BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE LETTER NO. 791 FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO INCREASE THE RATES FOR ALL NATURAL GAS SALES AND TRANSPORTATION SERVICES BY IMPLEMENTING A GENERAL RATE SCHEDULE ADJUSTMENT ("GRSA") IN THE COMPANY'S COLORADO P.U.C. NO. 6 GAS TARIFF TO BECOME EFFECTIVE JANUARY 17, 2011.	)	DOCKET NO. 10AL-963G

SETTLEMENT AGREEMENT

May 25, 2011

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

* * * * *

IN THE MATTER OF ADVICE LETTER NO. 791 FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO INCREASE THE RATES FOR ALL NATURAL GAS SALES AND TRANSPORTATION SERVICES BY IMPLEMENTING A GENERAL RATE SCHEDULE ADJUSTMENT ("GRSA") IN THE COMPANY'S COLORADO P.U.C. NO. 6 GAS TARIFF TO BECOME EFFECTIVE JANUARY 17, 2011.	DOCKET NO. 10AL-963G

SETTLEMENT AGREEMENT

Public Service Company of Colorado ("Public Service" or the "Company"), the Staff of the Colorado Public Utilities Commission ("Staff") and the Colorado Office of Consumer Counsel ("OCC") (collectively, the "Settling Parties") hereby enter into this Settlement Agreement. However, the OCC neither supports nor opposes the agreement reached between the Company and Staff set forth in Section 5 regarding the recovery of gas storage inventory costs through the Gas Cost Adjustment.

INTRODUCTION

On December 17, 2010, Public Service filed Advice Letter No. 791 – Gas with the Colorado Public Utilities Commission ("Commission" or "CPUC"), proposing to increase rates for its natural gas sales and transportation services by implementing a General Rate Schedule Adjustment ("GRSA") in the Company's Colorado P.U.C. No. 6 – Gas tariff, to become effective January 17, 2011, as later modified to become effective February 7, 2011. In addition to proposing to increase its annual base rate revenues by

$27,483,653, the Company proposed to 1) terminate cost recovery of the return component on the average gas storage inventory balance through base rates and commence recovery of these costs through the Gas Cost Adjustment ("GCA"); 2) implement a new Pipeline System Integrity Adjustment ("PSIA"), effective January 1, 2012; 3) eliminate the Partial Decoupling Rate Adjustment ("PDRA"); and 4) revise portions of the Charges for Rendering Service to update these charges to current cost levels.

As part of a Stipulation and Agreement reached with the Staff in Docket No. 10F-011G, the Company agreed to file a Phase I rate case before the end of 2010. That Stipulation and Agreement was approved by the Commission pursuant to Decision No. R10-0599, mailed June 14, 2010. The Company filed Advice No. 791 – Gas in accordance with the terms of the approved Stipulation and Agreement.

The Company also filed Direct Testimony and Exhibits in support of the proposed rate and tariff changes. The Company's proposed revenue requirement was calculated based on a forecast test year ("FTY") consisting of the twelve months ending December 31, 2011.

On February 7, 2011, Public Service filed Supplemental Direct Testimony of Scott B. Brockett. The purpose of Mr. Brockett's February 7 Supplemental Direct Testimony was to demonstrate the increase that would be required if the estimated Pipeline System Integrity costs were recovered through the GRSA rather than the proposed PSIA, as ordered by the Commission in Decision No. C11-0040 and clarified in Decision No. C11-0124.

On February 28, 2011, the Company filed Supplemental Direct Testimony of Deborah A. Blair. The purpose of Ms. Blair's February 28 Supplemental Direct Testimony was to present the gas department's revenue requirements study based on a historic test year ("HTY") consisting of the twelve months ending December 31, 2010, with pro forma adjustments, as directed by the Commission in Decision No. C11-0040 and clarified in Decision No. C11-0124.

On March 14, 2011, Ms. Blair submitted Second Supplemental Direct Testimony and Exhibits and Ms. Hyde submitted Supplemental Direct Testimony and Exhibits for purposes of updating and correcting the 2011 FTY cost of service originally filed by the Company on December 17, 2010. The net effect of the revisions made by the Company on March 14, 2011 was to decrease the Company's revenue deficiency from $27.5 million to $25,632,286.

On April 11, 2011, various parties filed Answer Testimony and Exhibits objecting to aspects of the Company's requested rate changes, the FTY cost of service ("COS") and overall revenue requirement, capital structure, and return on equity, among other issues. Both the Staff and the OCC used as their starting point the Company's 2010 HTY filed on February 28, 2011 and recommended overall base rate revenue reductions. In addition, the OCC filed testimony, which was subsequently revised on May 17, 2011, responding to the Company's FTY filing and recommended an overall base rate revenue reduction. Staff's calculated revenue reduction, based on a HTY ending December 31, 2010, adjusted for known and measurable changes, corrected as of the time of hearing, was $17.5 million. The OCC's calculated revenue reduction, based on a HTY ending December 31, 2010, after incorporating all of its recommended adjustments was $991,000. The OCC's calculated revenue reduction, based on a FTY ending December 31, 2011, after incorporating all of its recommended adjustments, was $87,000.

In its Rebuttal Case filed on May 9, 2011, the Company updated its 2011 FTY and 2010 HTY COS to reflect certain corrections, additional information, as well as concessions in response to issues raised by the Intervenors in their Answer Testimony. Based on corrections and concessions that the Company detailed in its Rebuttal Testimony, the Company calculated a revenue deficiency of $20.3 million based on the FTY and $20.7 million based on the HTY.

Hearings in this case were scheduled to begin on May 23, 2011. Immediately prior to hearings, Staff and the Company reached a settlement in principle settling all contested issues in this case, other than the issue raised by Energy Outreach Colorado ("EOC") regarding the treatment of residential late payment revenues, which Staff and the Company agreed should be decided by the Commission based on the record evidence. The next day, May 24, 2011, the Company met with the OCC. After negotiating a few additional terms, the OCC joined the settlement in principle.

PUBLIC INTEREST

The Settling 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, consistent with Commission Rule 1408 encouraging settlements and, that therefore, the compromises and settlements reflected in this Settlement Agreement are in the public interest. The Settling Parties further agree that the results of the compromises and settlements reflected by this Agreement are just, reasonable and in the public interest.

SETTLEMENT

This Settlement Agreement is intended to be a comprehensive settlement resolving all issues raised by the Staff and the OCC with respect to the Company's Phase I rate case filing. To the extent that an issue has not been addressed specifically in this settlement, the Settling Parties agree that the Company's position as set forth in its Rebuttal Testimony and Exhibits, shall govern for purposes of cost recovery until new rates take effect as a result of the next Phase I rate case filed by the Company.

1. Base Rate Revenue Increase

The Settling Parties agree that the Company shall be authorized to put into effect, beginning September 5, 2011, a GRSA equal to 3.12% representing an annual base rate revenue increase of $10.9 million over the rates that are currently in effect. The GRSA shall apply to all base rate elements contained in the natural gas sales and transportation rate schedules affected by the Company's rate change filing.

The rate base used in the calculation of the return component underlying the $10.9 million revenue increase is a test year consisting of the Company's 2010 HTY adjusted to reflect an approximation of the 13-month average plant-in-service and CWIP balances for the period June 30, 2010 through June 30, 2011 rather than the year end balances originally used by the Company to determine rate base. The Settling Parties agree that return on rate base shall be calculated using the adjusted plant-in-service and CWIP balances described in this paragraph. The Settling Parties also agree that the Rate Case Principles set forth in Section 2 shall be incorporated into the test year cost of service that is the basis for the base rate increase agreed to as a result of this Stipulation.

2. Rate Case Principles Incorporated into the Base Rate Revenue Increase

The following rate case principles are incorporated into the test year COS used to calculate the $10.9 million base rate revenue increase agreed to by this Stipulation.

A. Authorized Return on Equity, Cost of Debt and Return on Rate Base.

For purposes of settlement, the Settling Parties agree that the test year COS shall incorporate a weighted average cost of debt equal to 5.86 percent consistent with the calculation reflected in Revised Exhibit No. GET-2 filed with Company witness Tyson's Rebuttal Testimony and Exhibits on May 9, 2011. The Settling Parties also agree to use an authorized Return on Equity ("ROE") of 10.10 percent resulting in an overall return on rate base of 8.24 percent.

B. Capital Structure

The Settling Parties agree that for purposes of calculating the revenue deficiency in this proceeding, the Company shall use a capital structure consisting of 56 percent equity and 44 percent debt, which is consistent with what the Company has forecasted for its actual capital structure to be used for regulatory purposes beginning in 2012.

C. Deferred Transmission Integrity Management Programs Costs

The Settling Parties agree that the Company shall be permitted to amortize the regulatory asset created by the deferral of O&M expenses incurred in implementing its federally-mandated Transmission Integrity Management Program ("TIMP") as of December 31, 2010, in the amount of approximately $27.1 million, as set forth in Exhibit A to this Settlement Agreement, over a five-year period commencing September 5,

2011. This is in addition to the $7,073,600 annual TIMP O&M costs included in the test year COS. The Company agrees to implement a negative rider or to reduce its GRSA, as necessary, to reflect the expiration of this five-year amortization period. The Settling Parties agree that the Commission's approval of this Settlement Agreement will constitute its approval of the Company's past deferred accounting and ratemaking treatment of TIMP O&M expenses and further authorization for the Company to amortize the $27.1 million regulatory asset commencing September 5, 2011.

D. Construction Work In Progress and Plant Held for Future Use.

The Settling Parties agree that the Company shall include in rate base an estimate of the 13 month average Construction Work In Progress ("CWIP") balance for the period June 30, 2010 through June 30, 2011 and Plant Held for Future Use ("PHFU") as of June 30, 2011. The Company shall also include in the test year COS an offset to earnings equal to the estimate of the Allowance for Funds Used During Construction ("AFUDC") for the twelve months ending June 30, 2011.

E. Tax Normalization and Allowance for Net Operating Losses

The Settling Parties agree that the Company shall calculate the revenue deficiency using full tax normalization, allowing the Company to provide for deferred taxes on all book/tax timing differences, including the Company's proposed offset to accumulated deferred income taxes ("ADIT") for the net operating loss carry forward applicable to the Company's gas department for income tax purposes for calendar year 2010. The Company agrees to file on each April 30, as necessary, a GRSA (or to modify its then-current GRSA, if applicable) to reflect the revenue requirement effect of any reduction or elimination of the NOL carry forward offset to ADIT included in the test year COS. This change in rates shall be made in a manner that is consistent with the income tax normalization requirements for public utilities under the Internal Revenue Code. The NOL carry forward offset to ADIT included in the test year COS is equal to $9,007,058 and the revenue requirement associated with this offset is equal to $1,059,099.

F. Rate Case Expenses

The Settling Parties agree that the Company shall be permitted to amortize $1,207,316 million in rate case expenses over a three-year period beginning September 5, 2011. The level of rate case expenses has been reduced by $75,000 from the level initially requested by the Company, which is equal to the Company's estimate of its expenses associated with hiring one of its outside consultants. The Company further agrees that the rolling balance method of treating amortizations of rate case expenses as described in the Company's Rebuttal Testimony shall not apply with respect to the rate case expenses being amortized pursuant to this Settlement Agreement. In the event the Company files a rate proceeding prior to the time that these rate case expenses are fully amortized, the unamortized balance shall not be rolled in to the revenue requirements calculation in the next rate case.

G. Treatment of Gain on Sale of the Technical Services Building.

The Settling Parties agree that the gain on sale of the Technical Services Building shall be amortized over two years as set forth in the Company's Rebuttal Testimony. The Company shall be permitted to increase its GRSA or implement an alternative positive rider to reverse the effect of this amortization effective September 5, 2013.

H. Other Cost of Service Adjustments.

Staff's 2010 HTY COS included a number of adjustments to expenses included in the Company's 2010 HTY COS that have been accepted by the Company in arriving at this Settlement Agreement. These include Staff's recommended adjustments to incentive compensation, alcohol expense, and aviation costs, and the shift in regulatory and resource planning labor. The Company has also accepted the OCC's recommendation to revise the revenue lag associated with residential late payment revenues to thirty-three days for purposes of calculating cash working capital to reflect the change in the billing of late payment fees to non-residential customers beginning June 2010.

In addition to these adjustments, the Company has corrected the common plant allocator used in its HTY COS as filed on February 28, 2011 and has updated the out-of period adjustment it made initially to reflect the known and measurable 2011 increases in pension and benefits cost. The Company also accepted Staff's recommended change to remove the unamortized TIMP balance from rate base. Lastly, the Company has made a minor reduction in the test year COS to incorporate recently received IRS guidance regarding the 2010 tax law changes on bonus depreciation.

The Settling Parties agree that the settlement as to all adjustments to the test year COS discussed in this Section 2.H. shall have no precedential effect going forward and shall not limit or affect the positions that the Settling Parties may take on such issues in any subsequent Phase I rate proceeding.

J. Test Year Billing Determinants.

The Settling Parties agree that the billing determinants used for purposes of calculating test year revenues shall be the billing determinants proposed by Company witness Ms. Marks in her Supplemental Direct Testimony and Exhibits.

K. Treatment of Residential Late Payments.

Staff and OCC take no position regarding the issues raised by EOC in its Answer Testimony relating to the treatment of residential late payments and the proposal made by Ms. Hyde to address EOC's concerns in her Rebuttal Testimony. The Settling Parties agree that the test year COS shall be adjusted, as necessary, to reflect the Commission's ruling on the disposition of the residential late payment revenues and resulting credits to the cost of service.

L. Summary of Adjustments to the Company's 2010 HTY COS.

The following table summarizes the impact of the adjustments the Company has agreed to make to its 2010 HTY COS to derive the test year COS that is the basis for the new rates agreed to as a result of this Stipulation.

Supplemental Direct (HTY) Proposed Revenue Deficiency	$27,427,994
Correction of Common Plant Allocator	$ (251,932)
Aircraft costs	$ (340,707)
Remove Deferred IMP from Rate Base	$ (2,714,532)
Elimination of Alcohol Expenses	$ (5,682)
ROE from 10.9 to 10.8%:	$ (876,730)
Adjust 2011 pension and benefit expenses	$ (1,137,681)
IRS Guidance on Bonus Tax Depreciation Law/NOL Carry forward	(67,365)
Gain on Sale of TSB	$ (873,473)
Cash Working Capital - Revenue Lag Days for Late Payment	$ (418,252)
Rebuttal (HTY) Proposed Revenue Deficiency	$ 20,741,640

ROE from 10.8 to 10.1%:	$ (6,986,839)
2012 Cap Structure – 56% equity	$ (690,753)
Eliminate Shift in Regulatory and Resource Planning Labor	$ (228,245)
Reduce Rate Case Expenses and change Amortization period to three years	$ (239,910)
Remove a portion of Incentive Pay	$ (874,953)
TY depreciation:	$ (482,659)
True Up NOL Carry forward to Final COS	$ 330,782
TY average rate base	$ (468,893)
Revenue Lag Days	$ (199,287)
Settled Revenue Deficiency:	$10,900,883

3. Rate Case Principles to be used in Calculating Gas Utility Earnings in the Annual Appendix A.

Attached to this Settlement Agreement as Exhibit B are the rate case principles the Settling Parties agree shall be applied by the Company in calculating the gas department earnings for purposes of its annual Appendix A filings.

4. Pipeline System Integrity Adjustment Clause

The Settling Parties agree that the Company shall be permitted to implement a Pipeline System Integrity Adjustment ("PSIA") mechanism, providing for an initial PSIA rate, effective January 1, 2012 for the purposes of recovering costs that are incremental, either positive or negative, to those O&M and capital costs associated with the Company's TIMP, AMRP, CAB, and DIMP programs, and the Edwards to Meadow Mountain and West Main Pipeline Projects, as further defined in the PSIA tariff attached hereto as Exhibit C.

For purposes of applying the tariff formula for the PSIA Adjustment Calculation the "Projects Base Amount" shall be $14,249,527 as reflected in Exhibit D. This shall be the Projects Base Amount in effect until the Commission issues a final order in the

Company's next Phase I rate case that establishes a new Projects Base Amount. The revenue requirement impact of the 2012 PSIA shall also include the deferred TIMP and DIMP O&M costs incurred by the Company from January 1, 2011 through September 4, 2011.

The Settling Parties agree that the only portion of the Edwards to Meadow Mountain Pipeline Project cost that may be recovered through the PSIA is the cost corresponding to replacement of the pipeline with like size. In the case of the Edwards to Meadow Mountain Pipeline Project, the percentage attributable to replacing the line with like size has been set at 73.4% as provided in the estimate shown in Exhibit E. The Company may seek to recover the balance of the Edwards to Meadow Mountain Pipeline cost in a Phase I ratemaking proceeding.

The Settling Parties agree that the only portion of the West Main Pipeline Project cost that may be recovered through the PSIA is the cost corresponding to replacement of the pipeline with like size. In the case of the West Main Pipeline Project, the percentage attributable to replacing the line with like size has been set at 77.1% as provided in the estimate shown in Exhibit F. The Company may seek to recover the balance of the West Main Pipeline Project cost in a Phase I ratemaking proceeding.

No other major pipeline projects are permitted to be included in the PSIA without obtaining prior Commission approval. The Company agrees to submit a report each year by April 1 detailing the costs incurred during the previous year. This report will explain how the project costs were managed and any deviations between budgeted and actual costs. To the extent interested parties wish to challenge any of the activities or their respective costs, they can request that the Commission convene a hearing within ninety (90) days of the date the Company files its report. The Company would file the first such report on April 1, 2013.

The Company agrees to file a Phase I rate case within three years of December 17, 2010 and at least every three years thereafter for so long as the PSIA remains in effect.

5. Recovery of Costs Associated with Gas Stored Underground Inventory Through the GCA.

OCC neither opposes nor supports the agreements reflected in this Paragraph. Staff and the Company agree that, commencing with the Company's annual GCA filing to be filed in mid-September 2011 for rates to be effective October 1, 2011, the Company shall commence recovering its Gas Storage Inventory Costs ("GSIC") through the Gas Cost Adjustment clause, as proposed in the Direct Testimony and Exhibits of Company witness John Kundert. Staff and the Company further agree that the GSIC for the period September 5, 2011 until October 1, 2011 shall be added to and recovered as part of the Company's Deferred Gas Cost.

6. Elimination of Partial Decoupling Rate Adjustment.

The Settling Parties agree to the Company's proposal to eliminate the PDRA as proposed by Company witness Brockett in his Direct Testimony and Exhibits.

7. Approval of Company Proposed Depreciation Rates.

The Settling Parties agree that the depreciation rates proposed by Company witness Lisa Perkett. as reflected in Appendices A and B to Exhibit LHP-4, pp. 78-85, filed with her Direct Testimony and Exhibits, shall be approved by the Commission.

8. Additional Deferred Accounting Authority.

Consistent with the ratemaking treatment provided for in this Settlement Agreement, Public Service shall be authorized to defer ongoing expenses and credits related to remaining work associated with the environmental cleanup of the Fort Collins manufactured gas plant site, and the decommissioning of the Leyden Gas Storage Facility site. The "rolling balance" concept shall continue to apply to the amortization of these costs, such that if the two-year amortization period expires prior to the effective date of new rates resulting from a general rate case proceeding, the Company shall file a negative rider to reflect the removal of such amortizations. The amortization expense included in the Company's base rates associated with these projects is shown in Revised Exhibit No. DAB-8, Schedule 24, page 4 for the Fort Collins amortization and Revised Exhibit No. DAB-8, Schedule 24, page 5 for the Leyden amortization.

Consistent with the PSIA treatment of TIMP O&M costs incurred after January 1, 2011 as described in Paragraph 4 of this Settlement Agreement, the Company shall be authorized to defer the O&M expenses incurred under the Company's Transmission Integrity Management program in excess of the base allowance included in current rates for the period January 1, 2011 through September 4, 2011.

9. Charges for Rendering Service.

Staff and OCC took no position as to the Company's proposed changes to its the Charges for Rendering Service as set forth in the Direct Testimony and Exhibits of Company witness, Priya Burkett, but agree to the implementation of such tariff for cost recovery purposes only.

IMPLEMENTATION

The Settling Parties agree that, with the exception of the change in the GCA referenced in Section 5, *infra,* the rate and tariff changes resulting from this Settlement Agreement should be approved by the Commission to become effective September 5, 2011.

GENERAL TERMS AND CONDITIONS

This Settlement Agreement reflects compromise and settlement of all issues raised or that could have been raised by the Settling Parties in this Docket other than those relating to the Company's proposed donation of residential late payment revenues to EOC and removal of the associated revenue credit reflected in the COS.

This Settlement Agreement shall not become effective until the issuance of a final Commission Order approving the Settlement Agreement, which Order does not contain any modification of the terms and conditions of this Settlement Agreement that is unacceptable to any of the Settling Parties. In the event the Commission modifies this Settlement Agreement in a manner unacceptable to any of the Settling Parties, that Settling Party shall have the right to withdraw from this Agreement and proceed to file a written statement or position advocating its position on any issues that were raised by that Settling Party in this docket. The withdrawing Settling Party shall notify the Commission and the other Parties to this proceeding by e-mail within three business days of the Commission modification of this Settlement Agreement ("Notice of Withdrawal") that the party is withdrawing from the Settlement Agreement and designating the precise issues that the withdrawing party wishes to address in a further statement of position.

The withdrawal of a Settling Party shall not automatically terminate this Agreement as to the withdrawing party or any other party. However, within three business days of the date of the Notice of Withdrawal from the first withdrawing party, the remaining Settling Party shall designate any issues that it intends to address in its written statement of position. The withdrawing parties shall have and be entitled to exercise all rights with respect to the issue addressed subsequent to entry of the Commission's order that they would have had in the absence of this Settlement Agreement.

In the event that this Agreement is not approved, or is approved with conditions that are unacceptable to any Settling Party who subsequently withdraws, the negotiations or discussions undertaken in conjunction with the Agreement shall not be admissible into evidence in this or any other proceeding, except as may be necessary in any proceeding to enforce this Settlement Agreement.

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

The Settling Parties specifically agree and understand that this Settlement represents a negotiated settlement in the public interest with respect to the various Public Service rate matters that have been agreed to in this Settlement. Nothing in this Settlement Agreement shall preclude the Company from seeking prospective changes in its gas rates by an appropriate filing with the Commission or shall preclude any other party from filing a Complaint or seeking an Order to Show Cause to obtain prospective changes in the Company's gas rates.

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

The Settling Parties understand that this Settlement Agreement will not be executed by all parties to this docket. The Settling Parties agree to reasonably defend this Settlement Agreement before the Commission against challenges that may be made by non-executing parties.

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

Dated this 25th day of May, 2011.

PUBLIC SERVICE COMPANY OF COLORADO

By: Karen T Hyde
Karen T. Hyde
Vice President, Rates and Regulatory Affairs
Xcel Energy Services Inc.
1800 Larimer St., Suite 1400
Denver, Colorado 80202

Agent for Public Service
Company of Colorado

Approve as to form:

By:______________________________

Ann E. Hopfenbeck, #15460
Ducker, Montgomery, Lewis & Bess, P.C.
c/o Xcel Energy Services Inc.
1800 Larimer St., Suite 1100
Denver, CO 80202
Telephone: (303)294-2059
Fax: (303)294-2988
Ann.e.hopfenbeck@xcelenergy.com
ahopfenbeck@duckerlaw.com

Attorney for Public Service
Company of Colorado

COLORADO OFFICE OF CONSUMER COUNSEL

By: ______________________________

P.B. Schechter
Rate/Financial Analyst
Colorado Office of Consumer Counsel
1560 Broadway, Suite 200
Denver, CO 80202
Phone: (303) 894-2124
Fax: (303) 894-2117
pb.schechter@dora.state.co.us

Office of the Attorney General
John W. Suthers, Attorney General

Approved as to Form:

By:______________________________

Stephen W. Southwick, 30389
First Assistant Attorney General
Office of the Attorney General
1525 Sherman St., 7th Floor
Denver, CO 80203
Phone: (303) 866-5869
Fax: (303) 866-5691
stephen.southwick@state.co.us

Approve as to form:

By:____________________________

Ann E. Hopfenbeck, #15460
Ducker, Montgomery, Lewis & Bess, P.C.
c/o Xcel Energy Services Inc.
1800 Larimer St., Suite 1100
Denver, CO 80202
Telephone: (303)294-2059
Fax: (303)294-2988
Ann.e.hopfenbeck@xcelenergy.com
ahopfenbeck@duckerlaw.com

Attorney for Public Service
Company of Colorado

COLORADO OFFICE OF CONSUMER COUNSEL

By: PB Schechter

P.B. Schechter
Rate/Financial Analyst
Colorado Office of Consumer Counsel
1560 Broadway, Suite 200
Denver, CO 80202
Phone: (303) 894-2124
Fax: (303) 894-2117
pb.schechter@dora.state.co.us

Office of the Attorney General
John W. Suthers, Attorney General

Approved as to Form:

By: Stephen W. Southwick

Stephen W. Southwick, 30389
First Assistant Attorney General
Office of the Attorney General
1525 Sherman St., 7th Floor
Denver, CO 80203
Phone: (303) 866-5869
Fax: (303) 866-5691
stephen.southwick@state.co.us

STAFF OF THE COLORADO PUBLIC UTILITIES COMMISSION

By: ______________________________
Charles B. Hernandez
Chief Economist
Economic & Financial Analysis

Colorado Department of
Regulatory Agencies
Public Utilities Commission
1560 Broadway, Suite 250
Denver, CO 80202
Telephone: (303) 894-2901

Approved as to form:

____
Jean S. Watson-Weidner, #21036
Emanuel Cocian, #36562
Kevin Opp, #36607
Michael Santisi, #29673
Assistant Attorneys General
Office of the Attorney General
Business and Licensing Section
1525 Sherman Street, 5th Floor
Denver, CO 80203
Telephone: (303) 866-5158/5141

Counsel for Staff of the Colorado Public Utilities Commission

Public Service Company of Colorado
Amortization of Integrity Management Program Costs
12 Months Ended December 31, 2010

REVISED Exhibit No. DAB-8
Schedule 7

Line No.	Description	Amount
1	Unamortized Balance @ December 31, 2010	27,081,642
2	Annual Amortization (1)	5,416,328
3	Projected Unamortized Balance @ December 31, 2011	21,665,314
4		
5		
6	Annual Amortization (1)	5,416,328
7	Less: Per Book Amortization	2,542,287
8	Pro Forma Adjustment	2,874,041

(1) Five-year amortization.

Public Service Company of Colorado
Regulatory Principles and Adjustments
Used for Purposes of Calculating the Annual Appendix A Report

Line No.		Description
1		Rate Base is calculated using a 13-month average balance method, except for Cash Working Capital
2		The materials and supplies inventory balance is calculated using a 13-month average
3		Gas Storage Inventory balance is not included in rate base, rather it is recovered through the GCA
4		Rate Base adjustments are made on a 13-month average balance method, to the extent possible; otherwise, the sum of the prior year-end balance and the test year-end balance divided by two is used
5		Pro forma adjustments to Rate Base for known and measurable changes occurring outside the test year are generally not made when using an historic test year
6		Common plant is allocated to the gas department based on a study of all common plant assets that assigns an allocation method for each type of asset
7		Adjustment to PIS and plant-related items for projects not related to the gas department, e.g., SmartGridCity and Wind Predictor
8		Adjustments to PIS and plant-related items related to the office consolidation in Downtown Denver and the sale of the TSB facility.
9		Construction Work in Progress (CWIP) is included in rate base with an AFUDC offset to earnings
10		Contractor retentions are eliminated from the CWIP balance
11		Capital lease assets are not included in rate base
12		Eliminate a portion of the materials and supplies inventory balance allocated to construction-related projects
13		Cash Working Capital components are: natural gas purchased for resale costs; O&M expense, paid time off, incentive pay, taxes other than income taxes, federal and state income taxes and franchise and sales taxes
14		Cash Working Capital factors are based on a lead-lag study
15		The prepaid pension asset is recognized in rate base on a pre-tax basis
16		Deductions from rate base include: customer deposits and customer advances for construction
17		Full normalization is the method of accounting for income taxes
18		Net ADIT balances are a reduction to rate base, as opposed to a cost-free component in the capital structure
19		Eliminate ADIT related to items not included in the cost of service

Public Service Company of Colorado
Regulatory Principles and Adjustments
Used for Purposes of Calculating the Annual Appendix A Report

Line No.		Description
20		Eliminate ADIT related to the Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" (SFAS109)
21		Include an adjustment to ADIT and Deferred Income Tax expense associated with the interest on CWIP
22		Eliminate all gas purchased for resale and deferred gas costs
23		Include pro forma adjustments to O&M expenses for known and measurable changes occurring both in the test period (in-period adjustments), and outside the test year (out-of-period adjustments)
24		Out-of-period adjustments to O&M expense are generally not made for items expected to occur more than one year after the test year has ended when using an historic test year
25		Eliminate O&M expenses that are not recovered through base rates, but rather recovered through other mechanisms
26		Eliminate O&M expense for the office consolidation in Downtown Denver and the sale of TSB
27		Reclassify labor costs from gas purchased for resale FERC accounts to base rates
28		Eliminate the expenses associated with the Front Range Pipeline
29		Include the revenue associated with Pipeline System Integrity Rider in the the cost of service along with the costs associated with these programs that are recovered through the PSIA.
30		Include an amortization of the Transmission Integrity Management Programs that have been deferred through December 31, 2010 for 5 years beginning September 5, 2011.
31		Include incentive pay at actual cost levels.
32		Include customer deposit interest as an adjustment to Customer Operations expense
33		Exclude Demand Side Management costs from base rates
34		Eliminate advertising expenses related to marketing, promotion, community relations, image, and political ads
35		Include safety, conservation and customer program related advertising costs in the cost of service
36		Eliminate American Gas Association dues that are associated with certain advertising and lobbying
37		All lobbying expenses and donations booked in FERC Account 426 are not included in the cost of service

Public Service Company of Colorado
Regulatory Principles and Adjustments
Used for Purposes of Calculating the Annual Appendix A Report

Line No.		Description
38		Cost allocation between regulated and non-regulated business activities is based on the Cost Allocation and Assignment Manual, with adjustments for A&G loadings on non-regulated business included in A&G expense
39		Include an adjustment to pension and benefit expense to reflect the level of costs one year following the test year when using an historic test year based on the most recent actuarial study
40		Include an adjustment to regulatory commission expense to reflect the level of CPUC annual regulatory fees based on one year following the test year when using the historic test year
41		Included an adjustment to eliminate the expenses associated with the long-term portion of the officers' incentive compensation
42		Eliminate employee expenses not in compliance with corporate accounting guidelines
43		Include an amortization of rate case expense to recover the incremental costs of Docket No. 10AL-963G
44		Include adjustments to depreciation and amortization expense to correspond with adjustments made to plant and accumulated depreciation, or to exclude amounts not included in the cost of service, e.g., SmartGridCity, Wind Predictor software, TSB, and SSP leasehold improvements
45		Eliminate property taxes associated with Front Range Pipeline
46		Include an adjustment to eliminate the payroll taxes associated with the labor costs related to the Front Range Pipeline
47		Include an adustment to payroll taxes for any adjustment to test period employee labor costs
48		Current Federal and State income taxes are calculated as follows: taxable income is determined by using revenues less expenses, then synchronized interest expense is deducted and taxable additions/deductions are added, then state and federal income tax rates are applied.
49		Deferred income tax expense and the amortization of investment tax credits are added to the cost of service
50		Eliminate deferred taxes associated with accounts that are not included in the cost of service
51		Include an offsetting adjustment to earnings for Allowance for Funds Used During Construction (AFUDC)
52		AFUDC addition to earnings is based on actual test-period expenses and is not annualized, if rate base is calculated using a 13-month average instead of a year-end balance

Public Service Company of Colorado
Regulatory Principles and Adjustments
Used for Purposes of Calculating the Annual Appendix A Report

Line No.		Description
53		Adjustments are made to eliminate other revenue amounts not included in retail base rates, e.g., rate refunds, Quality of Service Plan incentives
54		Include interest on the deferred balances associated with environmental cleanup expense and the Leyden closure costs
55		All cost of service line items are allocated to the retail jurisdiction based on either a fundamental allocator or a derived allocator. The fundamental allocators include the peak day demand, annual consumption and the total number of customers
56		Direct assignment of any cost of service item to either the retail or the FERC jurisdiction are identified
57		The capital structure is based on actual year-end book balances
58		Eliminate Notes Payable/Notes Receivable with subsidiaries from debt component in capital structure
59		Eliminate investment in subsidiaries, subsidiary retained earnings, net non-utility plant, other investments, other funds and other comprehensive income from the equity component in capital structure
60		The cost of debt corresponds with the debt balances in the capital structure, and includes bond premiums or discounts, underwriting expenses, and other expenses of issue
61		Present revenues used to derive the revenue deficiency is based on billed revenues, adjusted to eliminate the revenues billed on various recovery mechanisms, e.g., GCA, GDSMCA, PDRA and PEAP
62		No adjustments to present revenues for customer additions or losses to the test year sales
63		Test year gas sales are normalized for weather

NATURAL GAS RATES
PIPELINE SYSTEM INTEGRITY ADJUSTMENT N

APPLICABILITY

All rate schedules for natural gas service are subject to a Pipeline System Integrity Adjustment ("PSIA") designed to collect the costs of Projects, as defined herein. The PSIA amounts will be subject to annual changes to be effective on January 1 of each year. The PSIA to be applied to each rate schedule is as set forth on Sheet No. 47C.

ANNUAL FILINGS

Each proposed revision in the Pipeline System Integrity Adjustment will be accomplished by filing an advice letter on October 1 of each year to take effect on the following January 1. The Company will include in its annual PSIA filings all pertinent information and supporting data on each of the Projects, e.g., project description and scope, project costs, in-service date, etc.

DEFINITIONS

Deferred PSIA Balance is the balance, positive or negative, of PSIA revenues at calendar year-end for the year prior to the annual November 1 PSIA filing less the Pipeline System Integrity Costs as forecast by the Company for the previous calendar year of the annual October 1 PSIA filing.

Pipeline System Integrity Cost is defined as (1) a return, equal to the Company's projected weighted average cost of capital, on the projected increase in the retail jurisdictional portion of the thirteen (13) month average net plant in-service balances associated with the Projects for the following calendar year in which the PSIA will be in effect exclusive of all plant in-service included in the determination of the revenue requirements approved in the Company's last general gas rate case; (2) the plant-related ownership costs associated with such incremental plant investment, including depreciation, accumulated deferred income taxes, and income taxes; and (3) the projected incremental Operating and Maintenance expenses related to the Projects for the following calendar year in which the PSIA will be in effect.

Pipeline System Integrity Cost Projects ("Projects") are defined as the Transmission Integrity Management Program ("TIMP"), the Distribution Integrity Management Program ("DIMP"), the Accelerated Main Renewal Program ("AMRP"), the Cellulose Acetate Butyrate Services Replacement Program ("CAB"), the Edwards to Meadow Mountain Pipeline and the West Main Replacement.

(Continued on Sheet No. 47A)

PUBLIC SERVICE COMPANY OF COLORADO

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

NATURAL GAS RATES
PIPELINE SYSTEM INTEGRITY ADJUSTMENT

N

DEFINITIONS - Cont'd

Pipeline System Integrity Cost Projects ("Projects") - Cont'd
For the West Main Replacement project, the projected net plant in-service balances for the following calendar year will be reduced by 22.9 percent for purposes of determining the Pipeline System Integrity Cost as defined above. For the Edwards to Meadow Mountain project, the projected net plant in-service balances for the following calendar year will be reduced by 26.6 percent for purposes of determining the Pipeline System Integrity Cost as defined above.

Projects Base Amount is defined as the amount of Projects cost included in the determination of the revenue requirements approved in the Company's last general gas rate case.

PSIA True-up Amount is equal to the difference, positive or negative, between the Pipeline System Integrity Cost as forecasted for the calendar year prior to the annual October 1 filing and the actual PSIA cost incurred by the Company for the calendar year immediately preceding the annual October 1 filing.

PSIA ADJUSTMENT CALCULATION
Pipeline System Integrity Adjustment is equal to the Pipeline System Integrity Cost, minus the Projects Base Amount, plus or minus the PSIA True-up Amount, plus or minus the Deferred PSIA Balance. Notwithstanding the preceding sentence, for the initially effective PSIA, the deferred operating and maintenance costs related to the TIMP incurred from January 1, 2011 until the effective date of the rates approved in Docket No. 10AL-963G shall be included in the calculation of the 2012 PSIA. The PSIA shall be calculated for each rate schedule based on a dollar per therm basis as follows:

$$PSIA = A - B \pm C \pm D$$

Where:

A = Pipeline System Integrity Cost
B = Projects Base Amount
C = PSIA True-up Amount
D = Deferred PSIA Balance

ALLOCATION OF PSIA COSTS
For purposes of developing the annual PSIA rates in the RATE TABLE provided on Sheet No. 47C, the annual Pipeline System Integrity Adjustment will be allocated to classes based on the their projected annual use during the calendar year in which the PSIA will be effective.

(Continued on Sheet No. 47B)

COLO. PUC No. 6 Gas

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 47B

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

Cancels
Sheet No.

NATURAL GAS RATES
PIPELINE SYSTEM INTEGRITY ADJUSTMENT

N

PSIA ADJUSTMENT WITH CHANGES IN BASE RATES

Whenever the Company implements changes in base rates as the result of a final Commission order in a general gas rate case setting new rates based on approved revenue requirements, the Company shall simultaneously adjust the PSIA to remove all costs that have been included in base rates.

(Continued on Sheet No. 47C)

ADVICE LETTER NUMBER

ISSUE DATE

DECISION NUMBER

VICE PRESIDENT,
Rates & Regulatory Affairs

EFFECTIVE DATE February 7, 2011

COLO. PUC No. 6 Gas

PUBLIC SERVICE COMPANY OF COLORADO

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

Sheet No. 47C

Cancels
Sheet No.

NATURAL GAS RATES

PIPELINE SYSTEM INTEGRITY ADJUSTMENT N

RATE TABLE

ILLUSTRATIVE

Rate Schedule	**Billing Units**	**Type of Charge**	**PSIA Rate**
Residential Service			
RG	Therm	Usage	$0.00679
RGL	Therm	Usage	$0.00679
Commercial & Industrial Sales Service			
CSG	Therm	Usage	$0.00679
CLG	Dekatherm	Usage	$0.06790
CGL	Therm	Usage	$0.00679
IG	Dekatherm	Usage	$0.06790
Gas Transportation Service			
TFS	Dekatherm	Usage	$0.06790
TFL	Dekatherm	Usage	$0.06790
TI	Dekatherm	Usage	$0.06790

ADVICE LETTER NUMBER

ISSUE DATE

DECISION NUMBER

VICE PRESIDENT,
Rates & Regulatory Affairs

EFFECTIVE DATE January 1, 2012

Public Service Company of Colorado
Revenue Requirements related to Pipeline System Integrity Adjustment
Summary
Projects Base Amount

Line No.		Total Gas	Retail Allocation	Retail Jurisdiction
1	Rate Base			
2	Gas Plant in Service	52,087,316	(1)	52,043,300
3	Less: Gas Accumulated Reserve for Depreciation	267,293	(1)	267,143
4	Net Plant	51,820,023		51,776,158
5				
6	Accumulated Deferred Income Taxes	12,405,592	(1)	12,395,131
7				
8	Net Rate Base (ln 4 - ln 6)	39,414,431		39,381,026
9				
10	Income Tax Expense			
11	Net Rate Base			39,381,026
12	Rate of Return on Rate Base			8.24%
13	Earnings before Interest			3,244,997
14				
15	Net Rate Base			39,381,026
16	Cost of Debt			2.58%
17	Interest Expense			1,016,030
18				
19	Additions and Deductions for Taxes	(32,441,816)	(1)	(32,414,492)
20				
21	State Taxable Amount (ln 13 - ln 17 + ln 19)			(30,185,526)
22	State Income Tax Rate			4.63%
23	State Income Taxes			(1,397,590)
24				
25	Net Federal Taxable Amount (ln 21 - ln 23)			(28,787,936)
26	Federal Income Tax Rate			35.00%
27	Federal Income Taxes			(10,075,777)
28				
29	Deferred Income Taxes	12,405,592	(1)	12,395,131
30				
31	Total Income Taxes (ln 23 + ln 27 + ln 29)			921,764
32	Tax Gross Up Factor			1.61316341
33	Total Income Tax Expense			1,486,956
34				
35	O&M and Payroll Expenses	9,262,103	(1)	9,250,432
36	Depreciation Expense	267,293	(1)	267,143
37	Total Operating Deductions (ln 33 through ln 36)			11,004,530
38				
39	Return on Rate Base (ln 13)			3,244,997
40				
41	Revenue Requirements (ln 37 + ln 39)			14,249,527

Note 1: Retail Allocation specific to each PSIA Project.

Public Service Company of Colorado
Revenue Requirements related to Pipeline System Integrity Adjustment
Project No. 11226060 - CAB
Projects Base Amount

Line No.		Total Gas	Retail Allocation	Retail Jurisdiction
1	Rate Base			
2	Gas Distribution Plant in Service	2,985,707	100.00%	2,985,707
3	Less: Gas Distribution Accumulated Reserve for Depreciation	16,375	100.00%	16,375
4	Net Plant	2,969,332		2,969,332
5				
6	Accumulated Deferred Income Taxes	854,946	100.00%	854,946
7				
8	Net Rate Base (ln 4 - ln 6)	2,114,386		2,114,386
9				
10	Income Tax Expense			
11	Net Rate Base			2,114,386
12	Rate of Return on Rate Base			8.24%
13	Earnings before Interest			174,225
14				
15	Net Rate Base			2,114,386
16	Cost of Debt			2.58%
17	Interest Expense			54,551
18				
19	Additions and Deductions for Taxes	(2,249,634)	100.00%	(2,249,634)
20				
21	State Taxable Amount (ln 13 - ln 17 + ln 19)			(2,129,960)
22	State Income Tax Rate			4.63%
23	State Income Taxes			(98,617)
24				
25	Net Federal Taxable Amount (ln 21 - ln 23)			(2,031,343)
26	Federal Income Tax Rate			35.00%
27	Federal Income Taxes			(710,970)
28				
29	Deferred Income Taxes	854,946	100.00%	854,946
30				
31	Total Income Taxes (ln 23 + ln 27 + ln 29)			45,359
32	Tax Gross Up Factor			1.61316341
33	Total Income Tax Expense			73,171
34				
35	O&M and Payroll Expenses (1)	525,625	100.00%	525,625
36	Depreciation Expense	16,375	100.00%	16,375
37	Total Operating Deductions (ln 33 through ln 36)			615,171
38				
39	Return on Rate Base (ln 13)			174,225
40				
41	Revenue Requirements (ln 37 + ln 39)			789,397

Note 1: Revised Exhibit No. DAB-8, Schedule 16

Public Service Company of Colorado
Revenue Requirements related to Pipeline System Integrity Adjustment
Project No. 10523090 - Integrity Management Program
Projects Base Amount

Line No.		Total Gas	Retail Allocation	Retail Jurisdiction
1	Rate Base			
2	Gas Transmission Plant in Service	23,049,124	99.84%	23,011,093
3	Less: Gas Transmission Accumulated Reserve for Depreciation	87,572	99.84%	87,428
4	Net Plant	22,961,552		22,923,665
5				
6	Accumulated Deferred Income Taxes	5,052,054	99.84%	5,043,718
7				
8	Net Rate Base (ln 4 - ln 6)	17,909,498		17,879,947
9				
10	Income Tax Expense			
11	Net Rate Base			17,879,947
12	Rate of Return on Rate Base			8.24%
13	Earnings before Interest			1,473,308
14				
15	Net Rate Base			17,879,947
16	Cost of Debt			2.58%
17	Interest Expense			461,303
18				
19	Additions and Deductions for Taxes	(13,179,554)	99.84%	(13,157,808)
20				
21	State Taxable Amount (ln 13 - ln 17 + ln 19)			(12,145,803)
22	State Income Tax Rate			4.63%
23	State Income Taxes			(562,351)
24				
25	Net Federal Taxable Amount (ln 21 - ln 23)			(11,583,452)
26	Federal Income Tax Rate			35.00%
27	Federal Income Taxes			(4,054,208)
28				
29	Deferred Income Taxes	5,052,054	99.84%	5,043,718
30				
31	Total Income Taxes (ln 23 + ln 27 + ln 29)			427,159
32	Tax Gross Up Factor			1.61316341
33	Total Income Tax Expense			689,078
34				
35	O&M and Payroll Expenses (1)	7,073,600	99.84%	7,061,929
36	Depreciation Expense	87,572	99.84%	87,428
37	Total Operating Deductions (ln 33 through ln 36)			7,838,434
38				
39	Return on Rate Base (ln 13)			1,473,308
40				
41	Revenue Requirements (ln 37 + ln 39)			9,311,741

Note 1: Revised Exhibit No. DAB-8, Schedule 17

Public Service Company of Colorado
Revenue Requirements related to Pipeline System Integrity Adjustment
Project No. 11330308 - Replace West Main
Projects Base Amount

Line No.		Total Gas	Retail Allocation	Retail Jurisdiction
1	Rate Base			
2	Gas Transmission Plant in Service	3,627,145	99.84%	3,621,160
3	Less: Gas Transmission Accumulated Reserve for Depreciation	3,598	99.84%	3,592
4	Net Plant	3,623,547		3,617,568
5				
6	Accumulated Deferred Income Taxes	1,287,662	99.84%	1,285,537
7				
8	Net Rate Base (ln 4 - ln 6)	2,335,885		2,332,031
9				
10	Income Tax Expense			
11	Net Rate Base			2,332,031
12	Rate of Return on Rate Base			8.24%
13	Earnings before Interest			192,159
14				
15	Net Rate Base			2,332,031
16	Cost of Debt			2.58%
17	Interest Expense			60,166
18				
19	Additions and Deductions for Taxes	(3,380,693)	99.84%	(3,375,115)
20				
21	State Taxable Amount (ln 13 - ln 17 + ln 19)			(3,243,122)
22	State Income Tax Rate			4.63%
23	State Income Taxes			(150,157)
24				
25	Net Federal Taxable Amount (ln 21 - ln 23)			(3,092,965)
26	Federal Income Tax Rate			35.00%
27	Federal Income Taxes			(1,082,538)
28				
29	Deferred Income Taxes	1,287,662	99.84%	1,285,537
30				
31	Total Income Taxes (ln 23 + ln 27 + ln 29)			52,843
32	Tax Gross Up Factor			1.61316341
33	Total Income Tax Expense			85,244
34				
35	O&M and Payroll Expenses	-	99.84%	-
36	Depreciation Expense	3,598	99.84%	3,592
37	Total Operating Deductions (ln 33 through ln 36)			88,836
38				
39	Return on Rate Base (ln 13)			192,159
40				
41	Revenue Requirements (ln 37 + ln 39)			280,996

Public Service Company of Colorado
Revenue Requirements related to Pipeline System Integrity Adjustment
Project No. 11094408 - Accelerated Main Replacement Program
Projects Base Amount

Line No.		Total Gas	Retail Allocation	Retail Jurisdiction
1	Rate Base			
2	Gas Distribution Plant in Service	22,425,340	100.00%	22,425,340
3	Less: Gas Distribution Accumulated Reserve for Depreciation	159,748	100.00%	159,748
4	Net Plant	22,265,592		22,265,592
5				
6	Accumulated Deferred Income Taxes	5,210,930	100.00%	5,210,930
7				
8	Net Rate Base (ln 4 - ln 6)	17,054,662		17,054,662
9				
10	Income Tax Expense			
11	Net Rate Base			17,054,662
12	Rate of Return on Rate Base			8.24%
13	Earnings before Interest			1,405,304
14				
15	Net Rate Base			17,054,662
16	Cost of Debt			2.58%
17	Interest Expense			440,010
18				
19	Additions and Deductions for Taxes	(13,631,935)	100.00%	(13,631,935)
20				
21	State Taxable Amount (ln 13 - ln 17 + ln 19)			(12,666,641)
22	State Income Tax Rate			4.63%
23	State Income Taxes			(586,465)
24				
25	Net Federal Taxable Amount (ln 21 - ln 23)			(12,080,176)
26	Federal Income Tax Rate			35.00%
27	Federal Income Taxes			(4,228,061)
28				
29	Deferred Income Taxes	5,210,930	100.00%	5,210,930
30				
31	Total Income Taxes (ln 23 + ln 27 + ln 29)			396,403
32	Tax Gross Up Factor			1.61316341
33	Total Income Tax Expense			639,463
34				
35	O&M and Payroll Expenses (1)	1,662,878	100.00%	1,662,878
36	Depreciation Expense	159,748	100.00%	159,748
37	Total Operating Deductions (ln 33 through ln 36)			2,462,089
38				
39	Return on Rate Base (ln 13)			1,405,304
40				
41	Revenue Requirements (ln 37 + ln 39)			3,867,393

Note 1: Revised Exhibit No. DAB-8, Schedule 19

Public Service Company of Colorado
Revenue Requirements related to Pipeline System Integrity Adjustment
Project No. 11095389 - Edwards to Meadow Mountain Loop
Projects Base Amount

Line No.		Total Gas	Retail Allocation	Retail Jurisdiction
1	Rate Base			
2	Gas Transmission Plant in Service	-	99.84%	-
3	Less: Gas Transmission Accumulated Reserve for Depreciation	-	99.84%	-
4	Net Plant	-		-
5				
6	Accumulated Deferred Income Taxes	-	99.84%	-
7				
8	Net Rate Base (ln 4 - ln 6)	-		-
9				
10	Income Tax Expense			
11	Net Rate Base			-
12	Rate of Return on Rate Base			8.24%
13	Earnings before Interest			-
14				
15	Net Rate Base			-
16	Cost of Debt			2.58%
17	Interest Expense			-
18				
19	Additions and Deductions for Taxes	-	99.84%	-
20				
21	State Taxable Amount (ln 13 - ln 17 + ln 19)			-
22	State Income Tax Rate			4.63%
23	State Income Taxes			-
24				
25	Net Federal Taxable Amount (ln 21 - ln 23)			-
26	Federal Income Tax Rate			35.00%
27	Federal Income Taxes			-
28				
29	Deferred Income Taxes	-	99.84%	-
30				
31	Total Income Taxes (ln 23 + ln 27 + ln 29)			-
32	Tax Gross Up Factor			1.61316341
33	Total Income Tax Expense			-
34				
35	O&M and Payroll Expenses	-	99.84%	-
36	Depreciation Expense	-	99.84%	-
37	Total Operating Deductions (ln 33 through ln 36)			-
38				
39	Return on Rate Base (ln 13)			-
40				
41	Revenue Requirements (ln 37 + ln 39)			-

Edwards to Meadow Mountain Pipeline Project

Cost per inch mile	$	179,607	
Materials	$	19,398	10.8%
Construction	$	65,736	36.6%

	6" line	16" line	Difference
Materials	$ 1,047,492	$ 2,793,312	$ 1,745,820
Construction	$ 3,549,744	$ 9,465,984	$ 5,916,240
total incremental cost			$ 7,662,060

E2MM line costs	$ 28,800,000
Base like for like costs	$ 21,137,940
Cost to increase diameter	7,662,060
Percentage attributable to base	73.4%
Percentage attributatble to increased diameter	26.6%

Notes:
Inch per mile is based on actual costs for Winter Park pipeline completed in 2010.
Materials and Construction costs are actual percentages from Winter Park pipeline.

West Main Pipeline Project - Current Plan (Preliminary Engineering)

Project Description - Preliminary	
Current miles to be renewed/replaced	81.87
Miles like for like	35.51
Total miles "upsized"	46.36

Current project estimate	$ 130,000,000
Like for like renewal	$ 60,472,000
Amount for increased diameter	$ 69,528,000

		8" pipeline	16" pipeline	Difference
Construction	$ 65,736	$ 24,380,168	$ 48,760,335	$ 24,380,168
Materials	$ 14,452	$ 5,359,958	$ 10,719,916	$ 5,359,958
				$ 29,740,125
West Main projected costs				$ 130,000,000
Base like for like costs				$ 100,259,875
Cost to increase diameter				$ 29,740,125
Percentage attributable to base costs				77.1%
Percentage attributabele to increased diameter				22.9%

Notes:
Milliken to Berthoud line base costs. Materials were about 28.2% of costs, and construction about 47.2%.
Construction primarily rural farm fields. West Main suburban, roads, etc.
Used Winter Park construction costs (per inch mile) as better estimate of construction costs.
Project currently in preliminary engineering stage. August/September time frame for better estimates.
Material cost based on Mlliken project.