Public Service Company of Colorado
Docket 06S-234EG
Technical Conference – November 7, 2006

Rate Case Principles for Calculating Annual Appendix A Report Beginning with 2007 Calendar Year Report

Docket No. 02S-315EG and Prior Base Rate Cases:

Each test year has unique circumstances in our books and records, which could drive what known and measurable adjustments will be made in the determination of revenue requirements.

Rate Base will be calculated using a 13-month average of month-end balances except for Cash Working Capital (calculated using pro forma expenses multiplied by the appropriate cash working capital factors) and the coal, oil and natural gas used for electric generation inventory balances (calculated using the average of the 12 monthly average balances during the test year). To the extent possible pro forma adjustments to rate base will be made using the 13-month average of month-end balances, otherwise can use the sum of the prior year-end balance and the test year-end balance divided by two. Specific assignment of plant to either CPUC or FERC jurisdiction will use year-end balances.

AFUDC addition to earnings will be based on actual test-period expenses, not annualized.

Adjustments to rate base for changes after the end of the test year are not included.

The unamortized negative acquisition adjustment resulting from the Colorado Ute transaction is included in rate base and is being amortized over the remaining life of the assets acquired.

An adjustment is made to eliminate from plant in service fifty percent of the investment in specific distribution substations serving Holy Cross Rural Electric Association ("HCE").

An adjustment is made to eliminate from plant in service the amount of cost associated with the Pawnee turbine blade project that exceeded the Commission-ordered expenditure cap.

Reclassify certain high voltage facilities within the Company's distribution substations from distribution plant to transmission plant, reclassify certain transmission substations to distribution plant, and reclassify certain

common communication equipment from common plant to general transmission and general distribution plant. Generation interconnection facilities at transmission substations are allocated using the production demand allocator. Reclassify related accumulated depreciation reserve consistent with plant reclassifications.

Functionalize Intangible plant in service.

Common plant is allocated to the electric, gas, thermal energy and non-regulated departments based on an annual study of all common plant assets and assigning an allocation method for each type of asset.

Eliminate Southeast Water Rights from future use plant, and include an adjustment to miscellaneous service revenue for the debt recovery of the asset.

Eliminate contractor retentions from construction work in progress (“CWIP).

CWIP is included in rate base with an offsetting addition to earnings for allowance for funds used during construction (“AFUDC”).

Capital lease assets are not included in rate base.

An adjustment is made to eliminate a portion of the materials and supplies inventory balance allocated to construction-related projects.

Cash working capital components consist of per book fuel costs, per book purchased power costs, pro forma operation and maintenance expenses (“O&M”), both directly incurred by the Company and charges from Xcel Energy Services, Inc., vacation liability, taxes other than income (payroll taxes, property taxes, sales and use taxes), federal and state income taxes and franchise fees and sales taxes paid. The cash working capital factors from the 2002 rate case will be used.

The prepaid pension asset is recognized in rate base on a pre-tax basis.

Deductions from rate base include customer deposits, Qualifying Facilities deposits (net of accrued interest), and customer advances for construction.

Full normalization is the method of accounting for income taxes.

The accumulated deferred income tax reserve is a reduction to rate base, as opposed to a cost-free component in the capital structure. Adjustments to accumulated deferred income tax reserve include eliminating amounts that are not included in the cost of service calculation (e.g. unbilled

revenue, FSV nuclear-related items, FERC only related items, DSM, Earnings Test refunds, etc.), accounts that are associated with the Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes ("SFAS 109"), ½ of pre-1971 Investment Tax Credits, and interest on CWIP.

Retail Base Rate Revenue does not include revenues billed on various recovery mechanisms: ECA, PCCA, AQIR, DSMCA, RESA, and ISOC. Unbilled revenues are not included in the determination of revenue requirements.

No adjustments are included to account for customer additions or losses to the test year sales or base rate revenues.

No adjustment is made to test year electric sales to normalize for weather.

Eliminate FERC Account 449 – Provision for Rate Refund, and the following miscellaneous revenue accounts/amounts that are not in retail base rates: 1) QSP bill credits; 2) Joint Operating Agreement revenue; and 3) Wholesale related transmission revenues.

Include Oil and Gas Royalty revenues and related Administrative expenses in the determination of revenue requirements.

An adjustment is made to miscellaneous revenues to eliminate the discounts given to certain contract customers under §40-3-104.3(2)(a).

Eliminate deferred energy and capacity costs booked to FERC Account 557.

Eliminate out-of-period accounting entries.

Include pro forma adjustments in the determination of revenue requirements in order for the test period to be representative of future conditions. Adjustments are made for known and measurable changes occurring both in the test period (in-period adjustments) and outside the test year (out-of-period adjustments). Out-of-period pro forma adjustments are generally not made for items expected to occur more than one year after the test year has ended.

O&M associated with incremental retail and wholesale sales are eliminated.

Interest on QF deposits is included in Production O&M.

Interest on customer deposits is included in Customer Operations expense.

Service guarantee rebates are eliminated from Customer Operations expense.

Lease expense and pole attachment fees associated with the Dark Fiber is included in the determination of revenue requirements.

Advertising expense related to specific energy conservation, safety, and customer programs and services are included in the determination of revenue requirements. These advertising expenses must directly benefit customers.

Advertising expense related to marketing, promotion, community relations, image and political ads are eliminated.

Edison Electric Institute ("EEI") dues that are associated with certain advertising and lobbying, as found in the National Association of Regulatory Utility Commissioner's ("NARUC") most recent annual audit report are eliminated.

All lobbying expenses and donations are excluded from the determination of revenue requirements.

Annualize CPUC annual fee.

Eliminate amortizations of DSMCA costs and the FSV regulatory liability from amortization expense. Include the amortization of the Colorado Ute Acquisition Adjustment in amortization expense. Adjust depreciation expense to eliminate the amount associated with 50% of the HCE distribution substations, and the Pawnee turbine blade project.

Cost allocation between regulated and non-regulated business activities is based on the most recently filed Cost Allocation Manual and the Fully Distributed Cost Allocation Study.

Adjustments to deferred income tax expense include eliminating amounts that are not included in the cost of service calculation (e.g. unbilled revenue, FSV nuclear-related items, FERC only related items, DSM, Earnings Test refunds, etc.), amounts that are associated with the SFAS 109, and the deferred taxes associated with the interest on CWIP.

Gain on the disposition of emission credits due to the Department of Energy auction is included in the determination of revenue requirements.

Adjustments are made to the capital structure to eliminate the following items: 1) Notes payable/receivable with subsidiaries; 2) investment in

subsidiaries; 3) subsidiary retained earnings; 4) net non-utility plant; 5) other investments at cost; 6) other funds; and 7) other comprehensive income.

Cost of Debt is the actual cost as of the end of the year, and includes bond premiums or discounts, underwriting expenses and other expenses of issue.

The allocation between the retail and wholesale jurisdictions is performed on a line-by-line basis for both rate base and earnings.

The gross-up factor applied to the calculated earnings deficiency includes a component to increase bad debt expense for the increase in base revenues, incremental State and Federal income tax expense, incremental franchise and sales tax expense and related Cash Working Capital effects.

The revenue requirements study will be presented with the more traditional "top-down" approach, taxable income is derived by starting with revenue less expenses and then synchronized interest is deducted and Schedule M items are added.

Other Dockets:

Docket No. 02S-485E – Air Quality Improvement Rider –

Credit the levelized annual revenue requirement used to develop the AQIR less the amount credited in the PCCA, and include this amount as an addition to Other Electric Revenue.

Docket No. 04S-164E – Phase 2 Rate Case –

Fuel expenses, purchased power energy expenses and purchased wheeling expenses are eliminated from the determination of revenue requirements.

Allocate rate base and costs between the retail and wholesale jurisdictions based on the methodology approved by the CPUC.

Docket No. 05S-161E – High Voltage Direct Current Converter ("HVDC") –

The HVDC is 100% included in rate base with no adjustment.

Docket No. 06S-234EG – 2006 Rate Case Settlement Agreement:

Revenue increase of 12.70% on base rate revenue effective January 1, 2007 will be annualized.

The current authorized Return on Equity will be 10.50%

The capital structure ratio will be based on actual balances, unless the resulting common equity ratio is greater than 60%, then the equity ratio will be capped at 60%.

Depreciation rates per the Settlement Agreement effective January 1, 2007.

Non-Comanche 3 transmission expenditures will be included in CWIP with an AFUDC offset to earnings.

Retail / Wholesale jurisdictional allocation of capacity costs will be based on the 12 Coincident Peak (12 CP) method, except that the capacity sold under wholesale contracts that are for specific amounts of capacity will be directly assigned to the wholesale jurisdiction. The Cheyenne Light, Fuel and Power all-requirements contract will be included in the wholesale jurisdiction in developing the production demand jurisdictional allocator for as long as the contract is in place.

Comanche 3 CWIP will be treated as follows in the determination of revenue requirements: 1) no retail jurisdictional AFUDC will be booked on the 2005 and 2006 CWIP expenditures beginning January 1, 2007; 2) AFUDC will be booked on new CWIP expenditures beginning January 1, 2007; 3) the joint ownership agreements with HCE and Intermountain Rural Electric Association will be reflected as reductions in the CWIP balances; and, 4) the projected CWIP balances one year after the test year will be included in rate base without an AFUDC offset to earnings.

The unamortized balance of the Pawnee 2 Pre-Engineering and the Metro Ash Disposal site costs at December 31, 2006 will be amortized to expense over 2 years beginning January 1, 2007.

Actual rate case expenses incurred through December 31, 2006 will be amortized to expense over 2 years beginning January 1, 2007.

The gain on the sale of the steel railcars will be netted with actual one-time costs incurred through December 31, 2006, which include additional lease expenses, actual delivery charges associated with the new aluminum railcars, and the incremental coal handling O&M expenses at the Cherokee and Pawnee generating stations. The net gain will be amortized to expense over 10 years beginning January 1, 2007.

All purchased capacity costs are eliminated from revenue and costs beginning January 1, 2007.

An adjustment will be made to eliminate the expenses associated with energy Trading activities. The retail jurisdictional share is equal to $2,046,140.

Non-gratuitous revenues billed under the tariff effective January 1, 2007 will be reflected as billed in the determination of revenue requirements.

The residential late payment fee billed under the tariff effective January 1, 2007 will be reflected as billed in the determination of revenue requirements.

The assets, revenues, and costs associated with the WindSource product will be excluded from the determination of revenue requirements, consistent with the Company's filed CAM and Fully Distributed Cost Study.