argued that the use of year-end rate base violates the matching principle and presented testimony disputing that Public Service's gas department was actually experiencing earnings attrition. Staff pointed out that the majority of the Company's gas plant additions are of the type that immediately produce revenues and, therefore, are not subject to regulatory lag. In addition, Staff witness Kunzie and OCC witness Peterson argued that the conditions that prompted the Commission to adopt year-end rate base in the past no longer exist.

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 and gas stored underground. In cases where the 13-month data are not available, 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. Cash working capital is calculated using *pro forma* expenses as reflected in S&A Attachment C, Schedule 4 (column entitled "Adjusted Total Gas") multiplied by the working capital factors as reflected in S&A Attachment C. Gas stored underground is reflected as an average of the twelve monthly average balances for the test year. The AFUDC addition to earnings shall be based upon the actual test-period amount, not annualized.

5. Amortization of Environmental Clean-up Costs, Leyden Gas Storage Costs and Rate Case Expenses

Background. In its filed case, Public Service proposed to amortize certain costs which had been deferred for accounting purposes and to include the annual amortized amount in its revenue requirement. These deferred costs relate to (a) the environmental clean-up of a former Manufactured Gas Plant ("MGP") site in Fort Collins, Colorado; (b) the Leyden Gas Storage Facility ("Leyden"), which is in its final stage of closure and abandonment plan; and (c) rate case expenses. The deferred amounts, the amortization period and the annual amortized amount proposed by the Company are as follows:

Deferred Costs	Total	Amortization Period	Annual Allowance
MGP Cleanup	$6,237,099	4 yrs.	$1,559,275
Leyden	$4,818,862	4 yrs.	$1,204,716
Rate case expense	$1,009,241	2 yrs.	$504,621

In his direct testimony, Company witness Mr. Willemsen noted that the Company will continue to defer ongoing costs for these matters, along with any related credits for recoveries under the Company's insurance policies or from other parties, until the Company's next gas rate case, wherein the Company will include the balance of previously unrecovered costs, plus the unamortized balance of deferred costs remaining from this case, and propose to amortize them in a similar manner. To address the possibility that the amortization period will expire before the effective date of the rates in its next rate case, Public Service further proposed to follow the same procedure ordered by the Commission in Public Service's gas rate cases in Docket No. 98S-518G (Decision No. C99-579, mailed June 8, 1999) and Docket No. 00S-422G (Decision No. C01-231, mailed March 15, 2001); i.e., Public Service will file an application on less-than-statutory notice to decrease its rates by the applicable annual amortized amount, through a General Rate Schedule Adjustment rider, upon the expiration of the amortization period.

Both Staff and the OCC objected to Public Service's proposal concerning the amortization and recovery of rate case expenses. Staff witness Ms. McGee-Stiles recommended the use of a three-year, instead of a two-year, amortization period and OCC witness Mr. Peterson challenged the level of estimated legal expenses included in the Company's calculation of rate case expenses, recommending a reduction of $200,000 in the total amount to be amortized. In addition, Staff witness Ms. McGee-Stiles recommended that the annual amortizations for MGP environmental clean-up costs and Leyden costs be collected and tracked through a separate rate rider, citing the problem of the timing of the amortization periods in relation to the filing of the Company's rate cases.

Resolution. In resolution of this issue, the Parties agree that Public Service's proposals as to the amortization and deferred accounting concerning MGP environmental clean-up costs, Leyden costs and rate case expenses should be adopted except that the estimated costs included in the total rate case expense will be reduced from $589,501 to $498,426 to reflect Public Service's actual booked amount for these costs as of November 30, 2005. The resulting annual amortized amount for rate case expense is $459,083, as detailed in S&A Attachment C, Schedule 19. These annual amortized expenses are included in the settled revenue requirement and in the development of the settled base rates. No separate rate rider will be placed into effect to collect any of these amortizations. If the amortization period applicable to any of these items expires prior to the effective date of rates resulting from the Company's next rate case, the Company will file an application on less than statutory notice to place into effect a negative rider that will reduce rates by the amount of the annual amortization expense for the amortization that had expired. With respect to the amortization of rate case expenses, such negative rider would go into effect on February 1, 2008, and with respect to the amortization of MGP environmental clean-up costs and Leyden costs, such negative rider would go into effect on February 1, 2010. Any such negative rider would remain in place until the effective date of the rates resulting from the Company's next gas rate case in which revenue requirements are determined.

6. Pipeline Integrity Management Costs

Background. In its filed case, Public Service proposed to include one-third of the total $8,351,700 of estimated costs necessary to carry-out the Company's Pipeline Integrity Management Plan, which was completed in December 2004 in compliance with new federal pipeline safety laws and the U.S. Department of Transportation Office of Pipeline Safety regulations promulgated thereunder. As the new regulations require that 50% of the pipeline risk assessment work be completed by 2007, Public Service proposed to recover the three-year average, or $2,783,900, of the total amount estimated made by Public Service to complete these assessments. Both Staff and the OCC challenged these estimated costs based on the relatively high degree of uncertainty regarding the amount and timing of the necessary expenditures, and whether they qualified under the known and measurable standard. OCC witness Mr. Peterson recommended that the Commission approve the amount Public Service had budgeted for 2005, or $735,000.

Resolution. In resolution of this issue, the Parties agree that Public Service should be permitted to include $735,000 in the settled revenue requirement for recovery of Pipeline Integrity Management Costs. For regulatory accounting purposes, the Company shall be permitted to defer in a regulatory asset account the amounts incurred during 2005, 2006 and 2007 under the Pipeline Integrity Management Plan that are in excess of $735,000 per year that has been included as part of the Company's settled revenue requirement.

7. American Gas Association Dues

Background. In its filed case, Public Service proposed to include in its test year revenue requirement $206,615 in 2004 expenses for American Gas Association ("AGA") dues. This amount reflected a reduction of $10,331 in the amount of AGA dues actually incurred by Public Service in 2004, to account for the representative amount of AGA dues associated with the AGA's lobbying activities. Through the answer testimony of OCC witness David Peterson, the OCC recommended that the proposed amount of recoverable test year AGA dues be further reduced by the representative amounts associated with AGA's governmental relations and media communications (excluding environmental communications) activities, consistent with Commission practice. As a result, the OCC determined that expenses related to AGA dues be reduced by an additional $44,000.

Resolution. In resolution of this issue, the Parties agree that the allowance for AGA dues should be adjusted to exclude the amounts related to AGA's governmental relations and media communications (excluding environmental communications) activities. The resulting test year allowance for AGA dues included in the settled revenue requirement is $162,432.

8. GCA Recovery of Certain Costs Currently Recovered in Base Rates

Background. In its filed case, Public Service proposed that certain specified costs that would typically be recovered in base rates and included in the test-year revenue requirements, be recovered instead through the Company's Gas Cost Adjustment ("GCA") mechanism. These costs are: (1) personal property taxes assessed on the Company's gas stored in underground storage facilities in Kansas; (2) electric energy costs used to operate the Company's Yosemite #5 compressor station; and (3) net shrinkage costs at the Company's processing plants. The Company argued that GCA recovery of these costs was appropriate because (a) the actual amount of costs incurred by the Company are directly affected by and vary with the commodity price of gas, (b) these costs are similar to and directly associated with other costs currently recovered through the GCA and (c) these costs are more related to the cost of procuring gas supplies than the cost of providing local delivery services. Through the testimony of Staff witnesses Ms. McGee-Stiles and Mr. Kwan, Staff opposed the

Company's proposed change of cost recovery mechanism, arguing that inclusion of such costs is inconsistent with the purpose of the GCA.

Resolution. In settlement of this issue, the Parties agree that, for purposes of this rate case, Kansas property taxes on gas inventory, Yosemite compressor costs and net gas shrinkage costs will continue to be recovered in base rates and that these costs shall not be recovered through the GCA mechanism. Such agreement is without prejudice to Public Service seeking Commission authorization in the future to recover these or other types of costs through the GCA mechanism or such other means of cost recovery as the Company deems appropriate.

9. Weather Normalization

Background. In its filed case, Public Service proposed to change the adjustment made to normalize test year sales revenues and quantities by replacing National Oceanic and Atmospheric Administration ("NOAA") thirty-year normal, adjusted to reflect updated data, with a straight ten-year average of actual heating degree days for the ten years ending with the test year. In short, Public Service proposed to adjust for weather based on average weather in its service territory over the past ten years, rather than using the 30-year standardization method approved by the Commission in Decision No. C99-579, mailed June 8, 1999, in Public Service's previous natural gas rate case in Docket No. 98S-518G. Staff witness Dr. Dianne Green and OCC witness Jon Loe opposed Public Service's proposal to include only ten years of heating degree day data in the calculation of the weather normalization adjustment and not use the NOAA normal data, arguing that using 30 years of data provides a more accurate indication of normal weather and that Public Service's proposal lacks proper statistical methodology and support. Dr. Green also corrected the description of weather normalization in her corrected testimony filed on November 30, 2005, making the description match the models that the Company and Staff had filed. This correction, which has been accepted by the Parties, affects only the description of the formula; the calculations in the models were correct as presented in the direct testimony of Mr. Brockett and the answer testimony of Dr. Green.

Resolution. The Parties agree that the weather normalization adjustment shall be calculated using the adjusted NOAA 30-year normal as approved by the Commission in Decision No. C99-579, mailed June 8, 1999, in Docket No. 98S-518G. Specifically, the adjustment is calculated by first averaging thirty years of actual annual heating degree days for the period 1971-2000. The actual thirty-year average for the period 1975-2004 is then calculated. Next, the ratio of the 1975-2004 thirty-year average to the 1971-2000 thirty-year average is multiplied by the 1971-2000 NOAA thirty-year normal. This result is then divided by the actual test-year heating degree days to derive the weather normalization factor. Test year volumes for the residential and commercial classes are then multiplied by the weather normalization factor.

10. Lead-Lag Study and Cash Working Capital

Background. Staff witness Ms. Friedman challenged the methodology used by the Company to develop its lead-lag study and the resulting cash working capital factors by stating that the underlying statistical methodology used to determine the sample for the lead-lag study was flawed because the proxy used in the study was a 1989 study conducted by Cheyenne Light, Fuel and Power. In addition to questioning the Company's use of customer data that pre-dated the test year by three to four years, Staff also questioned the randomness of the sample that the Company used for the lead-lag study. Staff advocated that the Company should be required to perform an appropriate lead-lag study based on test-year data in conjunction with every rate case. The Company responded in its Rebuttal Testimony that for purposes of this proceeding it used the lead-lag study and cash working capital factors that were approved by the Commission in 2003 in the Company's most recent combined rate case, Docket No. 02S-315EG. Company witness Mr. Willemsen disagreed with Staff's position that the Company should be required to conduct such a time-consuming and resource intensive lead-lag study with every rate case. Public Service also disagreed with Staff's claims that the lead-lag study that it relied upon in this proceeding was in any way flawed.

Resolution. Public Service, Staff, and the OCC agree to begin immediately to engage in good faith discussions to determine the statistical methodology and data collection processes, including the availability and access of data, to be used in performing future lead-lag studies, including the lead-lag study that will be performed in connection with the Company's next electric rate case expected to be filed during the spring of 2006. The Company understands that, regardless of whether agreement is reached regarding the method and data collection processes to be used for the Company's lead-lag study, Staff and/or the OCC may conduct their own lead lag study and recommend its use in any future rate case. Public Service agrees to provide Staff and the OCC with all information and data necessary within 30 days of such request, in native and electronic executable format, in order for them or their experts to conduct such a study. Public Service also agrees to provide all data and supporting information, and access to the personnel, equipment and software necessary to verify the data that Staff will need; provided, however, to the best extent possible, Staff and the OCC will attempt to use the similar internal processes used by Public Service to extract data from the Company's systems to minimize the burden on the Company during the process of conducting their separate lead-lag studies.

B. Cost Classification and Allocation

BACKGROUND.

The Company's currently-effective base rates for gas service were developed largely on the basis of the Settlement Allocation Method, or "SAM,"[3] adopted in accordance with the Stipulation and Agreement reached in the Company's last Phase II proceeding in Docket No. 99S-609G, as approved by the Commission in Decision No. C00-801, mailed July 21, 2000. That Stipulation and Agreement provided that the agreed-upon SAM method was deemed not to constitute a settled practice.

In its Class Cost of Service Study ("CCOSS"), the Company proposed to classify and allocate each cost based on whether, in the Company's judgment, the cost varies with the number of customers, peak demand or annual throughput. In implementing this approach, the Company imputed a minimum distribution system and classified the costs of this system as customer-related. The Staff, the OCC and EOC/AARP opposed the minimum system approach and the classification of any costs of distribution mains as customer-related. Staff and the OCC supported the application of the *Atlantic-Seaboard* method to allocate all non-customer related fixed costs. The *Atlantic Seaboard* method allocates 50% on the basis of

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[3] SAM allocates 75% of non-customer related fixed costs on demand and 25% on commodity.

demand and 50% on the basis of annual usage. The EOC/AARP advocated continued use of the SAM ("*Reverse United*") method adopted as part of the settlement in the last Phase II rate case in Docket No. 99S-609G. Atmos opposed application of the *Atlantic-Seaboard* method and recommended that the Commission adopt Public Service's minimum system approach or, in the alternative, the Straight Fixed-Variable method for allocating fixed costs.

RESOLUTION.

For purposes of settlement of this rate case, the Parties have compromised their differences by agreeing to a modified settlement allocation method. Under this method, distribution mains are not split into capacity- and customer-related components through the imputation of a minimum system. In addition, all fixed costs not classified as customer-related are allocated based on the reverse of the *United*[4] method, or "*Reverse United*." This method allocates 75% of the fixed costs on the basis of demand and 25% of the fixed costs on the basis of annual usage, which is the same methodology that is currently employed on Public Service's system but which was previously referred to as the SAM method. The CCOSS reflecting the modified settlement allocation method is reflected in S&A Attachment D. The Parties have also agreed to certain adjustments that mitigate the rate impact of this cost allocation on the commercial sales (CG) class. The Parties agree that the use of the *Reverse United* method, as well as the manner of resolution of other cost allocation issues described herein, is solely for the purposes of settlement and does not constitute a settled practice or otherwise have precedent-setting value in any future proceedings. The application of *Reverse United*, including the mitigation adjustments, and the resolution of other cost allocation issues are more fully described below:

1. The CCOSS appended hereto as S&A Attachment D is based on the *Reverse United* method, with no imputation of a minimum system.

2. The results of this method have been adjusted to limit the increase to the CG class to 18.00%. The net shortfall in test-year revenue resulting from this mitigation are recovered from TI and RG customers as follows: First, the increase to TI customers not receiving rate discounts is raised to the system average increase of 8.10%. The remaining revenue deficiency is then eliminated by raising the RG class increase from 4.72% to 4.84%.

3. The demand allocation factors for the RG and CG classes are derived by applying a 20% load factor to the classes' respective test-year weather-normalized throughput. The demand allocation factors for the IG and TI classes are derived by applying a 100% load factor to the classes' respective test-year throughput. The demand allocation factor for the Firm Transportation (TF) class is the sum of individual customers' Peak Daily Quantities (PDQ).

4. For purposes of the settled CCOSS, transportation discounts shall be spread to all customer classes. The result is that the sales and non-discounted transportation customers are allocated the revenue requirement responsibility

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[4] Opinion No. 671, *United Gas Pipe Line Company*, Docket No. RP72-75 (Phase II) (Issued October 31, 1973). Under the *United* method, 25% of fixed costs are allocated based on

for taxes associated with the discounted revenues in addition to revenue requirement responsibility associated with the recovery of the discounts provided to the transportation customers. Staff and the OCC expressly reserve their rights to argue that the revenue deficiencies for such transportation discounts should be disallowed or, if allowed, should be spread only within the customer class in which the discount was given.

5. Twenty percent of on-system underground storage costs have been allocated to the TF and TI classes.

6. The Parties agree to the use of the Company's CCOSS model for purposes of this proceeding. Staff notes that it has reconciled its CCOSS model (formerly referred to as the "WWRMM") with Public Service's CCOSS model in all respects except as to the tax effects of the allocation of revenues attributable to gas transportation discounts. Staff believes that use of Company's CCOSS model is just and reasonable considering the rate mitigation measures agreed to in this Stipulation. Although Staff agrees to the use of Public Service's model for purposes of settlement in this proceeding, such agreement is without prejudice to Staff proposing an alternative model in future gas rate case proceedings. Staff and the OCC specifically reserve their rights to challenge Public Service's method of allocating revenues and associated taxes attributable to gas transportation discounts in future cases.

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demand and the remaining 75% are allocated based on annual usage.

C. Rate Nomenclature

The Parties agree that the "Commodity Charge" currently applicable to its RG, CG and IG rate schedules and the "Transportation Commodity Charge" applicable to its TF and TI rate schedules should be renamed to "Volumetric Charge," so that it may be better understood as applying to usage and recovering delivery costs, not gas commodity costs.

D. Rate Design

The settled base rates and associated test-year revenue requirement by rate component are reflected in S&A Attachment E.[5] A comparison of the settled base rates with the Company's currently-effective rates and charges is reflected in S&A Attachment F. The settled base rates have been developed as follows:

1. Rates for the RG class are designed to recover approximately the RG revenue requirement (after mitigation) of $206,076,976, as set forth on S&A Attachment D. The RG Service and Facility Charge is $10.00,[6] which collects $132,654,150 (see S&A Attachment E). The remaining RG revenue requirement of $73,422,826 is recovered through a Volumetric Charge of $0.07956 per Therm (see S&A Attachment E).

2. Rates for the CG class are designed to recover approximately the CG revenue requirement (after mitigation) of $60,596,818, as set forth on S&A

5 The class revenues generated from the settled rates are slightly different from the classes' mitigated revenue requirements reflected in S&A Attachment D due to rounding. In other words, the rates do not include enough significant digits to recover precisely the classes' respective revenue requirements.

6 This amount is specifically a settlement amount and is not based on costs allocated in the CCOS study.

Attachment D. The CG Service and Facility Charge is $20.00,[7] which collects $22,777,360 (see S&A Attachment E). The remaining CG revenue requirement of $37,819,458 is recovered through a Volumetric Charge of $0.09555 per Therm (see S&A Attachment E).

3. Rates for the TF class are designed to recover approximately the TF revenue requirement of $25,223,071, as set forth on S&A Attachment D, minus revenues collected from customers on discounted rates of $1,017,937, (see S&A Attachment E) revenues from Special Facility Charges of $156,120, (see S&A Attachment E) revenues from Backup Supply Sales Service of $8,476, (see S&A Attachment E) and revenues from Unauthorized Overrun Transportation Penalty Charges of $11,100 (see S&A Attachment E). The resulting net revenues to be collected from customers on standard TF rates are $24,029,438. The TF Service and Facility Charge is $70.00, which collects $2,583,140 (see S&A Attachment E). The TF Volumetric Charge is maintained at its current level of $0.2300 per Dekatherm, and collects $6,337,383 (see S&A Attachment E). The remaining TF revenue requirement is collected through the Firm Capacity Reservation Charge of $4.66 per Dekatherm (see S&A Attachment E). The Minimum Rate for the TF Firm Capacity Reservation Charge is $0.68 per Dth (see S&A Attachment F).

[7] This amount is specifically a settlement amount and is not based on costs allocated in the CCOS study.

4. Rates for the TI class are designed to recover approximately the TI revenue requirement (after mitigation) of $8,254,840, as set forth on S&A Attachment D, minus revenues collected from customers on discounted rates of $1,046,302 (see S&A Attachment E), revenues from Unauthorized Overrun Transportation Penalty Charges of $40,500 (see S&A Attachment E), revenues from On-Peak Demand Charges of $3,747 (see S&A Attachment E), and revenues from backup Supply Sales Charges of $454 (see S&A Attachment E). The resulting net revenues to be collected from customers on standard rates are $7,163,837. The TI Service and Facility Charge is set at $140, which collects $367,360 (see S&A Attachment E). The TI Volumetric Charge of $0.3980 per Dekatherm is set to collect approximately the remaining TI revenue requirements of $6,796,469 (see S&A Attachment E).

E. <u>Earnings Cap</u>

Beginning with the calendar year ending December 31, 2006, and thereafter for each subsequent calendar year in which the terms of this Stipulation remain effective through at least October 31, Public Service agrees to calculate its earned ROE and to reduce its base rates for gas services by means of a negative rate rider for any earnings in excess of 10.5%. Public Service shall file its annual ROE calculation for the preceding calendar year with the Commission on or before April 1 of each year beginning on April 1, 2007. The Company's earnings will be measured using ratemaking principles[8] (including jurisdictional allocation methodologies) reflected in the rates resulting from this gas rate case proceeding. All Commission-ordered adjustments,[9] except pro forma adjustments,[10] shall be made to the annual earnings cap calculation. All accounting adjustments[11] will be made to the earnings cap calculation only to the extent that such adjustments correct transactions that should be properly counted in a period prior to the initial earnings cap test year (*i.e.*, 2006). Accounting adjustments affecting prior year's earnings cap calculation that do not become known until after the applicable earnings cap report for the prior year has been filed shall be recognized for the earnings cap calculation in the year they become known and are recorded on the books of Public Service in accordance with generally accepted accounting principles.[12] The Company agrees to calculate its annual ROE based on: a) its actual capital structure (per books, as adjusted) at the end of each test year; b) embedded cost of debt for each test year; c) its 13 month average rate base for each test year, as described in Section II.A.4 of this

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[8] Traditional ratemaking principles, including such concepts as "just and reasonable" and "used and useful," will be as strictly applied when calculating the annual earnings cap as they are when calculating the revenue requirement in a traditional Phase I rate proceeding.

[9] "Commission-ordered adjustment" shall be defined as any adjustment adopted by the Commission to insure that revenues, expenses, and rate base reflect traditional ratemaking principles.

[10] "Pro forma adjustments" shall be defined as annualization of price changes that occurred within the test year (in-period adjustments) or outside the test year (out-of-period adjustments).

[11] "Accounting adjustment" shall be defined as any adjustment required to insure that transactions properly counted in the calculation of the review period's earnings are included in the annual filing and that transaction that are properly counted in the calculation of earnings for previous or future review periods are excluded.

[12] This treatment for accounting adjustments is consistent with paragraph II.B of the Stipulation and Settlement Agreement adopted by the Commission in Decision No. R01-1034, mailed October 5, 2001, in the Company's 1999 earnings test proceeding in Docket Nos. 00M-632EG and 95A-531EG.

Stipulation; d) weather normalized revenues for each test year, using the weather normalization method described in Section II.A.9 of this Stipulation; and e) settled ratemaking principles approved by the Commission in this proceeding.

In the event that a material change in circumstances occurs subsequent to this rate case proceeding, any party may argue that, as a result, the Commission should determine the appropriate regulatory treatment regarding the issue affected for purposes of the earnings cap calculation. A material change in circumstances is a change that impacts the calculation of the gas department revenue requirement and: (1) occurs as a result of a Commission order; or (2) arises as a result of formal action by any other governmental body or other authority. For purposes of the earnings cap calculations, any party proposing a change in regulatory treatment as a result of a material change, as defined above, or proposing a regulatory treatment for an item for which there has been no previously accepted regulatory treatment, shall identify the material change in circumstances and the party's proposed new regulatory treatment in the party's testimony in the earnings cap docket and shall bear the burden of going forward and the burden of proof as to that proposed new regulatory treatment.

The earnings cap procedure to be followed is as follows: Public Service shall file earnings cap calculation and supporting information on or before April 1 of each year beginning April 1, 2007, and continuing through the term of this Settlement Agreement. The Company shall identify in its filing any change that the Company is requesting from previously accepted regulatory treatment and any item for which there has been no previously Commission approved regulatory treatment. Where references are made to settled ratemaking principles for purposes of application of the earnings cap, these settled principles shall only be deemed settled for the earnings cap calculations and proceedings that apply to periods before the conclusion of a subsequent general gas rate case proceeding, whether initiated by the Company or by any other party.

The Staff shall file a report with the Commission no later than May 30 in any year, identifying any matters in the Company's earnings cap calculation with which Staff takes issue. Any party may submit discovery requests to the Company after the Company's filing and prior to the Staff filing its report. Any other party that contests the Company's earnings cap calculation or the Company's proposed rate reduction, if any, shall file a protest with the Commission by May 30 of the same year. If a hearing on any earnings cap calculation is necessary, the Parties request that the Commission schedule any such hearing promptly.

Any earnings cap negative rider to base gas rates proposed by the Company shall go into effect on July 1 of each year and shall include interest at the Commission-approved customer deposit rate. Interest shall accrue on the full amount of excess earnings to be returned to customers from January 1 through June 30. The Rider Period will be the twelve months from July 1 of each year through June 30 of the following year. There shall be a true-up mechanism to the extent necessary to address any over/under recovery issues from the prior years.

Any changes to the rider ordered as a result of the earnings cap hearing shall be filed within 60 days of the mailed date of the final Commission order on the earnings cap calculation and shall be implemented and trued-up in the remainder of the Rider Period. The rider implemented after the conclusion of the hearing shall include interest at a rate equal to the Company's regulated return on rate base for the applicable test year on any difference between the earnings cap amounts used by the Company to calculate the Company's proposed rider that went into effect on July 1 and the earnings cap amount ultimately determined to be required by the Commission. Interest shall accrue from July 1 until the date of the implementation of the Commission's decision on the appropriate earnings cap amount.

F. <u>Workshops to Explore Rate Design Approaches</u>

In order to further investigate the important rate design, interclass rate comparability and class composition issues that were raised in this proceeding ("Workshop Issues"), the Company agrees to convene, and to invite all Parties to, a series of workshops. The intent of these workshops is to develop and, if possible, to come to a consensus regarding the Workshop Issues. The Parties agree that the workshops will commence within one month after the rates in this case become effective. Furthermore, the Parties electing to participate in the workshops agree to file a written report with the Commission informing it of the results of the workshop no later than September 1, 2006. The Parties agree that simulation runs with alternative rate designs will use the settled revenue requirements and cost allocations from this proceeding and will be provided as part of the report. If a consensus is reached by all workshop participants, the Company will file an application, prior to or as part of its next gas rate case, to implement the agreed to changes. If a consensus cannot be reached by all workshop participants, a participant is free to use any information from the workshops, other than information designated as confidential or proprietary, to advocate positions in the Company's next rate case filing.

G. Gas Storage Facilities

The Staff and the Company have also discussed the possibility of a different treatment of additional regional storage facilities that can be owned or accessed by the Company to the benefit of its customers, particularly in consideration of the recent retirement of the Leyden Gas Storage facility in Arvada, Colorado. Staff and the Company agree that storage facilities may create the opportunity for the Company to mitigate the seasonal cost of gas supply. Staff and the Company agree that the addition of storage facilities are required to provide operational support for balancing of receipts and deliveries on its system. However, Staff and Public Service also acknowledge the challenges of new storage and related pipeline projects, including the significant amount of capital investment required, the long lead time for development, potential regulatory lag, the inherent risk of such projects, and the cost allocation and rate design issues for such facilities that may provide benefits across departments (*i.e.*, gas and electric), as well as customer classes. Staff, the OCC and Public Service recognize that some changes to the traditional regulatory and ratemaking processes may be necessary to facilitate such projects in the future. The Company agrees to apprise Staff and the OCC of new storage opportunities and Staff and the OCC agree to work with the Company to investigate progressive financing and cost recovery methods to facilitate the development and construction of such gas storage and related pipeline facilities in a manner that does not create attrition to the Company's gas utility earnings.

H. Terms and Conditions of Gas Transportation Service

1. Revised Fuel Reimbursement Percentage

Background. In its filed case, Public Service proposed to update the current TF and

TI Fuel Reimbursement Percentage of 1.46 percent, which was based on a study conducted in 2000, to reflect the results of the Company's study, included as Exhibit No. SBB-8 to Company's witness Brockett's direct testimony, based on test-year receipts and deliveries. The new percentage based on this update is 0.86 percent. Through the answer testimony of Mr. Kwan, Staff opposed the revision of the Fuel Reimbursement Percentage proposed by Public Service as too low, and more reflective of an aberrant year rather than a normal year. Mr. Kwan did not propose a revised calculation, but rather recommended that the current Fuel Reimbursement Percentage not be changed. In his rebuttal testimony, Company witness Mr. Brockett responded to Mr. Kwan's concern by offering to provide for a tariff requirement that the Fuel Reimbursement percentage be updated at least once per year.

Resolution. For purposes of settlement, the Parties agree that the Fuel Reimbursement Percentage shall be changed from 1.46% to 0.86 % upon the effective date of the base rates approved by the Commission as part of this Stipulation. Within 30 days following the date of the Commission's order approving this Stipulation, Public Service shall file an advice letter proposing to implement new tariff provisions that require Public Service to file separate annual filings to update the Fuel Reimbursement Percentage. The first such filing would be submitted for implementation no later than one-year from the effective date of the new Fuel Reimbursement Percentage resulting from this Stipulation.

2. Imbalance Cashouts Related to Prior Period Adjustments

Background. In their answer testimonies, Atmos and Seminole both raised an issue of equity concerning provisions in Public Service's gas transportation tariff that require that corrections to billed quantities from prior months resulting from meter errors or billing errors related to delivered quantities ("Measurement Errors") be treated as ordinary gas transportation imbalances, which must then be cured in kind or cashed out at rates which include a substantial penalty. Atmos and Seminole complain that these types of prior period adjustments can be substantial and that, with the significant increases in the market price of gas, these provisions have become unnecessarily punitive to end-use customers. This is particularly egregious, according to Seminole, because Public Service was solely responsible for the Measurement Error and the transportation customer had no means by which to prevent the Measurement Error. Atmos and Seminole proposed that transportation customers have the option of paying for these corrections at the Company's weighted average cost of gas. In his cross answer testimony, Staff witness Kwan opposed giving transportation customers the election either to make up imbalances created by prior period adjustments in kind or by cashing out the imbalance, thus giving these customers the price transparency opportunity to make a decision based on the lower gas prices. Moreover, Staff disagrees that the imbalance cashout provisions of the Company's gas transportation tariff are punitive.

Resolution. In resolution of this issue, Public Service, Atmos, Seminole and Staff agree to resolve this issue separately as to (1) pending and currently unresolved imbalances resulting from prior period adjustments due to Measurement Errors and (2) those imbalances resulting from such prior period adjustments which occur on and after the effective date of this Stipulation. The agreed to modifications to the gas transportation terms and conditions are reflected in tariff sheet Nos. T1, T3 through T6, T11, T13 through T14, as reflected in S&A Attachment A.

For all pending and currently unresolved imbalances resulting from prior period adjustments (i.e., still within the six-month imbalance make-up period) as of the effective of the Commission's order approving this Stipulation, Public Service, Staff, Atmos and Seminole agree that such imbalance shall be immediately cashed out at an amount equal to the weighted average commodity cost of gas, as has been calculated by the Company for the applicable month. This treatment shall apply immediately to all such prior period adjustment imbalances existing for Atmos's and Seminole's accounts and shall apply to any other Shipper with pending prior period adjustment imbalances that advises Public Service within 20 days of the effective date of the Commission's order approving this Stipulation that it elects such one-time treatment. Any such Shipper shall have the right to opt out of such one-time treatment and to have such imbalances treated as ordinary gas transportation imbalances subject to the Shipper's right to make up the gas in-kind or be cashed out at the standard cashout rates. Public Service shall provide notice to all such other Shippers having pending prior period adjustment imbalances of their right to elect such one-time treatment within three days of the effective date of the Commission's order herein. Public Service shall maintain documentation in order to facilitate Staff's audit on any unresolved imbalance that qualifies for this one-time treatment. Public Service, Staff, Atmos and Seminole clarify that this is not now a reclassification of unresolved imbalances into prior period adjustments and none is contemplated in the future.

Prior period adjustments resulting from the Company's Measurement Errors (as these errors are clarified in the revised language of the tariff) occurring on and after the effective date of this Stipulation shall be resolved by implementing billing adjustments to reflect the sale or purchase, as the case may be, of the additional or reduced quantities at prices based on the higher or the lower of the Colorado Interstate Gas Company Rocky Mountain spot gas price index or the Panhandle Eastern Pipeline Company spot gas price index[13] or the weighted average commodity cost of gas as calculated by the Company for each month of the prior period and in the amounts in which the corrected quantities were applied.

To the extent that the weighted average commodity cost of gas is not defined in the tariff, the Company will clarify the method for such calculation as part of its general gas transportation tariff filing to be filed on or before February 28, 2006, as discussed in Section II.H.3 below. Also in that filing, the Company shall make a proposal as to a reasonable amount of costs, if any, that should be included in the imbalance cashout rates to account for upstream pipeline services.

3. Remaining Issues Concerning Gas Transportation Terms and Conditions

Background. Atmos, Seminole and Staff, through Mr. Kwan, raised several issues concerning the terms and conditions of gas transportation service. Some of the issues raised by Seminole and Atmos are customer-specific and are most appropriately resolved through discussions between the Company's representatives and those of Atmos or Seminole. Mr. Kwan requests that the Commission incorporate by reference testimony that he filed in Docket No. 00P-304G concerning Public Service's practices with regard to the cash out of gas transportation imbalances. Public Service has indicated that it has definite plans to make a filing to propose significant revisions to its gas transportation tariffs, including changes to

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[13] The two indexes are as reported in the table titled "Prices of Spot Gas Delivered to Pipelines," in the first monthly issue of Inside F.E.R.C.'s Gas Market Report published by Platts.

the provisions concerning gas transportation imbalance cashouts, and other changes to comply with the Commission's new Rules Regulating Gas Utilities promulgated in Docket No. 03R-520G.

Resolution. In order to provide a forum in which these and similar types of issues may be resolved, to the extent they cannot otherwise be resolved through informal discussions, Public Service, Staff, Atmos and Seminole agree that, on or before February 28, 2006, Public Service shall file an advice letter proposing changes to its gas transportation terms and conditions which will provide a forum in which Staff's, Atmos' and Seminole's issues concerning the terms and conditions of the Company's gas transportation services may be raised and considered by the Commission. Public Service agrees that parties may raise any issue relating to the Company's gas transportation terms and conditions in that proceeding. Public Service agrees to meet informally with Atmos, Staff and Seminole in advance of such filing in order to advise them of the general nature of changes that Public Service intends to propose in such filing before it is made.

I. Customer Complaints and Issues Related to the Implementation of CRS

Background. Staff witness, Doug Platt, raised issues about a significant rise in billing complaints that Staff categorizes as not compliant with filed tariffs or Commission rules associated with the implementation of CRS, the Company's new billing and customer resource system. In addition, Staff provided evidence of the rise in non-compliant customer complaints relating to the Company's Sync Bill product (formerly One-Bill). EOC/AARP witness Ronald Binz raised concerns about the number of vendor defect reports concerning CRS and the possibility of unwarranted secondary "excess" costs in CRS implementation; he recommended a separate Commission inquiry on the propriety of CRS investment and expense. In their Rebuttal Testimony Company witnesses, Mr. Chamberlain and Mr. Lawless, in response to the concerns of Staff, explained that the Company expected to experience some increase in complaints to the Commission's External Affairs section with the implementation of CRS. As these witnesses testified, the Company put in place various processes to track and address CRS related complaints and began to see a decrease in such complaints, including complaints regarding the Sync Bill product within a year following implementation of the new system. In Rebuttal Testimony directed at the testimony of Mr. Binz of EOC/AARP, Company witness Mr. Lawless stated that, while the CRS project was a very difficult one, the system as implemented was a success. Mr. Lawless also stated that secondary costs associated with the implementation of CRS were of short duration and reasonable.

Resolution. For purposes of settlement and in order to address Staff's concerns, the Company agrees to continue to work closely with the Commission's External Affairs Section to address and resolve informal complaints as completely and quickly as possible consistent with Commission Rules. Staff reserves the right to address these issues of customer complaints at another time in the future and to make any adjustments warranted should these matters not adequately be addressed. EOC/AARP reserve their rights in any future proceeding to question the prudence of the investment and expenses associated with the implementation of the CRS.

J. Miscellaneous Issues

1. Venue Issues

Background. Through the testimony of Staff witness Mr. Kwan, Staff raised the concern that there is some uncertainty where, as between a general rate case proceeding and the gas cost prudence review proceeding, certain issues that affect the Company's GCA rates should be raised by Staff and considered by the Commission. Staff believes the gas cost prudence review proceeding is the venue for determining whether rates were just and reasonable for costs recovered through the GCA. Additionally, Staff is concerned that residential and commercial customers are, by default, responsible for any revenue shortfall relating to costs that flow through the GCA. Staff maintains that the GCA prudence review is akin to a "rate case" (Phase I [revenue requirement] and Phase II [cost allocation, rate design, and tariff issues]) on gas costs. Staff believes that a rate case on LDC delivery costs sets "just and reasonable" rates on a prospective basis and a rate case on the GCA provides a hindsight review on whether rates are "just, reasonable, and/or prudent." Public Service, on the other hand, disputes such a broad view of the scope of a gas cost prudence review. Public Service believes that only those gas costs for which it obtains expedited recovery and which are included for collection in the GCA are subject to review and disallowance by the Commission in a GCA prudence review proceeding. Public Service asserts that this more limited view of the scope is consistent with the Commission's GCA Rules, 4 *Code of Colorado Regulations (CCR)* 723-8, as well as the Commission's Decision No. C03-0618, mailed June 6, 2003, in Docket No. 00P-304G, in which the Commission examined the scope of GCA prudence review proceedings and determined that certain issues raised therein were outside such scope. Nevertheless, the Company agrees that demarcation of proper review for these issues needs to be further clarified by the Commission.

Resolution. Public Service and Staff agree that resolution of this dispute by the Commission is important for the orderly administration of future proceedings before the Commission and is in the public interest. For purposes of resolving this issue, Staff and Public Service agree to file with the Commission, on or before February 6, 2006, a joint petition for a declaratory ruling framing the dispute concerning the proper forum for addressing issues affecting GCA rates, so that the Commission may consider the positions of the parties and issue an order resolving such dispute. Such petition will be served on all Parties and all other Commission-regulated gas utilities in Colorado having GCA mechanisms in their tariffs and shall also be subject to any additional notice requirements imposed by the Commission. Such petition shall also request the establishment of procedures that include the opportunity for Staff, Public Service and any other party that is granted intervention by the Commission to provide simultaneous initial briefs and reply briefs for the Commission's consideration. Public Service and Staff agree that the filing of briefs for the Commission's consideration will satisfy procedural due process requirements and that a full, trial-type hearing and formal taking of evidence is not necessary for the resolution of their dispute, and hereby waive their rights thereto.

2. Issues Raised But Not Expressly Dealt With in this Stipulation

Except as modified in this Stipulation and for the purpose of this settlement, the Parties agree to implementation of the proposals contained in the Company's rate case application as originally filed on May 27, 2005, and as corrected on July 8, 2005, and

Commission approval of this Stipulation shall constitute Commission approval of all such aspects of the rate case application as filed by the Company.

3. <u>No Settled Practice</u>

The Parties agree that this Stipulation and the settlement rates, terms and conditions of service and the cost allocation, rate design and other methods contained in the S&A Attachments including, but not limited to, the Settled Revenue Requirement and the Settled CCOSS, have been agreed to by the Parties solely for purposes of settlement and do not constitute a settled practice or otherwise have precedent-setting value in any future proceedings. 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 Earnings Cap Calculations. 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 Earnings Cap Calculations). Nothing in this Stipulation shall preclude the Company from seeking prospective changes in its natural gas service rates by an appropriate filing with the Commission. Nothing in this Stipulation shall preclude any other party from filing a complaint or seeking an order to show cause to obtain prospective changes in the Company's natural gas service rates and/or provisions in the Company's tariff.

III. TERM OF THIS STIPULATION AND AGREEMENT

This Stipulation shall take effect upon its approval by the Commission. Nothing in this Stipulation shall be construed as precluding the Company from filing a general rate case to change the rates for its natural gas services at any time. Nothing in this Stipulation shall be construed to limit the Company from applying to the Commission for adjustment clauses or for any other change to the Company's gas rates. Nothing in this Stipulation shall be construed to prevent the Staff of the Commission (by seeking an order to show cause) or any other party (by filing of a complaint) from seeking review by the Commission of the justness and reasonableness of the Company's natural gas service rates.

Except as provided in this paragraph, the provisions of this Stipulation shall terminate and have no continuing effect upon the effective date of the revised rates for natural gas services resulting from Public Service's next comprehensive rate case, whether initiated through the Company's filing of a rate case, an order to show cause, or complaint. Where reference is made in the Stipulation to provisions that apply for a period of time (for example, the references to the Earnings Cap in Section II.E above), all such time period provisions of this Stipulation may be modified by a subsequent filing with the Commission or subsequent stipulation approved by the Commission.

IV. EFFECTIVE DATE OF SETTLEMENT RATESAND TERMS AND CONDITIONS OF SERVICE

Subject to implementation of the Stipulation in accordance with Article IV hereof, the rates and terms and conditions of service set forth herein shall go into effect upon the date as directed by order of the Commission. The settlement in this case recognizes that the Company is currently not recovering its cost of service. The Parties agree that the increased rates resulting from this settlement should become effective as early as practicable as ordered by the Commission. Such implementation can be prior to the expiration, on February 6, 2006, of the maximum 210-day suspension period pursuant to the Commission's orders in this proceeding.

V. IMPLEMENTATION

This Stipulation shall not become effective until the issuance of a final Commission Order approving the Stipulation that does not modify the Stipulation in a manner that is unacceptable to any of the Parties. In the event the Commission modifies this Stipulation in a manner unacceptable to any Party, that Party shall have the right to withdraw from this Stipulation 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 Stipulation by e-mail within three business days of the Commission modification that the Party is withdrawing from the Stipulation 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 Stipulation 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 Stipulation. 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 they would have had in the absence of this Stipulation.

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 Stipulation 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 Stipulation shall not be admissible into evidence in this or any other proceeding, except as may be necessary in any proceeding to enforce this Stipulation.

The Parties agree that, upon final Commission approval of this Stipulation, the Company will file an Advice Letter with the Commission, on not less than one day's notice prior to effective date ordered by the Commission, that will include a citation to the order approving the Stipulation, and the settlement rates, terms and conditions and tariff sheets set forth herein in S&A Attachment A. The Parties agree that the Commission's order should direct Public Service to place into effect tariff sheets reflecting the tariff changes that are in all respects identical to the *pro forma* tariff sheets contained in S&A Attachment A hereto, with the exceptions that (i) the GCA rates reflected on Sheets 10A and 11 shall be updated to reflect the then-effective monthly GCA rates as may be approved by the Commission after the filing of this Stipulation and (ii) the effective date of the Commission's order shall be inserted in the tariff sheets where such reference is indicated. The settlement rates, terms and conditions shall then become final rates, terms and conditions to be effective as provided in Article III hereof and shall not be subject to refund, nor shall they be subject to modification except in accordance with the Public Utilities Law and the Commission's Rules and Regulations promulgated there under.

VI. 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 Stipulation reflects compromise and settlement of all issues raised or that could have been raised in this docket. This Stipulation shall be filed as soon as possible with the Commission for Commission approval.

Approval by the Commission of this Stipulation shall constitute a determination that the Stipulation represents a just, equitable and reasonable resolution of issues that were or could have been contested among the parties in this proceeding. The Parties 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 that the results of the compromises and settlements reflected in this Stipulation are in the public interest.

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

The Parties agree to a waiver of compliance with any requirements of the Commission's Rules and Regulations to the extent necessary to permit all provisions of this Stipulation to be carried out and effectuated.

DATED this 20th day of December, 2005.

Respectfully submitted,

PUBLIC SERVICE COMPANY OF COLORADO

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CERTIFICATE OF SERVICE

I hereby certify that on this 20th day of December, 2005, the original and five (5) copies of the foregoing "STIPULATION AND AGREEMENT IN RESOLUTION OF PROCEEDING" was hand-delivered to:

Doug Dean, Director
Colorado Public Utilities Commission
1580 Logan Street, OL-2
Denver, CO 80203

And a copy was e-mailed, hand-delivered or placed in the U.S. mail, postage prepaid, and addressed to:

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Denver, CO 80220

Irene A. Nuñez

NATURAL GAS RATES
RULE 10(f) RATE COMPONENTS

Rate Schedule	Sheet No.	Type of Charge	Billing Units	Rate/Charge	
RG	14	Metering & Billing	--	$10.12	I
		Commodity Costs:			
		Distribution System	Therm	$ 0.08048	R
		Natural Gas cost	Therm	$ 0.87300	
		Interstate Pipeline Cost	Therm	$ 0.06740	
		Total		$ 1.02092	R
CG	16	Metering & Billing	--	$20.23	I
		Commodity Costs:			
		Distribution System	Therm	$ 0.09666	I
		Natural Gas cost	Therm	$ 0.87300	
		Interstate Pipeline Cost	Therm	$ 0.06690	
		Total		$ 1.03651	I
IG	18	Metering & Billing	--	$70.81	R
		On-Peak Demand Cost:			
		Distribution System	DTH	$ 4.71	R
		Natural Gas cost	DTH	$ 0.06	I
		Interstate Pipeline Cost	DTH	$ 2.82	
		Total		$ 7.59	R
		Commodity Costs:			
		Distribution System	DTH	$ 0.5062	I
		Natural Gas cost	DTH	$ 8.7250	
		Interstate Pipeline Cost	DTH	$ 0.4650	
		Total		$ 9.6962	I
		Unauthorized Overrun Cost:			
		For Each Occurrence:			
		Distribution System	DTH	$25.29	I

Note: The above rates and charges are for informational bill presentation purposes only in accordance with Commission Rule 10(f) and include the base rates and charges plus all applicable gas rate adjustments. For billing purposes however, reference should be made to the appropriate rate schedules set forth herein.

PUBLIC SERVICE COMPANY OF COLORADO

COLO. PUC No. 6 Gas

Attachment A

Sheet No. 11

P.O. Box 840
Denver, CO 80201-0840

Cancels
Sheet No.

NATURAL GAS RATES
RATE SCHEDULE SUMMATION SHEET

Rate Schedule	Sheet No.	Type of Charge	Billing Units	Base Rate	Adjustments (Percent) (1)	Gas Cost Adjustment	
RG	14	Service and Facility		$10.00	1.16%	$ --	II
		Volumetric	Therm	0.0796	1.16%	0.9404	TRI
RGL	15	One or Two Mantles per month		$7.18	1.16%	--	II
		Additional Mantle		3.59	1.16%	--	II
		Volumetric	Therm		1.16%	0.9190	TI
CG	16	Service and Facility		$20.00	1.16%	--	II
		Volumetric	Therm	0.0955	1.16%	0.9399	TII
CGL	17	One or Two Mantles per month		$7.18	1.16%	--	II
		Additional Mantle		3.59	1.16%	--	II
		Volumetric	Therm		1.16%	0.9190	TI
IG	18	Service and Facility		$70.00	1.16%	--	RI
		On-Peak Demand Charge	DTH	4.66	1.16%	2.8800	RI
		Volumetric	DTH	0.5004	1.16%	9.1900	TII
		Unauthorized Overrun	DTH	25.00	1.16%	--	I

(1) The Rate Adjustment is the sum of the Demand Side Management Cost Adjustment (DSMCA), the Quality of Service Plan, and any applicable General Rate Schedule Adjustments (GRSA).

ADVICE LETTER NUMBER

ISSUE DATE

DECISION NUMBER

VICE PRESIDENT, Policy Development

EFFECTIVE DATE

NATURAL GAS RATES
RATE SCHEDULE SUMMATION SHEET

Rate Schedule	Sheet No.	Type of Charge	Billing Units	Base Rate	Adjustments (Percent) (1)	Gas Cost Adjustment	
TF	30	Service and Facility	--	$70.00	1.16%	$ --	II
		Firm Capacity Reservation Charge:		--			
		Standard	DTH	4.660	1.16%	--	II
		Minimum	DTH	0.680	1.16%	--	RI
		Volumetric:					T
		Standard	DTH	0.230	1.16%	0.057	RI
		Minimum	DTH	0.010	1.16%	0.057	R
		Authorized Overrun	DTH	0.230	1.16%	0.057	RI
		Unauthorized Overrun					
		Volumetric:					T
		Standard	DTH	25.00	1.16%	0.057	R
		Minimum	DTH	0.230	1.16%	0.057	RI
		Firm Supply Reservation	DTH	0.000	1.16%	2.880	I
		Backup Supply	DTH	0.230	1.16%	(2)	RI
		Authorized Overrun	DTH	0.230	1.16%	(2)	RI
		Unauthorized Overrun					
		Sales:					
		Standard	DTH	25.00	1.16%	--	I
		Minimum	DTH	0.230	1.16%	--	RI

(1) The Rate Adjustment is the sum of the Demand Side Management Cost Adjustment (DSMCA), the Quality of Service Plan, and any applicable General Rate Schedule Adjustments (GRSA).

(2) The Gas Cost Adjustment applicable to this rate is subject to monthly revision as provided for on Sheet No. 50H.

(Continued on Sheet No. 11B)

PUBLIC SERVICE COMPANY OF COLORADO

P.O. Box 840
Denver, CO 80201-0840

NATURAL GAS RATES
RATE SCHEDULE SUMMATION SHEET

Rate Schedule	Sheet No.	Type of Charge	Billing Units	Base Rate	Adjustments (Percent) (1)	Gas Cost Adjustment	
TI	31						D
		Service and Facility Charge		$140.00	1.16%	$ --	RI
		Volumetric:					T
		Standard	DTH	0.398	1.16%	0.057	II
		Minimum	DTH	0.010	1.16%	0.057	I
		Authorized Overrun Transportation	DTH	0.398	1.16%	0.057	II
		Unauthorized Overrun Volumetric:					T
		Standard	DTH	25.00	1.16%	0.057	I
		Minimum	DTH	0.398	1.16%	0.057	II
		On-Peak Demand	DTH	4.66	1.16%	2.880	RI
		Backup Supply	DTH	0.230	1.16%	(2)	RI
		Unauthorized Overrun Sales:					
		Standard	DTH	25.00	1.16%	--	I
		Minimum	DTH	0.230	1.16%	--	RI

(1) The Rate Adjustment is the sum of the Demand Side Management Cost Adjustment (DSMCA), the Quality of Service Plan, and any applicable General Rate Schedule Adjustments (GRSA).

(2) The Gas Cost Adjustment applicable to this rate is subject to Monthly revision as provided for on Sheet No. 50H.

ADVICE LETTER NUMBER ____________ ____________ ISSUE DATE ____________

DECISION NUMBER ____________ VICE PRESIDENT, Policy Development EFFECTIVE DATE ____________

NATURAL GAS RATES | RATE

RESIDENTIAL GAS SERVICE

SCHEDULE RG

APPLICABILITY

Applicable within the entire territory served by Public Service Company of Colorado as described on Sheet Nos. 4-9 to Residential service. Not applicable to resale service.

MONTHLY RATE

Service and Facility Charge, per customer	$10.00	I
Volumetric Charge, all gas used per Therm	$ 0.07956	TR
MONTHLY MINIMUM...	$10.00	I

GAS RATE ADJUSTMENT

This rate schedule is subject to the Gas Rate Adjustments commencing on Sheet No. 40.

GAS COST ADJUSTMENT

This rate schedule is subject to the Gas Cost Adjustment commencing on Sheet No. 50.

PAYMENT

Bills for gas service are due and payable within ten days from date of bill. Residential customers have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of fourteen (14) business days from the scheduled due date. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive months.

CONTRACT PERIOD

All contracts under this schedule shall be for a minimum period of twelve (12) consecutive months and thereafter until terminated, where service is no longer required, on three days' notice.

RULES AND REGULATIONS

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations on file with The Public Utilities Commission of the State of Colorado.

NATURAL GAS RATES | RATE

RESIDENTIAL GAS OUTDOOR LIGHTING SERVICE

SCHEDULE RGL

APPLICABILITY

Applicable within the entire territory served by Public Service Company of Colorado as described on Sheet Nos. 4-9, only to Residential service, customer-owned gas luminaires of the mantle type where the natural gas for such luminaires does not pass through the meter measuring customer's other gas consumption and the luminaire was installed prior to April 1, 1976. Not applicable to resale service.

MONTHLY RATE

Charge for one or two mantle fixture, per fixture.......	$ 7.18	I
Charge for each additional mantle over two mantles, per mantle per fixture...............................	3.59	I

MONTHLY MINIMUM

Minimum charge shall be the billing under this schedule.

GAS RATE ADJUSTMENT

This rate schedule is subject to the Gas Rate Adjustments commencing on Sheet No. 40.

GAS COST ADJUSTMENT

This rate schedule is subject to the Gas Cost Adjustment commencing on Sheet No. 50.

PAYMENT

Bills for gas service are due and payable within ten days from date of bill. Residential customers have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of fourteen (14) business days from the scheduled due date. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive months.

CONTRACT PERIOD

New contracts are not available hereunder. Where existing service is no longer required customer may terminate service on three days' notice.

(Continued on Sheet No. 15A)

PUBLIC SERVICE COMPANY OF COLORADO

P.O. Box 840
Denver, CO 80201-0840

NATURAL GAS RATES

COMMERCIAL GAS SERVICE

SCHEDULE CG

	RATE	
APPLICABILITY Applicable within the entire territory served by Public Service Company of Colorado as described on Sheet Nos. 4-9 to Commercial service. Not applicable to resale service.		
MONTHLY RATE		
Service and Facility Charge, per customer..........	$ 20.00	I
Volumetric Charge, all gas used per Therm...........	0.09555	I
MONTHLY MINIMUM.......................................	$ 20.00	I

GAS RATE ADJUSTMENT

This rate schedule is subject to the Gas Rate Adjustments commencing on Sheet No. 40.

GAS COST ADJUSTMENT

This rate schedule is subject to the Gas Cost Adjustment commencing on Sheet No. 50.

PAYMENT AND LATE PAYMENT CHARGE

Bills for gas service are due and payable within ten days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month.

CONTRACT PERIOD

All contracts under this schedule shall be for a minimum period of thirty days and thereafter until terminated, where service is no longer required, on three days' notice.

NATURAL GAS RATES | RATE

COMMERCIAL GAS OUTDOOR LIGHTING SERVICE

SCHEDULE CGL

APPLICABILITY

Applicable within the entire territory served by Public Service Company of Colorado as described on Sheet Nos. 4-9, only to customer-owned gas luminaries of the mantle type where the natural gas for such luminaries does not pass through the meter measuring customer's other gas consumption and the luminaire was installed prior to April 1, 1976. Said applicability is further limited, after November 4, 1979, for Commercial and Industrial customers and after December 31, 1981, for Municipal customers, to be applicable only to locations for which customer has been granted an exemption, by order of the Public Utilities Commission of the State of Colorado, to the prohibition on use of outdoor gas lighting. Not applicable to resale service.

MONTHLY RATE

Charge for one or two mantle fixture, per fixture.......	$ 7.18	I
Charge for each additional mantle over two mantles, per mantle per fixture..............................	3.59	I

MONTHLY MINIMUM

Minimum charge shall be the billing under this schedule.

GAS RATE ADJUSTMENT

This rate schedule is subject to the Gas Rate Adjustments commencing on Sheet No. 40.

GAS COST ADJUSTMENT

This rate schedule is subject to the Gas Cost Adjustment commencing on Sheet No. 50.

PAYMENT AND LATE PAYMENT CHARGE

Bills for gas service are due and payable within ten days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month.

(Continued on Sheet No. 17A)

NATURAL GAS RATES

RATE

INTERRUPTIBLE INDUSTRIAL GAS SERVICE

SCHEDULE IG

APPLICABILITY

Applicable within the entire territory served by Public Service Company of Colorado as described on Sheet Nos. 4-9, to Industrial service where Company has available a supply of gas in excess of that required for service under higher priority schedules. Not applicable to resale service.

MONTHLY RATE

Service and Facility Charge, per customer...............	$70.00	R
On-Peak Demand Charge, for the maximum Daily On-Peak gas contracted for, per Dth............................	4.66	R
Volumetric Charge, all gas used per Dth..................	0.5004	TI

In calculating bills for gas service, the quantity of gas as registered on the meter shall be adjusted to a quantity based on sixty degrees Fahrenheit (60°F) and at a pressure of six ounces per square inch above average atmospheric pressure.

MONTHLY MINIMUM

The Monthly Minimum will be the Service and Facility Charge plus the On-Peak Demand Charge.

UNAUTHORIZED OVERRUN GAS

If, on any day when curtailment or interruption of gas usage has been ordered by Company, customer fails to curtail or shut off the use of gas when and as directed by Company and/or the total quantity of On-Peak gas taken by customer exceeds the amount contracted for, then all such gas taken after customer is directed by Company to curtail use of gas and until such time customer is authorized by Company to resume full use of gas shall constitute Unauthorized Overrun Gas. Customer shall pay $25.00 per Dth for all such Unauthorized Overrun Gas in addition to the Commodity Charge.

GAS RATE ADJUSTMENT

This rate schedule is subject to the Gas Rate Adjustments commencing on Sheet No. 40.

GAS COST ADJUSTMENT

This rate schedule is subject to the Gas Cost Adjustment commencing on Sheet No. 50.

NATURAL GAS RATES | RATE

FIRM GAS TRANSPORTATION SERVICE

SCHEDULE TF

APPLICABILITY

Applicable to Shippers having acquired by separate agreement, supplies of natural gas (Shipper's Gas) and where Company has available System capacity in excess of that presently required for service to existing firm gas sales Customers and firm Shippers. Service is applicable to firm transportation of Shipper's Gas from Company's Receipt Point(s) to the Delivery Point(s) through Company's System. Service provided hereunder is not available for transportation in interstate commerce and shall be in accordance with the Firm Gas Transportation Service Agreement (Service Agreement) between Company and Shipper, and the requirements of the Firm Gas Transportation Service provisions and the Gas Transportation Terms and Conditions of Company's Gas Transportation Tariff. Firm Capacity and Firm Supply quantities reserved under this rate schedule shall be designated for Receiving Party(s) at specific Delivery Point(s).

MONTHLY RATE - FIRM GAS TRANSPORTATION SERVICE CHARGES		I
Service and Facility Charge per service meter:	$ 70.00	
Firm Capacity Reservation Charge, per Dth.............		I
Standard Rate, per Dth.........................	$ 4.66	R
Minimum Rate, per Dth..........................	$ 0.68	T
Volumetric Charge: Applicable to all of Shipper's gas transported by Company up to Contracted Peak Day Quantity		
Standard Rate, per Dth.........................	0.2300	R
*Minimum Rate, per Dth..........................	0.010	
Authorized Overrun Transportation Charge, per Dth......	0.2300	R
Unauthorized Overrun Transportation Penalty Charge		
Standard Rate, per Dth.........................	$ 25.00	
Minimum Rate, per Dth..........................	0.2300	R

*The minimum Volumetric Charge shall be $.01, excluding the base gas cost, but in no instance will it be less than the variable costs of providing service. T

(Continued on Sheet No. 30A)

NATURAL GAS RATES | RATE

FIRM GAS TRANSPORTATION SERVICE

SCHEDULE TF

MONTHLY RATE - BACKUP SUPPLY SALES SERVICE CHARGES		
Firm Supply Reservation Charge, per Dth................	$ 0.00	
Backup Supply Sales Charge, per Dth...................	0.2300	R
Authorized Overrun Sales Charge, per Dth...............	0.230	R
Unauthorized Overrun Supply Penalty Charge		
Standard Rate, per Dth..........................	25.00	
Minimum Rate, per Dth...........................	0.2300	R

MONTHLY MINIMUM CHARGES

The Monthly Minimum shall be the sum of a) the Service and Facility Charge(s), b) the Firm Capacity Reservation Charge, and c) the Firm Supply Reservation Charge (if applicable). In the event that Company is required to make any payments including but not limited to franchise fees or payments, sales taxes, occupancy taxes or the like, as a result of the transportation service being rendered to Shipper by Company, these charges will be included in billing from Company to Shipper.

GAS RATE ADJUSTMENT

This rate schedule is subject to the Gas Rate Adjustments commencing on Sheet No. 40.

GAS COST ADJUSTMENT

The Transportation Commodity Charge, the Firm Supply Reservation Charge and the Backup Supply Sales Charges are subject to the Gas Cost Adjustment commencing on Sheet No. 50.

FUEL REIMBURSEMENT

Shippers receiving Firm Transportation Service shall include additional gas for Fuel Reimbursement to the quantity of gas delivered to Company. Unless otherwise specified, the fuel reimbursement for Firm Gas Transportation Service is 0.86%. R

CAPACITY INTERRUPTION OF SERVICE

Transportation service in excess of Peak Day Quantity is subject to availability of System capacity in Company's System. Should Company, in its sole judgment, determine that adequate System capacity is unavailable, then Shipper is subject to immediate Capacity Interruption of transportation service for those quantities in excess of Peak Day Quantity.

NATURAL GAS RATES | RATE

INTERRUPTIBLE GAS TRANSPORTATION SERVICE

SCHEDULE TI

APPLICABILITY

Applicable to Shippers having acquired by separate agreement, supplies of natural gas (Shipper's Gas) and where Company has available System capacity in excess of that presently required for service to existing gas sales Customers and Firm Transportation Shippers. Service is applicable to interruptible transportation of Shipper's Gas from Company's Receipt Point(s) to Shipper's Delivery Point(s) through Company's System. Service provided hereunder is not available for transportation in interstate commerce and shall be in accordance with the Interruptible Gas Transportation Service Agreement (Service Agreement) between Company and Shipper, and the requirements of the Interruptible Gas Transportation Service provisions and the Gas Transportation Terms and Conditions of Company's Gas Transportation Tariff.

MONTHLY RATE - INTERRUPTIBLE GAS TRANSPORTATION SERVICE CHARGES

Service and Facility Charge per service meter............	$140.00	R
Volumetric Charge: Applicable to all of Shipper's gas transported by Company up to Contracted Maximum Daily Transportation Quantity		T
Standard Rate, per Dth..........................	0.3980	I
*Minimum Rate, per Dth......................	0.010	
Authorized Overrun Transportation Charge, per Dth......	0.3980	I
Unauthorized Overrun Transportation Penalty Charge		
Standard Rate, per Dth..........................	25.00	
Minimum Rate, per Dth...........................	0.3980	I

*The minimum Volumetric Charge shall be $.01, excluding the base gas cost, but in no instance will it be less than the variable costs of providing service. T

(Continued on Sheet No. 31A)

NATURAL GAS RATES

INTERRUPTIBLE GAS TRANSPORTATION SERVICE

SCHEDULE TI

	RATE	
MONTHLY RATE - BACKUP SUPPLY SALES SERVICE CHARGES		
On-Peak Demand Charge, per Dth........................	$ 4.66	R
Backup Supply Sales Charge, per Dth..................	0.2300	R
Unauthorized Overrun Supply Penalty Charge		
Standard Rate, per Dth.........................	25.00	
Minimum Rate, per Dth..........................	0.2300	R

MONTHLY MINIMUM CHARGES

The Monthly Minimum shall be the sum of the a) the Service and Facility Charge(s), and b) the On-Peak Demand Charge (if applicable).

In the event that Company is required to make any payments including but not limited to franchise fees or payments, sales taxes, occupancy taxes or the like, as a result of the transportation service being rendered to Shipper by Company, these charges will be included in billing from Company to Shipper.

GAS RATE ADJUSTMENT

This rate schedule is subject to the Gas Rate Adjustments commencing on Sheet No. 40.

GAS COST ADJUSTMENT

The Transportation Commodity Charge, the On-Peak Demand Charge and the Backup Supply Sales Charges are subject to the Gas Cost Adjustment commencing on Sheet No. 50.

FUEL REIMBURSEMENT

Shippers receiving Interruptible Transportation Service shall include additional gas for Fuel Reimbursement to the quantity of gas delivered to Company. Unless otherwise specified, the Fuel Reimbursement for Interruptible Transportation Service is 0.86%. R

CAPACITY INTERRUPTION OF SERVICE

Transportation service hereunder is subject to availability of System capacity in Company's System. Should Company, in its sole judgment, determine that adequate System capacity is unavailable, then Shipper is subject to immediate Capacity Interruption of transportation service.

GAS TRANSPORTATION TERMS AND CONDITIONS

INDEX

GAS TRANSPORTATION TERMS AND CONDITIONS

DEFINITION OF TERMS - Cont'd

Firm Supply Reservation Quantity - The maximum daily quantity of sales gas, expressed in Dekatherms, available for purchase from Company on a firm basis, which is contracted by a Shipper to reserve supplies of natural gas in the event that adequate supplies of Shipper's Gas are not available for receipt by Company.

Firm Capacity - The aggregate total of the Peak Day Quantity for all Delivery Point(s) under Shipper's Firm Gas Transportation Service Agreement, expressed in Dekatherms.

Fuel Reimbursement - A quantity of gas, equal to a percentage of the quantity of Shipper's Gas delivered to Company, to compensate Company for fuel required for transportation service hereunder.

Imbalance - The difference between the quantity of Shipper's Gas allocated by the Interconnecting Party(s) at the Receipt Point(s) less Fuel Reimbursement and the quantity of gas delivered to the Receiving Party at the Delivery Point(s) for Shipper's account as determined by Company. In the event supplies of Shipper's Gas are not available for receipt by Company but Shipper is authorized and has nominated to receive Backup Supply Sales Gas, the quantity of such gas received from Company shall be subtracted from the quantity of gas consumed by the Receiving Party at the Delivery Point(s) before the existence of an Imbalance is determined.

Imbalance Resolution Gas - The quantity of gas necessary to correct previous months' cumulative Imbalance between Company and Shipper.

Interconnecting Party(s) - The operator of the facilities immediately upstream of the point of interconnection between the facilities of the Company and the pipeline, residue plant, or wellhead Receipt Points.

Master Agreement - Gas Transportation Service Agreement providing for delivery to one or more Receiving Parties which are not the Shipper.

Maximum Daily Transportation Quantity - (MDTQ) is the maximum daily quantity of gas expressed in Dekatherms which Company agrees to transport to Shipper as set forth on an Exhibit to the Interruptible Service Agreement.

Measurement Error - An error caused by a defect or malfunction in a gas measurement device or an unintentional human error in the retrieval, entry, processing, calculation, posting or transcribing of volumetric data, resulting in the communication by Company of an incorrect quantity of gas delivered to a Receiving Party. Measurement Error does not include errors in measurement due to a communication line failure. N

GAS TRANSPORTATION TERMS AND CONDITIONS

Month - The period beginning at 8:00 a.m. Mountain Standard Time on any day of a calendar month and ending at 8:00 a.m. Mountain Standard Time on the same day of the succeeding calendar month, or such other consecutive monthly period designated by Company. S

Nomination Entry Error - An unintentional error in Company's manual entry or the confirmation of Shipper's receipt point quantity nomination. N

Nominations - The Quantity of gas supplies requested to be transported on the Company's System for a specific day. Nominations are to be adjusted to include Fuel Reimbursement and shall be made on a Dekatherm basis. S

DEFINITION OF TERMS

Operational Area - Regional areas of Company's system consisting of pipeline facilities that receive and deliver gas which is regularly comingled and interchanged with other gas supplies received and delivered in that operational area. Currently, the Company's Operational Areas are Front Range, Denver/Pueblo, Southern, Western, and Sterling. Receiving Parties under a Gas Transportation Service Agreement shall be grouped under a specific Operational Areas based on their location.

Operational Flow Order (OFO) - An order issued for a specific Gas Day(s) and designated Operational Area by Company to alleviate conditions which threaten or could threaten the safe operation or integrity of Transporter's system or to maintain operations required to provide efficient and reliable firm service under the following circumstances: a) when delivery system pressure or other unusual conditions are reasonably expected, in Company's judgment, to jeopardize the operation of the Company's system; b) when transmission, storage, or supply resources are being used at or near maximum deliverability; c) when one or more upstream pipelines call an operational flow order and such operational flow order creates conditions on Company's system which necessitate calling an Operational Flow Order; and d) when Company is unable to fulfill its firm service obligations or to maintain overall operational integrity of the system. When issued, the Operational Flow Order shall specify the Tolerance Range of over or underdelivery permitted for the Gas Day(s).

Peak Day Quantity (PDQ) - The maximum daily quantity of gas expressed in Dekatherms which Company agrees to deliver for Shipper at each delivery point as set forth on an Exhibit to the Firm Gas Transportation Service Agreement. The Peak Day Quantity shall be established at a level intended to represent no less than the Receiving Party's actual daily usage at each Delivery Point.

Primary Receipt Point(s) - Receipt Point(s) specified in the Firm Gas Transportation Service Agreement as Primary Receipt Point(s) where Receiving Party is entitled to firm service on Company's System. Primary Receipt Point(s) will be identified in an Exhibit to the Service Agreement.

GAS TRANSPORTATION TERMS AND CONDITIONS

DEFINITION OF TERMS - Cont'd

Prior Period Adjustment - A retroactive revision in the gas usage quantity reported by Company necessitating a correction of Company's billing for gas transportation service to Shipper for a period of more than one month, as the result of a Measurement Error. N

Psia - Pressure in pounds per share inch absolute. S

Receipt Point(s) - The point of interconnection between the facilities of the Company and the Interconnecting Party(s) wherein the Company receives gas for the account of Shipper for transportation on its System, as specified on an Exhibit to the Service Agreement. S

Receiving Party(s) - The party or parties that receive gas from Company at the Delivery Point(s) as specified in an Exhibit to the Service Agreement. S

Request for Gas Transportation Service - A written request for transportation service submitted by any prospective Shipper as provided in these Gas Transportation Terms and Conditions.

Secondary Receipt Point(s) - Receipt Point(s) which are not specified in the Firm Transportation Service Agreement as Primary Receipt Point(s). Subject to prior approval of Company, Shipper may request, pending approval by Company, to shift firm capacity from Primary Receipt Point(s) to Secondary Receipt Point(s) for the period of time designated by Company. Shipper forfeits the equal amount of capacity at the primary receipt point that was shifted from primary receipt point to secondary receipt point(s) for the period of time designated by Company.

Shipper - Any party who has executed a Service Agreement with Company. Shipper may be the Receiving Party, or may be the holder of a Master Agreement acting on behalf of one or more Receiving Parties.

Supply Curtailment - The discontinuance of transportation or Backup Supply Sales Service as a result of the inability of Company to provide such service due to non-receipt of Shipper's Gas or the lack of availability of Company's gas supply, respectively. The phrase "Supply Curtailment" shall have the same meaning as "Curtailment."

System - The pipelines, compressor stations, regulator stations, meters, gas processing facilities and other related facilities owned by Company and utilized in providing transportation service.

Tolerance Range - The quantity or percentage of the total transportation quantity specified in an Operational Flow Order that can be under or over delivered to an Operational Area by a Shipper under a Service Agreement, during the period of an Operational Flow Order without incurring penalty(s).

GAS TRANSPORTATION TERMS AND CONDITIONS

Year - A period of 365 consecutive days or 366 consecutive days if such period includes February 29, unless otherwise specified. S

CONDITIONS OF GAS TRANSPORTATION SERVICE

Pressure at Delivery Point(s) - Unless otherwise agreed upon, Company shall cause the gas to be delivered at each Delivery Point at such pressures as may prevail from time to time in Company's System.

Pressure at Receipt Point(s) - Shipper shall deliver or cause gas to be delivered at each Receipt Point at a pressure sufficient to allow the gas to enter Company's System. Shipper shall not, except by mutual written agreement, be required or permitted to deliver the gas at any Receipt Point at a pressure in excess of the maximum allowable operating pressure of Company's System as established by the Company.

Prior to commencement of service hereunder, Shipper shall have completed a Request for Gas Transportation Service and shall have executed a Service Agreement.

Requests for Transportation Service.

(a) Shipper shall submit to Company a fully completed Request for Gas Transportation Service. The request will either be approved or denied by Company within thirty (30) days of the receipt thereof. If Company provides notice that additional facilities are required as a condition for approval, Company will specifically set forth the estimated cost of said facilities and any additional charges. The written notice of approval shall also set forth the cost, if any, of conversion from sales service. If denied, written notification will be provided to Shipper detailing the reasons for denial, as well as an explanation of what changes would be necessary to make the Request for Gas Transportation Service acceptable.

(b) All requests for Transportation Service shall be submitted in writing to Company in the form included in these Gas Transportation Terms and Conditions or a facsimile thereof;

(c) Company shall endeavor to provide service within the time specified in the written request, but shall not be obligated to do so. Requests shall be considered received only if the information specified in the Request for Transportation Service is provided.

Gas Transportation Service Agreement (Service Agreement).
Upon Company approval of Request for Gas Transportation, Company shall tender Shipper a Service Agreement in accordance with this gas transportation tariff.

GAS TRANSPORTATION TERMS AND CONDITIONS

IMBALANCE PROVISION

Shipper shall make every effort to manage daily receipts of Shipper's Gas and deliveries to the Receiving Party(s) so that the Imbalance(s) at the end of each Month, including any Imbalance(s) under the five (5) Dth quantity limitation carried forward from the previous Month, are as close to zero as practicable. Determination of such Imbalance(s) will be made after adjusting for Fuel Reimbursement.

If at the end of any Month the imbalance is in excess of twenty-five percent T
(25%), except to the extent such excess was caused by a Measurement Error or T
Nomination Entry Error, then the imbalance will be cashed out effective on the last T
day of such month to zero percent (0%) when the Shipper is billed by Company for the month in which the imbalance occurred. Shipper's exceeding the twenty-five percent (25%) imbalance threshold are prohibited from decreasing the amount of the imbalance by swapping imbalances, or nominating imbalance payback gas during the succeeding month.

Shippers having imbalances which are 25% or less at the end of any Month shall endeavor to bring such imbalance to zero percent of actual usage within the
subsequent billing period. If at the end of the subsequent billing period the T
Imbalance is greater than two percent (2%), then Shipper shall be subject to the Over and Under-Delivery provisions of this tariff ("Cashout") and the Imbalance shall be brought to two percent (2%). Any Imbalance remaining after said Cashout shall be added to the current Month's Imbalance and carried forward into the following Month.

Company may enter into separate Imbalance Agreements with Shipper that take into consideration, special unique circumstances.

Imbalance Trading. A Shipper may trade or "swap" Imbalance Gas between its own Service Agreements as well as with another Shipper to eliminate or reduce its own Imbalances or the Imbalances of both Shippers. Any "swap" of Imbalance shall not cause the Company to receive less value than the Company would have received had the "swap" not occurred. Any Imbalance "swap" shall be subject to the following conditions:

a. Shippers are responsible for making whatever arrangements they deem necessary to finalize and document the Imbalance "swap" among themselves.
b. Shippers may post notice of Imbalances available for "swap" on Company's Electronic Bulletin Board.
c. Shippers may request the Company, in writing, to post notice of Imbalances available for "swap" on Company's Electronic Bulletin Board for the Shipper.
d. Only "swaps" which have the effect of reducing individual Agreement Imbalances shall be permitted.
e. Shipper must notify Company in writing of the material terms of the "swap" arrangement. Shippers' written notice will be deemed to be the Shipper's direction to Company to make the Imbalance "swap" on the Shipper's account.

GAS TRANSPORTATION TERMS AND CONDITIONS T

OVER-DELIVERIES OF SHIPPER'S GAS SUPPLIES

In the event the quantity of gas delivered to the Shipper or Receiving Party(s), as determined by the Company at the Delivery Point(s) is less than the quantity allocated by the Interconnecting Party(s), adjusted for Fuel Reimbursement at the end of the subsequent billing period, by more than two percent (2%), including any Imbalance from the prior monthly billing period, except to the extent T such excess was caused by a Measurement Error or Nomination Entry Error, then T Company will correct the Imbalance to two percent (2%) of Shipper's prior month deliveries by purchasing from the Shipper the difference between a) Receiving Party(s)' deliveries and b) the quantity allocated by Interconnecting Party(s) adjusted for Fuel Reimbursement. These purchases shall be made at a rate equal to seventy-five percent (75%) of the lesser of the CIG Rocky Mountain spot gas price index or the Panhandle Eastern Pipeline Company spot gas price index as reported in the table titled "Prices of Spot Gas Delivered to Pipelines," in the first monthly issue of Inside F.E.R.C.'s Gas Market Report published by Platts, or the weighted T average commodity cost of gas as calculated by the Company for the Month in which the Imbalance was created. These purchases shall be applied as a credit on the Shipper's succeeding monthly statement. These purchases shall not be made by Company if the imbalance quantities aggregated for each Operational Area under the Service Agreement are five (5) Dth or less. An imbalance created by a Prior Period T Adjustment shall be cashed out immediately pursuant to the section below entitled T Imbalances Due to Prior Period Adjustment. T

UNDER-DELIVERIES OF SHIPPER'S GAS SUPPLIES

In the event the quantity of gas delivered to the Shipper or Receiving Party(s), as determined by the Company at the Delivery Point(s) is greater than the quantity allocated by Interconnecting Party(s), adjusted for Fuel Reimbursement at the end of the subsequent monthly billing period, by more than two percent (2%), including any Imbalance from the prior monthly billing period, except to the extent T such excess was caused by a Measurement Error or Nomination Entry Error, then T Company shall correct the Imbalance to two percent (2%) of Shipper's prior month deliveries by selling to the Shipper, the difference between a) Receiving Party(s)' deliveries and b) the quantity allocated by Interconnecting Party(s) adjusted for Fuel Reimbursement. The rate and terms for such sales shall be a rate equal to one hundred twenty-five percent (125%) of the greater of the CIG Rocky Mountain spot gas price index or the Panhandle Eastern Pipeline Company spot gas price index as reported in the table titled "Prices of Spot Gas Delivered to Pipelines", in the first monthly issue of Inside F.E.R.C.'s Gas Market Report published by Platts, or T the weighted average commodity cost of gas as calculated by the Company for the month in which the Imbalance was created, plus the maximum rate for interruptible transportation service under Rate Schedule TI of Colorado Interstate Gas Company's then-effective FERC gas tariff plus all applicable surcharges. These sales shall not be made by Company if the imbalance quantities aggregated for each Operational Area under the Service Agreement are five (5) Dth or less. An imbalance created by a Prior Period Adjustment T shall be cashed out immediately pursuant to the section below T entitled Imbalance Due to Prior Period Adjustment. T

GAS TRANSPORTATION TERMS AND CONDITIONS N

IMBALANCE DUE TO PRIOR PERIOD ADJUSTMENT

An imbalance created by a Prior Period Adjustment occurring on and after ***[enter the effective date of the Commission's order approving the Stipulation and Agreement in Docket No. 05S-264G]*** that reflects an over delivery of Shipper's gas shall be immediately purchased by Company at an amount equal to the difference between the quantities upon which Company's previous billings were based and the corrected quantities for each month affected by the Measurement Error, not to exceed 24 months, multiplied by a rate equal to the lesser of (1) the Colorado Interstate Gas Company Rocky Mountain spot gas price index or (2) the Panhandle Eastern Pipeline Company spot gas price index, as such indexes are reported in the table titled "Prices of Spot Gas Delivered to Pipelines," in the first monthly issue of Inside F.E.R.C.'s Gas Market Report published by Platts, or (3) the weighted average commodity cost of gas as calculated by the Company for the Months in which the corresponding Imbalance was created.

An imbalance created by a Prior Period Adjustment occurring on and after ***[enter the effective date of the Commission's order approving the Stipulation and Agreement in Docket No. 05S-264G]*** that reflects an under delivery of Shipper's gas shall be immediately sold by Company at an amount equal to the difference between the quantities upon which Company's previous billings were based and the corrected quantities for each month affected by the Measurement Error, not to exceed 24 months, multiplied by a rate equal to the greater of (1) the Colorado Interstate Gas Company Rocky Mountain spot gas price index or (2) the Panhandle Eastern Pipeline Company spot gas price index, as such indexes are reported in the table titled "Prices of Spot Gas Delivered to Pipelines," in the first monthly issue of Inside F.E.R.C.'s Gas Market Report published by Platts for the applicable Month, or (3) the weighted average commodity cost of gas as calculated by the Company for the Months in which the corresponding Imbalance was created.

For all unresolved imbalances caused by Prior Period Adjustments and existing on ***[enter the effective date of the Commission's order approving the Stipulation and Agreement in Docket No. 05S-264G]***, such imbalance shall be immediately cashed out at an amount equal to the difference between the quantities upon which Company's previous billings were based and the corrected quantities for each month affected by the Measurement Error, not to exceed 24 months, multiplied by a rate equal to the weighted average commodity cost of gas as calculated by the Company for the Month which the corresponding Imbalance was created. The foregoing provision shall apply to all such Prior Period Adjustment imbalances existing as of ***[enter the effective date of the Commission's order approving the Stipulation and Agreement in Docket No. 05S-264G]***, unless Shipper has made a one-time election within 20 days thereof, in accordance with the procedures adopted by the Colorado Public Utilities Commission in Docket No. 05S-264G, to opt out of such immediate cash out transaction and instead to make up such Prior Period Adjustment imbalance in kind.

GAS TRANSPORTATION TERMS AND CONDITIONS N

Prior Period Adjustments shall be calculated by Company for the entire period during which the Measurement Error occurred, but not more than 24 months. If the Prior Period Adjustment results in an amount due Shipper by Company, Company shall credit the full amount of such Prior Period Adjustment on Shipper's next monthly bill. If the Prior Period Adjustment results in an amount due Company by Shipper, Company shall include such additional amount on Shipper's next monthly bill. Company will allow Shipper an amount of time equal to the period during which the Measurement Error occurred to remit the Prior period Adjustment amount, but in no event shall this period be longer than six (6) months. The Company and Shipper may, at Shipper's option, enter into an installment plan arrangement.

GAS TRANSPORTATION TERMS AND CONDITIONS

BALANCING UPON TERMINATION

Upon termination or cancellation of the Service Agreement, if transportation service is not continued under another Service Agreement, any under-deliveries shall be eliminated at the earliest practicable date, not to exceed thirty (30) days following such termination or cancellation. If at the end of the thirty (30) day period an under-delivery exists, then, as appropriate, Company shall sell to Shipper such quantities which are due Shipper and Shipper shall purchase from Company such quantities in accordance with the terms and conditions of the under-deliveries of Shipper's Gas Supplies section of this tariff. If the Imbalance is caused by an over-delivery of Shipper's Gas then Company shall eliminate any over-deliveries by purchasing any quantities which are due Shipper at the next billing cycle in accordance with the terms and conditions of over-deliveries of Shipper's Gas Supplies section of this tariff.

If Service Agreement is terminated and service continues under another Service Agreement, the Imbalance may upon Shipper's request be transferred to new Service Agreement and the Imbalance Provisions shall apply. D

FAILURE OF SHIPPER'S SUPPLY

Should Shipper fail to cause Shipper's Gas to be supplied to Company for transportation, Shipper will immediately notify Company of this condition. If Shipper has not contracted for Firm Supply Reservation Service, then, upon request, Company will inform Shipper if Backup Supply Sales Service is available from Company. If Company informs Shipper that said Backup Supply Sales Service is not available, continued use of gas by Receiving Party shall be considered Unauthorized Overrun Penalty Service.

SUPPLY CURTAILMENTS

Company will, within a reasonable time, confirm with Interconnecting Party(s) an Interconnecting Party(s)'s Supply Curtailment of a Shipper's Gas supplies. If a Shipper's Gas supplies are curtailed, Company will accept, until 8:00 a.m. CCT the morning of such gas Day, revised Nominations that conform with the receipt quantities confirmed by the Company from the curtailed Interconnecting Party(s). The Company will also allow resourcing of curtailed quantities from existing or new Receipt Point(s), provided the revised Nomination is submitted no later than 8:00 a.m. CCT the morning of such gas Day. Shipper is responsible to notify the Interconnecting Party(s) to make corresponding confirmations of supply to Company no later than 11:30 a.m. CCT the morning of such gas Day.

Public Service Company of Colorado **S&A Attachment B**
Settlement Issue Revenue Requirement Impact
Docket No. 05S-264G

Line No.		Issue Impact	Cummulative Revenue Requirement
1	Original Filing		34,545,332
2			
3	Settlement Issues:		
4	Capital Structure (55.49% Equity & 6.44% Cost of Debt)	(665,248)	33,880,084
5	Weather Normalization	(1,790,048)	32,090,036
6	PIM limit to $735,000	(2,047,906)	30,042,130
7	ROE 10.5%	(4,328,307)	25,713,823
8	Average Rate Base	(3,131,114)	22,582,709
9	Actual Rate Case Expenses to Date	(45,678)	22,537,031
10	AGA Dues	(44,038)	22,492,993
11			
12	Final Settled Revenue Requirement		22,492,993

Public Service Company of Colorado
Calculation of Revenue Deficiency / Excess
At December 31, 2004

S&A Attachment C
Corresponds to Exhibit TLW-1
Schedule 1

Line No.	Description	Gas
1	Net CPUC Jurisdictional Rate Base (1)	1,004,185,107
2		
3	Allowed Return on Rate Base (2)	8.70%
4		
5	Required Earnings	87,364,104
6		
7	Net CPUC Jurisdictional Operating Earnings (3)	73,473,362
8		
9	Deficiency / (Excess)	13,890,742
10		
11	Gross-up	1.619279486
12		
13	Revenue Increase / (Decrease)	22,492,993

(1) Schedule 3, page 3.
(2) Schedule 2.
(3) Schedule 4, page 7

Public Service Company of Colorado
Gas Department Cost of Capital
At December 31, 2004

S&A Attachment C
Corresponds to Exhibit TLW-1
Schedule 2

Line No.	Description	Per Books	(1) Pro Forma Adjustments	Adjusted Capital	Ratio
1	Long Term Debt	2,272,750,000	(250,211,030)	2,022,538,970	44.51%
2					
3	Common Equity	2,374,648,524	147,184,668	2,521,833,192	55.49%
4					
5	Total	4,647,398,524	(103,026,362)	4,544,372,162	100.00%
6					
7					
8					
9					
10		**Ratio**			
11					
12	Long Term Debt	44.51%	6.44%	2.87%	
13					
14	Common Equity	55.49%	10.50%	5.83%	
15					
16	Total	100.00%		8.70%	

(1) - Adjustments:

Long Term Debt:	
Replace Maturing Bonds with Equity	(244,500,000)
Notes Payable to Subsidiaries	(5,711,030)
Total Long Term Debt	(250,211,030)
Common Equity:	
Eliminate Net Non-Utility Plant	(77,522,429)
Eliminate Investment in Subsidiary Companies:	(62,713,592)
Replace Maturing Bonds with Equity	244,500,000
Eliminate Unappropriated Retained Earnings of NCI	71,820,573
Eliminate Other Investments at Cost	(1,687)
Eliminate Other Funds	(28,898,197)
Total Common Equity	147,184,668

Public Service Company of Colorado
Gas Department - Rate Base
At December 31, 2004

S A Attachment C
Corresponds to Exhibit No. TLW-1
Schedule 3

Line No.	Description	Account	Total Gas	Adjustments	Adjusted Total Gas	Allocator	Specific Assignments FERC	Specific Assignments CPUC	Adjusted Total FERC	Adjusted Total CPUC
1	**Intangible Plant:**									
2	Organization Expense	1301	6,734	0	6,734	PIS-SUBT			6	6,728
3	Franchises and Consents	1302	208,024	0	208,024	PIS-SUBT			193	207,831
4	Misc. Intangible Plant - Software	1303.2	7,738,255	0	7,738,255	PIS-SUBT			7,186	7,731,069
5	**Total Intangible Plant**		7,953,013	0	7,953,013				7,385	7,945,628
6										
7	**Production & Gathering Plant:**									
8	Producing Lands	1325.1	0	0	0	P&GDMD			0	0
9	Rights of Way	1325.4	66,194	0	66,194	P&GDMD			2	66,192
10	Field Compressor Station Structures	1327	17,168	0	17,168	P&GDMD			0	17,168
11	Field Meas. & Reg Station Structures	1328	154,124	0	154,124	P&GDMD			4	154,120
12	Other Structures	1329	8,799	0	8,799	P&GDMD			0	8,799
13	Field Lines	1332	3,813,055	0	3,813,055	P&GDMD			97	3,812,958
14	Field Compressor Station Equipment	1333	248,249	0	248,249	P&GDMD			6	248,243
15	Field Meas. & Reg Station Equipment	1334	1,630,648	0	1,630,648	P&GDMD			42	1,630,606
16	Other Equipment	1337	0	0	0	P&GDMD			0	0
17	**Total Production & Gathering Plant**		5,938,237	0	5,938,237				151	5,938,086
18										
19	**Products Extraction Plant:**									
20	Land Owned in Fee	1340.1	49,449	0	49,449	PEDMD			1	49,448
21	Structures & Improvements	1341	604,117	0	604,117	PEDMD			15	604,102
22	Extraction & Refining Equipment	1342	4,265,993	0	4,265,993	PEDMD			109	4,265,884
23	Pipe Lines	1343	4,871	0	4,871	PEDMD			0	4,871
24	Extracted Products Storage Equipment	1344	294,078	0	294,078	PEDMD			8	294,070
25	Compressor Station Equipment	1345	290,017	0	290,017	PEDMD			7	290,010
26	Gas Measuring & Regulating Equipment	1346	17,733	0	17,733	PEDMD			0	17,733
27	**Total Products Extraction Plant**		5,526,258	0	5,526,258				140	5,526,118
28										
29	**Underground Storage:**									
30	Land Owned in Fee	1350.1	985,100	0	985,100	USDMD			499	984,601
31	Land Rights	1350.4	157,336	0	157,336	USDMD			80	157,256
32	Structures & Improvements	1351	3,748,997	0	3,748,997	USDMD			1,900	3,747,097
33	Storage, Leaseholds and Rights	1352.1	494,910	0	494,910	USDMD			251	494,659
34	Reservoirs	1352.2	16,245,368	0	16,245,368	USDMD			8,231	16,237,137
35	Non-Recoverable Natural Gas	1352.3	300,614	0	300,614	USDMD			152	300,462
36	Lines	1353	4,229,694	0	4,229,694	USDMD			2,143	4,227,551
37	Compressor Station Equipment	1354	12,856,966	0	12,856,966	USDMD			8,514	12,850,452
38	Measuring & Regulating Equipment	1355	822,648	0	822,648	USDMD			417	822,231
39	Purification Equipment	1356	1,013,856	0	1,013,856	USDMD			514	1,013,342
40	Other Equipment	1357	209,613	0	209,813	USDMD			106	209,507
41	**Total Underground Storage**		41,065,102	0	41,065,102				20,807	41,044,295
42										
43	**Transmission Plant:**									
44	Land Owned in Fee	1365.1	947,064	0	947,064	TRDMD			4,778	942,286
45	Right of Way	1365.2	10,763,626	0	10,763,626	TRDMD			54,301	10,709,325
46	Structures & Improvements	1366	12,681,574	0	12,681,574	TRDMD			63,977	12,617,597
47	Other Structures	1366.3	183,491	0	183,491	TRDMD			926	182,565
48	Mains	1367	162,607,240	0	162,607,240	TRDMD			820,330	161,786,910
49	Compressor Station Equipment	1368	65,035,949	0	65,035,949	TRDMD			328,097	64,707,852
50	Measuring & Regulating Equipment	1369	25,835,812	0	25,835,812	TRDMD			130,338	25,705,474
51	Communication Equipment	1370	1,868,660	0	1,868,660	TRDMD			9,427	1,859,233
52	**Total Transmission Plant**		279,923,416	0	279,923,416				1,412,174	278,511,242
53										
54	**Distribution Plant:**									
55	Land Owned in Fee	1374.1	372,760	0	372,760	DRDMD			0	372,760
56	Land Rights	1374.2	4,100,567	0	4,100,567	DRDMD			0	4,100,567
57	Structures & Improvements	1375	2,475,085	0	2,475,085	DRDMD			0	2,475,085
58	Mains	1376	545,723,002	0	545,723,002	DRDMD			0	545,723,002
59	Compressor Station Equipment	1377	841,163	0	841,163	DRDMD			0	841,163
60	Meas. & Reg. Station Equipment-General	1378	12,238,344	0	12,238,344	DRDMD			0	12,238,344
61	Meas. & Reg. Station Equipment-City Gate	1379	3,741,919	0	3,741,919	DRDMD			0	3,741,919
62	Services	1380	375,194,503	0	375,194,503	DRDMD			0	375,194,503
63	Meters	1381	101,562,561	0	101,562,561	DRDMD			0	101,562,561
64	Automated Meter Reading	1381.2	43,277,623	0	43,277,623	DRDMD			0	43,277,623
65	Meter Installations	1382	94,130,858	0	94,130,658	DRDMD			0	94,130,658
66	House Regulators	1383	27,247,526	0	27,247,526	DRDMD			0	27,247,526
67	Other Equipment	1387	46,158	0	46,158	DRDMD			0	46,158
68	**Total Distribution Plant:**		1,210,951,869	0	1,210,951,869				0	1,210,951,869

Public Service Company of Colorado
Gas Department - Rate Base
At December 31, 2004

Line No.	Description	Account	Total Gas	Adjustments	Adjusted Total Gas	Allocator	Specific Assignments FERC	Specific Assignments CPUC	Adjusted Total FERC	Adjusted Total CPUC
1	**General Plant:**									
2	Land Owned in Fee	1389.1	182,944	0	182,944	PIS-SUBT			170	182,774
3	Land Rights	1389.2	2,762	0	2,762	PIS-SUBT			3	2,759
4	Structures & Improvements	1390	531,484	0	531,484	PIS-SUBT			494	530,990
5	Buildings	1390B	1,838,991	0	1,838,991	PIS-SUBT			1,708	1,837,283
6	Partitions	1390P	5,385	0	5,385	PIS-SUBT			5	5,380
7	Remodeling	1390.1	44,103	0	44,103	PIS-SUBT			41	44,062
8	Office Furniture & Equipment	1391	1,855,980	0	1,855,980	PIS-SUBT			1,724	1,854,256
9	Partitions in Leased Buildings	1391P	1,236,897	0	1,236,897	PIS-SUBT			1,149	1,235,748
10	Office Equip. Info. System Computers	1391.2	44,755	0	44,755	PIS-SUBT			42	44,713
11	Transportation Equipment	1392	3,183,982	0	3,183,982	PIS-SUBT			2,957	3,181,025
12	Stores Equipment	1393	10,555	0	10,555	PIS-SUBT			10	10,545
13	Tools, Shop and Garage Equipment	1394	5,303,236	0	5,303,236	PIS-SUBT			4,925	5,298,311
14	Laboratory Equipment	1395	1,274,224	0	1,274,224	PIS-SUBT			1,183	1,273,041
15	Transportation Equipment	1396	445,473	0	445,473	PIS-SUBT			414	445,059
16	Communication Equipment	1397	173,717	0	173,717	PIS-SUBT			161	173,556
17	Miscellaneous Equipment	1398	115,279	0	115,279	PIS-SUBT			107	115,172
18	**Total General Plant**		16,249,767	0	16,249,767				15,093	16,234,674
19										
20	**Gas Stored Underground**	0117	8,435,152	0	8,435,152	USDMD			4,274	8,430,676
21										
22	**Total**		1,576,042,614	0	1,576,042,814				1,460,024	1,574,582,790
23										
24	**Common Plant Allocated**		151,821,923	0	151,621,923	PIS-SUBT			140,988	151,680,935
25										
26	**Total Gas Plant in Service**		1,727,864,737	0	1,727,864,737				1,601,012	1,726,263,725
27										
28	**Reserve for Depreciation and Amortization:**									
29	Production and Gathering		5,070,459	0	5,070,459	PIS-P&G			129	5,070,330
30	Products Extraction		1,723,174	0	1,723,174	PIS-PE			44	1,723,130
31	Underground Storage		30,208,616	0	30,208,616	PIS-US			15,306	30,193,310
32	Transmission		112,830,327	0	112,830,327	PIS-TR			569,213	112,261,114
33	Distribution		427,097,633	0	427,097,633	PIS-DR			0	427,097,633
34	General		5,236,504	0	5,236,504	PIS-GEN			4,864	5,231,640
35	Common		89,693,992	0	89,693,992	PIS-CMN			83,293	89,610,699
36	**Total Reserve for Depreciation and Amortization**		671,860,705	0	671,860,705				672,849	671,187,856
37										
38	**Net Plant In Service:**									
39	Production and Gathering		867,778	0	867,778				22	867,756
40	Products Extraction		3,803,084	0	3,803,084				96	3,802,988
41	Underground Storage		19,291,638	0	19,291,638				9,775	19,281,863
42	Transmission		167,093,089	0	167,093,089				842,961	166,250,126
43	Distribution		783,854,236	0	783,854,236				0	783,854,236
44	General		18,966,276	0	18,966,276				17,614	18,948,662
45	Common		62,127,931	0	62,127,931				57,695	62,070,236
46	**Total Net Plant in Service**		1,056,004,032	0	1,056,004,032				928,163	1,055,075,869
47										
48	**Plant Held for Future Use:**									
49	Production and Gathering				0	P&GDMD			0	0
50	Products Extraction				0	PEDMD			0	0
51	Underground Storage				0	USDMD			0	0
52	Transmission		1,105,413		1,105,413	TRDMD			5,577	1,099,836
53	Distribution				0	DRDMD			0	0
54	Common and General				0	PIS-SUBT			0	0
55	**Total Plant Held for Future Use**		1,105,413	0	1,105,413				5,577	1,099,836
56										
57	**Construction Work In Progress:**									
58	Intangible		314	0	314	P&GDMD			0	314
59	Production and Gathering		(145,904)	0	(145,904)	P&GDMD			(4)	(145,900)
60	Products Extraction		75,757	0	75,757	PEDMD			2	75,755
61	Underground Storage		1,282,010	0	1,282,010	USDMD			650	1,281,360
62	Transmission		4,126,262	0	4,126,262	TRDMD			20,816	4,105,446
63	Distribution		16,134,432	(504,987)	15,629,445	DRDMD			0	15,629,445
64	General		3,587,816	0	3,587,816	PIS-SUBT			3,332	3,584,484
65	Common		18,261,034	0	18,261,034	PIS-SUBT			16,958	18,244,076
66	**Total Construction Work in Progress**		43,321,721	(504,987)	42,816,734				41,754	42,774,980
67										
68	**Total Plant**		1,100,431,166	(504,987)	1,099,926,179				975,494	1,098,950,685

Public Service Company of Colorado
Gas Department - Rate Base
At December 31, 2004

S A Attachment C
Corresponds to Exhibit No. TLW-1
Schedule 3

Line No.	Description	Account	Total Gas	Adjustments	Adjusted Total Gas	Allocator	Specific Assignments FERC	Specific Assignments CPUC	Adjusted Total FERC	Adjusted Total CPUC
1	**Utility Materials and Supplies**		5,408,674	(1,120,136)	4,288,538	PIS-SUBT			3,983	4,284,555
2	**Gas Stored Underground Average Balance**		97,563,267	0	97,563,267	CPUC			0	97,563,267
3	**Cash Working Capital - Direct:**									
4	Gas Costs:									
5	Expense		781,271,635		781,271,635	CPUC			0	781,271,635
6	Factor		0.007699		0.007699				0.007699	0.007699
7	Gas Costs Working Capital Amount		6,015,010	0	6,015,010				0	6,015,010
8										
9	O&M Expense:									
10	Expense		119,500,212		119,624,077				122,005	119,502,072
11	Factor		0.008672		0.008656				0.008656	0.008656
12	Working Capital Amount		1,036,306	(840)	1,035,466				1,056	1,034,410
13										
14	Taxes Other than Income:									
15	Expense		20,848,643		20,682,046				18,620	20,663,426
16	Factor		(0.591434)		(0.590515)				(0.590515)	(0.590515)
17	Taxes Other than Income Working Capital Amount		(12,330,596)	117,538	(12,213,058)				(10,995)	(12,202,063)
18										
19	Federal Income Tax:									
20	Expense		(5,636,921)		2,912,662				234,669	2,677,993
21	Factor		0.020932		0.020932				0.020932	0.020932
22	Federal Income Tax Working Capital Amount		(117,992)	178,960	60,968				4,912	56,056
23										
24	State Income Tax:									
25	Expense		(517,219)		404,009				32,550	371,459
26	Factor		(0.184959)		(0.184959)				(0.184959)	(0.184959)
27	State Income Tax Working Capital Amount		95,664	(170,389)	(74,725)				(6,020)	(68,705)
28										
29	Franchise Tax:									
30	Expense		22,872,979		22,872,979	CPUC			0	22,872,979
31	Factor		0.031890		0.031890				0.031890	0.031890
32	Franchise Tax Working Capital Amount		729,419	0	729,419				0	729,419
33										
34	Sales Tax:									
35	Expense		36,688,148		36,688,148	CPUC			0	36,688,148
36	Factor		0.019918		0.019918				0.019918	0.019918
37	Sales Tax Working Capital Amount		730,755	0	730,755				0	730,755
38										
39	**Total Cash Working Capital - Direct**		(3,841,434)	125,269	(3,716,165)				(11,047)	(3,705,118)
40										
41	**Cash Working Capital - Service Company Charges:**									
42	O&M Expense:									
43	Expense		48,597,441		48,597,441	EXP-SUBT			49,565	48,547,876
44	Factor		0.033834		0.033834				0.033834	0.033834
45	Total O&M Expense		1,644,246	0	1,644,246				1,677	1,642,569
46										
47	**Total Cash Working Capital - Service Company Charges**		1,644,246		1,644,246				1,677	1,642,569
48										
49	**Regulatory Asset**		0		0	PIS-TOT			0	0
50	**Prepaid Assets**		25,601,204	0	25,601,204	EXP-SUBT			26,111	25,575,093
51	**Accumulated Deferred Income Taxes:**									
52	Accelerated Amortization Property - Gas		0		0	N/A			0	0
53	1/2 Pre - 1971 ITC		0	0	0	PIS-NET			0	0
54	Interest on CWIP		0	(197,407)	(197,407)	PIS-NET			(174)	(197,233)
55	Account 190		69,918,095	(4,543,916)	65,374,179	PIS-NET			57,460	65,318,719
56	Account 282		(187,212,371)	148,722	(187,063,649)	PIS-NET			(164,418)	(186,899,231)
57	Account 283		(13,706,825)	(8,523,448)	(22,230,273)	PIS-NET			(19,539)	(22,210,734)
58	**Total Accumulated Deferred Income Taxes**		(131,001,101)	(13,116,049)	(144,117,149)				(126,671)	(143,990,478)
59	**Lease Accruals**		0		0	N/A			0	0
60	**Customer Deposits**		(10,347,826)	0	(10,347,826)	CPUC			0	(10,347,826)
61	**Customer Advances for Construction**		(65,787,639)	0	(65,787,639)	CPUC			0	(65,787,639)
62										
63	**Net Original Cost Rate Base**		1,019,670,557	(14,615,903)	1,005,054,654				869,547	1,004,185,107

Public Service Company of Colorado
Gas Department - Net Operating Earnings
12 Months Ended December 31, 2004

Line No.	Description	Account	Labor	Non-Labor	Total Gas	Adjustments	Adjusted Total Gas	Allocator	Specific Assignments FERC	Specific Assignments CPUC	Adjusted Total FERC	Adjusted Total CPUC
1	**Rate Revenue:**											
2	Billed	480-489		1,074,450,461	1,074,450,461	(794,435,067)	280,015,394	CPUC	950,040		950,040	279,065,355
3	Unbilled	480-489		1,492,778	1,492,778	(1,492,778)	0	N/A			0	0
4	**Total Rate Revenue**		0	1,075,943,239	1,075,943,239	(795,927,845)	280,015,394		950,040	0	950,040	279,065,355
5												
6	**Other Revenue:**											
7	Late Payment Revenue			1,477,494	1,477,494	(15,131)	1,462,363	CPUC			0	1,462,363
8	Miscellaneous Service Revenue			1,790,235	1,790,235	133,735	1,923,970	TOTREV			1,744	1,922,226
9	Miscellaneous Service Refunds			0	0		0	N/A			0	0
10	Rent from Electric Property			48,748	48,748	31,287	80,035	PIS-NET			70	79,965
11	Product Extraction Gas			961,046	961,046	116,056	1,077,102	PECOMM			109	1,076,993
12	Other Gas Revenue			1,129,732	1,129,732	(376,793)	752,939	TOTREV			683	752,256
13	**Total Other Revenue**		0	5,407,255	5,407,255	(110,846)	5,296,409		0	0	2,606	5,293,803
14												
15	**Total Revenue**		0	1,081,350,494	1,081,350,494	(796,038,691)	285,311,803		950,040	0	952,646	284,359,158
16												
17	**Gas Purchased for Resale:**											
18	Natural Gas Wellhead Purchases	0800	0	0	0	0	0	N/A			0	0
19	Natural Gas Gasoline Plant Outlet Purchases	0802	0	727,462,971	727,482,971	(727,462,971)	0	N/A			0	0
20	Natural Gas Transmission Line Purchases	0803	0	97,482,219	97,482,219	(97,462,219)	0	N/A			0	0
21	Purchased Gas Cost Adjustment	0805	0	7,759,563	7,759,563	(7,759,563)	0	N/A			0	0
22	Exchange Gas	0806	0	(269,168)	(269,168)	269,168	0	N/A			0	0
23	Well Expenses - Purchased Gas	0807	280,187	23,209,430	23,489,617	(23,489,617)	0	N/A			0	0
24	Gas Delivered/Withdrawn from Storage	0808	0	(65,612,429)	(65,612,429)	65,612,429	0	N/A			0	0
25	Gas Used for Products Extraction	0811	0	(1,281,575)	(1,281,575)	1,281,575	0	N/A			0	0
26	**Total Gas Purchased for Resale**		280,187	788,751,011	789,031,198	(789,031,198)	0				0	0
27												
28	**Other Gas Supply:**											
29	Gas Transmission - GRI	0803	0	250,952	250,952		250,952	CPUC			0	250,952
30		0807	0	0	0		0	CPUC			0	0
31	Gas Used for Compressor Station Fuel	0810	0	(3,211,858)	(3,211,858)		(3,211,858)	CPUC			0	(3,211,858)
32	Gas Used for Other Utility Operations	0812	0	(188,956)	(188,956)		(188,956)	CPUC			0	(188,956)
33	Other Gas Supply Expense	0813	161	2,882	3,043		3,043	CPUC			0	3,043
34	**Total Other Gas Supply**		161	(3,146,980)	(3,146,819)	0	(3,146,819)				0	(3,146,819)

Public Service Company of Colorado
Gas Department - Net Operating Earnings
12 Months Ended December 31, 2004

Line No.	Description	Account	Labor	Non-Labor	Total Gas	Adjustments	Adjusted Total Gas	Allocator	Specific Assignments FERC	Specific Assignments CPUC	Adjusted Total FERC	Adjusted Total CPUC
1	**Underground Storage Operations:**											
2	Operations Supervision & Engineering	0814	122,620	52,587	175,207		175,207	PIS-TOT			162	175,045
3	Maps & Records	0815	0	0	0		0	PIS-TOT			0	0
4	Wells	0816	41,484	16,072	57,556		57,556	PIS-US			29	57,527
5	Lines	0817	11,238	1,074	12,312		12,312	PIS-US			6	12,306
6	Compressor Station	0818	122,957	24,301	147,258		147,258	PIS-US			75	147,183
7	Compressor Station Fuel	0819	0	837	837		837	PIS-US			0	837
8	Reg Station	0820	3,390	615	4,005		4,005	PIS-US			2	4,003
9	Purification	0821	17,921	864	18,785		18,785	PIS-US			10	18,775
10	Other	0824	69,016	192,110	261,126		261,126	PIS-US			132	260,994
11	Storage Royalty	0825	180	152,126	152,306		152,306	USCOMM			226	152,080
12	Rents	0826	0	62,084	62,084		62,084	PIS-TOT			58	62,026
13	**Total Underground Storage Operations**		388,806	502,670	891,476	0	891,476				700	890,776
14												
15	**Underground Storage Maintenance:**											
16	Maintenance Supervision & Engineering	0830	0	0	0		0	PIS-TOT			0	0
17	Maintenance of Structures and Improvements	0831	0	768	768		768	PIS-US			0	768
18	Maintenance of Reservoirs and Wells	0832	37,701	6,895	44,596		44,596	PIS-US			23	44,573
19	Maintenance of Lines	0833	989	701	1,690		1,690	PIS-US			1	1,689
20	Maintenance of Compressor Station Equipment	0834	42,006	10,986	52,992		52,992	PIS-US			27	52,965
21	Maintenance of Meas. and Reg Station Equipment	0835	3,787	12,701	16,488		16,488	PIS-US			8	16,480
22	Maintenance of Purification Equipment	0836	9,048	0	9,048		9,048	PIS-US			5	9,043
23	Maintenance of Compressor Equipment	0843	0	(23)	(23)		(23)	PIS-US			0	(23)
24	**Total Underground Storage Maintenance**		93,531	32,028	125,559	0	125,559				64	125,495
25												
26	**Total Underground Storage**		482,337	534,698	1,017,035	0	1,017,035				764	1,016,271
27												
28	**Production Operations:**											
29		0735	0	70,000	70,000		70,000	PIS-P&G			2	69,998
30		0750	0	0	0		0	N/A			0	0
31		0751	0	0	0		0	N/A			0	0
32	Field Lines Expense	0753	8,033	3,700	11,733		11,733	PIS-P&G			0	11,733
33	Field Compressor Station Fuel and Power	0755	0	0	0		0	P&GCOMM			0	0
34	Other Expenses	0759	121,106	60,727	181,833		181,833	PIS-P&G			5	181,828
35	Rents	0760	0	10,705	10,705		10,705	N/A			0	10,705
36					0		0	N/A			0	0
37	**Total Production Operations**		129,139	145,132	274,271	0	274,271				7	274,264
38												
39	**Production Maintenance:**											
40	Maintenance of Structures and Improvements	0762	0	0	0		0	N/A			0	0
41	Maintenance of Field Lines	0764	0	464	464		464	PIS-P&G			0	464
42	Maintenance of Field Compressor Station Equipment	0765	0	0	0		0	N/A			0	0
43	**Total Production Maintenance**		0	464	464	0	464				0	464
44												
45	**Total Production Expense**		129,139	145,596	274,735	0	274,735				7	274,728

Line No.	Description	Account	Labor	Non-Labor	Total Gas	Adjustments	Adjusted Total Gas	Allocator	Specific Assignments FERC	Specific Assignments CPUC	Adjusted Total FERC	Adjusted Total CPUC
1	**Products Extraction Operations:**											
2	Operations Supervision & Engineering	0770	0	7,158	7,158		7,158	PIS-PE			0	7,158
3	Operation Labor	0771	0	0	0		0	PIS-PE			0	0
4	Gas Shrinkage	0772	0	1,025,470	1,025,470		1,025,470	PIS-PE			26	1,025,444
5	Fuel	0773	0	256,104	256,104		256,104	PIS-PE			6	256,098
6	Materials	0775	0	0	0		0	PIS-PE			0	0
7	**Total Products Extraction Operations:**		0	1,288,732	1,288,732	0	1,288,732				32	1,288,700
8												
9	**Products Extraction Maintenance:**											
10		0783	0	7,974	7,974		7,974	PIS-PE			0	7,974
11	Maintenance Supervision & Engineering	0784	144	0	144		144	PIS-PE			0	144
12	Maintenance of Extraction & Refining Equipment	0786	83,428	23,154	106,582		106,582	PIS-PE			3	106,579
13	Maintenance of Pipe Lines	0787	0	0	0		0	PIS-PE			0	0
14	Maintenance of Other Equipment - Gas Extraction	0791	0	0	0		0	PIS-PE			0	0
15	**Total Products Extraction Maintenance:**		83,572	31,128	114,700	0	114,700				3	114,697
16												
17	**Total Products Extraction Expense**		83,572	1,319,860	1,403,432	0	1,403,432				35	1,403,397
18												
19												
20	**Total Production O&M**		975,396	787,604,185	788,579,581	(789,031,198)	(451,617)				806	(452,423)
21												
22	**Transmission Operations:**											
23	Operations Supervision & Engineering	0850	120,203	632,391	752,594	0	752,594	PIS-TR			3,797	748,797
24	System Control & Load Dispatching	0851	787,758	57,861	845,619	0	845,619	PIS-TR			4,266	841,353
25	Communication System Expenses	0852	0	0	0	0	0	PIS-TR			0	0
26	Compressor Station Labor & Expenses	0853	490,315	564,884	1,055,199	0	1,055,199	PIS-TR			5,323	1,049,876
27	Gas for Compressor Station Fuel	0854	0	2,750,851	2,750,851	0	2,750,851	TRCOMM			31,665	2,719,186
28	Mains Expenses	0856	1,318,057	1,095,173	2,413,230	735,000	3,148,230	PIS-TR			15,882	3,132,348
29	Measuring & Regulating Station Expenses	0857	304,484	373,672	678,156	0	678,156	PIS-TR			3,421	674,735
30		0858	0	0	0	0	0	PIS-TR			0	0
31	Other Expenses	0859	528,169	41,541	569,710	0	569,710	PIS-TR			2,874	566,836
32	Rents	0860	0	1,179,892	1,179,892	(822,095)	357,797	PIS-TR			1,805	355,992
33	**Total Transmission Operations**		3,548,986	6,696,265	10,245,251	(87,095)	10,158,156				69,033	10,089,123
34												
35	**Transmission Maintenance:**											
36	Maintenance Supervision & Engineering	0861	0	79,877	79,877	0	79,877	PIS-TR			403	79,474
37	Maintenance of Mains	0863	250,661	360,587	611,248	0	611,248	PIS-TR			3,084	608,164
38	Maintenance of Compressor Station Equipment	0864	323,399	304,080	627,479	0	627,479	PIS-TR			3,166	624,313
39	Maintenance of Meas. and Reg Station Equipment	0865	94,416	82,729	177,145	(1,593)	175,552	PIS-TR			886	174,666
40	Maintenance of Communication Equipment	0866	198,121	50,505	248,626	0	248,626	PIS-TR			1,254	247,372
41	Maintenance of Other Equipment	0867	0	0	0	0	0	PIS-TR			0	0
42	**Total Transmission Maintenance**		866,597	877,778	1,744,375	(1,593)	1,742,782				8,793	1,733,989
43												
44	**Total Transmission O&M**		4,415,583	7,574,043	11,989,626	(88,688)	11,900,938				77,826	11,823,112

Public Service Company of Colorado
Gas Department - Net Operating Earnings
12 Months Ended December 31, 2004

S A Attachment C
Corresponds to Exhibit No. TLW-1
Schedule 4

Line No.	Description	Account	Labor	Non-Labor	Total Gas	Adjustments	Adjusted Total Gas	Allocator	Specific Assignments FERC	Specific Assignments CPUC	Adjusted Total FERC	Adjusted Total CPUC
1	**Distribution Operations:**											
2	Operations Supervision & Engineering	0870	1,937,858	155,018	2,092,876	0	2,092,876	PIS-DR			0	2,092,876
3	Distribution Load Dispatching	0871	493,789	112,296	606,085	0	606,085	PIS-DR			0	606,085
4	Compressor Station Labor and Expenses	0872	0	0	0	0	0	PIS-DR			0	0
5	Compressor Station Fuel and Power	0873	0	0	0	0	0	PIS-DR			0	0
6	Mains and Services Expenses	0874	1,568,835	5,394,346	6,963,181	0	6,963,181	PIS-DR			0	6,963,181
7	Measuring & Reg. Station Expenses-General	0875	972,137	84,928	1,057,065	0	1,057,065	PIS-DR			0	1,057,085
8	Measuring & Reg. Station Expenses-Industrial	0876	0	81,111	81,111	0	81,111	PIS-DR			0	81,111
9	Measuring & Reg. Station Expenses-City Gate Chk	0877	0	135,184	135,184	0	135,184	PIS-DR			0	135,184
10	Meter and House Regulator Expenses	0878	2,127,204	(3,436,077)	(1,308,873)	0	(1,308,873)	PIS-DR			0	(1,308,873)
11	Customer Installation Expenses	0879	2,730,819	(203,371)	2,527,448	0	2,527,448	PIS-DR			0	2,527,448
12	Other Expenses	0880	4,152,377	4,800,648	8,953,025	0	8,953,025	PIS-DR			0	8,953,025
13	Rents	0881	0	1,906,156	1,906,156	0	1,906,156	PIS-DR			0	1,906,156
14	**Total Distribution Operations**		13,983,019	9,030,239	23,013,258	0	23,013,258				0	23,013,258
15												
16	**Distribution Maintenance:**											
17	Maintenance Supervision & Engineering	0885	218,353	369,281	587,634		587,634	PIS-DR			0	587,634
18	Maintenance of Structures and Improvements	0886	0	0	0		0	PIS-DR			0	0
19	Maintenance of Mains	0887	1,603,718	219,757	1,823,475		1,823,475	PIS-DR			0	1,823,475
20	Maintenance of Compressor Station Equipment	0888	0	0	0		0	PIS-DR			0	0
21	Maintenance of Meas. and Reg Station Equipment	0889	244,732	81,644	326,376		326,376	PIS-DR			0	326,376
22	Maintenance of Meas. and Reg Station Equip-City Gate	0891	109	12	121		121	PIS-DR			0	121
23	Maintenance of Services	0892	1,569,498	353,038	1,922,536		1,922,536	PIS-DR			0	1,922,536
24	Maintenance of Meters & House Regulators	0893	2,904,758	1,384,803	4,269,561		4,269,561	PIS-DR			0	4,269,561
25	Maintenance of Other Equipment	0894	0	0	0		0	PIS-DR			0	0
26	**Total Distribution Maintenance**		6,541,168	2,388,535	8,929,703	0	8,929,703				0	8,929,703
27												
28	**Total Distribution O&M**		20,524,187	11,418,774	31,942,961	0	31,942,961				0	31,942,961
29												
30	**Customer Accounting:**											
31	Supervision	0901	50,368	9,842	60,210	0	60,210	BILLS			3	60,207
32	Meter Reading Expenses	0902	2,949,268	2,000,427	4,949,695	0	4,949,695	CPUC			0	4,949,695
33	Customer Records & Collection Expenses	0903	8,711,349	13,117,177	21,828,526	0	21,828,526	BILLS			991	21,827,535
34	Uncollectible Accounts	0904	0	4,099,506	4,099,506	0	4,099,506	BILLS			186	4,099,320
35	Miscellaneous Customer Accounts Expense	0905	0	369,969	369,969	0	369,969	BILLS			17	369,952
36	Customer Deposit Interest Expense	GDEPINT				165,565	165,565	CPUC			0	165,565
37	**Total Customer Accounting**		11,710,985	19,596,921	31,307,906	165,565	31,473,471				1,197	31,472,274
38												
39	**Customer Service:**											
40	Supervision	0907	0	0	0	0	0	BILLS			0	0
41	Customer Assistance Expenses	0908	1,919,198	2,795,991	4,715,189	(2,022,469)	2,692,720	BILLS			122	2,692,598
42	Informational & Instructional Advertising Expenses	0909	0	275,155	275,155	28,572	301,727	BILLS			14	301,713
43	Miscellaneous Customer Service & Informational Expense	0910	0	0	0	0	0	BILLS			0	0
44	**Total Customer Service**		1,919,198	3,071,146	4,990,344	(1,995,897)	2,994,447				136	2,994,311
45												
46	**Sales Expense:**											
47	Supervision	0911	0	0	0		0	BILLS			0	0
48	Demonstration & Selling Expenses	0912	407,538	161,989	569,527		569,527	BILLS			26	569,501
49	Miscellaneous Sales Expenses	0916	0	0	0		0	BILLS			0	0
50	**Total Sales Expense**		407,538	161,989	569,527	0	569,527				26	569,501
51												
52	**Total Customer Operations**		14,037,721	22,830,056	36,867,777	(1,830,332)	35,037,445				1,359	35,036,086

Public Service Company of Colorado
Gas Department - Net Operating Earnings
12 Months Ended December 31, 2004

Line No.	Description	Account	Labor	Non-Labor	Total Gas	Adjustments	Adjusted Total Gas	Allocator	Specific Assignments FERC	Specific Assignments CPUC	Adjusted Total FERC	Adjusted Total CPUC
1	**Administrative & General:**											
2	Administrative & General Salaries	0920	7,542,360	0	7,542,360	0	7,542,360	EXP-SUBT			7,693	7,534,667
3	Office Supplies and Expenses	0921	0	6,850,451	8,850,451	(49,668)	6,800,783	EXP-SUBT			6,936	6,793,847
4	Administrative Expenses Transferred - Credit	0922	0	(1,563,070)	(1,563,070)	97,721	(1,465,349)	EXP-SUBT			(1,495)	(1,463,854)
5	Outside Services Employed	0923	0	3,288,779	3,288,779	0	3,288,779	EXP-SUBT			3,354	3,285,425
6	Property Insurance	0924	0	906,072	906,072	0	906,072	EXP-SUBT			924	905,148
7	Injuries and Damages	0925	627,325	1,559,334	2,186,659	0	2,186,659	EXP-SUBT			2,230	2,184,429
8	Employee Pensions and Benefits	0926	16,451,298	0	16,451,298	2,297,432	18,748,730	EXP-SUBT			19,122	18,729,608
9	Regulatory Commission Expense	0928	0	1,765,196	1,765,196	494,418	2,259,614	EXP-SUBT			2,305	2,257,309
10	Duplicate Charges - Credit - Company Use	0929	0	(563,972)	(563,972)	0	(563,972)	EXP-SUBT			(575)	(563,397)
11	General Advertising Expense	0930	0	1,268,083	1,268,083	(797,018)	471,065	EXP-SUBT			480	470,585
12	Rents	0931	0	970,873	970,673	0	970,673	EXP-SUBT			990	969,683
13	Building Maintenance	0935	0	48,936	48,936	0	48,936	EXP-SUBT			50	48,886
14	**Total Administrative & General**		24,620,983	14,530,482	39,151,465	2,042,885	41,194,350				42,014	41,152,338
15												
16	**Total O&M**		64,573,870	843,957,540	908,531,410	(788,907,333)	119,624,077				122,005	119,502,072
17												
18	**Depreciation & Amortization Expense:**											
19	Production				78,307	1,559,275	1,637,582	PIS-P&G			42	1,637,540
20	Products Extraction				144,257		144,257	PIS-PE			4	144,253
21	Underground Storage				1,411,978	1,204,716	2,616,694	PIS-US			1,326	2,615,368
22	Transmission				4,072,738		4,072,738	PIS-TR			20,546	4,052,192
23	Distribution				29,235,359	0	29,235,359	PIS-DR			0	29,235,359
24	General				816,556	0	816,556	PIS-GEN			758	815,798
25	Common				9,001,149	677,836	9,678,985	PIS-CMN			8,988	9,669,997
26	**Total Depreciation & Amortization Expense**				44,760,344	3,441,827	48,202,171				31,664	48,170,507
27												
28	**Taxes Other Than Income:**											
29	Property Taxes				17,715,037	(186,597)	17,548,440	PIS-NET			15,424	17,533,016
30	Payroll Taxes				3,110,849		3,110,649	EXP-SUBT			3,173	3,107,476
31	Other Taxes				22,957		22,957	EXP-SUBT			23	22,934
32					0		0					
33	**Total Taxes Other Than Income**				20,848,643	(186,597)	20,682,046				18,620	20,663,428

Public Service Company of Colorado
Gas Department - Net Operating Earnings
12 Months Ended December 31, 2004

S A Attachment C
Corresponds to Exhibit No. TLW-1
Schedule 4
Page 6 of 7

Line No.	Description	Account	Labor	Non-Labor	Total Gas	Adjustments	Adjusted Total Gas	Allocator	Specific Assignments FERC	Specific Assignments CPUC	Adjusted Total FERC	Adjusted Total CPUC
1	**Income Tax Expense:**											
2												
3												
4	Earnings Before Interest						96,803,510				780,357	96,023,153
5												
6	Rate Base						1,005,054,654				869,547	1,004,185,107
7	Cost of Debt						2.87%				2.87%	2.87%
8	Interest Expense						28,845,030				24,956	28,820,074
9												
10	**Taxable Additions/Deductions:**											
11	Plant Related - Account 190						(13,074,068)	PIS-NET			(11,491)	(13,062,577)
12	Plant Related - Account 281						0	PIS-NET			0	0
13	Plant Related - Account 282						(77,607,847)	PIS-NET			(68,213)	(77,539,634)
14	Plant Related - Account 28						(1,362,064)	PIS-NET			(1,197)	(1,360,867)
15	Plant Related - Perm & Flowthrough						(1,425,297)	PIS-NET			(1,253)	(1,424,044)
16	Bad Debts						890,080	PIS-NET			782	869,298
17	Inventory Reserve						(471,777)	PIS-NET			(415)	(471,362)
18	Environmental Remediation						1,710,116	PIS-NET			1,503	1,708,613
19	Executive Incentive Plans						(289,901)	LABOR			(217)	(289,684)
20	Litigation Reserve						1,609,256	LABOR			1,206	1,608,050
21	Vacation Liability Accrual						250,118	LABOR			187	249,931
22	Customer Adv - Construction						29,326,829	PIS-NET			25,776	29,301,053
23	Deferred Compensation Plan Reserve						(24,854)	LABOR			(19)	(24,835)
24	Pension Expense						(307,116)	LABOR			(230)	(306,886)
25	Post Employment Benefits - FAS 106 (OPEB)						984,876	LABOR			738	984,138
26	Post Employment Benefits - FAS 112						108,540	LABOR			81	108,459
27	Book Unamort. Cost of Reacquired Debt						437,278	PIS-NET			384	436,894
28	Meal & Entertainment						13,252	LABOR			10	13,242
29												
30	**Total Additions/Deductions**						(59,232,579)				(52,368)	(59,180,211)

Line No.	Description	Account	Labor	Non-Labor	Total Gas	Adjustments	Adjusted Total Gas	Allocator	Specific Assignments FERC	Specific Assignments CPUC	Adjusted Total FERC	Adjusted Total CPUC
1	State Taxable Amount						8,725,901				703,033	6,022,868
2	State Income Tax Rate						4.63%				4.63%	4.63%
3	State Income Tax Amount				(517,219)	921,228	404,009				32,550	371,459
4												
5	Federal Taxable Amount						8,321,892				670,483	7,651,409
6	Federal Income Tax Rate						35.00%				35.00%	35.00%
7	Federal Income Tax Amount				(5,636,921)	8,549,583	2,912,662				234,669	2,677,993
8												
9	Deferred Income Taxes:											
10	Depreciation Related				38,469,308	(2,011,364)	36,457,943	DEPREXP			23,949	36,433,994
11	Labor Related				(124,983)	(3,180,825)	(3,305,807)	LABOR			(2,478)	(3,303,329)
12	Other				(12,713,350)	2,068,360	(10,644,990)	PIS-NET			(9,356)	(10,635,634)
13	Interest on CWIP				0	197,407	197,407	CWIP			193	197,214
14	Total Deferred Income Taxes				25,630,975	(2,926,422)	22,704,553				12,308	22,692,245
15												
16	ITC - Generated				0		0					
17	ITC - Amortized				(770,754)		(770,754)	PIS-NET			(677)	(770,077)
18												
19	**Total Income Tax Expense**				18,706,081	6,544,389	25,250,470	67,203,079			278,850	24,971,620
20												
21	**Gain on Disp. of Allowances**				0		0	(477,334)	(1,255,810)			
22	**Gain/Loss on Utility Plant**			849,735	849,735		849,735	PIS-NET			747	848,988
23												
24	**Total Operating Deductions**				991,996,743	(779,087,714)	212,909,028				450,392	212,458,636
25												
26	**Net Operating Earnings**				89,353,751	(16,950,976)	72,402,775				502,254	71,900,521
27												
28	**AFUDC Addition**				2,074,720	(500,344)	1,574,376	CWIP			1,535	1,572,841
29												
30	**Total Deductions**				989,922,023		211,334,652				448,857	210,885,795
31												
32												
33	**Net Operating Earnings**				91,428,471	(17,451,320)	73,977,151				503,789	73,473,362

Public Service Company of Colorado
Details of Adjustments - Gas
12 Months Ended December 31, 2004

Line No.	Description	Account	Labor	Non-Labor	Total	Reference
1	Plant in Service					
2						
3	Intangible Plant:					
4						
5	Total Intangible Plant				0	
6						
7	Production & Gathering Plant:					
8						
9	Total Production & Gathering Plant				0	
10						
11	Products Extraction Plant:					
12						
13	Total Products Extraction Plant				0	
14						
15	Underground Storage:					
16						
17	Total Underground Storage				0	
18						
19	Transmission Plant:					
20						
21	Total Transmission Plant				0	
22						
23	Distribution Plant:					
24						
25	Total Distribution Plant:				0	
26						
27	General Plant:					
28						
29	Total General Plant				0	
30						
31	Common:					
32						
33	Total Common				0	
34						
35	Gas Stored Underground:					
36						
37	Total Gas Stored Underground				0	
38						
39	Total Plant in Service				0	
40						

Line No.	Description	Account	Labor	Non-Labor	Total	Reference
1	Accumulated Reserve for Depreciation and Amortization					
2						
3	Production & Gathering Plant:					
4						
5	Total Production & Gathering Plant				0	
6						
7	Products Extraction Plant:					
8						
9	Total Products Extraction Plant				0	
10						
11	Underground Storage:					
12						
13	Total Underground Storage				0	
14						
15	Transmission Plant:					
16						
17	Total Transmission Plant				0	
18						
19	Distribution Plant:					
20						
21	Total Distribution Plant:				0	
22						
23						
24	General:					
25						
26	Total General				0	
27						
28	Common:					
29						
30	Total Common				0	
31						
32	Total Accumulated Reserve for Depreciation and Amortization				0	
33						
34	Construction Work in Progress					
35						
36	Production & Gathering Plant:					
37						
38	Total Production & Gathering Plant				0	
39						
40	Products Extraction Plant:					
41						
42	Total Products Extraction Plant				0	
43						
44	Underground Storage:					
45						
46	Total Underground Storage				0	
47						
48	Transmission Plant:					
49						
50	Total Transmission Plant				0	
51						
52	Distribution Plant:					
53	Eliminate Contractor's Retentions				(504,987)	Schedule 9
54	Total Distribution Plant				(504,987)	

Line No.	Description	Account	Labor	Non-Labor	Total	Reference
1	General Plant:					
2						
3	Total General				0	
4						
5	Common:					
6						
7	Total Common				0	
8						
9	Total Construction Work in Progress				(504,987)	
10						
11	Total Plant				(504,987)	
12						
13	Materials and Supplies:					
14	Capitalized Materials and Supplies				(1,120,136)	Schedule 6
15	Total Materials and Supplies				(1,120,136)	
16						
17	Gas Stored Underground:					
18						
19	Total Gas Stored Underground		0	0	0	
20						
21	Cash Working Capital				125,269	Schedule 10
22						
23	Prepaid Assets:					
24						
25	Total Prepaid Assets				0	
26						
27	Accumulated Deferred Income Taxes					
28	1/2 Pre - 1971 ITC				0	
29	Interest on CWIP				(197,407)	Schedule 11
30						
31	Account 190:					
32	Eliminate Unbilled Revenue				(5,482,421)	
33	Eliminate Demand Side Management				1,458,212	
34	Eliminate FAS 109				(519,707)	
35	Total Account 190				(4,543,916)	
36						
37	Account 282:					
38	Eliminate FAS 109				148,722	Schedule 11
39						
40	Total Account 282				148,722	
41						
42	Account 283:					
43	Eliminate Deferred Costs				1,698,386	Schedule 11
44	Eliminate Unbilled Revenues				(10,609,696)	
45	Eliminate DSM				387,863	Schedule 11
46	Total Account 283				(8,523,448)	
47						
48	Total Accumulated Deferred Income Taxes				(13,116,049)	
49						
50	Customer Deposits:					
51						
52	Total Customer Deposits				0	
53						
54	Customer Advances for Construction:					
55						
56	Total Customer Advances for Construction				0	
57						
58	Total Rate Base				(14,615,903)	

Line No.	Description	Account	Labor	Non-Labor	Total	Reference
1	**Revenue**					
2	**Rate Revenue:**					
3	Eliminate Retail Unbilled Revenue			(1,492,778)	(1,492,778)	
4	Rebill Gas Revenue			(794,435,067)	(794,435,067)	Schedule 12
5	**Total Rate Revenue**		0	(795,927,845)	(795,927,845)	
6						
7	**Other Revenue:**					
8	Meter Turn-on				0	Schedule 13
9	Customer Connection, Return Check, & Succession Revenue				133,735	Schedule 13
10	Late Payment Revenue				(15,131)	Schedule 13
11	Products Extracted from Natural Gas				116,056	Schedule 13
12	Miscellaneous Service Revenues				(4,043)	Schedule 13
13	Sales Tax Commission				(372,750)	Schedule 13
14	Rent from Gas Property				31,287	Schedule 13
15	**Total Other Revenue**		0	0	(110,846)	
16						
17						
18	**Cost of Sales**					
19						
20	Eliminate Natural Gas Wellhead Purchases	0800	0	0	0	
21	Eliminate Natural Gas Gasoline Plant Outlet Purchases	0802	0	(727,462,971)	(727,462,971)	
22	Eliminate Natural Gas Transmission Line Purchases	0803	0	(97,482,219)	(97,482,219)	
23	Eliminate Purchased Gas Cost Adjustment	0805	0	(7,759,563)	(7,759,563)	
24	Eliminate Exchange Gas	0806	0	269,168	269,168	
25	Eliminate Well Expenses - Purchased Gas	0807	(280,187)	(23,209,430)	(23,489,617)	
26	Eliminate Gas Delivered/Withdrawn from Storage	0808	0	65,612,429	65,612,429	
27	Eliminate Gas Used for Products Extraction	0811	0	1,281,575	1,281,575	
28	**Total Cost of Sales**		(280,187)	(788,751,011)	(789,031,198)	
29						
30	**Transmission Operations:**					
31	DOT Integrity Management Expenses	0856		735,000	735,000	Schedule 14
32	Eliminate Front Range Pipeline Lease Payments	0860		(822,095)	(822,095)	Schedule 15
33	**Total Transmission Operations**		0	(87,095)	(87,095)	
34						
35	**Transmission Maintenance:**					
36	Eliminate Front Range Pipeline Expenses	0865	(1,534)	(59)	(1,593)	Schedule 15
37	**Total Transmission Maintenance**		(1,534)	(59)	(1,593)	
38						
39	**Total Transmission O&M**		(1,534)	(87,154)	(88,688)	
40						
41	**Distribution Operations:**					
42				0	0	
43					0	
44	**Total Distribution Operations**		0	0	0	
45						
46	**Total Distribution O&M**		0	0	0	
47						
48	**Customer Accounting Expense:**					
49	Customer Deposit Interest Expense	GDEPINT		165,565	165,565	Schedule 16
50	**Total Customer Accounting Expense**		0	165,565	165,565	
51						
52	**Customer Service Expense:**					
53	Transfer Update Advertising from Account 921	0909		26,572	26,572	Schedule 17
54	Eliminate Amortization of Regulatory Asset DSM E$P Gas	0908		(2,022,469)	(2,022,469)	
55	**Total Customer Service Expense**		0	(1,995,897)	(1,995,897)	
56						
57	**Total Customer O&M**		0	(1,830,332)	(1,830,332)	

Public Service Company of Colorado
Details of Adjustments - Gas
12 Months Ended December 31, 2004

S A Attachment C
Corresponds to Exhibit No. TLW-1
Schedule 5

Line No.	Description	Account	Labor	Non-Labor	Total	Reference
1	**Administrative & General Expense:**					
2	Eliminate Advertising Expense (Account 930)	0930		(753,018)	(753,018)	
3	AGA Dues	0930		(44,000)	(44,000)	
4	Transfer Update Advertising to Account 909	0921		(26,572)	(26,572)	Schedule 17
5	Eliminate Non-Recoverable Update Advertising	0921		(23,096)	(23,096)	Schedule 17
6	Annualize CPUC Fee	0928		35,335	35,335	Schedule 18
7	Rate Case Expense	0928		459,083	459,083	Schedule 19
8	Eliminate Front Range Pipeline Expenses	0926	(166)		(166)	Schedule 15
9	Pensions & Benefits	0926	2,297,598		2,297,598	Schedule 20
10	Adjust Allocation of A&G/CIS to Non-Utility	0922		97,721	97,721	Exhibit JSSP-2
11	**Total Administrative & General Expense**		2,297,432	(254,547)	2,042,885	
12						
13	**Total O&M Expense**		2,015,711	(790,923,044)	(788,907,333)	
14						
15	**Depreciation and Amortization Expense**					
16						
17	**Production:**					
18	Amortization of Fort Collins MGP Cleanup Costs			1,559,275	1,559,275	Schedule 21
19	**Total Production:**		0	1,559,275	1,559,275	
20						
21	**Underground Storage:**					
22	Amortization of Leyden Closure Costs			1,204,716	1,204,716	Schedule 21
23	**Total Underground Storage**		0	1,204,716	1,204,716	
24						
25	**Distribution:**					
26					0	
27	**Total Distribution**		0	0	0	
28						
29	**General:**					
30					0	
31	**Total General**		0	0	0	
32						
33	**Common:**					
34	Annualized Amortization of CRS Software			677,836	677,836	Schedule 21
35	**Total Common**		0	677,836	677,836	
36						
37	**Total Depreciation and Amortization Expense**		0	1,882,552	3,441,827	
38						
39	**Taxes Other than Income**					
40						
41	**Property Tax:**					
42	Property Tax Associated with Front Range Pipeline			(166,597)	(166,597)	Schedule 15
43	**Total Property Tax**		0	(166,597)	(166,597)	
44						
45	**Total Taxes Other Than Income**		(166,597)	(166,597)	(166,597)	
46						
47	**Income Tax Expense:**					
48	Federal Income Tax				8,549,583	
49	State Income Tax				921,228	
50						
51	**Deferred Income Tax Expense:**					
52	Depreciation Related				(2,011,364)	Schedule 11
53	Labor Related				(3,180,825)	Schedule 11
54	Other				2,068,360	Schedule 11
55	Interest on CWIP				197,407	Schedule 11
56	**Total Deferred Income Tax Expense**				(2,926,422)	
57						
58	ITC - Generated				0	
59	ITC - Amortized				0	
60						
61	**Total Income Tax Expense**				6,544,389	
62						
63	**Total Expenses**				(779,087,714)	
64						
65	**Net Operating Earnings**				(16,950,976)	
66						
67	**AFUDC**				(500,344)	Schedule 22
68						
69	**Total Net Operating Earnings**				(17,451,320)	

Public Service Company of Colorado
Gas Sales and Service Revenue Summary with 2002 Rate Case Rider
Twelve Months Ended December 31, 2004

S&A Attachment C
Corresponds to Exhibit No. TLW-1
Schedule 12

Line No.	Description	Customer Months	Billing Units	Rate	Base Rate Revenue	2002 Rate Case Rider	Base Rate Revenue Decrease Rate Case Rider	Base Rate Revenue With Rate Case Rider
1	**Firm Sales:**							
2	**RG:**				$ 209,553,158	-6.20%	$ (12,992,296)	$ 196,560,862
3	Customer Months	13,285,415		$ 9.00				
4	Commodity - Therms		922,870,242	$ 0.0977				
5								
6	**RGL:**				$ 4,436	-6.20%	$ (275)	$ 4,161
7	Customer Months	384						
8	Fixture Months		743	$ 5.58				
9	Mantle Months		104	$ 2.79				
10	Commodity - Therms		4,503					
11								
12	**CG:**				$ 54,736,076	-6.20%	$ (3,393,637)	$ 51,342,439
13	Customer Months	1,138,701		$ 16.20				
14	Commodity - Therms		395,737,406	$ 0.0917				
15								
16	**CG-IDS-T:**				$ 11,511	-6.20%	$ (714)	$ 10,797
17	Customer Months	187		$ 16.20				
18	Commodity - Therms		96,034	$ 0.0917				
19								
20	**CGL:**				$ 653	-6.20%	$ (40)	$ 613
21	Customer Months	63						
22	Fixture Months		104	$ 5.58				
23	Mantle Months		26	$ 2.79				
24	Commodity - Therms		720					
25								
26	**TF:**				$ 16,068	-6.20%	$ (996)	$ 15,072
27	Demand		809,112	$ -				
28	Commodity - Therms		368,529	$ 0.0436				
29								
30	**Interruptible Sales:**							
31	**IG:**				$ 167,504	-6.20%	$ (10,385)	$ 157,119
32	Customer Months	126		$ 90.00				
33	Demand Capacity - per DTH		214	$ 6.58				
34	Commodity - per DTH		354,945	$ 0.4360				
35								
36	**TI:**				$ 6,150	-6.20%	$ (381)	$ 5,769
37	Demand		8,040	$ 0.658				
38	Commodity - Therms		19,730	$ 0.0436				
39								
40	**Transportation Service:**							
41	**Firm Service:**							
42	**TF:**							
43	Customer Months	36,902		$ 60.00	$ 22,453,536	-6.20%	$ (1,392,119)	$ 21,061,417
44	Demand Capacity - Therms		32,419,689	$ 0.4070				
45	Specific Facility Revenue STD		12	$ 13,009.63				
46	Volumes - Therms		275,538,401	$ 0.0250				
47	TF - Electric Dept FSV				1,292,831	-6.20%	$ (80,156)	$ 1,212,676
48	Discounted Customers				$ 1,017,937	0.00%	$ -	$ 1,017,937
49	**Total TF**				$ 24,764,304		$ (1,472,275)	$ 23,292,030
50								
51	**Interruptible Service:**							
52	**TI:**							
53	Customer Months	2,624		$ 195	$ 7,068,435	-6.20%	$ (438,243)	$ 6,630,192
54	Volumes - Therms		170,749,080	$ 0.0384				
55	TI-Electric Department				$ 303,195	0.00%	$ -	$ 303,195
56	Discounted Customers				$ 743,107	0.00%	$ -	$ 743,107
57	**Total TI**				$ 8,114,737		$ (438,243)	$ 7,676,494
58								
59	**FERC:**				$ 950,040	0.00%	$ -	$ 950,040
60								
61								
62	**Total Pro Forma Revenue**				$ 298,324,637		$ (18,309,242)	$ 280,015,395
63								
64	**Book Revenue**				$ 1,074,450,461			$ 1,074,450,461
65								
66	**Pro Forma Adjustment**				$ (776,125,824)		$ (18,309,242)	$ (794,435,067)

PUBLIC SERVICE COMPANY OF COLORADO
ADJUSTED TEST PERIOD CUSTOMERS AND SALES (OUT OF PERIOD & RATE SHIFTS)
TWELVE MONTHS ENDED DECEMBER 31, 2004

Line No.			PER BOOK BILLING UNITS 12 ME Dec 2004	RATE SHIFTS	OUT-OF-PERIOD ADJUSTMENTS	ADJUSTED UNITS BEFORE NORMALIZATION	WEATHER NORMALIZATION ADJUSTMENTS	PROFORMA NORMALIZED ADJUSTED BILLING UNITS
1	WESTERN REGION							
2	RG-T	CUST. MOS	648,402		(1)	648,401		648,401
3		CONS - THERMS	43,176,776		(126)	43,176,650	(387,988)	42,788,662
4								
5	RGL-T	CUST. MOS	-			-		-
6		FIXTURE MOS	-			-		-
7		MANTLE MOS	-			-		-
8		CONS - THERMS	-			-		-
9								
10	CG-T	CUST. MOS	59,837	-	(9)	59,828		59,828
11		CONS - THERMS	14,902,391	-	(32,503)	14,869,888	(122,066)	14,747,822
12								
13	CGL-T	CUST. MOS	-		-	-		-
14		FIXTURE MOS	-			-		-
15		MANTLE MOS	-			-		-
16		CONS - THERMS	-		-	-		-
17								
18	IG	CUST. MOS	-	-	-	-		-
19		DEMAND	-	-	-	-		-
20		CONS - THERMS	-	-	-	-		-
21								
22	CG-IDS-T	CUST. MOS	19	-	-	19		19
23		CONS - THERMS	3,776	-	-	3,776	(42)	3,734
24								
25	MOUNTAIN REGION							
26	RG-T	CUST. MOS	402,617	-	(7)	402,610		402,610
27		CONS - THERMS	41,667,049	-	(727)	41,666,322	(87,250)	41,579,072
28								
29	RGL-T	CUST. MOS	-			-		-
30		FIXTURE MOS	-			-		-
31		MANTLE MOS	-			-		-
32		CONS - THERMS	-			-		-
33								
34	CG-T	CUST. MOS	59,605	-	(40)	59,565		59,565
35		CONS - THERMS	27,431,895	-	(48,922)	27,382,973	(44,954)	27,338,019
36								
37	CGL-T	CUST. MOS	-			-		-
38		FIXTURE MOS	-			-		-
39		MANTLE MOS	-			-		-
40		CONS - THERMS	-			-		-
41								
42	IG	CUST. MOS	4	-	-	4		4
43		DEMAND	-	-	-	-		-
44		CONS - THERMS	46,590	-	-	46,590		46,590
45								
46	CG-IDS-T	CUST. MOS	-			-		-
47		CONS - THERMS	-			-		-
48								

Line No.			PER BOOK BILLING UNITS 12 ME Dec 2004	RATE SHIFTS	OUT-OF-PERIOD ADJUSTMENTS	ADJUSTED UNITS BEFORE NORMALIZATION	WEATHER NORMALIZATION ADJUSTMENTS	PROFORMA NORMALIZED ADJUSTED BILLING UNITS
49	FRONT RANGE REGION							
50	RG-T	CUST. MOS	12,301,494		(87,090)	12,214,404		12,214,404
51		CONS - THERMS	828,574,706		(12,887,450)	815,687,256	22,815,252	838,502,508
52								
53	RGL-T	CUST. MOS	384			384		384
54		FIXTURE MOS	743			743		743
55		MANTLE MOS	104			104		104
56		CONS - THERMS	4,503			4,503		4,503
57								
58	CG-T	CUST. MOS	1,026,350	468	(7,511)	1,019,307		1,019,307
59		CONS - THERMS	347,101,537	3,170,250	(5,073,413)	345,198,374	8,453,191	353,651,565
60								
61	CGL-T	CUST. MOS	63		-	63		63
62		FIXTURE MOS	104			104		104
63		MANTLE MOS	26			26		26
64		CONS - THERMS	720		-	720		720
65								
66	IG	CUST. MOS	122	-	-	122		122
67		DEMAND	2,140	-	-	2,140		2,140
68		CONS - THERMS	3,502,863	-	-	3,502,863		3,502,863
69								
70	CG-IDS-T	CUST. MOS	148		-	148		148
71		CONS - THERMS	92,258		-	92,258	42	92,300
72								
73	TOTAL COMPANY							
74	RG-T	CUST. MOS	13,352,513	-	(87,098)	13,265,415		13,265,415
75		CONS - THERMS	913,418,531	-	(12,888,303)	900,530,228	22,340,014	922,870,242
76								
77	RGL-T	CUST. MOS	384	-	-	384		384
78		FIXTURE MOS	743	-	-	743		743
79		MANTLE MOS	104	-	-	104		104
80		CONS - THERMS	4,503	-	-	4,503		4,503
81								
82	CG-T	CUST. MOS	1,145,793	468	(7,560)	1,138,701		1,138,701
83		CONS - THERMS	389,435,823	3,170,250	(5,154,838)	387,451,235	8,286,171	395,737,406
84								
85	CGL-T	CUST. MOS	63	-	-	63		63
86		FIXTURE MOS	104	-	-	104		104
87		MANTLE MOS	26	-	-	26		26
88		CONS - THERMS	720	-	-	720		720
89								
90	IG	CUST. MOS	126	-	-	126		126
91		DEMAND	2,140	-	-	2,140		2,140
92		CONS - THERMS	3,549,453	-	-	3,549,453		3,549,453
93								
94	CG-IDS-T	CUST. MOS	167	-	-	167		167
95		CONS - THERMS	96,034	-	-	96,034	-	96,034
96								
97	TOTAL CUST - MOS		14,499,046	468	(94,658)	14,404,856	-	14,404,856
98	TOTAL CONS - THERMS		1,306,505,064	3,170,250	(18,043,141)	1,291,632,173	30,626,185	1,322,258,358

PUBLIC SERVICE COMPANY OF COLORADO
WEATHER NORMALIZATION STUDY
TWELVE MONTHS ENDED DECEMBER 31, 2004

LINE NO.	WEATHER REGION AND RATES	(1) ADJUSTED CUSTOMER MOS.	(2) AVERAGE CUSTOMER (Col 1 / 12)	(3) BASE LOAD PER CUSTOMER	(4) BASE LOAD (Col 2x Col3)	(5) ADJUSTED SALES	(6) HEATING SALES (Col 5 - Col 4)	(7) TEMP ADJ (Weather)	(8) ADJUSTED HEATING SALES (Col 6 x Col 7)	(9) NORMALIZED SALES (Therms) (Col 4 + Col 8)	(10) NORMALIZATION ADJUSTMENT (Therms) (Col 8 - Col 6)
1	WESTERN										
2	RG-T	648,401	54,033	220	11,887,260	43,176,650	31,289,390	0.9876	30,901,402	42,788,662	(387,988)
3	CG-T	59,828	4,986	1,008	5,025,888	14,869,888	9,844,000	0.9876	9,721,934	14,747,822	(122,066)
4	CG-T IDS	19	1.6	241	381	3,776	3,395	0.9876	3,353	3,734	(42)
5											
6	MOUNTAIN										
7	RG-T	402,610	33,551	403	13,521,053	41,666,322	28,145,269	0.9969	28,058,019	41,579,072	(87,250)
8	CG-T	59,565	4,964	2,595	12,881,580	27,382,973	14,501,393	0.9969	14,456,439	27,338,019	(44,954)
9	IG	4	-	-	-	46,590	46,590	1.0000	46,590	46,590	-
10											
11	FRONT RANGE										
12	RG-T	12,214,404	1,017,867	241	245,305,947	815,687,256	570,381,309	1.0400	593,196,561	838,502,508	22,815,252
13	CG-T	1,019,307	84,942	1,576	133,868,592	345,198,374	211,329,782	1.0400	219,782,973	353,651,565	8,453,191
14	CG-T IDS	148	12	7,601	91,212	92,258	1,046	1.0400	1,088	92,300	42
15	IG	122	10	-	-	3,502,863	3,502,863	1.0000	3,502,863	3,502,863	-
16											
17	TOTAL	14,404,409	1,200,367		422,581,913	1,291,626,950	869,045,037		899,671,222	1,322,253,135	30,626,185

PUBLIC SERVICE COMPANY OF COLORADO
CALCULATION OF WEATHER NORMALIZATION FACTOR
TWELVE MONTHS ENDED DECEMBER 31, 2004

S&A Attachment C
Corresponds to Exhibit No. TLW-1
Schedule 12

LINE NO.			FRONT RANGE REGION DEGREE DAYS	MOUNTAIN REGION DEGREE DAYS	WESTERN REGION DEGREE DAYS
1	December	2003	1,001	1,418	1,040
2	January	2004	1,022	1,414	1,336
3	February	2004	998	1,478	1,011
4	March	2004	569	785	464
5	April	2004	519	659	350
6	May	2004	192	380	104
7	June	2004	99	164	8
8	July	2004	17	97	0
9	August	2004	31	113	0
10	September	2004	131	320	109
11	October	2004	431	677	353
12	November	2004	830	1,045	789
13	PLUS: 1st week of December, 2004		245	360	331
14	LESS: 1st week of December, 2003		203	242	192
15					
16	TOTAL HDD		5,882	8,668	5,703
17					
18	30 YEAR AVERAGE (1)		6,117	8,641	5,632
19					
20	WEATHER NORMALIZATION FACTOR (2)		1.0400	0.9969	0.9876
21					
22					
23					
24					
25					
26	(1) Adjusted 30 Year average. Page 6 of 8.				
27					
28	(2) The Weather Normalization Factor is the quotient of 30 Year Average divided by Total HDD - line 18 divided by line 16.				

PUBLIC SERVICE COMPANY OF COLORADO
GAS DEPARTMENT
DETERMINATION OF THE ADJUSTED HEATING DEGREE DAY NORMALS
TWELVE MONTHS ENDED DECEMBER 31, 2004

LINE NO.	YEAR / ITEM	DENVER (DIA)	ALAMOSA (AIRPORT)	GRAND JUNCTION (AIRPORT)
1	1971	6,221	8,900	5,827
2	1972	6,012	8,691	5,438
3	1973	6,027	9,185	6,163
4	1974	5,925	9,018	6,022
5	1975	6,116	9,382	6,274
6	1976	5,716	8,864	5,834
7	1977	5,245	8,189	5,072
8	1978	6,202	8,391	5,764
9	1979	6,227	9,550	6,319
10	1980	5,538	8,166	4,905
11	1981	4,784	7,790	4,864
12	1982	6,207	8,582	5,319
13	1983	6,715	8,711	4,921
14	1984	6,386	9,487	5,784
15	1985	6,441	8,422	5,319
16	1986	5,288	7,916	4,923
17	1987	5,625	8,827	5,355
18	1988	5,848	8,999	5,862
19	1989	5,945	8,214	5,518
20	1990	5,584	8,344	5,449
21	1991	5,670	9,139	6,072
22	1992	5,423	9,785	5,315
23	1993	6,062	8,562	5,460
24	1994	5,182	8,305	5,050
25	1995	6,115	8,063	4,850
26	1996	6,164	8,134	5,263
27	1997	6,465	8,954	5,590
28	1998	5,940	8,251	5,458
29	1999	5,480	8,013	5,152
30	2000	6,010	7,825	5,153
31	2001	5,860	8,072	5,031
32	2002	6,253	8,400	5,703
33	2003	5,846	7,839	5,091
34	2004	5,882	8,668	5,703
35				
36	1971 - 2000 AVERAGE HEATING DEGREE DAYS	5,885	8,622	5,477
37				
38	1975 - 2004 AVERAGE HEATING DEGREE DAYS	5,874	8,528	5,412
39				

Public Service Company of Colorado
Gas Transportation Service Rebill - 12 Months Ending December 31, 2004
Pro Forma Using Current Base Rates

Line No.	Rate Schedule	Pro Forma Adjusted Customer Months	Service & Facility Charge ($)	Pro Forma Service & Facility Revenue ($)	Pro Forma Adjusted Volumes (Therms)	Commodity Charge Std Rate (per Therm $)	Pro Forma Commodity Revenue ($)	Pro Forma Adjusted Demand (Therms)	Capacity Charge Std Rate (per Therm $)	Pro Forma Capacity Revenue ($)	Pro Forma Total Revenue ($)
1	TF - Full Rate Contracts	36,902.44	60.00	2,214,146.68	275,538,401	0.025	6,888,460.04	32,419,689.05	0.407	13,194,813.44	22,297,420.16
2	TF- Full Rate Special Facility	12.00	13,009.63	156,115.56	0	0.025	0.00	0.00	0.407	0.00	156,115.56
3											
4	TF- Electric Dept - FSV	12.00	60.00	720.00	284,771,240	0.001	284,771.24	16,440,000.00	0.0611	1,004,484.00	1,289,975.24
5	TF- Electric Dept - FSV - Special Facility	12.00	238.00	2,856.00	0		0.00	0.00		0.00	2,856.00
6											
7	Sub-Total TF	36,938.44		2,373,838.24	560,309,641		7,173,231.28	48,859,689.05		14,199,297.44	23,746,366.96
8											
9											
10	TI - Full Rate Contracts except NA, PNA	2,623.95	195.00	511,670.25	142,759,820	0.0384	5,481,977.09	0	0	0.00	5,993,647.34
11	TI - Full Rate Contracts - NA, PNA	4.00	0.00	0.00	27,989,260	0.0384	1,074,787.58	0	0	0.00	1,074,787.58
12											
13	Sub-Total TI - Full Rate Contracts	2,627.95		511,670.25	170,749,080		6,556,764.67	0	0	0.00	7,068,434.92
14											
15											
16	TF&TI Full Rate and Ft. St. Vrain (FSV)	39,566.39		2,885,508.49	731,058,721		13,729,995.95	48,859,689.05		14,199,297.44	30,814,801.88
17											
18											
19	TF Discounted	84.00			65,817,040			4,990,890.00			1,017,937.16
20											
21	TI Discounted	132.00			71,476,660						743,107.00
22											
23	TI - Electric Department:										
24	TI - Electric Dept - PDG & PDN S35	12.00			30,736,720						187,537.00
25	TI - Electric Dept - PTD S09	12.00			128,560						72,242.00
26	TI - Electric Dept - PTD S10	12.00			547,860						43,416.00
27											
28	Sub-Total TI - Electric Department	36.00			31,413,140						303,195.00
29											
30	TF & TI Discounted and TI - Elec Dept	252.00			168,706,840			4,990,890.00			2,064,239.16
31											
32											
33	TF TOTAL	37,022.44			626,126,681						24,764,304.12
34											
35	TI TOTAL	2,795.95			273,638,880						8,114,736.92
36											
37	TOTAL TF & TI	39,818.39			899,765,561						32,879,041.04

Public Service Company of Colorado
Rate Case Expenses
12 Months Ended December 31, 2004

S&A Attachment C
Corresponds to Exhibit TLW-1
Schedule 19

Line No.	Description	Amount
1	Customer Noticing	263,689
2	Employee Expenses	612
3	Consultants and Outside Witnesses	146,202
4	Transcripts	0
5	Outside Legal	87,923
6	Total Rate Case Expenses to Date	498,426
7		
8	Unamortized portion of 2002 Rate Case Expense (1)	419,740
9		
10	Total	918,166
11		
12	One year amortization (2)	459,083

(1) - Approved Amount	2,502,375
Monthly Amortization	52,133
Number of Months (June '03 - December '05)	30
Amount Amortized at December 31, 2005	1,563,990
Unamortized Amount at December 31, 2005	938,385
Gas Portion (44.73%)	419,740

(2) - Two-year Amortization Period

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Summary

	Rate Base	CO	RG	RGL	CG	CGL	IG	TF	TI
1	Net Investment Rate Base	1,004,185,109	665,443,387	23,788	217,141,838	3,506	710,224	88,359,088	32,503,279
2	Required Rate of Return	8.700%	8.700%	8.700%	8.700%	8.700%	8.700%	8.700%	8.700%
3	Required Operating Income	87,364,105	57,893,575	2,070	18,891,340	305	61,790	7,687,241	2,827,785
	Operating Income								
4	Total Operating Income	73,473,370	54,410,691	1,148	13,465,006	172	45,808	4,361,805	1,188,740
5	Distribution Rev at Present Rates	277,852,679	196,560,862	4,161	51,353,236	613	157,119	22,094,426	7,682,263
6	Revenue Requirement - Customer Related	129,214,270	107,795,922	5,600	17,920,300	823	8,603	3,093,207	389,814
7	Customer Bills	14,444,762	13,265,415	912	1,138,868	117	126	37,094	2,812
8	Cost Per Customer per Bill	8.95	8.13	7.04	15.74	7.04	68.28	83.39	138.63
9	Revenue Requirement - Demand Related	117,103,818	69,955,802	(2)	30,923,631	(1)	58,175	14,681,134	1,485,080
10	Sales (Decatherms)	193,764,093	92,287,024	450	39,583,344	72	354,945	3,839,253	27,365,861
11	Cost per Decatherm or Capacity Charge per Decatherm	0.60	0.76	(0.01)	0.78	(0.01)	0.16	3.82	0.05
12	Revenue Requirement - Energy Related	54,027,585	28,077,717	107	12,413,102	14	120,648	7,448,731	5,967,268
13	Sales (Decatherms)	193,764,093	92,287,024	450	39,583,344	72	354,945	34,172,397	27,365,861
14	Cost per Decatherm	0.279	0.304	0.231	0.314	0.231	0.340	0.218	0.218
15	Demand & Commodity Requirement per Dkt. (Line 11 + Line 14)	0.883	1.062	0.226	1.095	0.226	0.504	na	0.272
16	Total Rev Req w D.A (Lines 6 + 9 + 12) w/o Mitigation	300,345,673	205,829,440	5,705	61,257,033	836	187,425	25,223,071	7,842,162
17	Percentage Change w/o Mitigation	8.10%	4.72%	37.11%	19.29%	36.54%	19.29%	14.16%	2.08%
19	Total Rev. Req with Mitigation	300,345,672	206,076,976	5,705	60,596,818	836	187,425	25,223,071	8,254,840
20	Percentage Change with Mitigation	8.10%	4.84%	37.11%	18.00%	36.54%	19.29%	14.16%	7.45%

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Summary: Functionalized Rate Base

	Plant In Service	Alloc	CO	RG	RGL	CG	CGL	IG	TF	TI
1	Production	Page 4-1	11,464,206	6,303,862	10	2,703,634	0	9,050	1,749,920	697,730
2	Storage	Page 4-1	49,475,176	32,769,478	63	14,054,370	10	49,513	1,838,304	763,438
3	Transmission	Page 4-1	278,511,243	153,145,937	279	65,681,999	44	219,859	42,512,504	16,950,622
4	Distribution	Page 4-1	1,210,951,868	833,734,855	40,806	239,101,268	6,012	466,390	101,813,906	35,788,630
5	General	Page 4-1	24,180,303	16,000,930	642	5,014,805	94	11,616	2,306,898	845,318
6	Intangible	Page 4-1	7,945,628	5,257,893	211	1,647,861	30	3,817	758,045	277,771
7	Common	Page 4-1	151,680,933	100,372,441	4,026	31,457,432	593	72,867	14,470,971	5,302,603
8	Total		1,734,209,357	1,147,585,396	46,037	359,661,368	6,783	833,111	165,450,549	60,626,113
	Net Plant									
9	Production	Page 4-2	4,670,746	2,568,319	4	1,101,515	0	3,687	712,952	284,269
10	Storage	Page 4-2	19,281,864	12,771,185	25	5,477,382	4	19,296	716,439	297,533
11	Transmission	Page 4-2	166,250,129	91,416,531	167	39,207,181	26	131,239	25,376,747	10,118,238
12	Distribution	Page 4-2	783,854,235	539,680,077	26,414	154,771,256	3,892	301,896	65,904,570	23,166,131
13	General	Page 4-2	11,139,814	7,371,594	296	2,310,310	43	5,351	1,062,783	389,436
14	Common	Page 4-2	69,879,083	46,241,370	1,855	14,492,372	273	33,570	6,666,746	2,442,898
15	Total		1,055,075,871	700,049,076	28,759	217,360,016	4,238	495,040	100,440,236	36,698,506
	Subtractions									
16	Total	Page 5-1	220,125,947	148,777,253	6,214	44,993,988	917	101,063	19,268,497	6,978,016
	Additions									
17	Constr Work In Progress	Page 6-1	43,874,820	26,711,500	603	9,788,095	87	28,161	5,299,721	2,046,653
18	Materials & Supplies	Page 6-1	4,284,554	2,835,236	113	888,583	16	2,059	408,764	149,783
19	Gas in Storage	Page 6-1	97,563,266	68,094,284	332	29,206,700	53	261,897	0	0
20	Miscellaneous	Page 6-1	27,217,662	19,300,617	227	4,745,188	33	12,184	2,254,966	904,447
21	Cash Working Capital	Page 6-1	-3,705,117	-2,770,074	-32	147,244	-4	11,946	-776,103	-318,094
22	Total		169,235,185	114,171,563	1,243	44,775,810	185	316,247	7,187,349	2,782,789
23	Rate Base		1,004,185,109	665,443,387	23,788	217,141,838	3,506	710,224	88,359,088	32,503,279

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Income Statement

	Present Operating Revenues	Alloc	CO	RG	RGL	CG	CGL	IG	TF	TI
1	Retail Revenues	Page 7-1	277,852,679	196,560,862	4,161	51,353,236	613	157,119	22,094,426	7,682,263
2	Fort St. Vrain Rev. Credit	Page 7-1	1,212,676	1,113,667	32	95,611	5	11	3,114	236
3	Other Operating Revenues	Page 7-1	5,293,803	4,861,589	141	417,379	23	46	13,594	1,031
4	Total Operating Revenues		284,359,158	202,536,118	4,334	51,866,226	641	157,175	22,111,135	7,683,530
	Expenses									
5	Operating Expenses									
6	Underground Storage	Page 8-1	-2,130,555	-1,532,761	-11	-657,441	-2	1,238	39,309	19,112
7	Other Production	Page 8-1	1,678,124	922,758	0	395,758	0	1,324	256,151	102,133
8	Transmission	Page 8-1	11,823,107	6,301,117	10	2,702,494	1	12,168	1,869,199	938,118
9	Distribution	Page 8-2	31,942,965	19,624,302	177	6,913,827	26	19,199	3,905,185	1,480,248
10	Customer Billing	Page 8-2	26,357,014	24,205,837	0	2,078,130	0	230	67,687	5,131
11	Customer Service	Page 8-2	3,729,378	3,425,312	99	294,072	17	32	9,152	694
12	Administrative and General	Page 8-2	41,152,336	26,593,004	1,066	8,334,435	157	25,971	4,581,720	1,615,984
13	Customer Accting./Mtring	Page 8-2	4,949,695	4,558,310	0	391,342	0	43	0	0
14	Total		119,502,063	84,097,879	1,341	20,452,616	199	60,206	10,728,402	4,161,420
15	Depreciation	Page 9-1	48,170,507	32,007,440	1,273	10,065,954	186	23,520	4,446,114	1,626,020
	Taxes									
16	Property/Other Taxes	Page 10 -1	20,663,427	13,862,627	500	4,151,159	74	9,621	1,925,921	713,524
17	State & Fed. Income Taxes	Page 11 -1	24,971,624	19,976,768	134	4,126,743	19	18,800	800,367	48,793
18	Total Taxes	Page 11 -1	45,635,051	33,839,395	634	8,277,901	93	28,421	2,726,288	762,317
19	Gain on Sale of Utility Property	Page 11 -1	848,988	779,672	23	66,937	4	7	2,180	165
20	Total Expense		212,458,633	149,165,042	3,225	38,729,535	475	112,139	17,898,624	6,549,592
21	AFUDC Expense	Page 12 -1	1,572,845	1,039,616	40	328,315	6	771	149,294	54,803
22	Total Operating Income		73,473,370	54,410,691	1,148	13,465,006	172	45,808	4,361,805	1,188,740

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Gross Plant in Service

	Production Plant	Alloc	CO	RG	RGL	CG	CGL	IG	TF	TI
1	P&G Plant	Coincident Peak Demand	5,938,085	3,265,195	6	1,400,394	0	4,688	906,401	361,401
2	P.E. Plant	Coincident Peak Demand	5,526,121	3,038,667	4	1,303,240	0	4,363	843,519	336,329
3	Total		11,464,206	6,303,862	10	2,703,634	0	9,050	1,749,920	697,730
	Storage Plant									
4	Underground Storage	Coincident Peak Demand	49,475,176	32,769,478	63	14,054,370	10	49,513	1,838,304	763,438
	Transmission Plant									
5	Mains	Coincident Peak Demand	161,786,910	88,962,325	162	38,154,610	26	127,716	24,695,472	9,846,599
6	Other Transmission Plant	Coincident Peak Demand	116,724,333	64,183,612	117	27,527,389	18	92,143	17,817,032	7,104,023
7	Total		278,511,243	153,145,937	279	65,681,999	44	219,859	42,512,504	16,950,622
	Distribution Plant									
8	Land & Right of Way	Dist Demand	4,473,329	2,459,765	5	1,054,956	0	3,532	682,818	272,253
9	Structures & Improvements	Dist Demand	2,475,085	1,360,984	2	583,706	0	1,953	377,802	150,638
10	Compressor Station Equip.	Dist Demand	841,161	462,533	0	198,373	0	664	128,397	51,195
11	Regulator Stations	Dist Demand	15,980,261	8,787,121	16	3,768,665	2	12,615	2,439,259	972,584
12	Meter Installations	Mtr Install. Study	94,130,658	78,620,668	0	6,817,272	0	3,248	8,077,160	612,309
13	Mains - Minimum Dist.	Min Dist. Study	0	0	0	0	0	0	0	0
14	Mains - Additional Capacity	CP Less Min Demand	545,723,003	300,078,587	547	128,699,214	88	430,798	83,300,231	33,213,538
15	Mains - Total		545,723,003	300,078,587	547	128,699,214	88	430,798	83,300,231	33,213,538
16	Services	Serv Study	375,194,503	296,844,134	0	75,689,819	0	8,374	2,465,288	186,887
17	Meters	Meter Study	101,562,561	80,635,152	0	16,752,990	0	4,595	3,875,994	293,829
18	House Regulators	Regul Study	27,247,526	24,630,013	0	2,114,546	0	611	466,957	35,399
19	Automated Mtr Reading	AMR Study	43,277,623	39,855,898	0	3,421,725	0	0	0	0
20	Gas Light Controls	Gas Light Study	46,158	0	40,236	0	5,922	0	0	0
21	Total		1,210,951,868	833,734,855	40,806	239,101,268	6,012	466,390	101,813,906	35,788,630
	General & Intangible Plant									
22	General	Gross Plant	16,234,675	10,743,037	431	3,366,944	64	7,799	1,548,853	567,547
23	Intangible	Gross Plant	7,945,628	5,257,893	211	1,647,861	30	3,817	758,045	277,771
24	Total		24,180,303	16,000,930	642	5,014,805	94	11,616	2,306,898	845,318
	Common Plant									
25	System	Gross Plant	151,680,933	100,372,441	4,026	31,457,432	593	72,867	14,470,971	5,302,603
26	Gas Plant in Serv		1,726,263,729	1,142,327,503	45,826	358,013,507	6,753	829,294	164,692,504	60,348,342

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Net Plant in Service

		Alloc	CO	RG	RGL	CG	CGL	IG	TF	TI
	Production Plant									
1	P&G Plant	Net Plant P&G Ratio	867,756	477,156	1	204,645	0	685	132,456	52,813
2	P.E. Plant	Net Plant P.E. Ratio	3,802,990	2,091,163	3	896,869	0	3,002	580,496	231,456
3	Total		4,670,746	2,568,319	4	1,101,515	0	3,687	712,952	284,269
	Storage Plant									
4	Underground Storage	Net Dist. Plant U.G. Ratio	19,281,864	12,771,185	25	5,477,382	4	19,296	716,439	297,533
	Transmission Plant									
5	Mains	Net Plant Trans. Ratio	96,574,538	53,103,774	97	22,775,414	16	76,237	14,741,327	5,877,674
6	Other Transmission Plant	Net Plant Trans. Ratio	69,675,591	38,312,757	70	16,431,767	11	55,002	10,635,419	4,240,564
7	Total		166,250,129	91,416,531	167	39,207,181	26	131,239	25,376,747	10,118,238
	Distribution Plant									
8	Land & Right of Way	Dist Demand	2,895,605	1,592,216	3	682,877	0	2,286	441,991	176,231
9	Structures & Improvements	Dist Demand	1,602,133	880,971	1	377,835	0	1,264	244,553	97,508
10	Compressor Station Equip.	Dist Demand	544,487	299,399	0	128,408	0	430	83,112	33,138
11	Regulator Stations	Dist Demand	10,344,090	5,687,941	10	2,439,473	1	8,166	1,578,942	629,557
12	Meter Installations	Net Plant Dist. Ratio	60,931,171	50,891,489	0	4,412,849	0	2,103	5,228,380	396,350
13	Mains - Minimum Dist.	Net Plant Dist. Ratio	0	0	0	0	0	0	0	0
14	Mains - Additional Capacity	CP Less Min Demand	353,248,794	194,242,131	354	83,307,542	57	278,857	53,920,590	21,499,263
15	Mains - Total		353,248,794	194,242,131	354	83,307,542	57	278,857	53,920,590	21,499,263
16	Services	Net Plant Dist. Ratio	242,864,979	192,148,456	0	48,994,338	0	5,421	1,595,792	120,973
17	Meters	Net Plant Dist. Ratio	65,741,873	52,195,473	0	10,844,281	0	2,975	2,508,947	190,197
18	House Regulators	Net Plant Dist. Ratio	17,637,438	15,943,111	0	1,368,755	0	395	302,263	22,914
19	Automated Mtr Reading	Net Plant Dist. Ratio	28,013,787	25,798,890	0	2,214,897	0	0	0	0
20	Gas Light Controls	Net Plant Dist. Ratio	29,878	0	26,045	0	3,833	0	0	0
21	Total		783,854,235	539,680,077	26,414	154,771,256	3,892	301,896	65,904,570	23,166,131
	General & Intangible Plant									
22	General	Net Plant Com & Gen. Ratio	7,479,280	4,949,294	199	1,551,144	29	3,593	713,553	261,468
23	Intangible	Net Plant Com & Gen. Ratio	3,660,534	2,422,300	97	759,166	14	1,758	349,230	127,969
24	Total		11,139,814	7,371,594	296	2,310,310	43	5,351	1,062,783	389,436
	Common Plant									
25	System	Net Plant Com & Gen. Ratio	69,879,083	46,241,370	1,855	14,492,372	273	33,570	6,666,746	2,442,898
26	Total Net Plant		1,055,075,871	700,049,076	28,759	217,360,016	4,238	495,040	100,440,236	36,698,506

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Subtractions to Net Plant (Page 1 of 1)

			CO	RG	RGL	CG	CGL	IG	TF	TI
1	Full Tax Normalization	Gross Plant	143,793,246	95,152,887	3,818	29,821,587	563	69,078	13,718,454	5,026,859
2	Interest on CWIP	Net Plant	197,234	130,865	5	40,633	1	93	18,777	6,860
3	Total		143,990,480	95,283,752	3,823	29,862,220	564	69,171	13,737,231	5,033,719
4	Customer Advances	Dist. Sales Revenue	65,787,640	45,294,490	2,217	12,989,705	327	25,338	5,531,266	1,944,297
5	Customer Deposits	Total Gross Plant	10,347,827	8,199,010	174	2,142,063	26	6,554	0	0
6	Total Subtractions		220,125,947	148,777,253	6,214	44,993,988	917	101,063	19,268,497	6,978,016

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Additions to Net Plant (Pg 1 of 1)

		Alloc	CO	RG	RGL	CG	CGL	IG	TF	TI
	CWIP									
1	Production & Gathering	Demand	-145,899	-80,226	0	-34,408	0	-115	-22,271	-8,879
2	Products Extraction	Demand	75,755	41,655	0	17,866	0	60	11,563	4,611
3	Transmission Plant	Demand	5,205,281	2,862,246	5	1,227,575	0	4,109	794,545	316,801
4	Distribution Plant	Demand	15,629,446	8,594,217	16	3,685,931	2	12,338	2,385,710	951,232
5	Underground Storage	Demand	1,281,361	848,698	2	363,994	0	1,283	47,611	19,773
6	Common & General	Demand	21,828,876	14,444,910	580	4,527,137	85	10,486	2,082,563	763,115
7	Total CWIP		43,874,820	26,711,500	603	9,788,095	87	28,161	5,299,721	2,046,653
	Materials & Supplies									
8	Materials and Supplies	Gross Plant	4,284,554	2,835,236	113	888,583	16	2,059	408,764	149,783
	Gas In Storage									
9	NatGas Underground	Present Rev	97,563,266	68,094,284	332	29,206,700	53	261,897	0	0
10	Total		97,563,266	68,094,284	332	29,206,700	53	261,897	0	0
	Miscellaneous									
11	Prepay: Pensions	Expense Subtotal	25,575,093	18,213,673	183	4,404,532	27	11,395	2,098,259	847,024
12	Xcel Energy Inc. Service Charges	Total Gross Plant	1,642,569	1,086,944	44	340,656	6	789	156,707	57,423
13	Total		27,217,662	19,300,617	227	4,745,188	33	12,184	2,254,966	904,447
	Working Cash									
14	Purchase Gas Exp - Commodity	Present Rev	6,015,009	4,198,176	20	1,800,663	3	16,147	0	0
15	Franchise Tax	Subtotal O&M Expense	729,419	503,213	12	134,342	2	362	66,288	25,200
16	Other O&M Expenses	Subtotal O&M Expense	1,034,409	722,669	13	181,692	2	515	93,498	36,020
17	Taxes Other Than Income	Expense Subtotal	-12,202,061	-8,689,875	-88	-2,101,435	-13	-5,436	-1,001,093	-404,121
18	Federal Income Tax	Net Plant	56,055	37,194	1	11,548	0	27	5,336	1,949
19	State Income Tax	Net Plant	-68,704	-45,586	-2	-14,154	0	-32	-6,541	-2,389
20	State Sales Tax	Subtotal O&M Expense	730,755	504,134	12	134,588	2	363	66,409	25,247
21	Total Working Cash		-3,705,117	-2,770,074	-32	147,244	-4	11,946	-776,103	-318,094
22	Total Additions		169,235,185	114,171,563	1,243	44,775,810	185	316,247	7,187,349	2,782,789
23	Total Rate Base		1,004,185,109	665,443,387	23,788	217,141,838	3,506	710,224	88,359,088	32,503,279

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Operating Revenue

	Retail Revenue	Alloc	CO	RG	RGL	CG	CGL	IG	TF	TI
1	Distribution Rev at Present Rates		277,852,679	196,560,862	4,161	51,353,236	613	157,119	22,094,426	7,682,263
2	Fort St. Vrain Rev. Credit	Rev Req/Customers	1,212,676	1,113,667	32	95,611	5	11	3,114	236
3	Subtotal		279,065,355	197,674,529	4,193	51,448,847	618	157,129	22,097,540	7,682,499
	Other Operating Rev									
4	Late Pay Penalties	Rev Req/Customers	1,462,363	1,342,968	39	115,297	6	13	3,755	285
5	Misc Service Revenues	Rev Req/Customers	1,922,226	1,765,285	51	151,554	8	17	4,936	374
6	Rent Revenues	Rev Req/Customers	79,965	73,436	2	6,305	0	1	205	16
7	Product Extraction	Rev Req/Customers	1,076,993	989,062	29	84,913	5	9	2,766	210
8	Other - Miscellaneous	Rev Req/Customers	752,256	690,838	20	59,310	3	7	1,932	146
9	Tot Other Op - Present		5,293,803	4,861,589	141	417,379	23	46	13,594	1,031
10	Total Revenue		284,359,158	202,536,118	4,334	51,866,226	641	157,175	22,111,135	7,683,530

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Operation & Maintenance (Pg 1 of 2)

	Underground Storage Expense	Alloc	CO	RG	RGL	CG	CGL	IG	TF	TI
1	Operation, Supv. & Engineering	Total U.S. Plant	175,044	115,939	0	49,725	0	175	6,504	2,701
2	Maint. Structures	Land & Structures Plant	768	509	0	219	0	0	28	12
3	Wells	Leashold Res Plant	102,101	67,625	0	29,004	0	102	3,794	1,576
4	Lines	Lines Plant	13,993	9,269	0	3,975	0	14	520	215
5	Compressor Station	Comp. Station Plant	200,124	132,551	0	56,849	0	200	7,436	3,088
6	Compressor Station Fuel	U.S. Commodity Throughput	838	534	0	229	0	2	40	32
7	Regulator Station	Meas. Station Plant	20,483	13,567	0	5,818	0	21	761	316
8	Purification	Purification & Oth. Plant	27,819	18,425	0	7,903	0	28	1,034	429
9	Other	Purification & Oth. Plant	260,993	172,867	0	74,141	0	261	9,697	4,027
10	Storage Royalty	U.G. Commodity Throughput	152,079	97,105	0	41,650	0	373	7,191	5,759
11	Rents	Total Plant	62,025	41,082	0	17,620	0	62	2,304	957
12	Other Gas Supply	RG, CG Commodity	-3,146,821	-2,202,235	-11	-944,573	-2	0	0	0
13	Total U.G. Expense		-2,130,555	-1,532,761	-11	-657,441	-2	1,238	39,309	19,112
	Prod.& Gath/Extract Expense									
14	Operations, Supv, & Engineering	Total P&G Plant	69,998	38,490	0	16,508	0	55	10,684	4,261
15	P & G - Field Lines	Field Lines Plant	11,733	6,452	0	2,767		9	1,791	714
16	P & G Other Expenses	Total P&G Plant	192,535	105,870	0	45,406	0	152	29,389	11,718
17	P & G Maint. Field Lines	Field Lines Plant	463	255	0	110	0	0	70	28
18	P.E. - Oper., Sup. & Eng. Labor	P.E. Total Plant	15,133	8,321	0	3,569	0	12	2,310	921
19	Gas Shrinkage	P.E. Total Plant	1,025,443	563,864	0	241,833	0	810	156,526	62,411
20	Fuel	P.E. Total Plant	256,096	140,821	0	60,396	0	202	39,091	15,586
21	Maint., Supv. & Engineering	P.E. Total Plant	144	79	0	34	0	0	22	9
22	Maintenance, Extraction & Refinin	Extraction Refining Plant	106,578	58,605	0	25,135	0	84	16,268	6,486
23	Total P &G Exp		1,678,124	922,758	0	395,758	0	1,324	256,151	102,133
	Transmission Expense									
24	Operation, Sup. & Engineering	Total Transmission Plant	748,795	411,743	0	176,590	0	591	114,298	45,573
25	System Control	Mains, Compres. & Meas.	841,350	462,637	0	198,418	0	664	128,425	51,206
26	Compressor Station	Compressor Total Plant	1,049,876	577,299	1	247,595	0	829	160,255	63,897
27	Compressor Fuel	Total Trans. Throughput	2,719,186	1,295,109	6	555,492	1	4,981	479,558	384,039
28	Mains Expense	Total Trans Mains Plant	3,132,347	1,722,395	3	738,709	0	2,472	478,128	190,640
29	Measuring & Reg Station Equip.	Meas. & Reg. Total Plant	674,736	371,019	0	159,125	0	533	102,993	41,066
30	Other	Total Transmission Plant	566,837	311,689	0	133,678	0	448	86,523	34,499
31	Rents	Total Transmission Plant	355,994	195,752	0	83,955	0	281	54,340	21,666
32	Maint. Sup & Engineering	Total Transmission Plant	79,473	43,701	0	18,743	0	62	12,131	4,837
33	Maintenance - Mains	Total Trans Mains Plant	608,164	334,413	0	143,425	0	481	92,831	37,014
34	Maint. - Comp. Station Equip.	Compressor Total Plant	624,312	343,293	0	147,234	0	493	95,296	37,996
35	Maint. - Meas. & Reg	Meas. & Reg. Total Plant	174,664	96,044	0	41,191	0	138	26,661	10,630
36	Maint. - Comm. Equip.	Total Comm. Plant	247,372	136,023	0	58,339	0	195	37,760	15,055
37	Total Transmission Exp		11,823,107	6,301,117	10	2,702,494	1	12,168	1,869,199	938,118

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Operation & Maintenance (Pg 2 of 2)

	Distribution Expense	Alloc	CO	RG	RGL	CG	CGL	IG	TF	TI
1	Supv. & Engineering	Total Dist. Plant	2,680,510	1,845,519	91	529,264	13	1,032	225,370	79,220
2	Load Dispatch	Mains, Comp. & Measuring	606,085	333,270	0	142,935	0	479	92,514	36,887
3	Mains	Total Dist. Mains Plant	10,709,193	5,888,700	11	2,525,575	2	8,454	1,634,673	651,778
4	Meas. & Reg. Station - Gen	Dist. Reg Station Plant	1,383,442	760,717	2	326,260	0	1,093	211,171	84,199
5	Meas. & Reg. Station - Ind	Dist. Reg Station Plant	81,111	44,601	0	19,128	0	64	12,381	4,937
6	Meas. & Reg. Station - City Gate	Dist. Reg Station Plant	135,305	74,401	0	31,909	0	107	20,654	8,234
7	Meters & House Regulators	Mtr, Mtr Inst., House Reg Plt	2,960,688	2,442,033	0	341,098	0	112	164,941	12,504
8	Customer Installations	Service Lat. Total Plant	2,527,449	1,999,652	0	509,875	0	56	16,607	1,259
9	Other Distribution	Mains Expense	8,953,026	4,923,030	9	2,111,414	2	7,068	1,366,608	544,895
10	Rents	Total Dist. Plant	1,906,156	1,312,380	64	376,369	9	734	160,265	56,335
11	Total Distribution		31,942,965	19,624,302	177	6,913,827	26	19,199	3,905,185	1,480,248
	Customer Accounting	Alloc								
12	Customer Acct/Mtring Exp	RG, CG, IC Customers	4,949,695	4,558,310	0	391,342	0	43	0	0
13	Customer Billing Exp	RG, CG, IC Customers	26,357,014	24,205,837	0	2,078,130	0	230	67,687	5,131
14	Customer Service & Info	Annual Bills	3,563,813	3,272,843	95	280,982	16	31	9,152	694
15	Customer Deposit Interest	Revenue	165,565	152,469	4	13,090	1	1	0	0
16	Total		35,036,087	32,189,459	99	2,763,543	17	305	76,839	5,825
	Admin & General									
17	Property Insurance	Total Gross Plant	905,147	598,967	23	187,721	3	435	86,355	31,643
18	A&G Gen Plant Maint.	Gross C&G Plant	48,886	32,350	1	10,138	0	24	4,663	1,710
19	A & G Other	Expense Subtotal	39,232,811	25,961,687	1,042	8,136,576	154	18,847	3,742,967	1,371,537
20	A &G Transportation	# of Trans Cust./Throughput	585,221	0	0	0	0	0	456,380	128,841
21	Phone Lines	# of IG Customers	6,664	0	0	0	0	6,664	0	0
22	GMS Expense	# of Trans Cust./Throughput	373,607	0	0	0	0	0	291,354	82,253
23	Total A & G Expense		41,152,336	26,593,004	1,066	8,334,435	157	25,971	4,581,720	1,615,984
24	Total O&M Expense		119,502,063	84,097,879	1,341	20,452,616	199	60,206	10,728,402	4,161,420

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Book Depreciation

	Production Plant	Alloc	CO	RG	RGL	CG	CGL	IG	TF	TI
1	Production & Gathering	P&G Gross Plant	1,637,542	900,440	2	386,185	0	1,293	249,958	99,664
2	Products Extraction	P.E. Gross Plant	144,252	79,320	0	34,019	0	114	22,019	8,779
3	Total		1,781,793	979,760	2	420,205	0	1,407	271,977	108,443
4	Underground Storage	U.S. Gross Plant	2,615,368	1,732,268	3	742,946	0	2,618	97,177	40,357
5	Transmission Plant	Trans. Gross Plant	4,052,193	2,228,193	4	955,639	0	3,199	618,535	246,623
6	Distribution Plant	Dist Gross Plant	29,235,357	20,128,412	985	5,772,493	145	11,259	2,458,038	864,025
7	Common & General	C & G Gross Plant	10,485,795	6,938,808	279	2,174,671	41	5,037	1,000,387	366,572
8	Total Book Deprec		48,170,507	32,007,440	1,273	10,065,954	186	23,520	4,446,114	1,626,020

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Taxes Other than Income Taxes

Property and Real Estate Taxes

	General Plant	Alloc	CO	RG	RGL	CG	CGL	IG	TF	TI
1	Property Tax	Total Net Plant	17,533,017	11,633,260	478	3,612,041	71	8,226	1,669,093	609,848
2	Other Taxes	Expense Subtotal	3,130,410	2,229,367	22	539,118	3	1,395	256,828	103,676
3	Total		20,663,427	13,862,627	500	4,151,159	74	9,621	1,925,921	713,524
4	Tot Non-Income Taxes		20,663,427	13,862,627	500	4,151,159	74	9,621	1,925,921	713,524
5	Subtotal Operating Expense		188,335,998	129,967,946	3,114	34,669,729	460	93,347	17,100,437	6,500,965

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Income Tax Summary

	Income Before Taxes	Alloc		CO	RG	RGL	CG	CGL	IG	TF	TI
1	Total Operating Revenues			284,359,158	202,536,118	4,334	51,866,226	641	157,175	22,111,135	7,683,530
2	less: Total Operating Expense			-167,672,570	-116,105,319	-2,614	-30,518,570	-385	-83,725	-15,174,516	-5,787,441
3	Taxes (other than Income)			-20,663,427	-13,862,627	-500	-4,151,159	-74	-9,621	-1,925,921	-713,524
4	Before Tax Book Income			96,023,160	72,568,171	1,219	17,196,497	181	63,829	5,010,697	1,182,565
	Inc Tax Additions										
5	Total Book Depr Exp			48,170,507	32,007,440	1,273	10,065,954	186	23,520	4,446,114	1,626,020
6	Total Tax Additions			48,170,507	32,007,440	1,273	10,065,954	186	23,520	4,446,114	1,626,020
	Inc Tax Deductions										
7	Schedule M Plant Expenses	Total Depreciation		61,522,629	40,879,408	1,627	12,856,081	238	30,039	5,678,508	2,076,728
8	Interest Expense	Rate Base		28,820,077	19,122,290	786	5,937,329	116	13,523	2,743,589	1,002,444
9	Other Tax Deductions	Exp Sub Less Dep Exp		-2,342,416	-1,668,186	-17	-403,409	-2	-1,043	-192,179	-77,580
10	Subtotal Operating Expense			188,335,998	129,967,946	3,114	34,669,729	460	93,347	17,100,437	6,500,965
11	Total			276,336,287	188,301,458	5,510	53,059,730	812	135,866	25,330,355	9,502,557
12	Taxable Net Income			8,022,870	14,234,659	-1,177	-1,193,503	-171	21,310	-3,219,220	-1,819,027
13	State Income Tax		4.63%	371,459	659,065	-54	-55,259	-8	987	-149,050	-84,221
14	ITC	Total Depreciation		-100,662	-66,887	-3	-21,034	0	-49	-9,291	-3,398
15	Interest on CWIP	Total Net Plant		24,024	15,939	1	4,949	0	11	2,287	836
16	Accum. Deferred State Inc. Tax	Depreciation		2,740,122	1,820,704	73	572,590	10	1,339	252,912	92,494
17	Total State Income Tax			3,034,943	2,428,822	17	501,246	2	2,288	96,858	5,711
18	Federal Income Tax		35.00%	2,677,994	4,751,458	-393	-398,385	-57	7,113	-1,074,560	-607,182
19	Accumulated Depreciation	Total Depreciation		19,754,909	13,126,374	522	4,128,086	76	9,645	1,823,369	666,837
20	ITC	Total Depreciation		-669,414	-444,799	-17	-139,884	-3	-327	-61,787	-22,597
21	Interest on CWIP	Total Net Plant		173,191	114,913	5	35,680	1	81	16,486	6,024
22	Total Federal Income Tax			21,936,680	17,547,947	117	3,625,497	17	16,512	703,509	43,082
23	Gain on Sale of Utility Property	Customers		848,988	779,672	23	66,937	4	7	2,180	165

PSCo - Gas Utility
Summary of Class Cost of Service Study: TY 2004 - Total

Allowance for Funds Used During Construction

	Production Plant	Alloc	CO	RG	RGL	CG	CGL	IG	TF	TI
1	P& G Plant	Net P&G Plant	-5,364	-2,950	0	-1,265	0	-4	-819	-326
2	P.E. Plant	Net P.E. Plant	2,786	1,532	0	657	0	2	425	170
3	Total		-2,578	-1,418	0	-608	0	-2	-394	-156
4	Storage	Net U.S.	47,116	31,207	0	13,384	0	47	1,751	727
5	Transmission	Net Trans	150,959	83,008	0	35,601	0	119	23,043	9,187
6	General	Net Dist	574,698	395,677	19	113,474	3	222	48,318	16,985
7	Common & General	Net C & G	802,651	531,142	21	166,464	3	385	76,576	28,060
8	Total AFUDC		1,572,845	1,039,616	40	328,315	6	771	149,294	54,803

PUBLIC SERVICE COMPANY OF COLORADO
DOCKET NO. 05S-264G - NATURAL GAS RATE CASE
SETTLED RATE DESIGN AND PRICE OUT
BASED ON 12 MONTHS ENDING DECEMBER 31, 2004

S&A Attachment E
(Corresponds to Exhibit No. SBB-2 (pp. 3 & 4))

CLASS AND TYPE OF CHARGE	SETTLED CHARGE	TEST-YEAR BILLING DETERMINANTS (BILLS OR DTH.)	SETTLED TEST-YEAR REVENUE
RG			
Service and Facility Charge	$ 10.00	13,265,415	$ 132,654,150
Volumetric Charge	$ 0.7956	92,281,320	$ 73,419,018
Total RG Revenue			*$ 206,073,168*
RGL			
Charge per Fixture (First Two Mantles)	$ 7.18	743	$ 5,335
Charge per Fixture (Additional Mantles)	$ 3.59	104	$ 373
Total RGL Revenue			*$ 5,708*
CG			
Service and Facility Charge	$ 20.00	1,138,868	$ 22,777,360
Volumetric Charge	$ 0.9555	39,581,231	$ 37,819,866
Total CG Revenue			*$ 60,597,226*
CGL			
Charge per Fixture (First Two Mantles)	$ 7.18	104	$ 747
Charge per Fixture (Additional Mantles)	$ 3.59	26	$ 93
Total CGL Revenue			*$ 840*
IG			
Service and Facility Charge	$ 70.00	126	$ 8,820
On-Peak Demand Charge	$ 4.66	214	$ 997
Volumetric Charge	$ 0.5004	354,945	$ 177,614
Unauthorized Overrun Gas Charge	$ 25.00	-	$ -
Total IG Revenue			*$ 187,432*

CLASS AND TYPE OF CHARGE	SETTLED CHARGE	TEST-YEAR BILLING DETERMINANTS (BILLS OR DTH.)	SETTLED TEST-YEAR REVENUE
TF			
FIRM GAS TRANSPORTATION SERVICE			
Service and Facility Charge	$ 70.00	36,902	$ 2,583,140
Specific Facility Revenue	$ 13,010	12	$ 156,120
Standard Firm Capacity Reservation Charge	$ 4.66	3,241,969	$ 15,107,576
Standard Volumetric Charge (1)	$ 0.2300	27,553,840	$ 6,337,383
Discounted Transportation Revenue		6,581,704	$ 1,017,937
Unauthorized Overrun Transportation Penalty Charge	$ 25.00	444	$ 11,100
BACKUP SUPPLY SALES SERVICE			
Firm Supply Reservation Charge	$0.00	80,911	$ -
Backup Supply Sales Charge (2)	$ 0.2300	36,853	$ 8,476
Unauthorized Overrun Supply Penalty Charge	$ 25.00	0	$ -
Total TF Revenue			*$ 25,221,732*
TI			
INTERRUPTIBLE GAS TRANSPORTATION SERVICE			
Service and Facility Charge	$ 140.00	2,624	$ 367,360
Standard Volumetric Charge (1)	$ 0.3980	17,074,908	$ 6,795,813
Discounted Transportation Revenue		10,288,980	$ 1,046,302
Unauthorized Overrun Transportation Penalty Charge	$ 25.00	1,620	$ 40,500
BACKUP SUPPLY SALES SERVICE			
On-Peak Demand Charge	$ 4.66	804	$ 3,747
Backup Supply Sales Charge (3)	$ 0.2300	1,973	$ 454
Unauthorized Overrun Supply Penalty Charge	$ 25.00	0	$ -
Total TI Revenue			*$ 8,254,176*
TOTAL TEST-YEAR REVENUE			**$ 300,340,282**

(1) Includes proposed test-year revenue from Authorized Overrun Service and Unauthorized Overrun Service provided at minimum rate.

(2) Includes proposed test-year revenue from Authorized Overrun Sales Charge.

(3) Includes proposed test-year revenue from Unauthorized Overrun Service at minimum rate.

CLASS AND TYPE OF CHARGE	CURRENT CHARGE w/o GRSA	CURRENT CHARGE w/ GRSA AND w/o DSMCA	SETTLED CHARGE
RG			
Service and Facility Charge	$ 9.00	$ 8.44	$ 10.00
Volumetric Charge	$ 0.9770	$ 0.9164	$ 0.7956
RGL			
Charge per Fixture (First Two Mantles)	$ 5.58	$ 5.23	$ 7.18
Charge per Fixture (Additional Mantles)	$ 2.79	$ 2.62	$ 3.59
CG			
Service and Facility Charge	$ 16.20	$ 15.20	$ 20.00
Volumetric Charge	$ 0.9170	$ 0.8601	$ 0.9555
CGL			
Charge per Fixture (First Two Mantles)	$ 5.58	$ 5.23	$ 7.18
Charge per Fixture (Additional Mantles)	$ 2.79	$ 2.62	$ 3.59
IG			
Service and Facility Charge	$ 90.00	$ 84.42	$ 70.00
On-Peak Demand Charge	$ 6.58	$ 6.17	$ 4.66
Volumetric Charge	$ 0.436	$ 0.4090	$ 0.5004
Unauthorized Overrun Gas Charge	$ 25.00	$ 23.45	$ 25.00

CLASS AND TYPE OF CHARGE	CURRENT CHARGE w/o GRSA	CURRENT CHARGE w/ GRSA AND w/o DSMCA	SETTLED CHARGE
TF			
FIRM GAS TRANSPORTATION SERVICE			
Service and Facility Charge	$ 60.00	$ 56.28	$ 70.00
Standard Firm Capacity Reservation Charge	$ 4.07	$ 3.82	$ 4.66
Minimum Firm Capacity Reservation Charge	$ 0.94	$ 0.94	$ 0.68
Standard Volumetric Charge	$ 0.250	$ 0.230	$ 0.2300
Minimum Volumetric Charge	$ 0.01	$ 0.01	$ 0.01
Authorized Overrun Transportation Charge	$ 0.250	$ 0.230	$ 0.2300
Standard Unauthorized Overrun Transportation Penalty Charge	$ 25.00	$ 23.45	$ 25.00
Minimum Unauthorized Overrun Transportation Penalty Charge	$ 0.250	$ 0.230	$ 0.2300
BACKUP SUPPLY SALES SERVICE			
Firm Supply Reservation Charge	$ -	$ -	$0.00
Backup Supply Sales Charge	$ 0.436	$ 0.4090	$ 0.2300
Authorized Overrun Sales Charge	$ 0.436	$ 0.4090	$ 0.230
Standard Unauthorized Overrun Supply Penalty Charge	$ 25.00	$ 23.45	$ 25.00
Minimum Unauthorized Overrun Supply Penalty Charge	$ 0.436	$ 0.4090	$ 0.2300
TI			
INTERRUPTIBLE GAS TRANSPORTATION SERVICE			
Service and Facility Charge w/ Phone Line	$ 240.00	$ 225.12	N/A
Service and Facility Charge w/o Phone Line	$ 195.00	$ 182.91	$ 140.00
Standard Volumetric Charge	$ 0.384	$ 0.360	$ 0.3980
Minimum Volumetric Charge	$ 0.01	$ 0.01	$ 0.01
Authorized Overrun Transportation Charge	$ 0.384	$ 0.360	$ 0.3980
Standard Unauthorized Overrun Transportation Penalty Charge	$ 25.00	$ 23.45	$ 25.00
Minimum Unauthorized Overrun Transportation Penalty Charge	$ 0.384	$ 0.360	$ 0.3980
BACKUP SUPPLY SALES SERVICE			
On-Peak Demand Charge	$ 6.58	$ 6.17	$ 4.66
Backup Supply Sales Charge	$ 0.436	$ 0.409	$ 0.2300
Standard Unauthorized Overrun Supply Penalty Charge	$ 25.00	$ 23.45	$ 25.00
Minimum Unauthorized Overrun Supply Penalty Charge	$ 0.436	$ 0.409	$ 0.2300

Public Service Company of Colorado **Attachment G**

Gas Department

Gas Rate Case Customer Impact Study - Settlement

Customer Class	Existing Rate	Proposed Rate	Monthly Average Usage	Monthly Existing Bill	Monthly Proposed Bill	Monthly Difference $	Difference %
Residential - Schedule RG							
Service and Facility Charge	$ 9.00	$ 10.00		$ 9.00	$ 10.00	$ 1.00	
Commodity Charge	$ 0.09770 /therm	$ 0.07956 /therm	68.34 therm	6.68	5.44	(1.24)	
Subtotal				$ 15.68	$ 15.44	$ (0.24)	
Base Rate Riders	-5.04%	1.16%		(0.79)	0.18	0.97	
Base Rate Amount				$ 14.89	$ 15.62	$ 0.73	4.90%
GCA	$ 0.94040	$ 0.94040		$ 64.27	$ 64.27	$ -	
Total Bill				$ 79.16	$ 79.89	**$ 0.73**	**0.92%**
Commerial - Schedule CG							
Service and Facility Charge	$ 16.20	$ 20.00		$ 16.20	$ 20.00	$ 3.80	
Commodity Charge	$ 0.09170 /therm	$ 0.09555 /therm	342.81 therm	31.44	32.76	1.32	
Subtotal				$ 47.64	$ 52.76	$ 5.12	
Base Rate Riders	-5.04%	1.16%		(2.40)	0.61	3.01	
Base Rate Amount				$ 45.24	$ 53.37	$ 8.13	17.97%
GCA	$ 0.91900	$ 0.91900		$ 315.04	$ 315.04	$ -	
Total Bill				$ 360.28	$ 368.41	**$ 8.13**	**2.26%**
Interruptible - Schedule IG							
Service and Facility Charge	$ 90.00	$ 70.00		$ 90.00	$ 70.00	$ (20.00)	
Commodity Charge	$ 0.4360 /Dth	$ 0.5004 /Dth	2,817.03 Dth	1,228.22	1,409.64	181.42	
Subtotal			2,817.03	$ 1,318.22	$ 1,479.64	$ 161.42	
Base Rate Riders	-5.04%	1.16%		(66.44)	17.16	83.60	
Base Rate Amount				$ 1,251.78	$ 1,496.80	$ 245.02	19.57%
GCA	$ 9.19000	$ 9.19000		$ 25,888.46	$ 25,888.46	$ -	
Total Bill				$ 27,140.24	$ 27,385.26	**$ 245.02**	**0.90%**
Firm Transportation - Schedule TF							
Service and Facility Charge	$ 60.00	$ 70.00		$ 60.00	$ 70.00	$ 10.00	
Firm Capacity Charge	$ 4.07	$ 4.66 /Dth	104.00 Dth	$ 423.28	$ 484.64		
Commodity Charge	$ 0.2500 /Dth	$ 0.2300 /Dth	926.50 Dth	231.63	213.10	(18.53)	
Subtotal			103.50065	$ 714.91	$ 767.74	$ (8.53)	
Base Rate Riders	-5.04%	1.16%	921.2379	(36.03)	8.91	44.94	
Base Rate Amount				$ 678.88	$ 776.65	$ 97.77	14.40%
GCA	$ 0.05700	$ 0.05700		$ 52.81	$ 52.81	$ -	
Total Bill				$ 731.69	$ 829.46	**$ 97.77**	**13.36%**
Interruptible Transportation - Schedule TI							
Service and Facility Charge	$ 195.00	$ 140.00		$ 195.00	$ 140.00	$ (55.00)	
Commodity Charge	$ 0.3840 /Dth	$ 0.3980 /Dth	621.21 Dth	238.54	247.24	8.70	
Subtotal			2,817.03	$ 433.54	$ 387.24	$ (46.30)	
Base Rate Riders	-5.04%	1.16%		(21.85)	4.49	26.34	
Base Rate Amount				$ 411.69	$ 391.73	$ (19.96)	-4.85%
GCA	$ 0.05700	$ 0.05700	4,684.74	$ 35.41	$ 35.41	$ -	
Total Bill				$ 447.10	$ 427.14	**$ (19.96)**	**-4.46%**