201 P.U.R.4th 225, 2000 WL 944956 (Conn.D.P.U.C.)

(Publication page references are not available for this document.)

Re Connecticut Natural Gas Corporation
Docket No. 99-09-03

Connecticut Department of Public Utility Control
May 25, 2000

ORDER decreasing the revenue requirement of a natural gas local distribution company (LDC) by $117,062 (.04%), reflecting an authorized rate of return on equity of 10.8%.

Given the limited effect that the decrease would have on customer bills, department finds that the public interest would be best served by applying the $117,062 to the LDC's cast iron and bare steel pipe replacement program.

The cost of equity conclusion reached by the department is derived from the constant growth discounted cash flow model and encompasses a risk premium consideration.

The LDC is denied rate recovery of premiums paid for a weather stabilization insurance policy obtained to mitigate large swings in earnings during periods of extremely warm weather. Department finds that the insurance is not necessary for the provision of safe and quality service to ratepayers.

Department directs the LDC to continue to share interruptible margins above an $8.8 million target with ratepayer according to a previously established margin-sharing formula. The LDC had proposed to reduce the target to $4.4 million and put realized margins between $4.4 million and $8.8 million in a deferred account to support a community economic development program.

Depreciation expense is calculated using the average life group procedure along with the straight line method and the remaining life technique. Department rejects a proposal to change to an equal life group procedure, but accepts proposed changes in average service lives and salvage values.

Department commends the LDC for its gas supply planning, finding that its aggressive approach toward adjusting its supply portfolio in response to changes in customer requirements is a major factor in its continuing position as the state's lowest-cost gas distributor.

The lead lag study filed by the LDC in support of its proposed working capital allowance is adjusted to reduce the net lag days from 32.25 days to 20.56 days, yielding a substantial reduction to proposed rate base.

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Department approves a 50/50 sharing of the costs of an executive incentive compensation plan, finding that the plan had benefitted both ratepayers and shareholders.

A ruling on a proposed performance-based rate plan for the LDC is deferred to the rate design phase of the proceeding.

1. RATES, § 120.1

[CONN.] Reasonableness -- Test period -- Historical test year -- Adjustments to mid-point of rate year -- Natural gas rate proceeding.

2. VALUATION, § 25

[CONN.] Value for rate making -- Date of valuation -- Mid-point of rate year -- Natural gas local distribution company.

3. VALUATION, § 27

[CONN.] Value for rate making -- Measure of value -- Natural gas local distribution company.

4. VALUATION, § 281

[CONN.] Natural gas local distribution company -- Plant-in-service -- Forecasted plant additions.

5. VALUATION, § 96

[CONN.] Accumulated depreciation -- Ascertainment -- Rate base reduction -- Natural gas local distribution company.

6. VALUATION, § 192

[CONN.] Property included or excluded -- Deferred debits -- Natural gas local distribution company.

7. VALUATION, § 192

[CONN.] Property included -- Deferred debits -- Rate case expense -- Conservation and energy efficiency programs -- Natural gas local distribution company.

8. VALUATION, § 192

[CONN.] Property included -- Deferred debits -- Statement of Financial Accounting Standards No. 106 -- Postretirement benefits obligations -- Deferred deficiency -- Natural gas local distribution company.

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9. VALUATION, § 192.1

[CONN.] Accumulated deferred income taxes -- Deduction from rate base -- Corresponding adjustment to income tax expense -- Natural gas local distribution company.

10. VALUATION, § 293

[CONN.] Working capital allowance -- Calculation of allowable cash requirements -- Lead/lag study -- Revised elements -- Exclusion of non-cash items -- Natural gas local distribution company.

11. VALUATION, § 293

[CONN.] Working capital allowance -- Lead/lag study -- Revenue lag days -- Expense lag days -- Natural gas local distribution company.

12. VALUATION, § 299.1

[CONN.] Working capital allowance -- Lead/lag study -- Expense lag days -- Taxes -- Natural gas local distribution company.

13. VALUATION, § 293

[CONN.] Working capital allowance -- Lead/lag study -- Check clearance float -- Natural gas local distribution company.

14. VALUATION, § 309

[CONN.] Working capital allowance -- Particular allowances -- Net lag days -- Natural gas local distribution company.

15. VALUATION, § 298

[CONN.] Prepaid expenses -- Insurance -- Property taxes -- Natural gas local distribution company.

16. VALUATION, § 128

[CONN.] Injuries and damages reserve -- Average projected balance -- Adjustment for insurance expense reduction -- Natural gas local distribution company.

17. REVENUES, § 2

[CONN.] Forecasts -- Adjustments to test year -- Natural gas local distribution company.

18. REVENUES, § 5

(Publication page references are not available for this document.)

[CONN.] Natural gas -- Firm transportation service -- Adjustments to test year -- Local distribution company.

19. REVENUES, § 5

[CONN.] Natural gas -- Interruptible target margin -- Sharing of excess margins -- Local distribution company.

20. REVENUES, § 2

[CONN.] Forecasts -- Proposed adjustments to test year -- Grant or denial -- Known and measurable standard -- Natural gas local distribution company.

21. REVENUES, § 5

[CONN.] Natural gas -- Off-system sales -- Margin sharing -- Local distribution company.

22. EXPENSES, § 125

[CONN.] Natural gas local distribution company -- Operation and maintenance expense -- Adjustments.

23. EXPENSES, § 19

[CONN.] Depreciation -- Straight line method -- Remaining life technique -- Continued use of average life group procedure -- Revised service lives and salvage values -- Natural gas local distribution company.

24. DEPRECIATION, § 28

[CONN.] Calculation of annual depreciation -- Straight line method -- Remaining life technique -- Continued use of average life group procedure -- Natural gas local distribution company.

25. DEPRECIATION, § 28

[CONN.] Calculation of annual depreciation -- Straight line method -- Remaining life technique -- Rejection of equal life group procedure -- Natural gas local distribution company.

26. DEPRECIATION, § 55

[CONN.] Natural gas local distribution company -- Straight line method -- Remaining life technique -- Continued use of average life group procedure -- Revised service lives and salvage values.

27. EXPENSES, § 105

(Publication page references are not available for this document.)

[CONN.] Employee benefits -- Adjustment to reflect payroll expense reduction -- Natural gas local distribution company.

28. EXPENSES, § 118

[CONN.] Uncollectibles -- Hardship arrearage forgiveness -- Natural gas local distribution company.

29. EXPENSES, § 10

[CONN.] Inflation -- Revised composite factor -- Application to expenses not adjusted elsewhere -- Natural gas local distribution company.

30. EXPENSES, § 114

[CONN.] Income taxes -- Interest synchronization adjustment -- Natural gas local distribution company.

31. EXPENSES, § 114

[CONN.] Income taxes -- Connecticut Corporation Business tax -- Natural gas local distribution company.

32. EXPENSES, § 114

[CONN.] Federal income taxes -- Deferred taxes -- Natural gas local distribution company.

33. EXPENSES, § 109

[CONN.] Property taxes -- Use of current assessments and mill rates -- Natural gas local distribution company.

34. EXPENSES, § 109

[CONN.] Payroll taxes -- Calculation methodology -- Vacancy adjustment -- Natural gas local distribution company.

35. EXPENSES, § 95

[CONN.] Salaries and wages -- Payroll taxes -- Natural gas local distribution company.

36. EXPENSES, § 109

[CONN.] Gross receipts tax -- Adjustment for growth in firm transportation revenues -- Natural gas local distribution company.

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37. EXPENSES, § 62

[CONN.] Insurance -- Directors and officers liability -- Natural gas local distribution company.

38. EXPENSES, § 60

[CONN.] Weather stabilization insurance -- Grounds for disallowance -- Natural gas local distribution company.

39. EXPENSES, § 125

[CONN.] Natural gas local distribution company -- Weather stabilization insurance -- Grounds for disallowance.

40. EXPENSES, § 21

[CONN.] Injuries and damages reserve -- Relation to insurance expense -- Natural gas local distribution company.

41. EXPENSES, § 125

[CONN.] Natural gas local distribution company -- Maintenance -- Repairs to corporate headquarters -- Repaving of parking lot -- Capitalization and inclusion in rate base.

42. VALUATION, § 180

[CONN.] Maintenance -- Repairs to corporate headquarters -- Repaving of parking lot -- Natural gas local distribution company.

43. EXPENSES, § 26

[CONN.] Public relations -- Community and civic affairs -- Disallowance -- Natural gas local distribution company.

44. EXPENSES § 63

[CONN.] Legal expense -- Outside services -- Five-year average -- Natural gas local distribution company.

45. EXPENSES § 76

[CONN.] Outside services -- Three-year average -- Elimination of non-recurring charge -- Natural gas local distribution company.

46. EXPENSES § 105

(Publication page references are not available for this document.)

[CONN.] Payroll expense -- Executive incentive compensation -- Allocation between ratepayers and shareholders -- Natural gas local distribution company.

47. EXPENSES § 95

[CONN.] Payroll expense -- Vacated positions -- Adjustment to reflect most recent employee count -- Natural gas local distribution company.

48. EXPENSES § 99

[CONN.] Payroll expense -- Overtime charges -- Five-year average -- Natural gas local distribution company.

49. EXPENSES § 49

[CONN.] Pension expense -- Qualified defined benefit plans -- Natural gas local distribution company.

50. EXPENSES § 49

[CONN.] Pension expense -- Supplemental retirement plan -- Factors affecting allowance -- Strength of economy -- Exclusion of incentive compensation from benefits calculation -- Natural gas local distribution company.

51. EXPENSES § 49

[CONN.] Pension expense -- Employee savings plan -- 401K -- Matching contributions -- Natural gas local distribution company.

52. EXPENSES § 49

[CONN.] Postretirement benefits other than pensions -- Statement of Financial Accounting Standards No. 106 -- Current expense -- Discount rate -- Projected return on assets -- Natural gas local distribution company.

53. EXPENSES § 89

[CONN.] Regulatory commission expense -- Reduction for expected decline in regulatory activity -- Inflation factor for remaining costs -- Natural gas local distribution company.

54. EXPENSES § 89

[CONN.] Rate case expense -- Disallowance of rate design costs in excess of average -- Four-year amortization -- Natural gas local distribution company.

55. EXPENSES, § 118

(Publication page references are not available for this document.)

[CONN.] Uncollectibles -- Weighted average write-off percentage -- Adjustment for new firm customer -- Natural gas local distribution company.

56. EXPENSES, § 125

[CONN.] Natural gas local distribution company -- Required change in operating income -- Revenue conversion factor.

57. EXPENSES, § 9

[CONN.] Ascertainment -- Required change in operating income -- Revenue conversion factor -- Natural gas local distribution company.

58. EXPENSES, § 126

[CONN.] Natural gas local distribution company -- Cost of gas and gas supply -- Base gas costs -- Adjustment for new customer.

59. GAS, § 7

[CONN.] Supply planning -- Adjustments to pipeline capacity portfolio -- Increased sendout capacity -- Local distribution company.

60. GAS, § 5.1

[CONN.] Pipeline safety -- Cast iron/bare steel replacement program -- Local distribution company.

61. SERVICE, § 334

[CONN.] Natural gas -- Pipeline safety -- Gas odor complaint response time -- Gas odor report line -- Safety advertising program -- Local distribution company.

62. GAS, § 5.1

[CONN.] Pipeline safety -- Gas odor complaint response time -- Gas odor report line -- Safety advertising program -- Local distribution company.

63. INTERCORPORATE RELATIONS, § 14.2

[CONN.] Utility dealings with unregulated affiliates -- Reporting requirements -- Time reporting practices -- Natural gas local distribution company.

64. APPORTIONMENT, § 43

[CONN.] Joint expenses -- Transactions and relationships with unregulated affiliates -- Cost allocation -- Officer payroll -- Time-based allocator -- Natural gas local distribution company.

65. EXPENSES, § 51

[CONN.] Allocation of costs to unregulated affiliates -- Officer payroll allocator -- Natural gas local distribution companies.

66. INTERCORPORATE RELATIONS, § 14.2

[CONN.] Utility dealings with unregulated affiliates -- Common officers and directors -- Code of conduct -- Natural gas local distribution company.

67. INTERCORPORATE RELATIONS, § 14.2

[CONN.] Utility transactions with affiliates -- Pricing of transactions -- Natural gas local distribution company.

68. SERVICE, § 332

[CONN.] Natural gas -- Customer service -- Local distribution company.

69. PAYMENT, § 63

[CONN.] Security for payment -- Customer deposits -- Return of deposit -- Natural gas local distribution company.

70. PAYMENT, § 34

[CONN.] Denial of service -- Arrearages -- Spousal responsibility -- Natural gas local distribution company.

71. PAYMENT, § 53

[CONN.] Enforcing payment -- Late payment charges -- Credit agency reporting -- Natural gas local distribution company.

72. RETURN, § 15

[CONN.] Reasonableness -- Cost of capital allowances -- Legal standard.

73. RETURN, § 26

[CONN.] Factors affecting reasonableness -- Cost of capital -- Weighted cost of each component.

74. RETURN, § 26.1

[CONN.] Reasonableness -- Capital structure -- Capitalization ratios and costs -- Natural gas local distribution company.

75. RETURN, § 26.1

[CONN.] Reasonableness -- Capital structure -- Wholly-owned subsidiary utility -- Proposed use of consolidated capital structure of corporate parent -- Grounds for rejection.

76. RETURN, § 26.2

[CONN.] Reasonableness -- Cost of debt -- Natural gas local distribution company.

77. RETURN, § 26.2

[CONN.] Reasonableness -- Cost of equity -- Estimation methodologies -- Discounted cash flow model -- Risk premium method -- Capital asset pricing model -- Comparable earnings method -- Natural gas local distribution company.

78. RETURN, § 26.4

[CONN.] Reasonableness -- Cost of equity -- Department analysis -- No weight given to capital asset pricing model or comparable earnings approach -- Natural gas local distribution company.

79. RETURN, § 26.4

[CONN.] Reasonableness -- Cost of equity -- Department analysis -- Reliance on constant growth discounted cash flow model -- Risk premium consideration -- Natural gas local distribution company.

80. RETURN, § 26.4

[CONN.] Reasonableness -- Cost of equity -- Constant growth discounted cash flow model -- Composition of proxy group -- Natural gas local distribution company.

81. RETURN, § 26.4

[CONN.] Reasonableness -- Cost of equity -- Discounted cash flow analysis -- Growth component -- Natural gas local distribution company.

82. RETURN, § 26.4

[CONN.] Reasonableness -- Cost of equity -- Discounted cash flow analysis -- Yield component -- Natural gas local distribution company.

83. RETURN, § 26.4

[CONN.] Reasonableness -- Cost of equity -- Risk premium method -- Comparison with results of discounted cash flow model -- Natural gas local distribution company.

84. RETURN, § 92

[CONN.] Natural gas local distribution company -- Overall rate of return -- Reasonableness.

85. AUTOMATIC ADJUSTMENT CLAUSES, § 34

[CONN.] Weather normalization adjustment mechanism -- Rejection of proposed mechanism -- Natural gas local distribution company.

86. AUTOMATIC ADJUSTMENT CLAUSES, § 45

[CONN.] Revenue requirement clauses -- Weather normalization adjustment mechanism -- Rejection of proposed mechanism -- Natural gas local distribution company.

87. RATES, § 373

[CONN.] Natural gas -- Allocation of decrease -- Application to cast iron and bare steel pipe replacement program -- Local distribution company.

88. EXPENSES, § 125

[CONN.] Natural gas local distribution company -- Cast iron and bare steel pipe replacement program -- Funding -- Local distribution company.

Before Arthur, Goldberg, and Arnold, commissioners.

BY THE DEPARTMENT:

DECISION

EXECUTIVE SUMMARY

The Connecticut Natural Gas Company, in its initial application dated November 9, 1999, requested approval from the Department of Public Utility Control for new rates designed to produce revenues, on an annualized and normalized basis, of $286,304,927, or approximately $15,738,284 in excess of those produced by the Company's present rate structure. This is an increase of 5.8% over present rates. The Company subsequently submitted two revised versions of its rate request. One version proposed an increase of $13,904,707 for total revenues of $285,273,202 (Version A). The next proposed an increase of $16,536,609 for total revenues of $294,315,742 (Version B). This Decision addresses Version B.

Major Rate Base Adjustments

The most significant adjustment to the company's proposed rate base was based on the Department's review of the Company's proposed lead/lag study. The resulting adjustment to working capital allowance reduced that rate base item by $4,714,931 to $12,861,863.

Revenues and Revenue Adjustments

The Company proposed to lower its interruptible target margin from $8,833,575 to $4,400,000. The Department found no basis for such a reduction, and therefore retained the interruptible target margin at its current level. The ultimate effect of the interruptible target margin adjustment, combined with adjustments to the Company's proposed levels of firm transportation service, increases operating revenues over those proposed by the Company by $4,601,275.

Expenses and Expense Adjustments

The Department's adjustment to the Company's proposed depreciation expense resulted in a reduction of $3,160,685. This reduction was principally a result of the Department's rejection of the Company's proposal to employ the Equal Life Group method. The Department found that the Company has been fully compensated for its plant using the Average Life Group method, and that the ALG method should be continued. The Department rejected the Company's request to recover premiums for weather stabilization insurance, reducing operating expenses by $993,063. The Department's rejection of the WSI was based on its determination that such insurance is not necessary for the provision of quality service to ratepayers. The Department also reduced the Company's pro forma request for property taxes by $807,768, as a portion of the request was based on an expectation of a property tax increase in Hartford, which is not known and measurable at this time.

Alternative Ratemaking Plans

The Company requested approval of a performance based rate plan. The Department deferred ruling on the Company's proposal to Phase II of this proceeding. Weather Normalization Adjustment

The Department rejected the Company's request for a weather normalization adjustment. Authorized Rate of Return

The Department's review of the evidence indicated an authorized rate of return of 10.80%.

The effect of all of the adjustments made by the Department establishes a revenue requirement for the Company of $282,263,346. This equates to a $117,062 or .04% decrease to current revenue requirements.

I. INTRODUCTION

A. BACKGROUND OF THE PROCEEDING

By application dated November 9, 1999, filed pursuant to the General Statutes of

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Connecticut (Conn. Gen. Stat.) §§ 16-19 and 16-19b, the Connecticut Natural Gas Corporation (CNG or Company) requested approval from the Department of Public Utility Control (Department) of new and amended rate schedules (Application). The proposed new rates were designed to produce revenues of $286,304,927 on an annualized and normalized basis, which is $15,738,284 or 5.8% in excess of revenues being produced by the Company's present rate structure. Subsequently, the Company submitted two revised versions of its request for a revenue increase. Version A proposed an increase of $13,904,707 for total revenues of $285,273,202. Version B proposed an increase of $16,536,609 to produce revenues at proposed rates of $294,315,742. Late Filed Exhibit No. 4, Attachments A and B, p. 2.

By letter dated September 14, 1999, the Department approved the Company's request to bifurcate the rate proceeding into a revenue requirement phase and a cost of service rate design phase. As a result, any approved change in revenue requirements in this proceeding would be applied on a volumetric throughput basis until new rates are designed in Phase II.

B. CONDUCT OF THE PROCEEDING

By Notice of Hearing dated December 10, 1999, pursuant to Conn. Gen. Stat. §§ 16-19 and 16-19b, the Department held a public hearing on this matter on January 11, 2000, at its offices, Ten Franklin Square, New Britain, Connecticut, and at 7:00 p.m. at the Hartford City Hall, 550 Main Street, Hartford, Connecticut. The hearing continued at the offices of the Department on January 12, 13, 18 and 19, and February 8, 9, 10, and 16, 2000. A hearing was also held at 7:00 p.m. on January 18, 2000, at the Greenwich Town Hall, 101 Field Point Road, Greenwich, Connecticut. By Notice of Close of Hearing dated March 7, 2000, the hearing was closed.

In the Application, the Company requested approval of a Rate Plan Alternative (RPA) that would replace the traditional cost of service regulation method used in determining rates. Marquardt PFT, p. 4. On January 11, 2000, the presiding Commissioner ruled from the bench that the Department would defer ruling on incentive-based rate plans to Phase II, of the instant docket. Tr. 01/11/00, p. 7. Subsequently, the Company submitted an Incentive Rate Plan (IRP) that would replace the RPA. Bryant Supplemental Testimony, p. 1. Further, on February 18, 2000, the Company filed a motion for a hearing on the IRP. By letter dated March 7, 2000, the Department responded to the motion, upholding its earlier directive to defer ruling to Phase II.

The Department issued a draft Decision in this matter on April 20, 2000. All Parties and Intervenors were provided the opportunity to submit written exceptions to and present oral arguments on the draft Decision. In the cover letter to its Written Exceptions, the Company gave its consent to a one-week extension of the 180-day statutory deadline for issuing a Decision. Subsequently, the Company consented to a further extension of time to May 26, 2000.

C. PARTIES AND INTERVENORS

(Publication page references are not available for this document.)

The Department recognized the following as Parties to this proceeding: Connecticut Natural Gas Corporation, P.O. Box 1500, Hartford, Connecticut 06103-1500; the Office of Consumer Counsel (OCC), Ten Franklin Square, New Britain, Connecticut 06051; and the Prosecutorial Division of the Department (PRO), Ten Franklin Square, New Britain, Connecticut 06051. The Department granted the Office of the Attorney General (AG) intervenor status in this proceeding.

D. PUBLIC COMMENT

The Department held evening hearings in Hartford on January 11, 2000, and in Greenwich on January 18, 2000 for the purpose of taking public comment. No members of the public attended either of the hearings.

II. DEPARTMENT ANALYSIS

A. TEST YEAR/RATE YEAR

[1] It is the practice of the Department in utility rate cases to establish rates prospectively upon the basis of a historical test year, adjusted for pro forma purposes. In this case, the Company used the operating results for the 12 months ending June 30, 1999, as its test year. The Department will accept this time period as the test year. As in the past, the Company has adjusted its test year to reflect its rate base and capital structure to the midpoint of the rate year (i.e., the year that rates will be in effect). Additionally, revenues were adjusted for test-year customers and certain expenses were adjusted for known changes. The Company also applied an inflation factor to those expenses that were not adjusted elsewhere.

In Version A and B of Late Filed Exhibit No. 4, the Company provided updated schedules, including Schedule C-1/C-2, B-1, D-1.0, E-3.1, and E-3.4. Version A (Attachment A) reflects corrections to the revenue requirement that were identified during discovery and in the public hearings. Version B (Attachment B) summarizes the updates provided during discovery and incorporates corrections from Version A in the final revenue requirement. Consequently, the Department uses Version B in its analysis.

B. RATE BASE

[2] CNG has calculated its rate base as of the midpoint of its proposed rate year. Thus, the rate base consists of the average, depreciated cost of the Company's plant in service as of October 31, 2000. The rate base also includes materials and supplies, working capital, fuel reserve, prepaid taxes and deferred expenses. Additionally, CNG reduced the sum of those assets by its accumulated deferred income taxes and the Company's injuries and damages reserve.

1. Pro Forma Plant In Service

[3, 4] CNG included $472,666,612 of plant in service in its rate base. This represents the average of the month end balances for the 13-month period ending April 30, 2001. Jones PFT, p. 3. The mid-point of that rate year period is October 31, 2000. The Department derived the $472,666,612 by reducing CNG's $474,069,035 of plant in service by its $1,402,423 of construction work in progress. Late Filed Exhibit No. 4, Schedule B-1, Version B, p. 3.

a. Pro Forma Plant Additions

CNG based its pro forma plant additions on its 2000 capital budget and 2001 forecast. The Company reduced these amounts by 9% to reflect the historical relationship between budgeted and actual capital expenditures. Jones PFT, p. 4. Application of this 9% historical variance provided a $4,383,893 reduction to the capital budget amounts added to plant in service for the purposes of projecting the rate year average balance. Late Filed Exhibit No. 1, ADR-77. CNG indicated that in the five fiscal years ended September 30, 1999, the Company actually experienced a 10.2% variance between budgeted capital improvements and actual plant additions. Id., ADR-29. Therefore, CNG should have reduced additions to plant by $4,968,412 ([$4,383,893 / 9.0%] X 10.2%). Accordingly, the Department will reduce the $474,069,035 plant in service included in the Company's rate base by $584,519 ($4,968,412 -- $4,383,893).

In Section II.D.18, below, the Department reduced the Company's pro forma operations and maintenance (O&M) expense by $222,500, to reflect the disallowance of certain repairs and repaving costs. The Department makes a corresponding increase to CNG's plant in service to provide for a return on this projected Company investment. Accordingly, the Department will increase plant in service by 50% of the expense disallowance or $111,250 to reflect the average investment in the rate year.

b. Accumulated Depreciation

[5] For rate base purposes, CNG reduced its $474,069,035 pro forma plant in service by $183,050,675 of accumulated depreciation. Late Filed Exhibit No. 4, Version B, p. 3. The Company added the sum of projected depreciation expense through June 30, 2000, to the accumulated depreciation balance at the end of the test year. CNG appropriately included adjustments for projected retirements in this calculation. Jones PFT, p. 4.

In Section II.B.1.a, above, the Department reduced CNG's total plant in service by $584,519. That requires a $29,440 reduction to CNG's pro forma depreciation expense (see Section II.D.3, below). Therefore, the Department will reduce CNG's accumulated depreciation by $14,720 ($29,440 X 50%). In that Section, the Department also increased plant in service by $111,250. This requires a corresponding $5,607 increase to the Company's pro forma depreciation expense. Therefore, the Department will increase CNG's accumulated depreciation by $2,803 ($5,607 X 50%). Thus, the total adjustments to accumulated depreciation, relative to changes in CNG's plant in service, equal $11,917 ($14,720 -- $2,803).

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In Section II.D.3, below, the Department reduces depreciation expense by $3,136,852. Therefore, the Department will reduce CNG's accumulated depreciation by $1,568,426 ($3,136,852 X 50%).

The total adjustment to CNG's accumulated depreciation, therefore, is $1,580,343 ($11,917 + $1,568,426).

2. Deferred Debits

The Application reflects $4,237,695 of deferred debits in rate base. Schedule B-1.0. The deferred debits represent the 13-month average unamortized balance in the deferred debit accounts during the rate year. Jones PFT, p. 7. Subsequently, the Company indicated that it anticipated revising this pro forma rate base item by $188,111 to $4,048,884. CNG later incorporated the $188,811 adjustment with a reduction of $742,268 ($4,048,884 -- $3,306,616), that eliminates the portion of the FAS 106 deferral that the Company did not fund with cash. Late Filed Exhibit No. 4, Schedule B-1, Version B, p. 3. The table below reflects the revised elements of the deferred debits in the Company's rate base:

Revised Deferred Debits Pro Forma	
[6-8] Conservation Rate SE Margins	$ 13,373
FAS 106 Deficiency	1,818,284
Rupp -- Public Act 93-417	356,558
Instant Rate Case	941,500
Cost of Service Study	176,901
Total	$ 3,306,616

a. Rate Case Expense

CNG calculated that the instant rate case would cost $941,500. In Section II.D.17.b. below, the Department made an adjustment to the rate design portion resulting in a 13-month average rate year balance of $912,350. Accordingly, the Department will reduce deferred debits in rate base by $14,575 ($941,500 - $912,350 x .5).

b. Rupp -- Public Act 93-417

As shown in the Revised Deferred Debits Pro Forma table above, CNG calculated this average deferral as $356,558. Based on the data provided in Schedule B-6.1, the Department has determined that $306,717 more accurately portrays the average balance of this deferral in the rate year. [FN1] Schedule B-6.1. The Department calculated this amount by taking the rate year ending balance of $292,753 and adding one-half of the net pro forma activity ($27,928 X .5) for the year. Accordingly, the Department will reduce this rate base element by $49,841.

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c. FAS 106 Deficiency

The Company's revised application includes Financial Accounting Standard No. 106 -- Employers' Accounting for Post-Retirement Benefits Other Than Pensions (FAS 106) costs of $2,560,552. Late Filed Exhibit No. 1, ADR-64. As illustrated in the table above, CNG subsequently calculated that the average deferred FAS 106 deficiency is $1,818,284. OCC recommends removal of the entire $2,560,552 unrevised balance of this account on the basis that '...it appears that CNG has included in rate base the difference between what the Department allowed in the last rate case and what the full FAS 106 accrual would be. This does not represent a cash contribution... .' Larkin PFT, pp. 6 and 8. OCC believes that 'this funding is projected to occur during the first month of the rate year ' and that CNG should not include this amount as an addition to rate base because it did not fund this amount during the five-year phase-in period. OCC Brief, pp. 23-24.

The Department must reject OCC's recommendation to remove the deferred FAS 106 costs from CNG's rate base. In Late Filed Exhibit No. 4, Version B CNG removed 29% of the balance that represents non-cash additions to the deferral. The Department finds this reasonable and accepts the Company's proposal, as revised.

d. Summary of Deferred Debits

The total deferred debits of $3,306,616 are reduced by $64,416 ($14,575 + $49,841) for an allowed amount of $3,242,200, as detailed in the table below.

Summary of Deferred Debits	
Conservation Rate SE Margins	$ 13,373
FAS 106 Deficiency	1,818,284
Rupp/Public Act 93417	306,717
Instant Rate Case	926,925
Cost of Service Study	176,901
Total	$ 3,242,200

3. Accumulated Deferred Income Taxes

[9] Accumulated deferred income taxes represent the sum of all net income tax deferrals made by the Company through the mid-point of the rate year. For ratemaking purposes, the Department requires the reduction of a company's rate base by this amount. CNG, in complying with this requirement, has proposed to reduce its pro forma rate base by $47,551,514 of accumulated deferred income taxes. Schedule B-1.0.

The Department has decreased the Company's book depreciation expense by a net amount of $3,160,685, as discussed in Section II.D.3, below. This expense decrease creates an identical increase in the difference between CNG's book depreciation

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and its tax depreciation. Because the Company's deferred tax expense is a function of the difference between book and tax expenses, the Department makes a corresponding increase to CNG's deferred federal income tax expense of $1,260,323. The Department calculated this adjustment in its analysis of the Company's O&M expenses in Section II.D.7.d, below. This O&M expense requires a corresponding adjustment to the Company's accumulated deferred taxes account. The Department will increase CNG's accumulated deferred taxes by $630,162 (50% X $1,260,323).

4. Working Capital Allowance

[10-14] The Department includes a working capital component in a company's rate base to compensate shareholders for the cash investment required to fund day-to-day business operations. This need arises because of a timing difference between a company's provision of service and receipt of the revenues associated with that service from ratepayers.

In the Decision dated October 13, 1995, in Docket No. 95-02-07, Application of the Connecticut Natural Gas Corporation for a Rate Increase -- Phase I (Previous Rate Decision), the Company used the 45-day method, also known as the one-eighth formula, to determine part of the working capital it included in its rate base. Thus, 12.50% of its pro forma O&M expenses were included in the working capital requirement. In addition to O&M expenses, the Department approved inclusion of a 10-day allowance for its cost of gas expense. The sum of the 12.50% O&M allowance and the 10-day allowance for cost of gas expense comprised the total working capital allowed by the Department for rate base purposes.

In the Previous Rate Decision, the Department ordered the Company to file a lead/lag study as part of its next rate case. Decision, p. 87. A lead/lag study estimates a company's cash working capital requirements for inclusion in rate base and substitutes for the one-eighth formula. CNG engaged the services of a consultant who based his lead/lag study (Original Study) on CNG data from the 12-months ended September 30, 1998, for developing lag days only. The Original Study then applied lag days to pro forma expenses to calculate the Company's cash working capital requirement. The Original Study indicates that CNG needs 32.25 net days of cash or $20,749,392. McDaniel PFT, pp. 1, 3 and Exhibit SGM-1.

The Company submitted a supplemental study based on the 12 months ending September 30, 1999 (Supplemental Study) that showed a dramatic decrease in the collection lag from 43.77 days to 38.53 days, a 5.24-day reduction. Jones Supplemental Testimony, p. 2. The Company stated that the decrease reflects the aberrational impact of much warmer than normal weather. The Company believes that the Original Study, as modified through corrections and updates during the hearing, represents the best estimate of the Company's working capital needs. Brief, p. 4.

The Original Study developed the 32.25 net day requirement by reducing its revenue lag of 62.38 days by its 30.13 cash expense lag days. McDaniel PFT, Exhibit SGM-1. It determined the Company's daily cash needs of $643,392 by dividing the sum of its pro forma cash operating expenses of $234,837,946 by 365. Thus, the Original Study concluded that the 32.25-day requirement was $20,749,392 (32.25 X $643,392). Id.

OCC believes that the Department should reduce CNG's working capital allowance by $6,626,846, reflecting changes to four elements of the Original Study:

1. Adoption of the revised collection lag that has 5.24 days less than the collection lag of the Original Study, reflecting more current collection data.

2. Correction of the computer expense lag from a negative 23.63 days to negative 37.38 days, thus eliminating prepaid invoices from the lag day calculation.

3. Correction of the insurance expense lag from a negative 251.85 days to negative 156.52 days. OCC states that insurance expense in the lag day calculations also contained prepaid expense amounts.

4. Incorporating five additional expense lag days to reflect check clearance time. This would take into account the clearing time for certain disbursements.

Larkin PFT, p. 11; Schedule B1, p. 4.

Additionally, OCC contends that the Company's policy of compensating employees in advance burdens ratepayers with carrying costs. Further, CNG's accounts receivable aging reflects a balance that is much less than what was used for the calculation of revenue collection lag, and that credit balances appear to be the result of the difference. These credits should be included in collection lag calculations. OCC Brief, pp. 24-28.

a. Cash Expenses

Some utility operating expenses do not require the outlay of cash. In the Previous Rate Decision, the Department excluded non-cash items from the expenses to calculate the Company's allowed working capital. Decision, p. 8. In the instant proceeding, Mr. McDaniel, stated that it was his intent to remove depreciation, amortization, uncollectibles and FAS-106 costs from operating expenses. He further stated that the purpose of his adjustment was to remove any non-cash expense because the Company would not have to invest in those and get a return on rate base. Tr. 1/18/00, pp. 902-903.

The Original Study used total O&M expenses of $234,837,946 to calculate a daily cash requirement of $643,392 ($234,837,946 / 365). However, the Department finds that in doing so, the Company did not exclude any amortizations or uncollectibles. CNG stated that the $53,255,742 of O&M expenses includes $631,128 of amortizations. Late Filed Exhibit No. 1, ADR-37. Subsequently, another CNG witness stated that the witness retained by the Company was in error in removing FAS 106 costs because cash funded the costs. Tr. 2/16/00, p. 1738. The statement contradicts the consultant's removal of $742,992 of non-cash costs from deferred

(Publication page references are not available for this document.)

debits in the compilation of the rate base. Late Filed Exhibit No. 4, Version B. The $742,992 constituted 29% of the deferral. In view of the conflicting testimony of two Company witnesses, the Department will apply the same percentage to the FAS 106 expense and accordingly consider that only 71% (100% - 29%) of CNG's FAS 106 cost represents cash.

Another CNG witness characterized the Company's hardship forgiveness expense as an amortization. Tr. 1/18/00, p. 837. The $631,128 amortization expense identified in Late Filed Exhibit No. 1, ADR-37 did not include hardship forgiveness costs. The Department recognizes hardship forgiveness as a specific type of uncollectible. Inspection of Schedule WPC-3.02 verifies that this hardship forgiveness activity is merely another type of accounts receivable write-off. The Company, however, does not directly write off the account, but transfers the balance to a deferred account. The Company then amortizes that account. Tr. 1/18/00, p. 836. Accordingly, the Department will classify hardship forgiveness expense as non-cash for purposes of the lead/lag study.

The Department finds that the following expenses are non-cash and should be excluded from the lead/lag study.

Non-Cash Expenses

Expense	Data Source	Application Amount
Hardship Forgiveness	Schedule C-3.24	$ 2,334,248
FAS 106 Costs	McDaniel PFT, SGM-3	578,767a
Other Amortization	Late Filed Exhibit No. 1, ADR-37	631,128
Total Amortization		3,544,143
Uncollectibles	Schedule C-3.02	4,838,399
Total Non-Cash O&M		$ 8,382,542

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a. (29% X $2,589,528 X 77.07% O&M allocator = $578,767)

In Section II.D.9.d, below, the Department removes insurance expense from CNG's operating expenses. Correspondingly, the Department removes insurance expense from the Company's total operating expense for the purpose of determining daily cash requirement. To offset this removal, the Department will include prepaid insurance in the Company's rate base.

In Section II.D.8.a, the Department removes property tax expense from CNG's expenses to determine other tax expense payment lag days more accurately. The Department also removes property tax expense from the Company's total operating expenses used for the daily cash requirement. To offset this removal, the Department will adjust rate base to include prepaid property taxes.

Therefore, the Department adjusts the Company's pro forma non-cash expenses as follows:

Adjusted Pro Forma Non-Cash Operating Expenses
5p

McDaniel PFT, Exhibit SGM-1		$234,837,946
Less: Non-Cash Expenses		
Uncollectibles	$ 4,838,399	
Amortization	3,544,143	
Unknown Difference	25,263	(8,407,805)
Less: Pro Forma Expenses Relative to Prepaid Expenses		
Insurance	2,760,581	
Property Taxes	4,989,188	(7,310,788)
5p		
ADJUSTED PRO FORMA CASH EXPENSES		$219,119,353
5p		

CNG revised its operating revenues and expenses late in the proceeding. The revision incorporated changes to which the Company acceded in the course of the hearing process. The table below reflects CNG's most current cash expenses.

Revised Cash Expenses	Revised Pro Forma Expenses (LFE-4 Version B)	Cash Adjustments	Adjusted Cash Expenses
Purchased Gas	$157,344,690		$157,344,690
O&M	52,851,999	$ (10,950,445)a	41,901,554
Depreciation	23,876,907	(23,876,907)	
Federal Inc. Tax	11,547,544		11,547,544
CCBT	1,872,945		1,872,945
Other Taxes	18,784,259	(4,989,188)b	13,795,071
Other, net	2,540	(2,540)	0
Totals	$266,280,884	$ (39,790,902)	$226,461,804

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a Uncollectibles + Hardship + Amortization + 29% FAS 106 + Insurance $4,645,721 + $2,334,248 + $631,128 + $578,767 + $2,760,581 = 10,950,445.

b Property Taxes.

(Publication page references are not available for this document.)

In Section II.D.18, the Department reduces CNG's operating expenses by $2,951,969. Of the total O&M adjustments, the Department did not apply $1,538,627 of the net reductions to its adjustment of the lead/lag study. The $1,538,627 of adjustments related to either non-cash adjustments or adjustments no longer relevant to the study. The $1,538,627 consists of the following:

Non-Cash O&M Adjustments	
Uncollectibles -- Net	$ (6,396)
Hardship Forgiveness	(163,132)
Rate Case Expense Amortization	(29,150)
Total Non-Cash Adjustments	(208,678)
Non-Applicable O&M Adjustments	
Injuries & Damages Reserve	(249,427)
WSI Policy	(993,063)
D&O Coverage	(87,459)
O&M Adjustments Not Applicable To Lead/Lag Study	$(1,538,627)

The Department deducted the remaining $1,413,342 ($2,951,969 -- $1,538,627) of O&M adjustments from the adjusted cash expenses shown above. The table below presents this calculation and the changes that occur, as a result of the Department's analysis, to purchased gas costs, federal corporate income taxes, Connecticut corporate business tax and other taxes.

Final Lead/Lag Study Cash Expenses	Adjusted Cash Expenses	Cash Adjustments	Final Cash Expenses
Purchased Gas	$157,344,690	$ 76,140	$157,420,830
O&M	41,901,554	(1,413,342)	40,488,212
Federal Inc. Tax	11,547,544	2,808,501	14,356,065
CCBT	1,872,945	650,623	2,523,568
Other Taxes	13,795,071	(248,066)	13,547,005
Totals	$226,461,804	$1,873,876	$228,335,680

a. Total Other Tax Adjustment of $(248,066), $7,194 from GRT and $(255,260) from payroll tax.

Accordingly, the Department calculates that for the purpose of the lead/lag study, CNG's allowable cash requirements are $228,335,680 per year and $625,577 per day ($228,335,680 / 365).

b. Revenue Lag Days

(Publication page references are not available for this document.)

The Original Study developed a total revenue lag of 62.38 days, which represents the average number of days required from the time CNG provides service to a customer to the date that the Company receives payment for that service. Three separate lags, calculated within the Original Study, comprise the total revenue lag. The first of these, the service lag, is the average time from the mid-point of a billing (or service) period to the end of that period. CNG determined its 15.21-day service lag by dividing 365 days by 12 to establish an average month of 30.42 days. The Company then used one-half of that amount, 15.21 days, for its service lag. McDaniel PFT, Exhibit SGM-2. The Department finds this calculation reasonable.

The billing lag occurs because the Company cannot immediately render bills at the end of a service period. The Company requires time to read meters, convert the meter data into dollars with the Company's billing system, and then mail the bills. The Original Study calculated an average billing lag of 3.40 days. Id., p. 62. The Company witness stated that, assuming the Company reads meters on a Monday, it would generate bills on Tuesday at approximately midnight and place them in the mail on Wednesday. Tr. 1/18/00, p. 896. The billing lag, calculated in the Original Study, assumes that all bills are read at noon Monday and mailed at the end of the day Wednesday, thus arriving at a two and one-half day lag. Tr. 1/18/00, p. 894. The Department finds it inconsistent to use a half-day convention on the meter reading day and not to use the half-day convention on the mailing date. Accordingly, the Department has recalculated the billing lag by removing a half-day from each billing lag calculation. Therefore, the Department finds that 2.90 provides a more realistic estimate of CNG's average billing lag.

The Original Study developed a collection lag of 43.77 days. Id. p. 74. The Supplemental Study used Fiscal Year 1999 data and determined that a 38.53- day collection lag existed.

Based on the above, the Department finds that a total revenue for service, billing and collection lag is 56.64 days (15.21 + 2.90 + 38.53).

c. Expense Lag Days

The expense lag represents the average number of days from the time that CNG uses a service or acquires a product until the Company actually pays for the service or product. The Company calculated 30.13 days as its expense lag. In determining this time, it first calculated a separate expense lag for each of five categories. The witness then weighted the days lag of each category by the Company's pro forma expense for that category. The table below, replicates the Company calculation. The total of the weighted amounts divided by the total expenses provides the average expense lag days.

CNG's Expense Lag Days	Amount	Category Lag Days	Weighted Amount
Purchased Gas	150,420,874	38.38	5,773,191,524

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O&M Expense	53,255,742	7.09	377,583,211
Other Taxes	18,003,908	27.85	501,408,838
Federal Income Tax	11,333,145	37.00	419,326,365
Connecticut Business Tax	1,823,277	1.70	3,099,571
	234,837,946	30.13	7,074,609,509

McDaniel PFT, Exhibit SGM-1.

i. O&M Expenses

CNG calculated an expense lag of 7.09 days with respect to other O&M expenses. Id., Exhibit SGM-3. To determine that amount, CNG calculated a separate expense lag for each of seven O&M sub-categories, then weighted the days lag of each category by the Company's expense for that category. The total of the weighted amounts divided by the total expenses provides the average expense lag days.

CNG's O&M Expense Lag	Amounta	Category Lag days	Weighted Amount
Payroll	$23,562,938	4.95	$116,636,543b
Computer	982,529	(37.38)	(36,726,934)
Medical	3,039,726	8.17	24,834,561
Insurance, Non-Group	803,211	(251.85)	(202,288,690)
Postage	565,787	9.82	(5,556,028)
Reg. Commission Exp.	672,148	(58.11)	(39,058,520)
Other	12,498,340	35.28	440,941,435
	$42,124,679	7.09	$298,782,367

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a. These expense items were for the fiscal year ended September 30, 1998.

b. The product of 23,562,938 times 4.95 equals 116,564,149. Id.

(a) Insurance Expense

The Original Study includes an examination of payments of insurance premiums. Typically, companies record payments of this nature as an asset on their books that are amortized over the policies' lives. CNG's witness concurred with this procedure and also admitted that some of the policies were for more than one year. Tr. 1/18/00, pp. 904-905.

In support of retaining the long-in-advance premium payments in the lead/lag study, CNG contended that a lead/lag study cannot selectively resort to reflecting generally accepted accounting principles with respect to expense deductions. Reply

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Brief, p. 5. The Department disagrees and believes that due to the advance nature of payments for insurance, it is inappropriate to include such expense in the study. Single payments for policies that extend over two or three years exacerbate the inaccuracies caused by advance payments in general. The inclusion of this expense distorts the calculation of the average lag of other O&M expenses. Accordingly, the Department will eliminate insurance payments from both the lag calculation and the calculation of CNG's daily cash requirement. However, as discussed in Section II.B.5.a, above, the Department will provide for prepaid insurance as a separate rate base item, affording the Company the opportunity to receive a return on funds it advances for insurance premiums.

(b) Computer Expense

Examination of computer-related invoice copies submitted with Late Filed Exhibit No. 46 confirms that the date information included in the Original Study for them was in error by one year. Thus, the expense was not paid well in advance as indicated. Based on the likelihood of other similar errors, the Department has recalculated the computer expense lag by adjusting invoice dates that differ from payment dates by one year. This recalculation reduces the negative expense lag from 37.38 days to 24.19 days.

Based on the adjustments made with respect to Computer and Insurance expense, the Department has recalculated the lag days of other O&M expenses in the table below.

O&M Expense Lag Allowed by Department	Amount	Category Lag Days	Weighted Amount
Payroll	$23,562,938	4.95	$116,564,149
Computer	982,529	(24.19)	(23,769,839)
Medical	3,039,726	8.17	24,834,561
Postage	565,787	9.82	(5,556,028)
Reg. Commission Expense	672,148	(58.11)	(39,058,520)
Other	12,498,340	35.28	440,941,435
	$41,321,468	12.44	$513,955,758

ii. Other Taxes

CNG has calculated an expense lag of 27.85 days with respect to Other Tax expense. McDaniel PFT, Exhibit SGM-4. In determining this amount, CNG's first set a separate expense lag for each of three sub-categories of Other Taxes, then weighted the days lag of each category by the Company's expense for that category. The total of the weighted amounts divided by the total expenses provides the average expense lag days.

Other Taxes Expense Lag as Filed	Category Lag	Weighted Amount

per Exhibit SGM-4	Amount	Days	
Property Taxes	$ 4,178,457	(70.93)	$(296,377,955)
Payroll Taxes	1,977,323	8.50	16,807,246a
Gross receipts Tax	9,246,265	76.62	708,448,824b
	$15,402,045	27.85	$ 428,878,115

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a. The product of $1,977,323 times 8.50 equals $16,807,290.

b. The product of $9,246,265 times 76.62 equals $708,451,736.

The Original Study included an examination of property tax payments. As with payments for insurance, these are typically made in advance; thus, it is also inappropriate to include these expenses in the study. CNG believes that the Original Study's methodology is more accurate and appropriate for determining the cash requirements associated with property taxes. This belief is founded on the premise that the study reflects timing differences in increments of a day where as the use of prepayment data is in net monthly increments. Late Filed Exhibit No. 47. There is no doubt that the prepayment method amortizes amounts on a monthly basis, which results in a less accurate average than a method that uses a daily basis. However, the Original Study does not use a purely daily basis. It sets an arbitrary date at the mid-point of the rate year and measures the tax payments against that date. This cannot produce a result more accurate than a monthly averaging of the prepayments. Therefore, the Department rejects CNG's contention that the Company's method is more accurate. Accordingly, the Department will eliminate property tax payments from both the lag calculation and the daily cash requirement calculation. The Department will, however, provide for prepaid taxes as a separate rate base item to allow the Company the opportunity to receive a return on funds it advances for this purpose. The table below, contains the Department's recalculation of the expense lag with regard to Other Taxes:

Other Taxes Expense Lag Allowed by Department	Amount	Category Lag days	Weighted Amount
Payroll Taxes	$ 1,977,323	8.50	$ 16,807,290
Gross receipts Tax	9,246,265	76.62	708,451,736
	$11,223,528	64.62	$725,259,026

iii. Prepayment of Federal Income Taxes

The Original Study calculated an expense lag with respect to the payment of the

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Company's corporate federal income taxes. The dates of CNG's four tax payments were measured against the mid-point of the entire year. This methodology places the liability for the entire year's expense at the mid-point of the year. Consequently, two payments are prepayments and two are arrearages. McDaniel PFT, Exhibit SGM-6, p. 75. The Department believes that this approach is flawed. As the Company generates income throughout the year, it accrues taxes. After the liability accrues, CNG periodically makes payments to the Internal Revenue Service (IRS) as required by law. Therefore, the Department believes that it is more accurate to use a methodology that assumes that all tax payments are made in arrears. The Department believes that this theory more accurately matches reality. The Department has recalculated the lag of federal income tax payments on that basis and determined that it is 52.38 days.

iv. Connecticut Corporation Business Tax Prepayment

The Original Study also calculated an expense lag with respect to the payment of the Company's Connecticut Corporate Business Taxes (CCBT). As with the payment of federal corporate income tax, this methodology places the liability for the entire year's expense at the mid-point of the year. Again, the Department believes that it is more accurate to use a methodology that assumes that all tax payments are made in arrears. Therefore, the Department has recalculated the lag of CCBT payments on that basis and finds that it should be 52.35 days.

v. Check Clearance

OCC's witness stated that the Company's lead/lag study failed to recognize a five-day check float. Larkin PFT, p. 12. A check float occurs because checks do not clear a bank account on the same day CNG issues them. The float represents the number of days between the date of check issue and the date of bank clearance. CNG conceded that a five-day float existed. The Company applied the five-day float to Other O&M expenses. Revised Schedule WTJ-5.

vi. Final Calculation of Cash Expense Lag Days

The table below reflects the Department's final calculation of cash expense lag days. In addition to adjusting the category lag days, the Department has recalculated the expense amounts to reflect the changes the Department made to arrive at the operating expenses in Section II.B.4.1, above.

Expense Lag Days Allowed by Department	Expense Amount	Catelgory Lag days	Weighted Amount
Purchased Gas	$150,421,874	38.38	$5,773,191,524
O&M Expense	39,943,758	12.44	466,900,350
Other Taxes	13,451,146	64.62	869,213,055
Federal Income Tax	11,314,708	52.38	592,664,405
CCBT	1,819,006	52.35	95,224,964

(Publication page references are not available for this document.)

$216,950,492	36.08	$7,827,194,297

d. Net lag

Based on the Department's analyses of CNG's revenue lag days and the Company's cash expense lag days, the Department has determined that CNG has a net cash lag of 20.56 days (revenue lag days of 56.64 less cash expense lag days of 36.08).

e. Conclusion on Cash Working Capital

The Department finds that 20.56 days represents the reasonable net lag for the determination of allowable working capital. Additionally, the Department finds that $625,577 represents the correct, adjusted pro forma expense per day to use in calculating the Company's working capital. Therefore, the Department finds that $12,861,863 (20.56 times $625,577) represents the reasonable working capital allowance in CNG's rate base. Accordingly, the Department will decrease the Company's working capital allowance in its rate base by $4,714,931. With regard to adjustments to the Original Study, the net result of all working capital adjustments produces an overall reduction of $3,572,136 ($940,853 Prepaid Insurance + $201,942 Prepaid Taxes -- $4,714,931 Lead/Lag Study) to CNG's rate base.

5. Prepaid Expenses

a. Prepaid Insurance

[15] CNG did not include any prepaid insurance in its rate base. In Section II.B.4, above, the Department removed insurance expense considerations from the Company's working capital. Therefore, the Department adds prepaid insurance to rate base.

CNG estimated that it would have average prepaid insurance of $2,021,375 in the rate year. Late Filed Exhibit No. 1, ADR-38. The Department, however, has adjusted insurance expense by disallowing $993,063 for weather stabilization insurance (WSI), and $87,459 for Directors and Officers (D&O) liability insurance. Id. Thus, the Department reduces prepaid insurance to $940,853 to reflect these adjustments [$2,021,375 -- ($993,063 + $87,459).

b. Prepaid Property Taxes

CNG also did not include any prepaid property taxes in its rate base. Schedule B-1.0. As with prepaid insurance, the Department removed property tax expense from the working capital calculations and must add prepaid property taxes to rate base.

The Company estimated that it would have average prepaid property taxes of $1,132,073 in the rate year. Late Filed Exhibit No. 47. In Section II.D.8.a, below, the Department adjusts property tax expense. Therefore, the Department reduces the prepaid property tax expense by 50% (to approximate the effect on prepaid taxes at the mid-point of the rate year) of the expense adjustment or $403,844. This results in allowed prepaid property taxes of $930,131 [($1,132,073 -- ($403,884 X .5)].

6. Injuries and Damages Reserve

[16] CNG reduced its rate base by $465,330, to reflect the average projected balance of its I&D reserve in the rate year. Schedule B-1.0. OCC has proposed to increase this reserve by $314,078. Larkin Direct Testimony, Exhibit L&A-1, Schedule C-3. The Company based the amount included in rate base for I&D on the average balance it calculated. Schedule B-8.0.

OCC contends that this reserve should be increased by $314,078, based on the test year I&D reserve balance. Larkin Direct Testimony, Exhibit L&A-1; Schedule C-3. The Company has consistently used average account balances in the rate year to construct its proposed rate base and the Department has recognized this methodology. In the absence of any testimony to the contrary, the Department must reject the OCC's recommendation and accept the Company pro forma amount, subject to other adjustments.

As noted above, the Department reduces the Company's pro forma insurance expense by $249,427 and makes a corresponding adjustment to the reserve.

7. Conclusion on Rate Base

With the adjustments indicated above, the Department finds that the appropriate rate base for the Company is $275,266,120. Table I in the Appendix shows the rate base presented by the Company and as adjusted by the Department.

C. REVENUES AND REVENUE ADJUSTMENTS

[17, 18] The Company stated that actual test year revenues, including PGA revenues, totaled $261,582,357. Pro forma adjustments reflecting normal weather, annualized customers, growth, and other revenues totaled $8,984,285 for the test year and an adjustment of $15,738,284 for the rate year, for a total adjustment of $24,722,569. This resulted in total rate year revenues at proposed rates of $286,304,927. Schedule C-1/C-2. Subsequently, CNG revised its proposed revenue increase to reflect updated gas costs, an increased sales forecast, and error corrections. In Version B, the Company proposed an additional increase of $8,010,815 or 3.1% over test year revenues. This results in rate year revenues at proposed rates of $294,315,742, or an increase of 8.9%. Late Filed Exhibit No. 4, Attachment B, p. 2.

1. New Firm Customer

The Company indicated that it did not include the load and revenue from an

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additional large use firm customer in the pro forma data. This seasonal firm customer is expected to take service prior to the start of the rate year and is projected to use 27,000 Mcf per year, providing additional revenue of $109,000. Response and Supplemental Response to Interrogatory GA-109; Late Filed Exhibit No. 4, p. 1. Since this customer will take service during the rate year, the Department increases pro forma revenues by $109,000.

2. Firm Transportation Service

The Company currently provides large firm transportation service (FTS-1) to customers with a minimum annual usage of 3,000 Mcf; small firm transportation service (FTS-2) with no minimum or maximum Mcf requirement; and non-telemetered firm transportation service (FTS-3) with a maximum annual usage of 500 Mcf. Revenues from these services for the test year equaled $6,676,428. Pro forma adjustments for weather normalization, annualized customers, growth, and other revenues totaled $3,710,535. With a rate year adjustment of $851,542, the total adjustment was $4,562,077. This resulted in total rate year revenues at proposed rates of $11,238,505. Schedule E-3.4, p. 1. Subsequently, the Company proposed an additional increase of $1,334,908 resulting in rate year revenues at proposed rates of $12,573,413. Late Filed Exhibit No. 4, Attachment B, p. 6a.

The Company indicated that during the test year there were 30 FTS-1, 731 FTS-2, and no FTS-3 customers. In the Decision dated March 17, 1999, in Docket No. 95-02-07, Application of the Connecticut Natural Gas Corporation for a Rate Increase-Reopened RE: Unbundling, the Department restricted availability of FTS-3 to commercial and industrial customers with annual usage of 500 Mcf or less. Decision, p. 12. When the Company estimated its pro forma customer levels by FTS service, it assumed that the existing 500 Mcf usage cap for FTS-3 customers would be eliminated in August 2000, three months into the rate year. Response to Interrogatory GA-134. There is no basis for the elimination of the FTS-3 cap, nor has there been any proposal for such a removal in the instant case.

The Company's pro forma revenues included a significant shift of customers from FTS-1 and FTS-2 to FTS-3 due to the projected elimination of the FTS-3 500 Mcf usage cap in August 2000. Subsequently, the Company provided a revised calculation that assumes the 500 Mcf usage cap remains in effect. The result increases pro forma revenues by $58,700. This increase is attributed to the $8.28 telemetering charge for the incremental FTS-2 customers no longer assumed to migrate to the non-telemetered FTS-3 rate. These additional revenues are partly offset by the lower delivery charge revenues from the 10 customers that would remain in FTS-1. Response to Interrogatory GA-129 Supplemental, p. 1. Because the Mcf usage cap will remain in effect, the Department increases operating revenues by $58,700 accordingly.

3. Interruptible Target Margin

[19] In the Previous Rate Decision, the Department set the Company's interruptible target margin at $8,833,575. Interruptible margins in excess of that

target were to be shared between firm ratepayers and the Company's shareholders. For the first $500,000 over the target, ratepayers would receive 75% in the form of a credit to the purchased gas cost account, and the Company would receive the rest. For margins in excess of $500,000 over the target, firm ratepayers would receive 25% and the Company 75%. In the event that the Company was unable to meet the target, it was authorized to defer (without carrying charges) up to $1 million of shortfall, pending recovery in a subsequent year or adjustment of the target. Decision, pp. 12-13.

In this rate case, the Company proposes to lower the target to $4,400,000. It also proposes to put realized margins between that amount and the previous target into a deferred account to be used to support a Community Economic Development (CED) program. The Company's principal argument for the reduction in the target is that too much of its earnings are dependent on the fortunes and actions of its large volume customers. Bolduc PFT, pp. 17-20.

The Company did not provide specific proposals for the CED program, recommending instead' ...that a separate proceeding be established, with appropriate public notice, to facilitate the widest participation by interested parties... .' Response to Interrogatory GA-151, p. 2. However, the Company expressed the opinion:

... that programs directed at redevelopment of the urban centers served by the Company are appropriate programs for funding under the Company's proposal. Such programs would encourage new residential and commercial construction in areas where the Company already has existing distribution facilities and, as such, these projects would result in high returns on investment and greater utilization of distribution assets. This is particularly true of significant portions of Hartford and New Britain, where unused residential and commercial structures have either been demolished, or are scheduled for demolition. These freed-up areas represent prime opportunities for development where minimal capital investment will be required by the Company to serve new loads.

Id., p. 1.

In its Brief, the Company refers to a continuation of its interruptible target margin at the $8.8 million level as '...a disaster waiting to happen.' The Company's concern is that the loss of even a single large customer would create a substantial margin shortfall. Brief, pp. 7-8. The Company argues that reducing its target margin as proposed would be consistent with the Department's Decision dated January 28, 2000, in Docket No. 99-04-18, DPUC Review of The Southern Connecticut Gas Company's (SCG) Rates and Charges -- Phase II (SCG Decision), because a target of $4.3 million was set in that case even though actual margins were at times substantially above that amount.

OCC argues that application of the Department's current policy regarding interruptible target margins requires continuation of the $8.8 million target and the sharing formulas currently in effect. OCC cites Company witness Bolduc's testimony to show that, not only has the Company made its target in all but two of the last 16 years, but it also made the target in 1998 and 1999, when oil prices declined to a 12-year low. OCC also argues that the Company's dependence on its large volume customers for margin recovery is not unusual and does not justify changing the target. Brief, pp. 57-62, 65-67.

OCC also argues against the Company's proposal for a CED program. OCC notes that SCG had such a program in place from 1996 through 1999, but that the program was implemented without causing a rate increase to customers. OCC also notes that the Company's ratepayers are already funding economic development programs through the State's Economic and Community Development program, which is enough support. Brief, pp. 62-65.

AG argues that the proposed reduction in the interruptible target margin be rejected. It states that the Company's claims that changes in the gas market have made its margin targets more difficult to achieve are speculative and not supported by the evidence in this proceeding. AG also opposes the Company's CED program proposals. Brief, pp. 7-9. PRO argues that there is not sustainable evidence supporting the proposed reduction. Brief, p. 9.

The Department has reviewed the Company's projections of customers, sales and margins, and its arguments regarding changes in oil and gas markets in general, and in its own markets in particular. Further, the Department finds that the types of programs described by the Company for its CED proposal appear to be self-serving, expanding the Company's distribution system. Such expansion is a shareholder responsibility. Therefore, the Department rejects ratepayer funding of the proposed CED program.

The Company also states that in the event the Department finds the CED plan unacceptable, it proposes to return all margins between $4.4 million and $8.8 million to ratepayers. Bryant PFT, pp. 35-36. The Department disagrees with any proposal to reduce the target margin. Further, the intent of the 50/50 split of excess margin is to provide an incentive to the Company to exceed the margin target. The Department believes that to return all margins between $4.4 and $8.8 million to ratepayers is a disincentive to that end. Therefore, the Department rejects the Company's proposal to return these margins to ratepayers. The Department finds no basis in any of these proposals for changing the target margin. Accordingly, the target will remain at $8,833,575. The Department also affirms CNG's current margin-sharing formula.

It is possible that additional restructuring of the gas industry might necessitate a change in the basis on which Connecticut LDCs compete for the interruptible market segment. In that event, the IS Mechanism, and its use in recovering a defined segment of each company's revenue requirement, would have to be reviewed. The proper place to address these questions would be a generic proceeding regarding restructuring, if and when it becomes necessary.

4. Downtown Cogeneration Associates

(Publication page references are not available for this document.)

[20] Downtown Cogeneration Associates (DCA) owns and operates a 4.5-megawatt cogeneration unit in downtown Hartford that the Company indicated may be shut down in 2000. The Company eliminated all DCA revenues and costs from its rate year estimates. Test year sales volumes were 466,778 Mcf, revenues $1,931,783, and margins $615,469. Bolduc PFT, p. 19; Response to Interrogatory GA-127.

OCC points out that, while the Company originally estimated that DCA would be shut down in September 2000, it now estimates November 1, 2000. Further, another party may purchase and operate the facility, and it may not be shut down at all. Thus, OCC argues that what is known about DCA's future does not meet the test of a 'known and measurable change' that would be required for exclusion of its revenues and costs. Thus, OCC states that test year margins from DCA should be restored to pro forma revenues. Brief, p. 49. PRO notes that DCA is currently on line and that there are outstanding issues concerning its future. Brief, p. 9.

The Company provided no evidence to show that the facility would not be operating. Therefore, the Department restores the revenues for DCA of $1,931,783 ($615,469 + (466,778 Mcf X $2.82)). Late Filed Exhibit No. 4, pp. 3 and 57. This adjustment is part of the interruptible target margin that the Department addresses in Section II.C.3, above.

5. Off-System Sales

[21] The Company has a policy of selling gas supplies off-system, if the after-tax margin is at least one cent per MMBtu for daily transactions and at least two cents per MMBtu for monthly transactions. Late Filed Exhibit No. 15. The Company reported that test year margins from off-system sales amounted to $3,491,054. Response to Interrogatory OCC-12. Over the last five fiscal years, off-system margins have varied from $1.5 million (1995) to $5.0 million (1996), averaging $3,301,923 per year. These margins are shared 85% to the customers and 15% to shareholders. Previous Rate Decision, p. 16.

OCC recommends that the Department include a pro forma level of these margins in the Company's revenues for ratemaking purposes. Specifically, OCC recommends that the realized amount of margin in the test year of $3,491,054 be included as a revenue adjustment. Brief, p. 48; Schedule 3. The Company objects to OCC's proposal, arguing that it would hurt firm customers in the long run because it would have to hold on to gas supply that it could otherwise relinquish. Brief, p. 10.

Including an allowance for off-system sales margins in revenue requirements would effectively require the Company to retain supply resources for what are uncertain sales. One of the reasons that CNG has the lowest purchased gas cost of the three Connecticut LDCs and in New England is that it has been aggressive in releasing unneeded supply. The Department will not make an adjustment for off-system sales. Margins will continue to be split 85% to ratepayers and 15% to shareholders.

6. Conclusion on Revenue Adjustments

(Publication page references are not available for this document.)

Based on the above, the Department will adjust pro forma revenues for the rate year by $109,000 for the new firm customer, $57,700 for firm transportation charges, and $4,433,575 for interruptible target margin. The total adjustments increase operating revenues by $4,601,275 and result in adjusted pro forma revenues at proposed rates of $298,917,017.

D. EXPENSES AND EXPENSE ADJUSTMENTS

1. Background

[22] The table below illustrates the changes in operating expenses between CNG's initial application and Late Filed Exhibit No. 4, Version B.

[Note: The following TABLE/FORM is too wide to be displayed on one screen. You must print it for a meaningful review of its contents. The table has been divided into multiple pieces with each piece containing information to help you assemble a printout of the table. The information for each piece includes: (1) a three line message preceding the tabular data showing by line # and character # the position of the upper left-hand corner of the piece and the position of the piece within the entire table; and (2) a numeric scale following the tabular data displaying the character positions.]

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	Application	Change	Version B
Purchased Gas	$150,421,874	$ 6,922,816	$157,344,690
O&M Expense	53,255,742	(403,743)	52,851,999
Depreciation	23,887,257	(10,350)	23,876,907
Taxes, Other	18,001,353	782,906	18,784,259
Income Taxes: Federal	11,314,708	232,836	11,547,544 Connecticut
Other Expenses	2,540	0	2,540
Total	$258,702,480	$ 7,578,404	$266,280,884

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 1,819,006  53,939  1,872,945

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Below are the details of the Company's Version B, $403,743 reduction in O&M expenses.

Marketing Intelligence System	$ (22,000)	
Outside Services	(32,348)	
Nominal Y2K Costs	(14,361)	
Payroll -- Vacancies	(160,493)	
Uncollectibles W/O Change In Revenue Requirement	(206,389) With Change In Revenue Requirement	13,711
Postal Expense	18,137	
Total	$(403,743)	

In addition to decreasing O&M expenses, CNG increased other taxes by $782,906. Version B of Late Filed Exhibit No. 4 provided for a $8,010,815 increase in revenues. The Company's weighted Gross Receipts Tax (GRT) rate is 4.29%. Schedule WPC-3.41. Thus, CNG requires $343,664 (4.29% X $8,010,815) of additional GRT. Further, the Company has claimed additional property taxes of $438,981 in Rebuttal Exhibit WPC-3.42a. The sum of these two tax adjustments ($343,925 + $438,981) equals the $782,906 increase.

2. Computer Expense

OCC recommends that the Department remove $37,335 in computer expenses: $14,835 related to Y2K and $22,500 related to the Marketing Intelligence System. Larkin PFT, p. 32. The Company made these expense changes in Late Filed Exhibit No. 4; thus, no further adjustment is necessary.

3. Depreciation Expense

[23-26] The Company submitted a depreciation study for property in service at September 30, 1997 (Depreciation Study) that uses the straight-line method and remaining life technique. Aikman PFT, p. 2. Based in part on the results of the Depreciation Study, CNG originally requested a pro forma depreciation expense of $23,887,257, an increase of $6,746,600 over test year. Schedule C-1/C-2, p. 1. CNG amended its original submission decreasing the additions to Account 387, Other Equipment -- Distribution by $189,529 and depreciation by $10,350. The revised pro forma expense is $23,876,907; $6,736,250 greater than the test year. Late Filed Exhibit No. 4, Version B; Attachment B, p. 2.; Schedule C-1/C-2 Revised, Version B, p. 2. The Depreciation Study employs the Average Life Group (ALG), or broad group procedure, currently in use, as well as the Company's proposed change to Equal Life Group (ELG), which, according to CNG, provides a more timely recovery of capital. Aikman PFT, Exhibit JHA-2, p. 8. The Company argues that '[t]he adoption of ELG for rate making will result in rates that more properly recover the cost associated with the consumption of the depreciable property as consumption of that property takes place.' Aikman PFT, p. 15. The relevant difference between ALG and ELG is in the development of the average remaining

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life. ALG uses a direct weighting of the remaining lives of each average life group, whereas ELG uses a reciprocal weighting procedure. Aikman PFT, p. 17.

The Company indicated that all of the historical life and net salvage analyses were made using only CNG history. Aikman PFT, Exhibit JHA-2, pp. 12-13. The Depreciation Study contains a brief discussion of each account and an explanation of the reasons for changes in service life, curve type or salvage value. The Company indicated that the total depreciation impact of $6,746,600 is caused by: increases in plant in service of $1,918,089 later adjusted to $1,907,739; updated ALG of $1,691,659; and use of ELG of $3,136,852. Late Filed Exhibit No. 1, ADR-72, Attachment, p. 1.

The two largest investments in Company plant are in Account No. 376, Mains, containing a test year balance of $180,058,131 after additions and transfers of $8,852,072 and retirements of ($359,197); and Account No. 380, Services, containing a test year balance of $124,865,530 after additions of $7,061,626 and retirements of $856,214. Schedule G-1.0, p. 2. These two accounts also represent the bulk of the proposed adjustments from the current ALG accrual rate to the proposed ALG rate and to the proposed ELG rate. The changes in accrual rate occur because of the Company's history of average service lives (ASL) and salvage values, and the proposed ELG methodology.

The salvage value of plant is the amount that can be recovered after the plant has been removed (a credit or a reduction to revenue requirements) or the cost to remove the plant from service. The table below shows how the changes in lives and salvage percent affect the ALG and ELG accrual rates in Account 376, Mains, and Account 380, Services, and the total plant:

Depreciation Comparison	Current	Revised	Current	Revised	Current	Revised	New
Account	ASL Yrs	ASL Yrs	Salvage	Salvage	ALG	ALG	ELG
376.00	65	62	-50%	-75%	2.32%	2.97%	3.35%
380.00	50	50	-145%	-175%	5.25%	5.79%	7.24%
Total Plant	42.8	44.2			3.74%	4.24%	5.01%

Aikman PFT, Exhibit JHA-2, pp. 19-22; 28-31; Decision dated December 15, 1993, in Docket No. 93-02-04, Application of Connecticut Natural Gas Corporation to Amend Its Rate Schedules (1993 Rate Case Decision), pp. 72-73.

Some of the other less significant accounts have drastic changes in their average service lives, but these are based on actual Company experience. The changes were tempered and moderate adjustments were made. The same criteria were used when the salvage values made drastic negative changes based on actual experience. Aikman PFT, Exhibit JHA-2, pp. 15-31; Response to Interrogatory GA-219. The Department finds the analyses performed within the Depreciation Study to be reasonable and supported by actual experience.

OCC opposes an increase in depreciation expense, with its attendant substantial increase in revenue requirements, if the ELG procedure is adopted. OCC contends that the current ALG procedure adequately addresses the depreciation needs of the Company and assures both timely and full recovery of capital expenditures. OCC contends that ELG is a complicated and time-consuming method for determining the division of plant into subgroups and the correct mortality rate. OCC asserts that use of ELG effectively accelerates the timing of revenue reimbursement, leading to a tendency to replace plant more quickly. OCC Brief, pp. 51-54. OCC is also concerned about the cost of removal, salvage, and any resulting net negative salvage because of the Company's most recent experiences. Additionally, OCC recommends that the Department order the Company to scrutinize and review its preventive maintenance practices since they have an effect on the extension of plant lives. Id., pp. 54-55.

In its brief, PRO argues against the adoption of ELG because CNG has not presented evidence that warrants a change to its depreciation calculations and notes that the Department has failed to accept ELG in the past. Further, PRO points out that the Depreciation Study was done using 9/30/97 information, which is not the best, most reasonable or most accurate data and recommends that the depreciation method and annual dollar amount remain unchanged. PRO also indicates that if the ELG method of depreciation is accepted, the amortization difference should be recovered over five years rather than one. Brief, pp. 14-15.

The goal of depreciation is to allocate the cost of a plant asset over its effective production life. The Department does not believe that ELG accrual rates are more appropriate than ALG rates in achieving that end. ELG lumps short-lived assets with those that are expected to last many years. Since ELG would value all the units the same, retirement of a short-lived asset would reduce the reserve by the same amount of dollars as the long-lived unit, producing a mismatch of production value. The Department rejected ELG in the 1993 Rate Case Decision for just this reason. The Company has not persuaded the Department that a change is warranted.

OCC is concerned about the increases in net negative salvage, especially in Account 376, Mains, and Account 380, Services. Brief, p. 55. The Department believes that although there has been a substantial increase in these specific accounts, it is supported by historical data. Further, there could have been larger increases had the Company not tempered these values. CNG, like most northern gas utilities, has a large amount of old cast iron and bare steel pipes. The Company has undertaken a program of accelerated replacement of these pipes, which the Department encourages. The Department therefore accepts these salvages.

In summary, the Company has been fully compensated for its plant using ALG. That procedure, along with the straight-line method and remaining life technique, has served the Company and ratepayers fairly and should be continued. The Company has not presented evidence that would warrant a change to ELG with its $3,136,852 increase in annual depreciation expense. The Department rejects the use of ELG in this case, but accepts the changes in average service lives and salvage values as filed.

In Section II.B.1.a. above, the Department reduces the Company's plant in service by $584,519. This requires a corresponding decrease in depreciation expense. The Company's initial application proposed a depreciation expense of $23,887,257 on an average plant in service of $474,266,881. This equates to a 5.04% embedded depreciation rate. Therefore, the Department will apply this rate to the plant in service adjustment and reduce depreciation expense by $29,440.

Additionally, in Section II.D.18. below, the Department reduced the Company's pro forma O&M expense by $222,500. The Department made a corresponding increase to plant in service, adding $111,250 to reflect the average investment in the rate year. Thus, an increase in depreciation expense is appropriate. Therefore, the Department will increase depreciation expense by $5,607 (5.04% X $111,250). The Department's total reduction to depreciation expense is $3,160,685 [$3,136,852 + ($29,440 - $5,607)].

4. Employee Benefits

[27] CNG calculated that it would incur an employee benefit expense of $4,756,495 in the rate year. Schedule C-3.30. Ninety-seven percent of the expense relates to medical and dental insurance for active and retired employees. In its calculation of the expense, the Company first determined the total expense of $6,171,656 and then allocated $4,756,495 (77.07%) to gas operations. Schedule WPC-3.30. This exceeded the test year expense of $3,901,474 by $855,021. Schedule C-3.30.

In Section II.D.13.d. below, the Department reduces CNG's payroll expense by $515,017. Based on that reduction, the Department reduces pro forma employee expense by $94,763. The Department multiplied the payroll change by 18.4%, the employee benefit rate provided by the Company to calculate this adjustment. Tr. 2/16/00, p. 1775.

Revised pro forma expenses in Version B, were not adjusted for employee benefits. Accordingly, the Department will further reduce this expense by $29,530 ($160,493 X 18.4%). Therefore, the total Department adjustment to employee benefits is $124,293 ($29,530 + $94,763).

5. Hardship Arrearage Forgiveness Program

[28] The Hardship Arrearage Forgiveness Program (Arrearage Program) provides low-income customers with an affordable mechanism to make consistent monthly payments, reduce arrearages and maintain service year round. Leavitt PFT, p. 7. Customers who meet the hardship criteria and receive State energy assistance funds have those funds matched by the Company. The Company also matches any payments program participants make. The Company contribution is recorded in a deferred account, which the Department has allowed the Company to amortize. (See, most recently, the Rate Case Decision, p. 28). Tr. 1/18/00, pp. 835-836. CNG requests

(Publication page references are not available for this document.)

that the Department approve a pro forma expense of $2,334,248, a $990,748 increase over test year expense. Schedule C-3.24.

OCC recommends that the Department reduce pro forma amortization expense by $326,264 to remain consistent with the Arrearage Program's current deferral trends. Brief, p. 31. OCC states that CNG has not supported the proposed $2,334,248 increase in the annual amortization expense adequately. OCC points out that WPC-3.24 does not contain a breakdown of the $2,334,248. Larkin PFT, p. 19. That schedule merely provides a reconciliation of the Company's deferral balance at September 1996 and its deferral balance at May 2000. The annual deferral has been decreasing in the past three years, which OCC attributes to the improvements in the economy and the fact that the program has been successful. Id., p. 32.

Additionally, OCC presented data indicating that the Company's deferrals for the fiscal years 1997, 1998 and 1999 decreased. Larkin Direct Testimony, Exhibit L&A-1; Schedule C-2. OCC recommends a decrease of $326,264 in the allowed expense for the rate year, calculated by applying the average of the previous three fiscal years' decrease to the most recent year's deferral, ($2,331,883 for Fiscal Year ending September 1999). OCC's methodology would produce a $2,007,984 deferral for the rate year.

CNG has proposed an expense that is '...based on what is likely to occur during the rate year.' Reply Brief. p. 24. However, the Company has not provided any indication of how it calculated the $2,334,248. In the absence of that data, OCC has proposed a reasonable calculation of the rate year expense. Because of the continual declines noted by OCC, the Department finds three years too short a time to provide a reliable average for this expense. Therefore, the Department will limit the adjustment to 50% of the OCC recommendation or $163,132. The Company will continue to defer hardship arrearage forgiveness expense that exceeds the $2,171,116 amount allowed by the Department.

6. Inflation Expense

[29] The Department typically allows utilities to apply a general inflation factor to O&M expenses not specifically adjusted elsewhere. The Company used a 2.944% composite inflation factor to adjust a pool of unadjusted expenses having a balance of $6,314,135 to produce an inflation expense of $185,869. Schedule C-3.03; Response to Interrogatory GA-34; Late Filed Exhibit No. 4, Version B. The Company excluded fixed and contractual expenses as well as nonrecurring items from this pool of O&M expenses. Responses to Interrogatories GA-31 and 32. The Company developed the 2.944% by using the quarterly Gross Domestic Price Deflator (GDP Deflator), in the range of 1.4% to 1.7%, as published in the April 1, 1999, Blue Chip Economic Indicators, and the August 10, 1999, Blue Chip Financial Forecasts. Schedule WPC-3.03a; Responses to Interrogatories GA-33 and 34. Mechanically, the Company calculated the inflation adjustment correctly; however, the inputs are subjective in nature and need revision.

OCC asserts there should be no inflation adjustment, since the Company has an

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objective in its 2000-2004 business plan to control annual O&M expense increases to keep them under the general inflation rate. Response to Interrogatory GA-17. OCC further reasons that if the Company's inflation adjustment is excluded, O&M expenses increase by 6.87%. If the Company has a goal of increasing its O&M expenses by less than general inflation, its filing does not reflect this. Larkin, Schultz and DeRonne PFT, pp. 20-21. OCC believes there is ample evidence demonstrating that a generic inflation adjustment should be denied, including that, historically, CNG's expenses have actually decreased. In addition, CNG's specific adjustments already increase expenses above and beyond general inflationary levels. Further, CNG has projected that future expenses are not expected to increase at the level of general inflation. OCC Brief, pp. 33-34.

Without an inflation adjustment, the Company would not be made whole for increases in its O&M expenses not adjusted for elsewhere. The Company's objective should be recognized in an adjustment to the inflation factor used; but there should also be a recognition of how difficult an objective that is to achieve. The Department finds the Company's mix of O&M expenses lends itself to a 20 basis point decrease. Using the Company's methodology, this results in a revised factor of 2.566%.

The Department has examined the group of accounts to which the Company applied the inflation adjustment and finds that some have already been adjusted for known and measurable changes in the form of maintenance, labor costs and market indices. Schedule WPC 3.03b. The Department's analysis centered on what was included in each individual account and the probability that inflation in the general economy would effect that account. For example, LP gas expense, Account Number 717, is related to liquid propane, which varies less with inflation but more with the market price of oil and gas. The purchased gas expense, Account Number 807, is directly linked to the purchase of gas for resale and not subject to inflationary pressures. Local storage labor and expenses, Account Number 841, are primarily labor costs, which have already been escalated. The same is true of maintenance of vaporization equipment, Account Number 848, other distribution expenses, account number 880; and meter reading expense, Account Number 902. Customer assistance expense, Account Number 908, is primarily associated with providing matching funds and should have no inflation associated with it. Outside services employed expense, Account Number 923, is for consulting services and should react to competitive bidding, which mitigates the effect of inflation. Maintenance of general plant, Account Number 932, is primarily labor and other expenses that CNG has already increased.

The following accounts and dollar amounts should be excluded from the base of expenses not adjusted elsewhere:

Account No. and Title	Dollar Amount
717 LP Gas Expense	$ 12,432
807 Purchased Gas Expenses	164,458
841 Local Storage Labor & Expenses	55,382

848 Maintenance of Vaporization Equip.	93,939
880 Other Distribution Expenses	937,882
902 Meter Reading Expenses	53,609
908 Customer Assistance Expense	123,082
923 Outside Services Employed	462,582
932 Maintenance of General Plant	75,195
Total	$1,978,561

Subtracting the $1,978,561 from the Company's base of $6,314,135 produces $4,335,754 in O&M expenses not adjusted elsewhere that should be subject to an inflation adjustment. Applying the revised composite inflation factor of 2.566% to this base of expenses produces an inflation expense for the Company of $111,255 (2.566% x $4,335,754). Therefore the Company's inflation expense is reduced by $74,614 ($185,869 - $111,255).

7. Income Taxes

a. Interest Synchronization

[30] The Department requires that interest expense be included in the calculation of a utility's state and federal income tax obligations. In the Previous Rate Decision, the Department stated that it 'believed that adjusting pretax income by an interest component based on rate base times the allowed weighted cost of debt is more appropriate because it better 'synchronizes' allowed taxes, interest costs and rate base.' Decision, p. 51. The Department has not found any reason to modify this determination. The size of a company's rate base, its cost of debt, and the percent of debt in the Company's capital structure all enter into the Interest Synchronization model.

CNG indicated that it used interest synchronization to determine the interest expense used in the calculation of its state and federal corporate income tax liabilities. Specifically, the Company reduced operating income by $10,719,919 in its initial Application. Late Filed Exhibit No. 1, ADR-24 and 27. The Department requires the following formula for the calculation of interest:

I Interest

R Rate Base

D Weighted Debt Percentage

$$I = R \times D$$

The Department has adjusted the Company's allowed rate base and its cost of debt. The Department has allowed the following amounts in this proceeding:

(Publication page references are not available for this document.)

Allowed Rate Base	$275,266,120
Weighted Debt Percentage	3.84%

(See Sections II.B.7 and II.J.4, respectively.)

Accordingly, the correct Interest Synchronization amount equals $10,577,857 ($275,266,120 X 3.84%). This will require the following adjustments to CNG's corporate income taxes:

	State	Federal
Adjusted Interest	$10,577,857	$10,577,857
Interest per Company	10,719,919	10,719,919
		142,062
Less State Tax Change		10,655
Change in Taxable Amount	142,062	131,407
Tax Rate	7.5%	35%
Tax Changea	$ 10,655	$ 45,992

a A decrease in interest expense will increase the Company's taxable income and cause a corresponding increase in state and federal taxes.

b. Connecticut Corporation Business Tax

[31] The Company based its pro forma CCBT on its projected financial operations at the rate of 7.5%. This produced pro forma CCBT of $1,872,945. Late Filed Exhibit No. 4, Version B. Based on the Department's interest synchronization, above, the Department will increase the Company's CCBT by $10,655. The Department also adjusts the Company's CCBT to reflect the allowed revenues and operating expenses.

c. Federal Income Taxes

[32] The Company based its pro forma federal income tax (FIT) on its projected financial operations, at a rate of 35%. This produced pro forma FIT expense of $11,547,544. Late Filed Exhibit No. 4, Version B. In light of the Department's adjustment to interest synchronization, above, the Department will increase the Company's FIT by $45,992. The Department also adjusts the Company's FIT to reflect the changes the Department has made to revenues and operating expenses.

d. Deferred Federal Income Taxes

CNG has included $297,000 of deferred income taxes as part of its pro forma operating expenses. The majority, $202,000, is a result of timing differences between book depreciation expense and tax depreciation expense. Late Filed Exhibit No. 1, ADR-27. The $76,000 deferred taxes in Schedule C1/C2, reflects netting the $297,000 against an investment tax credit of $221,000.

When the Department adjusts the Company's book depreciation expense, it increases the difference between CNG's book and tax depreciation expenses because the tax depreciation remains the same. Therefore, an adjustment to book depreciation requires an adjustment to deferred income taxes. The Department has reduced the Company's depreciation expense by $3,160,685. Therefore, the Department will increase CNG's deferred taxes by $1,260,323 ($237,051 + $1,023,272), calculated as follows:

	State	Federal
Change in Depreciation Expense	$3,160,685	$3,160,685
State Tax Rate	7.5%	
Deferred State Taxes	$ 237,051	(237,051)
		2,923,634
Federal Tax Rate		35%
Deferred Federal Taxes		$1,023,272

8. Other Tax Adjustments

a. Property Taxes

[33] CNG's initial Application included pro forma property taxes of $4,550,207. Schedule C-3.42. The Company used a 1% increase factor over prior tax bills for all Connecticut municipalities in its service area. Pro forma property tax expense also included additional taxes based on an estimate of increased assessments from revaluations in the City of Hartford (Hartford). Jones Rebuttal Testimony, Attachment WTJ-4. Subsequently, the Company increased the pro forma expense by $438,981 to $4,989,188, based on recent correspondence from Hartford. Late Filed Exhibit No. 4.

The Company acknowledges the Department's practice of using the most recent actual assessments and mill rates for purposes of setting utility rates. Brief, p. 21. However, the Company believes that the situation with Hartford is unique and argues that the Department should adopt the mill rate estimated by Hartford. The Company equates it with the use of a pro forma sales forecast, mid-year rate base projection or any other one of the numerous known and measurable adjustments used to set pro forma rates. Id., p. 23.

OCC recommends that the Department base rate year property tax expense on actual grand list and mill rates, which are known and measurable. Brief, p. 41. This would result in a rate year property tax expense of $4,181,420. OCC points out that the Hartford estimate will not be finalized until May 2000. Id., p. 42.

Special circumstances must exist for the Department to depart from established ratemaking practices that would have material consequences for ratepayers. Other than the letter from Hartford, which is not definitive, the Company has not presented any evidence to warrant a change. Therefore, the Department will use current assessments and mill rates resulting in allowable property tax expense of $4,181,420. Late Filed Exhibit No. 1, ADR-80. Accordingly, the Department will reduce CNG's pro forma property taxes by $807,768 ($4,989,188 - $4,181,420).

b. Payroll Taxes

[34, 35] CNG included $2,175,677 of payroll tax expense in its pro forma operating expenses, an increase of $275,210 over the test year balance of $1,900,467. Schedule WPC-3.42. The Company based its calculation in WPC-3.42b on annual increases in the maximum salaries subject to social security taxes. In 1998, the maximum salary was $68,800. Salaries of $72,600, $76,800 and $79,500 represent the maximum taxable salaries for 1999, 2000, and 2001, respectively. The increases in the maximums, therefore, were 6.14% from 1998 to 1999; 5.79% from 1999 to 2000; and 3.52% from 2000 to 2001. Schedule WPC-3.42b. CNG used these absolute increase rates to determine average increase rates for the rate year and determined that payroll taxes would increase by 6.02% from 5/1/99 to 4/30/00 and 5.03% from 5/1/00 to 4/30/01. These two calculations produce an increase of $221,818 for those periods ($117,622 and $104,196 respectively). Id.

PRO does not believe that the Company provided enough evidence to support the 35.7% payroll tax increase requested, and recommends that the Department reduce the Company's pro forma payroll taxes. PRO calculated allowable payroll taxes of $21,240 based on an allowable payroll increase of $277,646 and a tax rate of 7.65%. This allowance would require a $253,760 reduction in the expense. Brief, p. 12.

CNG used a flawed methodology in its calculation of payroll taxes by assuming that every employee earns the maximum salary subject to social security taxes. Accordingly, the Company applied an increase rate, based on the increase in maximum salaries, to the total of test year payroll taxes. The Company has indicated that no increase will occur in the social security tax rate of 7.65%. Schedule WPC-3.42b. Therefore, in cases where an employee earns less than the social security limit, the only tax increase the Company would incur for that employee would be the tax on any increase in his or her pay. The Company also erred in applying its theoretical increase percent to all payroll taxes.

The Company indicated that 52 employees earned more than the social security tax limit in the test year. Late Filed Exhibit No. 1, ADR-26. The response also indicated the same number of employees would exceed the social security taxing limit in the rate year. This represents 10.2% of the Company's 509 current employees. The Department will reduce CNG's payroll taxes by 89.8% (100% - 10.2%) of the $221,818 adjustment made by the Company or $199,193 (89.8% X $221,818). In addition to this adjustment, the Department must reduce pro forma payroll taxes relative to the Department's adjustment to pro forma payroll expense. In Section II.D.13, below, the Department reduces payroll expense by $515,017. The Company will have a payroll tax rate of 8.3% in the rate year. Tr. 2/16/00, p. 1775. Accordingly, the Department will reduce payroll taxes by an additional $42,746 ($515,017 X 8.3%).

In Version B, CNG made a vacancy adjustment of $160,493. However, the Company failed to make a corresponding adjustment for payroll taxes and the O&M allocation factor of 83.6%. Schedule WPC-3.28. Accordingly, the Department will further reduce this expense by $13,321 ($160,493 X 8.3%). The Department's total reduction to payroll taxes is $255,260 ($199,193 + $42,746 + $13,321).

c. Gross Receipts Tax

[36] Gas distribution companies are subject to the Connecticut gross receipts tax (GRT). GRT rates of 4% and 5% apply to residential customers and commercial/industrial customers, respectively. CNG's initial application projected a pro forma GRT expense of $10,599,786 for pro forma taxes at present rates. Schedule WPC-3.41. The Company's request for a $15,738,284 increase in its revenue requirement added $675,684 for a total pro forma GRT of $11,275,470. Schedule C1/C2. Subsequently, the Company increased its pro forma revenues by $8,010,815. Late Filed Exhibit No. 4, Version B. This increased pro forma GRT by $343,924. Together, the changes increased pro forma GRT by $709,958 to $11,619,394.

The Company calculated a 4.29% blended GRT rate by combining the calculated taxes on residential revenues and commercial revenues. Schedule WPC-3.41. CNG's calculation of its blended GRT rate properly excluded taxes on non-taxable interruptible service revenues. Tr. 1/11/00, p. 137.

In Section II.C, above, the Department adjusted CNG's revenues for firm transportation by $58,700, and for an additional customer by $109,000. The Department will make an adjustment to GRT at the rate of 4.29%. Therefore, the Department will increase CNG's GRT by $7,194 ([$58,700 + $109,000] X 4.29%).

d. Summary of Other Tax Adjustments

The Department's total adjustment for other taxes is $(1,055,804), $(255,260) for payroll tax, $(807,738) for property tax, and $7,194 for gross receipts tax.

9. Insurance

a. Directors and Officers Liability

[37] CNG has included the cost of D&O liability policies in pro forma insurance

expense. The D&O insurance provides the Company with coverage for certain types of wrongful acts by directors or officers of the corporation. Its intent is to safeguard the assets of the corporation so that the Company can continue to provide service to its customers and earn a fair return for its shareholders. The Company has two such policies. The first provides regular coverage and has a $84,100 annual premium. The Company included $70,308 of that premium (83.6%) in its pro forma expense. The second policy provides excess coverage and has a $87,900 annual premium. The Company included $73,397 of that premium in its pro forma expense for a total pro forma D&O insurance cost of $143,705 ($70,308 + $73,397). Schedule WPC-3.32.

OCC recommends that CNG's adjusted expenses be reduced by $81,807 to reflect the allocation of 20% of regular D&O liability insurance and 100% of the excess D&O liability insurance to shareholders. OCC would prefer that the cost be split equally between ratepayers and shareholders. Not withstanding that action, the OCC believes it appropriate to remain consistent with the Previous Rate Decision where 20% of the regulated premium was disallowed. OCC Brief, pp. 11, 37. Based on CNG testimony, PRO recommends a $7,031 reduction to this expense. PRO Brief, p. 11.

In the Previous Rate Decision, the Department found that the Company needed D&O insurance to attract and keep qualified directors and officers. However, because shareholders could also initiate suits against the directors and officers, the Department disallowed 20% of the premium of regular coverage. Additionally, the Department found that the Company had not justified allowance of premiums of excess D&O coverage in rates. Decision, p. 33.

The Company has not presented any evidence in the instant docket to warrant dissimilar treatment. Accordingly, the Department again disallows the cost of the excess coverage policy premium in its entirety and 20% of the regular policy. Accordingly, the Department will reduce this expense by $14,062 (20% X $70,308) to eliminate costs attributable to shareholders. The resultant allowed premium of $56,246 requires an adjustment of $14,062. Adding that to the disallowed excess coverage premium of $73,397 produces a total reduction to D&O insurance expense of $87,459.

b. Weather Stabilization Insurance

[38, 39] CNG seeks to recover $993,063 in premiums for a weather stabilization insurance (WSI) policy covering the 2000/2001 heating season. Schedule C-3.32. This approximates the cost of the policy for the 1999/2000 season but is more than the cost of the policy in the 1998/1999 season. The witness stated that the Company obtained this insurance coverage to mitigate large swings in the Company's earnings in periods of extremely warm weather. CNG also proposed to set up a deferred account to allow true-ups of insurance premium costs in future rate proceedings. Bolduc PFT, pp. 7, 10.

AG proposes that the Department reject CNG's proposal to recover any costs associated with WSI because it is not a cost that ratepayers should bear.

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Additionally, AG points out that shareholders have already been compensated for weather in the allowed ROE. Furthermore, the Company has failed to show that the WSI provides any real benefits to ratepayers. Brief, p. 6.

OCC opposes the inclusion of WSI premiums above the line. Brief, p. 44. OCC agrees with AG that weather related risks are reflected in a company's ROE, and further states that eliminating that risk would require a fundamental reassessment of the cost of doing business. Cotton PFT, p. 12.

PRO also recommends elimination of the WSI premium. PRO believes that the newness of this insurance product and other inherent liabilities render WSI too risky, and that ratepayers receive no benefit from the coverage. Brief, p. 10.

OCC also criticized the Company's proposal for a weather normalization adjustment (WNA), stating:

The spirit of regulation is that you do your best to set rates, whatever that might be, and then if the company fails under those rates to earn its authorized rate of return, it always has the option to come back and then go for higher rates. It affords the utility the opportunity to earn its rate of return, but it does not guarantee the utility the opportunity to earn its rate of return. This mechanism is designed to guarantee, in my opinion, the company's rate of return. Tr. 2/9/00, p. 1268.

The Department believes that the same reasoning should apply to any consideration of WSI because it has been proposed as a substitution to the WNA. Tr. 1/11/00, p. 134.

WSI is not necessary for the provision of safe and quality service to ratepayers. It only adds cost to service at the rate of about $0.50 per month for each of the Company's 140,000 ratepayers. Accordingly, the Department will reduce the Company's operating expenses by $993,063.

c. Injuries and Damages

[40] I&D is a self-insurance mechanism that covers deductibles. Tr. 1/11/00, p. 129. Its $568,000 cost is a significant element in total pro forma insurance expense of $2,455,067. Periodically throughout the Company's fiscal year, CNG credits its I&D reserve and make corresponding charges to its insurance expense account. CNG projects that it will use the I&D reserve to provide $289,200 in claims during the rate year. Schedule WPC-3.32; Late Filed Exhibit No. 1, ADR-41.

OCC believes that the I&D expense for the rate year should remain at the consistent average amount of $289,200, a reduction of $278,800 to the pro forma expense. Brief, p. 35. Additionally, OCC states that 'since no additional information has been provided to assure that the 'projected large' I&D claims are known and measurable, or if ratepayers should be responsible for these claims, the projected reserve balance should not reflect these large declines. ' Id., pp.

34-35.

PRO recommends reducing I&D expense by $250,000, based on CNG's $500,000 deductible for liability coverage and the belief that the Company's ratepayers should bear only one-half of that cost. Brief, p. 10.

In the past five fiscal years, the Company averaged $318,573 in claims paid from the reserve. At the end of the test year, the reserve had a balance of $929,879. Late Filed Exhibit No. 1, ADR-41 and 52. The Company asserts that the desired balance for the reserve is $1,000,000. Reply Brief, p. 28. Therefore, at the end of the test year, the Company's reserve fell short by only $71,121.

Based on the current adequacy of the Company's reserve, the Department believes that the average claims paid in the past five years provide a reasonable basis for determining the amount of expense necessary to replenish the reserve going forward. Accordingly, the Department will reduce the Company's pro forma expense by $249,427 ($568,000 - $318,573).

d. Insurance Adjustment Summary

The Department's total insurance expense adjustment equals the sum of its adjustments to D&O coverage, WSI and I&D or $1,329,949 ($87,489 + $993,063 + $249,427).

10. Maintenance of General Plant

[41, 42] The Company's pro forma O&M expense includes $788,800 relating to maintenance of general plant. Schedule WPC-3.27. Projected repairs of $162,500 to the Company's headquarters, and projected repaving costs of $60,000 for that building's parking lot provide the basis of the $208,200 increase in this expense from its test year level. Id. OCC recommends that the Department disallow the increase with respect to these projects, suggesting that the Company capitalize these costs because it is not known whether the Company will be staying 100 Columbus Boulevard, Hartford, CT., the location of its Corporate headquarters. If CNG's offices are moved, it is unlikely that these costs will be incurred. Larkin PFT, pp. 30-31. CNG does not believe that the possible future development pattern near the Company's headquarters should stop ordinary and necessary maintenance. Reply Brief, p. 31. The Department agrees that possible future moving plans should not preclude current maintenance. However, the Department does not consider the projects to be routine maintenance.

Therefore, the Department concurs with OCC and will accordingly reduce the Company's pro forma expense by $222,500. The Department has capitalized these costs and included them in CNG's rate base for the rate year.

11. Community and Public Relations Expense

[43] OCC has proposed reducing CNG's pro forma O&M expense by $27,965 to remove

community and public relations expenses. Brief, p. 41. OCC maintains that these are costs for improving the Company's image through funding of certain events. Larkin PFT, p. 32. The Company believes that it has an obligation to be an active participant in community and civic affairs. Reply Brief, p. 34.

The Department supports the Company's involvement in the community, but it shall not be at the expense of ratepayers. Therefore, the Department will reduce the Company's pro forma expense by $27,965.

12. Outside Services

a. Legal

[44, 45] The Application includes pro forma outside services legal expense of $790,500. Schedule WPC-3.18. The Company derived this expense by averaging its expense from July 1996 through June 1999. Use of this three-year average is consistent with the Previous Rate Decision. CNG indicates that it had an average legal expense of $828,500 during the past five fiscal years. Late Filed Exhibit No. 1, ADR-12. The Department believes that a five-year average, when available, provides for smoother averaging than a three-year when estimating future expenses because it contains more information. Accordingly, the Department will increase the Company's pro forma expense by $38,000 ($828,500 - $790,500).

b. Other

CNG's initial application included $451,321 in pro forma outside service expense, an averaging of the three years ending June 30, 1999. Schedule C-3.22; Schedule WPC-3.22. Subsequently, CNG reduced this expense by $32,348 to $418,973. Late Filed Exhibit No. 4, Version B.

OCC has proposed two adjustments to this expense. First, is removal of a $100,000 charge from the averaging process. The Company identified the charge in ADR-13 and indicated it should be reclassified. Second, a 1996 A. D. Little charge should be eliminated from the averaging process. The $303,281 charge occurred in July 1996 through July 1997 period. Response to Interrogatory OCC-103. OCC contends that the expense is non-recurring. OCC's witness further stated that 'if there is one significant expense that greatly exceeds the normal level, it would be appropriate to take that out in determining a normalized going forward amount.' Tr. 2/9/00, p. 1390. The Department concurs. That single expense is greater than the average of the remaining expense for the three-year period in which it occurred. The result of these two revisions to the three-year average Outside Services-Other expense calculation is a reduction in rate year expenses of $134,442. Larkin, et. al. PFT, p. 27 and Larkin Direct Testimony, Exhibit L&A-1, Schedule C-5.

Further examination of ADR-13 indicates that CNG's three fiscal year average of outside services -- other expense is $273,115. The Department will use the average as the basis for the Company's allowed pro forma expense because it eliminates the

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$303,281 non-recurring change noted above by using more current data. Accordingly, the Department will decrease CNG's pro forma expenses by $145,858 ($418,973-$273,115).

13. Payroll Expense

a. Short-Term Incentive Plan

[46] Pro forma payroll expense includes a short-term incentive plan (STIP) amount of $273,910 or 50% of the projected incentive of $547,820. Late Filed Exhibit No. 1, ADR-46. The incentive covers mid and senior-level managers, including officers.

The Company believes that its STIP benefits customers as well as shareholders. The goals embodied in the STIP relating to earnings per share, performance factors, and control of O&M expenses benefit the Company's customers, in addition to shareholders. Thus, the STIP should be allocated evenly between customers and shareholders and such an allocation is consistent with Department precedent. The Company also noted that the Department recently approved a 50/50 allocation of the STIP in the SCG Decision. Brief, p. 16.

CNG's management has made improvements that benefit both ratepayers and shareholders. Among its accomplishments are:

. the lowest purchased gas costs in the state and among the lowest in New England;

. the first in state LDC to develop and implement an accelerated program for replacing pipe that is no longer state-of-the-art. As stated in Section II. G. 1, below, the Company is proactive in preserving the safety of the public by having requested, established and implemented this program;

. of the three LDCs in the state, CNG's customer service operation received the highest rating from the Department, by having the lowest number of customer complaints filed with the Department during the calendar years 1998 and 1999;

Given these achievements, the Department believes that a sharing of the executive incentive compensation expense is appropriate and finds the Company's allocation of this expense 50% to ratepayers and 50% to shareholders and/or non-regulated operations is reasonable.

b. Vacated Positions

[47] In its Application, CNG increased payroll expense by $94,502 relative to vacated positions. The adjustment to test year expenses adds the salaries of four positions that were authorized but vacant at the end of the test year to the test year expense amount. Additionally, the pro forma adjustment added the salary of a new position that was not authorized during the test year to the test year expense amount. Schedule WPC-3.28f. Subsequently, the Company revised the calculation of

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this pro forma expense based on average vacancies in the test year ended June 30, 1999. On this basis, the Company reduced test year expense by $65,991. Schedule WPC-3.28f, revised. The Company added $160,493 ($94,502 + $65,991) to this expense in Late Filed Exhibit No. 4, Version B.

The Company believes that use of a single point in time does not provide accurate data. Accordingly, it advocates the use of test year average vacancies of 14 rather than the number of vacancies as of November 30, 1999. Response to Interrogatory OCC-194. OCC recommends that the Department reduce the expense by $491,958, in total, to reflect the most recent actual employee count on the record.

PRO agrees with the recommendations of the OCC's witness and supports a $493,965 reduction to CNG's operating expenses. PRO based this adjustment on the fact that the OCC witness recommended a $588,467 reduction (11 positions time an average salary of $53,497). PRO's recommendation, however, recognizes the adjustments already made by the Company. Brief, p. 11.

CNG had 519 employees as of June 30, 1999. Late Filed Exhibit No. 1, ADR-66. On November 30, 1999, the Company had 504 employees. Response to Interrogatory OCC-194. This decline in employee population equated to 14 vacancies. Tr. 1/11/00, p.176. The same number of vacancies existed on February 16, 2000. Tr. 2/16/00, p.1776. CNG based its revised pro forma expense on an average of seven vacancies in the test year. WPC-3.28f, revised. Additionally, the Company's calculation relied on an average salary of $53,497 that it incurred in the test year. Late Filed Exhibit No. 9.

The OCC has pointed out that the Company's employee level continues to decline subsequent to the test year. Reply Brief, p. 10. Based on the current high number of vacancies, the average vacancy rate in the rate year will be more than seven. This is further supported by the fact that the Company has not filled vacancies during the past three months. Based on previous employee counts, the November 30, 1999 level of employee count appears to represent a reasonable level of staffing. Accordingly, the Department will adopt PRO's recommendation and reduce the Company's pro forma expense by an additional $412,955 ($493,965 X 83.6% O&M allocator).

c. Overtime

[48] CNG's pro forma operating expenses include overtime charges of $1,687,537, an increase of $192,096 over test year. Schedule WPC-3.28c. The pro forma adjustment includes $119,854 to reflect a normalization of the rate year amount and $72,242 to reflect a 4.8% salary increase. CNG stated that the Company made the normalization adjustment '...to adjust the test year overtime to an amount expected during a year with normal weather.' Late Filed Exhibit No. 1, ADR-48.

Historical data provides the most reliable basis for determining a reasonable level of overtime for the Company's rate year. CNG had average overtime expenses of $1,493,754 during the past five fiscal years and capitalized an average of

13.53% of those expenses. Late Filed Exhibit No. 1, ADR-19. In the absence of any evidence to the contrary, the previous five years' average provides a reasonable expectation of future costs. Accordingly, the Department will adjust CNG's pro forma expense by $333,889, calculated as follows:

Average Overtime (Last 5 Years)	$ 1,493,754
Less: 16.4%, Capitalized	244,976
	1,248,778
4.8% Salary Rate Increase	59,941
	1,308,719
Company Pro forma	1,687,537
O&M allocator	83.6%
Pro forma O&M	1,410,781
Adjustment	$(102,062)

d. Payroll Adjustment Summary

The following table summarizes all of the Department's adjustments to the Company's pro forma payroll expense.

Vacated Position Adjustment	$(412,955)
Overtime Adjustment	(102,062)
Total Payroll Adjustment	$(515,017)

As indicated above, the Department reduces payroll expense by $515,017. The Company has a pension expense rate of 3.0% of payroll. Tr. 2/16/00, p. 1775. Accordingly, the Department will reduce pension expense by an additional $15,451 ($515,017 X 3.0%). Therefore, in addition to the $49,134 pension adjustment in Section II.D.13.a. above, the Department reduces pro forma pension expense relative to the Department's adjustment to pro forma payroll expense.

When CNG determined revised pro forma expenses to present expenses in Version B, it failed to make a corresponding adjustment to pension expense. Accordingly, the Department will further reduce this expense by $4,815 ($160,493 x 3.0%). Thus the total adjustment to pension expense, relative to the Department's payroll expense adjustments, is $20,266 ($15,451 + $4,815).

14. Pension Expense

[49-51] The Company's requested pro forma pension expense of $769,807 reflects

the projected expense of the following plans:

	Pro Forma	Reference
Pension Expense -- Qualified Plans	$(1,015,960)	WPC-3.29a
Pension Expense -- Officers Supplemental Retirement Plans	925,062	WPC-3.29a
Direct Payments to Retirees	28,400	WPC-3.29b
Employee Savings Plan	1,080,896	WPC-3.29c
Sub Total	1,018,398	
Percent Charged to Gas Operations	75.59%	WPC-3.29d
Pension Charged to Expense, Pro Forma	$ 769,807	

a. Qualified Plans and Supplemental Employee Retirement Plan

The Company sponsors three qualified pension plans with total pro forma expenses of $(1,015,960). The first plan is the Pension Plan (salaried employees), with expenses of $(39,820). The second, the Retirement Plan (Hartford bargaining unit employees), has expenses of $(993,908). The third plan is the Pension Plan B for Greenwich bargaining unit employees, with expenses of $(17,768). Schedule WPC-3.29a.

The Department analyzed the qualified defined benefit plans (Plans) expense of $(1,015,960) based on the Company's assumptions of 9.0% long-term return on plan assets, a 7.0% discount rate, and a 3.5% salary growth rate. The $(1,015,960), reflects gains made in return on plan assets. The Department believes an adjustment should not be made based on the return on plan assets. The discount rate, defined as the rate of interest under which the Plan's obligations could be settled, is intended to reflect market interest rates at the time of valuation. The Department also believes no adjustment should be made to the discount rate since it is reflective of market interest rates at the time of valuation. The salary growth rate is the anticipated growth rate in the aggregate salary level of the pension plan participants. This aggregate growth includes not only raises but also increases due to promotions. The Department believes the salary growth rate of 3.5% is reasonable.

The officers supplemental retirement plan (SERP) is a pension plan that acts as a supplement to the officers' retirement plan by providing retirement benefits on salary over the $150,000 limit for qualified plans under IRS guidelines. It is calculated using the average of earnings over the five calendar years out of the last 15 years preceding the date of determination that produces the highest average. Fifteen active officers of the Company are covered by the SERP. Late Filed Exhibit No. 39.

In the Previous Rate Decision, the Department disallowed the entire SERP for ratemaking purposes, stating that, 'Although the Department has allowed this in past rate cases it is too great of an expense to be borne by ratepayers struggling under a poor economy.' Decision, p. 45. The Department recently allowed a SERP in the SCG Decision. Based on the evidence presented, the Department finds that the economy is strong enough to allow this expense based on economic statistics for 1999-2008. Late Filed Exhibit No. 42.

However, the Department's analysis of the Plans finds that STIP should be excluded from the benefit calculation for ratemaking purposes since it is not part of regular base salary. Pension benefits should relate to income regularly received by an employee in the years before retirement. This is consistent with Department reasoning in the Previous Rate Decision, where the Department removed the STIP from base salary in the pension calculation. Decision, p. 46. This is an actuarial calculation done by removing the pro forma STIP amounts from each individual participant's compensation amounts. This methodology is necessary because actuarially, any benefits under the plan must be equal to its corresponding expense over the remaining working life of the employee, not just in one year. This amounts to a decrease in the pro forma pension expense but also an increase in the SERP. This increase in the gross SERP benefit is equal to 60% of base pay offset by the qualified Plans benefit. As a result, a decrease in the qualified pension plan benefit results in a corresponding increase in the SERP benefit. Late Filed Exhibit No. 39.

The calculation excluding the STIP from base salary and its effect on pension plan and SERP expenses produces an estimated downward adjustment of $65,000. Late Filed Exhibit No. 39. The Department applied the percentage charged to gas operation of 75.59% to the ($65,000) to determine the adjustment for gas operations of ($49,134).

b. Employee Savings Plan

The employee savings plan (ESP) is a qualified plan and is classified as a 401K. Tr. 1/18/00, p. 791. It is open to all employees on the first day of the month following their date of hire. Company employees may contribute between 1% and 16% of their pay on a pre-tax basis and between 1% and 10% of their pay on an after-tax basis. Total pre-tax, after-tax, and Company contributions may not exceed 25% of an employee's pay. To be eligible for Company matching contributions, an employee must be least 21 years of age and either have completed 1,000 hours of service during his or her first 12 months with the Company or completed 1,000 hours of service in any plan year. The Company will match a percentage of employee pre-tax contributions made to the plan based on years of service and employee age. Vesting is always 100% for any employee contributions and Company contributions increase from 20% to 100% over five-years.

In the Previous Rate Decision, the Department determined that an adjustment should be made based on a comparison of CNG's ESP with SCG and Yankee Gas Services (YGS). Decision, pp. 34-35. The three plans are now equivalent and no adjustment is necessary. Late Filed Exhibit No. 38; Tr. 2/16/00, pp. 1723-1726. In July 1998, CNG made changes to the 401K matching contribution structure, which resulted in

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approximately $134,500 in annual savings. Late Filed Exhibit No. 38; Tr. 1/18/00, p. 794. Most notably, the highest match prior to the change was 6%, and is now 4.5%. The savings were included in the test year and carried forward to the pro forma year. Tr. 2/16/00, p. 1726. Given the change in the matching contribution structure, the Department believes an adjustment should not be made.

c. Conclusion on Pension Adjustment

The Department finds the adjustment of ($49,134) should be applied to the overall requested pro forma pension expense of $769,807, resulting in a pension expense of $720,673.

15. Post Retirement Benefits Other Than Pensions

[52] Under the Financial Accounting Standard No. 106 -- Employers' Accounting for Post-Retirements Benefits Other Than Pensions (FAS 106), the Company is required to recognize these benefits during the working career of employees, not after they retire. Costs accrue from the date an employee is hired to the date of retirement when an employee is fully eligible to receive FAS 106 benefits. The present value of future benefits would be determined by employee retiree demographics.

The Company proposed a $2,652,244 FAS 106 expense, which includes the present expense as well as deferrals authorized by the Department in the Previous Rate Decision. Schedule WPC-3.30; Late Filed Exhibit No. 4, Version B. The current expense is based on the following assumptions:

	September 30, 1999
Discount Rate	7.0%
Salary increases	3.5%
Return on assets	8.0%
Medical trend	a. Under age 65 7.5/4.5% b. Over age 65 6.5/4.5%

Response to Interrogatory GA-41.

The discount rate, defined as the rate of interest under which the FAS 106 plan's obligations could be settled, is intended to reflect market interest rates at the time of valuation. The Department believes a 7.0% discount rate is reasonable for ratemaking purposes, because it reflects market interest rates at the time the actuary calculated the FAS 106 expense for the fiscal year ending September 30, 1999, which is the most recent year studied. A long-term rate of return is used to calculate the expected investment income on the fair value of FAS 106 assets. These assets are determined at the beginning of the year and adjusted for benefit payments and contributions expected to be made during the year. For the years 1994 through 1999, the actual average return on plan assets was 15.68%. Response to Interrogatory GA-42.

The Department believes that some movement in the long-term rate of return is justified, given the magnitude of recent historical earnings. The resulting adjustment must fall in a range of reasonableness given the other actuarial components and the long-term nature of the return. Asked if there was a range of reasonableness in the setting of the return on FAS 106 plan asset, the Company's witness stated, '[i]t could be plus or minus 50 basis points... depending on how one develops the range, it could be more.' Tr. 1/18/00, p. 762. The Department accepts the expert testimony of the Company's actuary and finds a 50 basis point increase is warranted. The Department believes the long-term rate of return should be set at 8.50% for ratemaking purposes based on the most recent historical returns and the actuary's testimony. To calculate the dollar impact, the Department analyzed calculations done by the Company. The Department concurs that every 10 basis point increase in the rate of return on the FAS 106 plan assets equates to a decrease in the expense level of $16,275. Response to Interrogatory GA-44. The Company established that 77.07% of all employee benefit expense is charged to gas operations. WPC-3.30. Thus, the 50 basis point increase in the return on plan assets equates to a decrease of $62,716 ($16,275 X 5 X 77.07%) to the Company's requested FAS 106 expense. Therefore, for ratemaking purposes, the Company's FAS 106 expense should be $2,589,528 ($2,652,244 - $62,716).

16. Regulatory Expense

a. Regulatory Commission Expense

[53] CNG has projected a $849,847 pro forma regulatory commission expense for the proposed rate year. Schedule C-3.10. The Company calculated the expense by applying a 2% inflation factor to the Department's $833,183 most recent assessment for the July 1, 1999, through June 30, 2000 period. Schedule WPC-3.10.

OCC noted that the Company has repeatedly received credits from the Department to adjust for actual expenditures. It recommended that this expense be based on a three-year average instead of going forward from the last known assessment. OCC states that the expense has been high due to electric industry restructuring and a decline could be expected in the future. Therefore, a general inflation factor should not be included in the calculation and the expenses should be reduced by $221,545 to $628,302. Larkin PFT, pp. 28-29; Larkin Direct Testimony, Exhibit L&A-1, Schedule C-6; Brief, pp. 38 and 40.

PRO believes that an average of the last two known increases of this expense, net of credits, should determine the pro forma expense. That would provide for a $28,786 increase. Alternatively, PRO suggests taking the actual expense of $650,605 for July 1, 1998, through June 30, 1999, and applying a 1.02% inflation factor that results in an expense of $663,617. Brief, p. 14.

An average provides a more reasonable measure of future expense, especially when it includes normally present credits as well as annual charges. However, the elimination of an element of an expense does not preclude the remaining elements from being subject to annual inflation increases. This would be especially true concerning the Department's assessment that an expense based materially on wages is subject to annual union increases. Therefore, the Department will apply CNG's inflation factor to OCC's recommended expense to determine the allowed regulatory commission expense. The Department calculates the expense as $640,868 (1.02 X $628,302). Accordingly, the Department will reduce CNG's regulatory commission expense by $208,979 ($849,847 - $640,868).

b. Rate Case Expense

[54] CNG calculated a pro forma rate case expense of $269,000. Schedule C-3.25. The Company derived this expense by amortizing $1,076,000 of total expenses over four years. Schedule WPC-3.25.

OCC recommends that the entire $269,000 cost included in the original filing for the amortization of rate case expenses be denied because it believes that no rate increase is appropriate. In the Department's April 14, 1993, Decision in Docket No. 92-06-12, Application of The Connecticut-American Water Company for a Rate Increase, the Department took such action. OCC cited this as a precedent for denying the Company's pro forma rate case expense in its entirety. Brief, pp. 43 and 44.

CNG believes that OCC's recommendation to disallow rate case expense adjustments is 'outrageous and unsupportable.' Reply Brief, p. 35. The Company points out that if it had not filed a rate case, the Department would have been obligated to initiate a mandatory four-year rate review under Conn. Gen. Stat. §16-19a. Id.

In the Decision Docket No. 92-06-12, the Department found that Connecticut-American Water Company was extremely unresponsive to requests for data regarding rate case expenses. That was a major factor in the Department's expense disallowance. The Department stated '[w]hen the Company fails to provide the information requested by the Authority, it runs the risk of disallowance.' Decision, p. 50. The Department has not found that to be the case in this proceeding. Therefore, the Department will reject OCC's recommendation to deny rate case expense in its entirety.

CNG's total costs of $1,076,000 included an estimated $245,000 for rate design. This exceeds the Company's average rate design costs in its previous rate cases by $128,400. This results in a difference of $116,600 ($245,000 - $128,000). Late Filed Exhibit No. 1, ADR-15. CNG's witness stated that ' [we] expect that that [rate design] will be far more extensive than anything we have done in the past. We really do not know the specifics of what we'll be undertaking.' Tr. 1/12/00, p. 274.

Given the uncertainty of the rate design costs, the Department must reject the Company's estimation and rely on the average in prior rate cases. Accordingly, the Department will reduce the Company's four-year amortization of the pro forma expenses by $29,150 ($116,600 / 4).

17. Uncollectibles

(Publication page references are not available for this document.)

[55] CNG's initial Application proposed a $4,838,399 pro forma uncollectible expense. Schedule C-3.02. The Company calculated this expense by applying a 1.88% average, net write-off factor to pro forma revenues, reduced by off-system sales. Schedule WPC-3.02. Subsequently, the Company reduced the write-off percentage to 1.86%. To develop the 1.86% factor, CNG averaged the ratio of actual net write-offs to revenues for fiscal years 1995 through 1999. Late Filed Exhibit No. 1, ADR-2; Schedule WPC-3.02, Revised. The pro forma expense included $297,040 for the requested $15,800,000 increase in CNG's revenue requirement.

The Company revised its estimate of the average write-off percentage a second time by taking into consideration $600,000 of hardship write-offs that occurred in 1995 and by updating 1999 for actual fiscal year information. This action reduced the average write-off percentage to 1.80%. Thus, the Company's expense decreased by $206,389. Late Filed Exhibit No. 4, Version A. CNG also increased the expense by $13,711 to reflect the expense change relating to the Company's $736,609 amended request for an increase in revenues ($16,536,609 - $15,800,000). Late Filed Exhibit No. 4, Version B. This results in an amended request for uncollectible expense of $4,635,721 ($4,838,399 - $206,389 + $13,711).

OCC recommends that the Department adopt a 1.44% uncollectible write-off rate, based on the actual write-off percentage that CNG experienced in FY 1999. OCC's recommendation results in $1,293,152 decrease in CNG's pro forma expenses. Larkin PFT, pp. 13-14. This would reduce CNG's uncollectible expense by $1,293,152 from $4,835,000 to $3,541,848 to reflect a decrease in the write-off percentage. OCC believes that this rate represents more current data and more closely approximates the 1.51% rate the Department adopted in the Previous rate Decision. Larkin PFT, pp. 15-16.

PRO believes that the Department should use a five-year average (1996-1999) of 1.73% to determine the Company's uncollectible expense. PRO recommends a $386,042 decrease in the expense. Brief, p. 13.

CNG believes that the Department should reject the OCC's proposal of a 1.44% uncollectible rate because it is arbitrary and does not reflect the use of representative data. Brief, p. 17. The Company contends that the use of the five-year average is appropriate because there is a correlation between weather and uncollectible percentages. Colder weather results in higher uncollectibles because at least some customers cannot pay large gas bills as easily as they can lower gas bills. Also, the use of a five-year average can help smooth out aberrations in a single year's worth of data. Finally, the Company notes that the use of five-year averages in this area is common regulatory practice. Brief, pp. 17-18.

Examination of the Company's write-off percentages over the past five years indicates that 1999 had abnormally low write-offs. OCC, however, has not provided any evidence that would suggest that the Company would incur this write-off percentage in the rate year.

However, in the case of uncollectibles, recent data may represent the results of more effective and efficient collection methods that will continue to bear fruit in the future. Additionally, to the extent that fiscal year 1999 is less than fiscal year 1998, more reliance should be placed on recent history. Therefore, to recognize the value of more recent data, the Department has developed a weighted average write-off percentage for CNG's last five fiscal years. The Department used the weights of one through five for this purpose and thus, calculated a 1.74% average write-off rate.

Uncollectible Write-Off Percent -- Calculation of Weighted Average

5p

Year	Uncollectible Rate	Weight	Product
5p			
1995	2.16%	1	2.16%
1996	1.64%	2	3.28%
1997	1.89%	3	5.68%
1998	1.93%	4	7.73%
1999	1.45%	5	7.25%
Totals		15	26.10%
Weighted Average (26.10% / 15)			1.74%

The table below provides the Department's calculation of its adjustment to the Company's pro forma uncollectible expense. The Department did not calculate this adjustment by multiplying the write-off rate differential of 0.6% (1.80% - 1.74%) times $265,310,755. That would have resulted in a $159,186 reduction in uncollectible expense. In Version B, when the Company increased present revenues by $7,212,491 ($270,566,642 - $277,779,133), it did not correspondingly increase its uncollectible expense to reflect this change. The Department has adjusted for the Company's oversight.

Pro Forma Revenues	$ 294,315,742
Less: Off System Sales	29,004,987
Subject to Uncollectible Expense	265,310,755
Write-Off Rate	1.74%
Uncollectible Expense	4,616,407
Less: Pro Forma Expense	4,635,721
Adjustment	$ (19,314)

In Section II.C., the Department adjusted CNG's revenues by $167,700 ($58,700 for FTS customers and $109,000 for new firm customer). The Department must make a

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corresponding adjustment increasing CNG's uncollectible expense by $2,918 (1.74% x $167,700). Thus, the total adjustment to CNG's uncollectible expense becomes an increase of ($16,396) ($2,918 - $19,314).

18. O&M Adjustment Summary

The following table summarizes the Department's adjustments to O&M expenses:

Expense Category	Amount
Fringe benefits	$ (124,293)
Hardship arrearage program	(163,132)
Inflation	(74,614)
D & O liability insurance	(87,459)
Weather stabilization insurance	(993,063)
Injuries and Damages insurance	(249,427)
Maintenance of general plant	(222,500)
Community and public relations	(27,965)
Outside services -- legal	38,000
Outside services -- other	(145,858)
Vacated positions	(412,955)
Overtime	(102,062)
Payroll adjustments -- pension	(20,266)
Qualified plans and SERP	(49,134)
FAS 106	(62,716)
Regulatory Commission	(208,979)
Rate case	(29,150)
Uncollectibles	(16,396)
Total Adjustments	$ (2,951,969)

E. REVENUE CONVERSION FACTOR

[56, 57] The Department employs a revenue conversion factor (RCF) to determine the change necessary in revenues to produce the required change in allowed operating income. This procedure is necessitated because allowed operating income represents income after applicable taxes and other adjustments. The Company used the following rates to calculate a RCF factor of 1.73781.

Gross Receipts Tax Rate	4.29%	
CCBT Tax Rate	7.50%	
FIT Tax Rate	35.00%	
Thus, the calculation is: Revenue Change	100.0000% Less: Gross Receipts Tax	4.2900%

	195.7100%
Less: Connecticut Corporation Business Tax (7.50% times 95.7100%)	7.1800%
	88.5300%
Less: Federal Income Tax (35.4659% time 88.5300%)	30.9900%
Net Income Percentage of Total Revenue	57.5400%
Revenue Conversion Factor -- Reciprocal of 57.5400%	1.73781

Late File Exhibit No. 42, p. 3. Schedule A-2.

1. Bad Debt Expense

In Section II.D.17. above, the Department found that 1.74% represents a reasonable bad debt write-off percentage. Because uncollectible expense is a function of revenues, the Department believes it appropriate when adjusting revenues to make comparable adjustments to uncollectible expense. Accordingly, the Department will incorporate CNG's bad debt percentage into the Company's RCF.

2. Allowed RCF

In the Department's calculation of CNG's RCF for this proceeding, the Department will use the following rates:

Gross Receipts Tax Rate	4.29%
Bad Debt Expense	1.74%
CCBT Tax Rate	7.50%
FIT Tax Rate	35.00%

Accordingly, the Department finds that the 1.76993 RCF, calculated in the table below, is reasonable.

Revenue Change	100.0000%
Less: Gross Receipts Tax	4.2900%
	95.7100%
Less: Bad Debt Expense	1.7400%
	93.9700%
Less: Connecticut Corporation Business Tax (7.50% times 93.9700%)	7.0478%
	86.9222%

Less: Federal Income Tax	
(35.0000% times 86.9222%)	30.4228%
Net Income Percentage of Total Revenue	56.4994%
Revenue Conversion Factor -- Reciprocal of 56.4994%	1.76993

F. COST OF GAS AND GAS SUPPLY

[58, 59] The Company proposed a total gas cost of $157,344,690, of which $94,160,324 is the proposed cost of supply for firm customers. The balance is for non-firm sales, including off-system sales. Late Filed Exhibit No. 4, Attachment B, p. 1. Dividing the proposed cost of gas supply for firm customers by estimated firm sales of 19,702,943 Mcf yields a firm gas cost of $4.779 per Mcf. Id., p. 6b. The Company's proposed base gas cost is up 11.0% from $4.306 per Mcf in the Previous Rate Decision. The Company's base gas cost had been quite stable until recently, exceeding the prior base gas cost in only two months during 1998 and 1999. Response to Interrogatory GA-99. Field prices for natural gas have firmed considerably in the last few months. This resulted in an increase of over 4% in total gas costs between the time that the Company's rate case was prepared (NYMEX Strip of July 28, 1999) and the time that it was updated at the end of the hearings (NYMEX Strip of January 28, 2000). Karanian PFT, p. 6; Late Filed Exhibit No. 4, p. 3. The Company reported that, despite a reduction in its total cost of gas, its base gas cost increased because of the migration of some of its customers from firm sales service to transportation services. Response to Interrogatory GA-100.

On the basis of the evidence provided by the Company, the Department approves the Company's proposed base cost of gas, with one minor adjustment. The adjustment is due to the additional new customer coming on line in April 2000, which the Company stated had not been included in its sales or revenue forecasts. Estimated requirements for that customer are 27,000 Mcf per year, resulting in increased gas expense of $76,140. Response to Interrogatory GA-109. With this adjustment, the total estimated gas cost is $157,420,830. The new base cost of gas for firm customers is $4.776 per Mcf ($94,236,464 / 19,729,943)

The Company made a number of adjustments in its gas supply pipeline capacity portfolio since its last rate case that have a total estimated value of $ 6,885,000. Late Filed Exhibit No. 18. The Company also increased the sendout capacity of its on-system peaking facility by 30,000 Mcf/day, with the increase to be in service during the rate year. Response to Interrogatory OCC-249.

As indicated in the Decision dated July 23, 1998, in Docket No. 97-07-11, DPUC Generic Investigation into Issues Associated with the Unbundling of Natural Gas Services by Connecticut Local Distribution Companies -- Phase I, the Department stated that until such time as the LDC obligation to serve changes, it would be imprudent to allow the LDCs to dispose of any capacity permanently. As such, the Department will carefully review, after the fact and for rate making purposes, the

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prudence and expected impact on ratepayers of these decisions by the LDCs. The Department reviewed the analysis on which these capacity adjustment decisions were made and finds them acceptable. The Department believes that the Company's aggressive approach toward adjusting its supply portfolio in response to changes in its customers' requirements is a major factor in its continuing position as Connecticut's lowest-cost gas distributor. The record shows that the Company's gas costs are among the lowest in the Northeast. Response to Interrogatory GA-104. The Department commends the Company for its performance.

G. PIPELINE SAFETY

1. Cast Iron/Bare Steel Replacement Program

[60-62] The physical facilities of the Company include a large amount of underground plant, some of which is modern and state of the art (coated, cathodically protected steel and plastic) and some not of modern materials (bare steel and cast iron). The Company has an ongoing program to evaluate its physical facilities, particularly those that are not state of the art, and identify for replacement or remediation those facilities that warrant the highest priorities. This is coupled with a program to replace facilities that are not state of the art on an accelerated basis. Thus, the Company is proactive in preserving the safety of the public. While replacement of most of the facilities that are not state of the art is desirable, it is a long-term process. The Company's commitment to an accelerated program is shortening this process.

2. Gas Odor Complaint Response Time

One factor that can affect the potential safety of the public and gas customers is the Company's response to reports of gas odors; that is, the amount of time it takes for a person competent and qualified in evaluating gas odors to arrive at the scene from the time the gas utility receives notice of the odor. A potential gas odor hazard cannot reliably be determined unless investigated by a competent, trained person. The more rapid a response, the less likely a true emergency will develop. The Department has established certain guidelines to evaluate the response of gas utilities: 30 minutes during normal business hours and 45 minutes at other times. This guideline was initially established in the form of monitoring reports of Class 1 and Class 2 leaks filed by the gas utilities under §16-11-12 of the Conn. Agencies Regs. [FN2] Gas utilities were required to explain any response that exceeded the guideline. It has only been in recent years that the Department has reviewed responses to all odor reports, rather than just reports for Class 1 and Class 2 leaks. The results of that review and the information contained in the Application indicate that the Company meets the guidelines only 86% of the time during normal hours and 97% of the time during off hours. Bryant PFT, p. 12.

The Department is concerned about the percentage of responses that fail to meet the guidelines; there must be improvement in this area. The Department is particularly concerned about response times in excess of one hour. As part of its routine operation, the Department recently began a program of requiring

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explanations for response times in excess of one hour. The Company should use the knowledge it gains from this on-going process to identify other areas of improvement. Improvements in response time come from increasing productivity of employees and increasing staff levels. The Department directs the Company to analyze its service department and to take the steps necessary to find improvements in productivity that will result in improved leak response times.

3. Safety Advertising Expenses

The Company is subject to the Minimum Federal Safety Standards, including requirements related to educating the public and local officials about the potential hazards of natural gas. The estimated expenditures for safety education have been approximately $70,000 per year from 1995 through 1999. Response to Interrogatory GPS-12. The estimated expenditures for safety advertising for the years 2000 through 2004 increase from $75,000 to $101,000 per year. However, the Company stated that it does not have a formal program to measure the effectiveness. Id. The expenditures for this program appear to be adequate, but the Company must develop a program and associated budget to measure the effectiveness of the program and gather feedback to ensure the necessary education is taking place. The Company also must request a technical meeting with the Gas Pipeline Safety Unit to discuss the proposed program.

4. Customer Leak Calls

For customers calling about a gas leak or any other emergency, the Company maintains a separate telephone number listed as 'To Report Gas Odor Only.' If a call from this line is received in the Call Center while other calls are waiting in queue, the odor call will automatically be shifted directly to Service Dispatch. If all lines are busy in Service Dispatch, the odor call is automatically placed at the front of the call-waiting queue in the Call Center and will be answered by the first available representative. Response to Interrogatory GPS-8. Some customers with gas leaks may call the main business lines and would wait in the queue and not receive priority response. During the hearing, the Company suggested implementing two programs to address this concern. The Company proposed to modify the current message-on-hold to advise customers calling with a gas leak to call back on the gas odor only line. Also, the Company will add the gas leak telephone number to monthly bills and the back of the envelope. Late Filed Exhibit No. 32. Implementing these two programs should give customers the necessary tools to receive the prompt attention that is needed for emergency calls. If the Company has any difficulty implementing either of these programs or begins to receive excessive non-emergency calls on the gas leak line, it should notify the Department's Gas Pipeline Safety Unit to discuss potential alternatives.

H. UNREGULATED AFFILIATES

1. Background

[63-67] The Company is wholly owned by CTG Resources, Inc. (CTG), which also owns

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The Energy Network, Inc. (TEN). TEN holds and operates CTG's unregulated, diversified businesses, which are primarily engaged in district heating and cooling, and also include CTG's equity investment in the Iroquois Gas Transmission System and Downtown Cogeneration Associates. CNG also has one wholly-owned subsidiary, CNG Realty Corporation (CNGR). CNGR is a single-purpose corporation that owns CTG's Operating and Administrative Center in downtown Hartford. The center is leased to CNG. CTG Resources, Inc. Form 10K for 1999, p. 1.

The Company provided information on the structure, organization and employment levels of its unregulated affiliates including detailed accounts of charges between the Company and its unregulated affiliates, and the bases for those charges. Responses to Interrogatories OCC-189 through 194; Schedule G-2.16. The Company also provided explanations for any significant changes on the account charges between the last rate case and the instant docket. Response to Interrogatory OCC-195.

However, the Company provided no information regarding subsidiaries of its affiliates, some of which do business with the Company. CTG's annual reports reveal that TEN holds a 50% interest in the DCA partnership. TEN subsidiary, The Hartford Steam Company (HSC) purchases steam from DCA. HSC also owns a cogeneration facility that serves Hartford Hospital with both steam and electricity. This facility may also use natural gas as a fuel and may buy its gas from the Company. The SEC Form 10K of CTG Resources dated September 30, 1998, indicates that the Company derived $2,299,000 from sales to affiliated companies in that year. CTG's 1998 10K also contains reference to a new marketing alliance with several firms:

... to provide energy for heating, cooling and electricity to large commercial, industrial and institutional facilities by combining cogeneration and district energy. As its role in this alliance, TEN will own and operate the individual customers' on-site district energy plants, which will be equipped with state-of-the-art energy systems provided by other members of the alliance.

To the extent that the plants covered by this alliance are located in the Company's service territory and are fueled by natural gas, these plants will also likely be customers of the Company.

OCC believes that the majority of regulated and non-regulated services and functions are properly segregated. OCC also states that the Company has a Classification of Accounts Manual that outlines how costs are to be allocated to organizational units and accounts within the affiliated companies and a Cost Allocation Manual that discusses the principles behind the allocations. Crane PFT, pp. 8-9. While OCC did not propose any specific adjustments to the Company's accounts, it did present some policy recommendations for the use of positive time reporting, a different allocation for officer payroll costs, common officers and directors asymmetrical pricing, and additional actions.

The record in this proceeding shows that the Company generally does a very good job of reporting on the relationships between its regulated and unregulated affiliates and that those relationships are appropriately structured and conducted. Schedule G-2.16; Responses to Interrogatories OCC 195 and 205; Crane PFT, pp. 8-9. The Department views OCC's recommendations as potential enhancements to processes or practices that the Company is already using. The Department will address each of OCC's recommendations below.

2. Time Reporting Practices

Positive time reporting requires employees to account for all of their time, rather than just the time that they spend working for one or more of the affiliates. OCC found that several different practices are being followed with regard to employees recording of their time. OCC recommend that the Company use positive time reporting for all employees who routinely provide services either to regulated and unregulated corporate entities or to regulated and unregulated divisions within a single corporate entity. Brief, p. 79.

The Department agrees with OCC's recommendation for positive time reporting. It appears to be the fair way to handle the problem of employees performing duties for both regulated and unregulated affiliates. The Company will be directed to develop a plan for implementing positive time reporting that provides for fully-operational positive time.

3. Specific Allocators

OCC recommends that a different allocator be developed for officer payroll costs. Net income available for common stock is currently used, and OCC's concern is that this under allocates costs to new ventures. OCC recommends that the Company be required to propose a new allocator. Id., p. 80.

The Department agrees with the need for a different allocator for officer payroll costs. However, rather than requiring the Company to propose a new one, the Department will require the use of officers' time records. Officers will be required to report their time and the allocation of their costs should be in proportion to the time that they spend on each business. For the time that officers spend on duties, that cannot be attributed to any of CTG's subsidiaries, the Company should allocate that time in proportion to the time that can be attributed to the various subsidiaries. For instance, if the Chairman spends 1,000 hours per year on TEN, 500 hours on CNG, and 500 hours on activities that cannot be attributed to a particular subsidiary, then two-thirds of the costs that the companies incur in maintaining his employment should be charged to TEN and one-third to CNG.

4. Common Officers and Directors

OCC is concerned that when the same individuals serve as officers and directors of both the Company and its unregulated affiliates, it is difficult to ensure that those affiliates deal with one another on an arm's-length basis. Moreover, there are times when the interests of one corporate entity may conflict with another. It is difficult to ensure that utility ratepayers' interests get appropriate consideration in those circumstances. Id., pp. 80-82. To address this, the Department will require the Company to submit a proposed code of conduct governing relationships of CNG officers and directors with unregulated affiliates.

5. Asymmetrical Pricing

OCC recommends that the Department adopt asymmetrical pricing for transactions among the Company's affiliates. Asymmetrical pricing provides that goods or services provided by a regulated utility company to an unregulated affiliate be priced at the higher of cost or the market price, while goods or services provided by an unregulated affiliate to a utility company are priced at the lower of cost or the market price. OCC notes that the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC) has adopted guidelines for transactions between regulated and unregulated affiliates, and that those guidelines provide for asymmetrical pricing. Id., pp. 82-84. The Company objects to OCC's recommendations of asymmetrical pricing. [FN3] Reply Brief, pp. 41-42.

The Department addressed the subjects of affiliate transactions and the NARUC Guidelines in the Decision dated January 19, 2000, in Docket No. 99-08-09, Joint Application of Energy East Corporation and CTG Resources (CTG), Inc. for Approval of a Change of Control. In that Decision, the Department required that the companies propose, by June 30, 2000, procedures for cost allocations and affiliate transactions to govern the relationship between Energy East and CTG. Id., p. 23. The Department recommended that the companies refer to the NARUC Guidelines when developing the required procedures. Id., p. 20. The Department will impose a similar requirement on the pricing of transactions among CTG's various subsidiaries. As part of the proposals to be filed by June 30, 2000 the Company will propose a pricing rule, and any procedures necessary for its implementation.

The NARUC Guidelines are characterized as '...a framework for regulated entities and regulatory authorities for the development of their own policies and procedures for cost allocation and affiliate transactions.' Guidelines, p. 1. The proposals to be filed by June 30 will address all areas covered by the Guidelines, and will address all of the cost allocations and affiliate transactions between Energy East and CTG, between CTG and all of its subsidiaries, and among all of CTG's subsidiaries.

I. CUSTOMER SERVICE ISSUES

1. Telephone Availability

[68-71] The Company stated that the highest averages of speed of answer and abandoned telephone call rates were in October 1994. Late Filed Exhibit No. 34. The average speed of answer (115 seconds) and abandoned call rates (11%) were due to Company customer service representatives not being familiar with a newly implemented customer information system. Tr. 2/16/00, pp. 1818-1819. In 1998-

1999, average speed of answered calls was 23 seconds and 3% of calls were abandoned. CNG indicated that it will use a 30-second average speed of answer and 3% abandoned call rate as benchmarks on how to operate or perform. Tr. 2/16/00, pp. 1814, 1821-1822. Within 10 business days following each occurrence, the Company is directed to notify the Department whenever the average speed of answer exceeds 30 seconds and the abandoned call rate is more than 3%.

2. Deposits

The Company requires that security deposits of residential and commercial customers be held for 12 and 18 months, respectively. Tr. 2/16/00, pp. 1885- 1886. When these customers make appropriate consecutive monthly payments on time, they are entitled to have their security deposits returned. However, the Company does not return the residential deposit after 12 consecutive monthly payments unless requested by the customer. Late Filed Exhibit No. 43. If no request is made, CNG will return the deposit after 18 months. Tr. 2/16/ 00, p. 1886. Under cross-examination, CNG agreed to return deposits to all customers who paid 12 monthly bills on time without having to make such a request. Tr. 2/16/00, p. 1888. The Company is directed to return all security deposits automatically and with interest to residential and commercial customers who have made 12 and 18 consecutive monthly payments, respectively.

3. Denial of Service

The Company reported that, except for spouses, it does not hold anyone other than the customer of record responsible for paying the bill. Moreover, it would not deny service to a new applicant at premises where service had been previously shut off for nonpayment subject to the applicant's providing identification. Tr. 1/18/00, pp. 872-878.

The Company's Rules and Regulations do not contain this language; therefore, the Company will include it.

4. Late Payment Charges

The Company's Rules and Regulations state that the postmark date on the return envelope is used to determine the date paid. However, the Company's witness stated that the date paid is the date the payment is logged into its accounts receivable system. The Company recognized that there is an inconsistency between the Company's Rules and Regulations and its actual practice in logging customers' payments. Late Filed Exhibit No. 43; Tr. 2/16/00, pp. 1853-1854. Further, the Company testified that a late payment charge applies if the payment reaches the Company after the due date on the bill. Tr. 2/16/00, p. 1858.

The Company also testified that it renders a late payment charge if a payment agent submits payments to the Company past the due date. Tr. 1/16/00, pp. 1852- 1853. However, the Company will credit the late fee to the customer's account when the Company is aware that the payment agent is responsible for the delinquent payment. The Department finds that the Company should be using the date the customer pays the agent when determining if a late payment charge should be rendered.

The Department directs the Company to submit a detailed proposal to amend its Rules and Regulations to provide for a 3-day grace period before assessing a late payment charge on payments received through the U.S. Postal Service and payments received from payment agents. The proposal should include examples that demonstrate when a late payment charge would be assessed and how the charge would be calculated.

5. Credit Rating Agency Reporting

The Company detailed its policy with respect to reporting information about a customer's nonpayment for gas service to credit rating agencies. According to the company, it can report a customer to a credit rating agency on the 61st day after the bill is sent because the bill states that it is due and payable on receipt. Late Filed Exhibit 43. [FN4]

Conn. Gen. Stat. § 16-262d(g) states that no gas company 'shall submit to a credit rating agency ...any information about a residential customer's nonpayment for [gas] service unless the customer is more than sixty days delinquent in paying for such service.' Therefore, the resolution of this issue depends on the interpretation of the word 'delinquent'. Because the Company reports customers to credit rating agencies on the 61st day after the billing date, the Company considers a customer to be delinquent on and after the date the bill was mailed. The Department considers this interpretation unreasonable, as it would treat an outstanding balance as delinquent simply because a bill was issued. A more reasonable interpretation of § 16-262d(g) would consider a balance delinquent only after its due date. Therefore, the Company will be directed to submit a revised credit rating agency reporting policy that comports with Conn. Gen. Stat. § 16-262d(g) as interpreted above.

J. COST OF CAPITAL

1. Introduction

[72, 73] In Federal Power Commission v. Hope Natural Gas Company, 320 US 591 (1944), the Court established criteria to determine cost of capital allowances. In its Decision, the Court determined that companies need to be allowed to earn a level of revenues sufficient to enable them to operate successfully, maintain their financial integrity and to attract capital and compensate their investors for their risk. By Connecticut law, utilities are entitled to a level of revenues that will allow them ' ...to cover their operating and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection for the relevant public interest both existing and foreseeable.' Conn. Gen. Stat. §16- 19e(a)(4).

(Publication page references are not available for this document.)

To determine a rate of return on rate base that is appropriate for CNG's overall cost of capital, the Department first identifies the components of the Company's capital structure. The cost of each capital component is then estimated and weighted according to its proportion of total capitalization. These weighted costs are summed to determine the Company's overall cost of capital, which becomes the allowed rate of return on rate base (ROR).

2. Capital Structure

[74, 75] The Company proposed that the following capital structure and associated cost rates, adjusted to the mid-point of the rate year for future financings, retirements of existing obligations, dividends and future retained earnings, be used for ratemaking purposes. Bolduc PFT, pp. 1-6; Schedule D-1.0; Late Filed Exhibit No. 4, Schedule D-1.0 -- Revised, Attachment B, p. 4. The capitalization ratios were based on debt and equity amounts reported on CNG's books starting with test year levels.

Class of Capital	Amount	% of Total	Cost	Weighted Cost
Short-Term Debt	$ 6,760,000	2.41	6.64%	0.16%
Long-Term Debt	$131,153,846	46.74	7.88%	3.68%
Total Debt	$137,913,846	49.15		3.84%
Customer Deposits	$ 532,469	0.19	2.30%	0.00%
Preferred Stock	$ 879,381	0.31	6.96%	0.02%
Common Equity	$141,303,000	50.35	12.40%	6.24%
Total Capitalization	$280,628,696	100.00		10.10%

OCC's witness, James A. Rothschild, recommended that the consolidated capital structure of CTG, the parent company of CNG, be used for ratemaking purposes because a stock repurchase executed in October 1997 changed the debt and equity ratios between CNG and CTG. Prior to 1997, CTG's consolidated equity amount typically had ranged from 5% to 10% less than the balance reported on CNG's books. Hanley PFT, Exhibit FJH-3, pp. 1-2. The stock repurchase leveraged CTG's unregulated operations upwards, notably TEN, while it reduced CTG's consolidated common equity to a range of 10% to 15% below the equity balance reported on CNG's books. Rothschild PFT, pp. 6, 12 and 13; Responses to Interrogatories OCC-279 and 280; and OCC-282; Late Filed Exhibit No. 48, Revised Exhibit FJH-3, pp. 1 and 2; Tr. 1/11/00, p. 68.

Mr. Rothschild acknowledged that the stock repurchase served to minimize CTG's overall cost of capital and he commended management for its implementation. Tr. 2/10/00, pp. 1635, 1636 and 1640. According to Mr. Rothschild, CTG's consolidated capital structure provides the best indication of what management believes will produce the lowest overall cost of capital in the long run. Tr. 2/10/00, p. 1633; Rothschild PFT, p. 11. In view of this, and based on the extent to which he believed that the acquisition of debt necessary to accomplish the stock repurchase depended on CNG's cash flow, Mr. Rothschild recommended that savings associated with CTG's consolidated capital structure be extended to CNG's ratepayers by using it for ratemaking purposes. Tr. 2/10/00, p. 1588.

The capitalization ratios and cost rates recommended by Mr. Rothschild are shown below.

Class of Capital	Ratios	Cost	Weighted Cost
Short-Term Debt	2.41	6.64%	0.16%
Long-Term Debt	59.09	8.21%	4.85%
.Pp			
Total Debt	61.50		5.01%
Customer Deposits	0.19	2.30%	0.00%
Preferred Stock	0.31	6.96%	0.02%
Common Equity	38.00	9.70%	3.69%
Total Capitalization	100.00		8.72%

Rothschild PFT, Schedule JAR-1 (updated 1/31/00, p. 1).

The Company concisely addressed some of the capital structure issues raised by Mr. Rothschild by stating:

There is no direct relationship between CTG's equity component and the equity reflected on CNG's books. CNG is a 100% wholly-owned subsidiary of CTG and the level of equity invested in CNG is that equity required to support CNG's overall investment in rate base. The equity investment carried on CNG's books combined with appropriate levels of long-term and short-term debt support the rate base investment. CTG is the only entity that issues new common equity to outside markets. As a result of the 1997 stock repurchase, a temporary reduction in CTG's equity and TEN's equity/debt ratio occurred. CNG's equity was not impacted by the stock repurchase as can be seen from its books of account. This is important in supporting CNG's overall cost of capital and in particular its bond cost which is targeted for an A rating.

Response to Interrogatory OCC-286.

Mr. Bolduc explained that the decision underlying the stock repurchase reflected management's understanding that CTG, as a holding company, needed to realign its financial targets and goals consistent with the future of the industry and improve shareholders' market liquidity and retain more cash flow. Recognizing that a majority of stockholders invested for long-term growth, CTG acted on the advice of its investment bankers, and took advantage of not being highly leveraged at the

TEN subsidiary and bought back two million shares of stock. Tr. 1/11/00, p. 73; Tr. 2/10/00 p.p. 1433 and 1435-1438. Mr. Bolduc stated that CTG management recognized there would be a short-term 'blip' in leverage as a result of the stock repurchase, but that the transaction had nothing to do with CNG's books. Tr. 1/11/00, p. 73; Tr. 2/10/00, p. 1441. Mr. Bolduc also stated that had CTG undertaken a leveraged buyout instead of a stock repurchase, thereby effectively consisting of all equity, CNG's capitalization structure would still be some combination of equity and debt. This debt-to-equity ratio would probably be 50/50 because the Department's holding company decision prohibits double leveraging, and CNG has to have a certain amount of debt to finance its capital needs. [FN5] Also, the ability to attract reasonable debt costs and to achieve and or maintain a straight A rating with the rating agencies requires a fairly balanced mix of debt and equity. Tr. 1/11/00, pp. 66-70; Tr. 2/10/00, p. 1453. According to Mr. Bolduc, CNG has to be looked at by itself because it is raising its own debt. Tr. 1/11/00, p. 74.

The Department finds that the recent change in equity and debt ratios on CTG's and CNG's balance sheets is within the realm of prudent financial management. Financial management, as exemplified by the stock repurchase, will cause capitalization ratios to change. Mr. Bolduc characterized the increase in debt on the consolidated financial statement as temporary and short-term. He testified that if TEN could not meet its debt service, the unregulated subsidiary would not have the opportunity to turn to CNG as a cash source. Tr. 2/10/00, pp. 1447 and 1448. He also testified that the issuance of debt in connection with the stock repurchase did not depend on CNG's cash flow. Id., p. 1443. Furthermore, to the extent that CTG's consolidated capital structure may be cost minimizing, a point acknowledged by Mr. Rothschild, CNG's capital structure may also be cost minimizing. Mr. Rothschild did not demonstrate otherwise.

Mr. Rothschild used the 24 gas distribution companies (LDCs) included in Value Line, whose average common equity ratio is almost precisely at the level of CNG (i.e., 50%), for CNG's common equity cost rate. He then made a 45 basis point upward adjustment to account for the increased risk associated with CTG's consolidated capital structure. Rothschild PFT, p. 7 and Schedule JAR-7. Mr. Rothschild provided no discussion as to how the adjustment was determined or how the increased risk was assessed. To the extent that the comparable risk LDCs, with capital structures similar to CNG, are proxies for CNG's common equity cost rate it is reasonable and appropriate to use a capital structure consistent with how CNG's rate base is financed. See discussion in Section, L.6, below.

The Department finds no evidence that warrants using CTG's consolidated capital structure for ratemaking purposes. Doing so would be inconsistent with CNG's credit quality, bond rating, degree of business risk, and could serve to undermine the integrity of CNG's presently invested capital.

3. Cost of Short-Term and Long-Term Debt and Preferred Stock

[76] The Department reviewed and accepts the cost of short-term debt of 6.64%

Schedules D-2.0, 3.0 and 4.0 long-term debt of 7.88%, and preferred stock of 6.96%, as submitted by the Company.

4. Cost of Equity

a. Introduction

[77] The Company's cost of equity testimony was prepared by Frank J. Hanley, who initially recommended 11.9% as an appropriate equity cost rate provided that the Department approve weather stabilization insurance or a weather normalization adjustment. Without WSI or WNA approval, his recommendation for the cost of equity was 12.15%. Mr. Hanley subsequently submitted updated exhibits using somewhat more current data and revised analyst estimates, leading him to conclude that the cost of equity had actually increased 50 basis points. Revised FJH Exhibits. On the basis of Mr. Hanley's updated testimony, the Company's requested revenue increase was revised to reflect a cost of equity of 12.4%, assuming WSI or WNA, or 12.65% if neither were approved.

Mr. Rothschild supported a common equity cost of either 9.45% or 9.0%, according to the capital structure adopted by the Department for ratemaking purposes. Based on revised stock price information, Mr. Rothschild subsequently revised his recommendation, concluding that CNG's cost of equity should be either 9.7% or 9.25%. Response to Interrogatory GA-228. The lower cost rate of 9.25% is applicable to CNG's 50.35% common equity capital structure, discussed in Section II . L.2., above.

b. Summary of Mr. Hanley's Testimony

i. Overview

Mr. Hanley evaluated CNG's cost of equity and determined his 11.9% and 12.4% recommendations based on applying the discounted cash flow (DCF), risk premium (RP), capital asset pricing model (CAPM), and comparable earnings methodologies to CTG and two proxy groups of LDCs. In Mr. Hanley's original pre-filed testimony, the summary equity costs ranged from 11.8% for CTG to 12.0% for the proxy group consisting of 13 companies. Hanley PFT, Exhibit FJH-1, p. 2. In his updated testimony, the indicated equity costs ranged from 12.4% to 12.5%. Hanley PFT, Exhibit FJH-1 Revised, p. 2. Mr. Hanley's final recommendations were based principally upon the proxy group consisting of five LDCs, whose equity cost initially was 11.9%, updated to 12.4%. Response to Interrogatory GA-190. In determining a summary cost of equity for CTG, Mr. Hanley gave zero weight to the results obtained from the DCF model because of CTG's intended merger with Energy East and the associated market price impact. Tr. 1/ 19/00, p. 942. For the two proxy groups, however, equal weight was given to all four cost of equity methodologies. Id. According to Mr. Hanley, informed judgment also played a role in determining the indicated equity cost rates. Hanley PFT, p. 75; Exhibit FJH-1, p. 1, Note (3).

The criteria for the LDC's included by Mr. Hanley in the proxy group of five were as follows: SIC Code of 4924 (natural gas distributor) by Standard & Poor's (S&P) PC Plus; actively traded common stock; more than 90% of 1998 operating revenues from gas operations; less than $1 billion in total capital outstanding at fiscal year-end 1998; long-term debt rated A-or better by S&P or A3 or better by Moody's; included in Value Line Investment Survey; no omission or cut in dividends during the five calendar years ending 1998 and up to the time of testimony preparation; and inclusion in S&P's Compustat PC Plus Data Base. Hanley PFT, pp. 20-21; Exhibit FJH-4, p. 2. The basis of selection for the proxy group of 13 LDC's was that they be the domestic LDCs included in CTG's 1998 proxy statement. This group was utilized at the request of CNG management, and included all the companies comprising the proxy group of five, plus eight others. [FN6] Response to Interrogatory GA-190. Mr. Hanley considered the proxy group of five as most comparable in risk to CNG based upon the selection criteria. Id.

ii. DCF Model

The details underlying Mr. Hanley's DCF study include: a dividend yield calculation based on spot data and stock market prices for a three, six, and twelve month averaging period; yield adjustments equal to one-half the indicated forward growth rates to incorporate for investor expectations of quarterly dividend increases (Adjusted DY); and forward growth rates based on five-year earnings growth forecasts issued by Value Line and Institutional Brokers Estimate System (I/B/E/S). Hanley PFT, pp. 43-47. In Mr. Hanley's original pre-filed testimony, the spot dividend yield was based on market price as of August 17, 1999, with the various monthly averaging periods ending July 31, 1999. Id., Exhibit FJH-11. Earnings growth rate estimates were taken from the Value Line Investment Survey dated June 25, 1999; those from I/B/E/S were as of August 12, 1999. Id., Exhibit FJH-13, p. 1. In Mr. Hanley's updated testimony, the spot dividend date was January 12, 2000, with three, six, and twelve-month dividend yields based on the annualized dividend rate and market price data (for each respective period) ending December 31, 1999. Id., Exhibit FJH-11 Revised. Earnings growth projections from Value Line were dated December 24, 1999, while those from I/B/E/S were as of January 6, 2000. Id., Exhibit FJH-13, p. 1 Revised. The results of Mr. Hanley's DCF cost of equity analyses are summarized below.

[Note: The following TABLE/FORM is too wide to be displayed on one screen. You must print it for a meaningful review of its contents. The table has been divided into multiple pieces with each piece containing information to help you assemble a printout of the table. The information for each piece includes: (1) a three line message preceding the tabular data showing by line # and character # the position of the upper left-hand corner of the piece and the position of the piece within the entire table; and (2) a numeric scale following the tabular data displaying the character positions.]

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	DCF Summary -- Original PFT Adjusted DY	DCF Summary -- Updated
CTG Resources, Inc.	(3.6%	+
Proxy Group of Five	(4.8%	+
Proxy Group of 13	(4.7%	+

1...+...10....+...20....+...30....+...40....+...50....+...60....+...70....

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 Growth      Equity Cost  Adjusted DY     Growth      Equity Cost
  5.8%)   =         9.4%        (3.2%  +   6.1%)   =         9.3%
  5.4%)   =        10.2%        (5.0%  +   5.8%)   =        10.8%
  6.9%)   =        11.6%        (4.8%  +   7.0%)   =        11.8%
75..80....+...90....+....0....+...10....+...20....+...30....+..
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iii. Risk Premium

For the risk premium portion of Mr. Hanley's analysis, prospective long-term bond yields applicable to CTG and the two proxy groups were derived from a consensus forecast of about 50 economists relative to the expected yield on Moody's Aaa-rated corporate bonds, subject to the following two adjustments: 1) to reflect the yield spread between Aaa-rated corporate debt and A-rated public utility bonds; and 2) to acknowledge the bond rating differences between CTG Resources, Inc. and the two proxy groups relative to A-rated public utility bonds. Id., pp. 49-50. This consensus forecast yield on Moody's Aaa-rated corporates was first specified at 7.0%; however, in Mr. Hanley's updated testimony it was 7.4%. [FN7] Id., Exhibit FJH-14, p. 1 and Exhibit FJH-14, p. 1 Revised. Upon final adjustment, based on the data used in original testimony, the prospective long-term debt cost rates deemed applicable to CTG, the proxy group of five, and the proxy group of 13 were 7.7%, 7.6%, and 7.6%, respectively. Id. In context of the updated exhibits, the attributed bond yields were 8.1%, 8.0%, and 8.0%, respectively. Id. The equity risk premium element of Mr. Hanley's analysis was developed using more than 70 years of stock and bond return data in two separate calculations: a beta-derived average based on historical and forecasted total market equity risk premiums; and a mean historical equity risk premium based on one-year holding period returns applicable to public utilities with A-rated bonds. Id., p. 51. The resultant average equity risk premiums deemed applicable to CTG, the proxy group of five, and the proxy group of thirteen were 4.4%, 4.4%, and 4.5%, respectively. In context of the updated exhibits, the attributed equity risk premiums were 4.6%, 4.6%, and 4.7%, respectively. Id., Exhibit FJH-14, p. 5 Revised. The results of Mr. Hanley's risk premium cost of equity analyses are summarized below.

[Note: The following TABLE/FORM is too wide to be displayed on one screen. You must print it for a meaningful review of its contents. The table has been divided into multiple pieces with each piece containing information to help you assemble a printout of the table. The information for each piece includes: (1) a three line message preceding the tabular data showing by line # and character # the position of the upper left-hand corner of the piece and the position of the piece within the entire table; and (2) a numeric scale following the tabular data displaying the character positions.]

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	RP Summary -- Original PFT Adjusted Prospective Bond Yields	RP Summary -- Updated
CTG Resources, Inc.	(7.7%	+
Proxy Group of Five	(7.6%	+
Proxy Group of 13	(7.6%	+

1...+...10....+...20....+...30....+...40....+...50....+...60....+...70..

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Equity Risk Premium		Equity Cost Rate	Adjusted Prospective Bond Yields		Equity Risk Premium		Equity Cost Rate
4.4%)	=	12.1%	(8.1%	+	4.6%)	=	12.7%
4.4%)	=	12.0%	(8.0%	+	4.6%)	=	12.6%
4.5%)	=	12.1%	(8.0%	+	4.7%)	=	12.7%

73....80....+...90....+....0....+...10....+...20....+...30...

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As shown above, the risk premium portion of Mr. Hanley's analysis initially indicated a cost of equity for the Company equal to about 12.1%. The use of more current data in the updated testimony suggested that the applicable equity cost rate had increased 60 basis points to approximately 12.7%.

iv. CAPM and Comparable Earnings

The following table summarizes the cost of equity conclusions reached by Mr. Hanley as a result of the CAPM and comparable earnings technique. Id., Exhibit FJH-1, p. 2 Revised.

5p	CAPM	Comparable Earnings		
	Original PFT	Updated	Original PFT	Updated
5p				
CTG Resources, Inc.	11.0%	11.8%	13.0%	14.0%
Proxy Group of Five	11.1%	11.8%	14.5%	14.5%
Proxy Group of 13	11.2%	12.0%	13.0%	13.0%
5p				

c. Summary of Mr. Rothschild's Testimony

i. Overview

Mr. Rothschild quantified CNG's cost of equity using the DCF and risk premium methods. His DCF approach encompassed two techniques, a constant growth formulation and a non-constant (or complex) growth approach. The results of the constant growth and the non-constant growth versions of the DCF model indicated a cost of equity ranging from 9.02% to 9.5%. Rothschild PFT, Schedule JAR-2 Revised. Mr. Rothschild's risk premium methodology determined a cost of equity of 8.85%. Id., Schedule JAR-9 Revised. Since Mr. Rothschild supported a 9.25% cost of equity using the Company's requested capital structure, it appears that he placed less weight on his risk premium analysis and relied principally on the results of the DCF method.

In developing the cost of equity based upon the constant growth DCF method, Mr. Rothschild employed two proxy groups of gas distribution utilities, the 24 LDCs covered by Value Line, and the group of gas distribution utilities included in the DCF analyses of the Company witness, Mr. Hanley. The cost of equity results based upon the non-constant growth DCF used the Value Line gas distribution companies only.

ii. Constant Growth DCF Model

The cost of equity indicated by the simplified version of the DCF model ranged from 9.03% to 9.1% for the LDCs included in Value Line. Id., Schedule JAR-3, p. 1 Revised. In terms of the gas distribution utilities included in Mr. Hanley's proxy groups, the cost of equity ranged from 9.02% to 9.09%. Schedule JAR-3, p. 2. Revised. The form of this version of the DCF model, where the cost of equity equals dividend yield plus future expected growth, is the same as that used by Mr. Hanley.

The details underlying Mr. Rothschild's constant growth DCF study include: dividend yields quantified by dividing the most current annualized dividend rate declared by each LDC by the stock price data as of January 31, 2000, and by the average of the high and low stock price for each company over the year ended January 31, 2000; yield adjustments (Adjusted DY) equal to one-half the future expected growth rate; and expected growth equal to the future expected return on equity times the percentage of earnings retention consistent with the selection of the dividend rate and expected return on equity, with an incremental adjustment to allow for the sustainable growth caused by the purchase or sale of common stock above book value. Id., pp. 21-24. Mr. Rothschild assumed a future expected return on book equity of 12.5% by evaluating: Value Line's forecasts of future expected returns; the return on equity consistent with Zacks Research (Zacks) consensus five-year growth estimates; absolute levels of, and trends in, allowed returns on equity to utility companies; and historical actual earned returns on equity. Id., pp. 25-27.

The results of this portion of Mr. Rothschild's DCF cost of equity analysis are summarized below.

[Note: The following TABLE/FORM is too wide to be displayed on one screen. You must print it for a meaningful review of its contents. The table has been divided into multiple pieces with each piece containing information to help you assemble a printout of the table. The information for each piece includes: (1) a three line message preceding the tabular data showing by line # and character # the position of the upper left-hand corner of the piece and the position of the piece within the entire table; and (2) a numeric scale following the tabular data displaying the character positions.]

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	Constant Growth DCF Cost of Equity Based on Avg. Market Price for Year Ending January 31, 2000 Adjusted DY	Constant Growth DCF Cost of Equity Based on Market Price as of January 31, 2000
Value Line LDCs	(5.0%	+
Company Witness LDCs	(4.9%	+

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1...+...10....+...20....+...30....+...40....+...50....+...60....+...70....+....
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Growth		Equity Cost	Adjusted DY		Growth		Equity Cost
4.1%)	=	9.1%	(5.2%	+	3.8%)	=	9.0%
4.1%)	=	9.0%	(5.3%	+	3.8%)	=	9.1%

80..+...90....+....0....+...10....+...20....+...30....+...40....

iii. Two Stage, Complex DCF Model

This version of the DCF methodology calculates the cost of equity based upon future expected cash flows evaluated over two stages over a long time frame. [FN8] For the first stage, Mr. Rothschild evaluated future earnings based upon Value Line's estimates of dividends per share and earnings per share for 1999 through 2003. In the second stage (i.e., 2004 through 2039), future earnings were determined by multiplying the future book value per share by the future expected earned return on book equity. Mr. Rothschild used the same future expected return on equity of 12.5% as utilized in the simplified version of the DCF model. Book value growth projections also included the effect of sales of new common stock. Mr. Rothschild assumed a constant dividend payout ratio over the second stage time period, equal to the payout ratio expected by Value Line for 1999. A constant market-to-book ratio was also assumed for the second stage, equal to the market-to-book ratio as currently exists. Id., pp. 31-32.

The two-stage DCF model indicated a cost of equity between 9.45% and 9.5% depending on whether the stock price averaging period was based on the year ending January 31, 2000, or on spot stock price data as of January 31, 2000. Id., Schedule JAR-4, pp. 1-4 Revised.

iv. Risk Premium

Mr. Rothschild's risk premium methodology consisted of adding the current inflation expectation of investors to the historical return on common stocks (net of inflation), to establish the 'inflation risk premium' cost of equity for a company of average risk, and then making a downward risk adjustment to account for the lower than market-average risk inherent in an investment in gas distribution utility stocks. The downward adjustment involved subtracting the yield on 90-day treasury bills (T-bills) from the historical return on common stocks (net of inflation) to arrive at an (unadjusted) equity risk premium over 90-day treasury bills. This was multiplied by the average beta of the gas distribution utilities to arrive at a risk adjusted equity premium over 90-day T-bills for gas distribution companies. The difference between the unadjusted equity risk premium over 90-day T-bills and the risk adjusted equity premium was then subtracted from the historical return net of inflation to arrive at an inflation-based risk premium cost of equity applicable to LDCs. Mr. Rothschild stated that the stability of the historical inflation risk premium made it a much more reliable measure than an historically-based bond interest risk premium, and that the yields on 90-day T-bills are used to make the downward risk adjustment because T-bills have a beta very close to zero. Id., pp. 38-41.

Numerically, Mr. Rothschild determined an inflation risk premium cost of equity for a company of average risk to range from 9.1% to 9.7%, based on adding investors' current inflation expectation of approximately 2.5% to the historical return on common stocks (net of inflation) that ranged from 6.6% to 7.2%, depending on the period of analysis. [FN9] The current inflation expectation of

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2.5% was derived by subtracting the yield on inflation-indexed treasury securities maturing in April 2028 (4.27%) from the yield on non-inflation-indexed treasury securities maturing in November 2028 (6.56%). The subsequent downward risk adjustment to the range of 9.1% to 9.7% made use of a 5.47% yield on 90-day T-bills and an average beta for gas distribution utilities of 0.62. The resultant range for the inflation-based risk premium cost of equity applicable to LDCs was 8.66% to 9.03%, mid-point at 8.85%. The latter value represented Mr. Rothschild's recommended risk premium cost of equity applicable to CNG. Id., JAR-9 Revised.

d. Department Analysis of Cost of Equity

i. Overview

[78-83] Nearly all of the analyses undertaken by Mr. Hanley and Mr. Rothschild to determine the investor required return on equity contained differences within methodology. However, the principal issues between the studies performed by the two cost of capital witnesses concerned the growth rate used in the DCF model and the risk premium assigned to the Company's common equity. The Department has carefully reviewed and considered the testimony of the two consultants, noting the compelling testimony of each, while making its own adjustments. The Department agrees with Mr. Rothschild that the risk premium and CAPM conclusions developed by Mr. Hanley are biased upward and concurs with his view that the comparable earnings portion of Mr. Hanley's analysis does not measure the cost of equity at all. Rothschild PFT, p. 10. The latter method did a particularly poor job of measuring CNG's true cost of equity as it produced results as high as 14.5%. Therefore, no weight has been given to the CAPM or the comparable earnings approach in determining the cost of equity. The Department prefers the proxy group approach used by Mr. Hanley in his DCF analyses, compared to the selection of comparative gas distribution companies from Value Line used by Mr. Rothschild. The Department finds that the former approach, and especially the LDCs that comprise Mr. Hanley's five-company proxy group most closely approximates the Company's risk characteristics. The Department did not consider any DCF outcomes performed specifically for CTG in view of the impact that the intended merger with Energy East has had on CTG's market price. Mr. Hanley stated that CTG's DCF cost rate must be viewed with caution, and he gave it no weight in making his final recommendation. Hanley PFT, p. 44; Tr. 1/19/00, p. 942. The Department agrees with this aspect of Mr. Hanley's testimony.

The cost of equity conclusion reached by the Department is derived from the constant growth DCF model in terms of the two proxy groups sponsored by Mr. Hanley. The Department's conclusion incorporates the more current information included in Mr. Hanley's updated exhibits as they relate to the DCF model (i.e., updated Exhibits FJH-11 and FJH-13), described below. It also incorporates changes to Mr. Hanley's analysis. Additionally, the Department's conclusion encompasses a risk premium consideration.

ii. Composition of the Proxy Group of 13

The Department has incorporated two specific modifications into the DCF analyses performed by Mr. Hanley, both of which reduce the indicated growth rates. The first relates to the composition of the proxy group of 13. It is the Department's judgment that SEMCO Energy, Inc. (SEMCO) makes a very poor choice for inclusion in a sample utility group that is used as a proxy for CNG. Of the 13 LDCs, it is only one of two that is classified as a diversified, instead of a distribution, natural gas company. See Edward Jones publication 'Natural Gas Industry Summary Monthly Financial and Common Stock Information,' October 31, 1999; Response to Interrogatory GA-40 part (a). The distinction is with respect to the extent to which operating revenues are derived from gas operations (i.e., distribution). For the distribution companies, at least 90% of operating revenues are so derived. For a diversified firm like SEMCO, the extent to which revenues are obtained from gas operations is less than 90%. Of greater concern to the Department, however, is the extent to which SEMCO's business, financial, and investment risks, as measured by several key variables, is significantly different from the other proxy companies.

The distinct risk profile differences between SEMCO and the remaining LDCs can be discerned from the dividend yield and growth information summarized in two of Mr. Hanley's exhibits. As compared to the average projected growth rate in earnings per share for the proxy group of 13 in terms of the individual Value Line and I/B/E/S projections (8.1% and 6.1%), and as compared to the 4.4% average dividend yield for the last six months of the entire proxy group, SEMCO is one of just three of the 13 companies whose individual projected growth (15.5% from Value Line and 8.3% from I/B/E/S) and yield measure (5.9%) are larger than the average for the group. [FN10] Hanley PFT, Exhibit FJH-13, p. 1 and Exhibit FJH-11, p. 1. (See also Rothschild PFT, p. 57, lines 2-7). Of the three companies, SEMCO's forecast earnings growth and average six-month dividend yield exceed the respective proxy group averages the greatest. The Department finds that SEMCO's investment risk characteristics are consistent with those of a high yield, high growth company. Consistent with this circumstance, which is atypical for the distribution companies that comprise the gas utility industry, SEMCO's payout ratio at 96% is among the highest in the gas industry. Response to Interrogatory GA-40, pp. 29-30. The high payout ratio, coupled with an erratic and negative earnings history over the period 1996 through 1998, calls into question SEMCO's prudence in managing its dividend payout policy. See Hanley PFT, Exhibit FJH-13, p. 12.

Additionally, as Mr. Hanley testified, SEMCO had the lowest bond rating (BBB) among all of the LDCs in the proxy group of 13. Response to Interrogatory GA-189. Finally, the percentage of SEMCO's outstanding shares of common stock held by institutions is just 9% and is more than two standard deviations from the mean of 29%. A circumstance that Mr. Hanley could not explain. Id., Exhibit FJH-12; Response to Interrogatory GA-22; Tr. 1/19/00, p. 962. These facts suggest that SEMCO is a far riskier investment than the other publicly traded gas utilities in the proxy group of 13. Therefore, to achieve a more accurate assessment of the Company's investor-required return, SEMCO has been removed from the DCF portion of the analysis.

iii. DCF Growth Rates

(Publication page references are not available for this document.)

The second Department modification to Mr. Hanley's DCF analysis addresses the specific selection of data to serve as a proxy for the rate of projected growth in the DCF model. Mr. Rothschild was highly critical of this aspect of Mr. Hanley's DCF judgments, characterizing as 'overly simplistic' the choice to use Value Line's forecasted five-year earnings per share as the relevant indicator of growth. Mr. Rothschild stated that Mr. Hanley failed to determine whether or not such a growth rate is reflective of the sustainable growth rate required in the dividend yield plus growth version of the DCF model. Rothschild PFT, p. 44. Mr. Rothschild also indicated that published future growth factors, such as Value Line's, are often overstated. Id. PFT, pp. 62-63 and Schedule JAR-10.

In theory, the growth component of the DCF formula should represent investors' expected growth in dividends and share value (capital appreciation). There are many ways to assess the rate of growth anticipated by investors. Mr. Hanley argues that growth in earnings per share dictates the growth in dividends per share and is the appropriate growth factor to use. Other experts in the field, including Mr. Rothschild, believe that the proper way to quantify growth is by computing an earnings retention growth rate based on the future expected return on equity. Still other experts support any one of a number of combinations involving dividends, earnings, book value, and/or retention growth. There is a strong relationship between these four financial measures. Dividends are driven by earnings; if there are no earnings, there can be no dividends. Similarly, earnings are driven by book value. One of the underlying premises of DCF theory is that the growth in dividends, earnings, and in book value will be equal over the long term. In reality, these growth measures are never equal on a short-term basis, but deviations are not sustained for a long period of time. For example, there is no reason for investors to expect that earnings growth much in excess of book value growth will be sustainable, or representative, over a long-term investment horizon, just as dividend growth in excess of earnings growth would not last for very long unless a company wanted to dilute its shareholders' value continuously.

The issues raised by Mr. Rothschild combined with the notorious volatility of earnings suggest to the Department that Value Line's projected five-year earnings growth rates may not be good indicators of cash flow growth (i.e., in dividends and stock price appreciation) even over the five years being measured. Therefore, to assess the suitability of relying solely on forecast earnings growth rates in this case, the Department undertook an analysis to: 1) compare five-year historical growth rates in book value, earnings, and dividends determined by a least-squares regression computation, with those calculated by Value Line where a geometric return is centered on two three-year averaging periods (i.e., 1996-1998 and 1991-1993); and 2) compare Value Line's five-year historical (actual) growth rates in book value, earnings, and dividends with its own forecasts. [FN11] A summary table comparing the various growth rates is shown below.

GROWTH RATE SUMMARY	DPS	EPS	BVPS			
	Dept.	Value	Dept.	Value	Dept.	Value

(Publication page references are not available for this document.)

	5 Yr. Hist.	Line 5 Yr. Hist.	5 Yr. Proj.	Line 5 Yr. Hist.	5 Yr. Hist.	Line 5 Yr. Proj.	5 Yr. Hist.	5 Yr. Hist.	5 Yr. Proj.
Atmos Energy	4.0%	4.0%	5.5%	10.0%	9.5%	11.5%	4.5%	4.0%	7.5%
*CNE	0.5%	1.0%	3.5%	3.5%	4.5%	4.0%	4.5%	4.5%	4.0%
Energen Corp.	3.5%	4.0%	3.5%	6.5%	7.5%	9.5%	10.5%	9.5%	8.0%
*Indiana Energy	4.0%	4.0%	4.0%	7.5%	9.5%	8.5%	3.0%	4.5%	6.5%
*Laclede Gas	1.5%	1.5%	2.5%	3.0%	5.5%	4.5%	4.0%	3.5%	3.0%
NJ Resources	1.5%	1.0%	2.5%	6.0%	9.5%	7.0%	2.5%	2.5%	5.0%
*NW Nat'l Gas	1.0%	1.0%	2.0%	-6.0%	8.5%	6.0%	5.0%	5.0%	4.5%
*Piedmont Nat'l	6.0%	6.0%	4.5%	7.5%	8.0%	6.5%	6.5%	6.5%	6.5%
Prov. Energy	1.0%	-1.5%	5.0%	-3.0%	7.0%	8.0%	2.0%	3.5%	5.5%
So. Jersey Inds.	0.0%	0.5%	1.0%	0.5%	1.0%	8.0%	2.5%	3.0%	4.5%
13-Company Proxy Group Avg.	2.2%	2.3%	3.4%	3.6%	7.1%	7.4%	4.5%	4.7%	5.5%
* 5-Company Proxy Group Avg.						5.9%			4.9%
CTG Resources	-5.0%	-1.5%	-2.0%	-1.0%	0.5%	6.5%	1.0%	2.5%	4.0%

Source: 1993-1998 DPS, EPS, and BVPS data from Value Line, used by the Department in a least-squares regression calculation, and Value Line's historical and projected rates of change from Hanley PFT, Exhibit FJH-13 and Revised Exhibit FJH-13, pp. 2-11, and 13 (SEMCO excluded). Growth rates are expressed to the nearest half percent in the convention used by Value Line, except in the portion of the table where proxy group averages are calculated.

Several observations may be drawn from the growth rates in the table. Despite the use of two distinct measuring techniques (i.e., the Department's least-squares regression and the Value Line methodology) using different years of data, the average five-year historical growth rates for dividends and book value for the 13-company proxy group are essentially identical (i.e., 2.2% vs. 2.3% in dividends, Department vs. Value Line; and 4.5% vs. 4.7% in book value, Department vs. Value Line). [FN12] This attests to the diligence and attention paid by management in the gas utility industry in setting dividend payment policy. It also attests to the stability of book value growth in the industry. The earnings growth calculations are an entirely different matter.

The average historical earnings growth for the 13-company proxy group using the Department's least-squares regression is 3.6%, whereas the Value Line averaging methodology determines historical earnings growth of 7.1% for the entire group. A review of the two columns reveals that the substantial discrepancy between the averages is attributable to the historical earnings data profiles for Northwest Natural Gas Company and Providence Energy Corporation. These profiles result in negative earnings growth by the least-squares method, but robust growth by the

Value Line approach. This indicates that the calculation of the earnings growth rate is very much a function of the start and end points, and weight attached thereto, of whatever measuring technique is used and, by implication, to the inherent volatility of earnings over short-term periods. Value Line's measuring procedure is better than least-squares because by averaging two separate three-year periods, and then comparing the averages with each other, the impact of an aberrant year in earnings is smoothed out, or discounted, to some extent. Nevertheless, using Northwest Natural Gas Company as an example, if 1991 and 1992 had produced 'normal' earnings (resulting in dividend payout ratios less than 100%, instead of 169% and 155% as reported), the five-year historical earnings growth rate calculated by Value Line would have been negative, instead of + 8.5%. Hanley PFT, Exhibit FJH-13, p. 9. In this instance, inadequate earnings over a two-year period were transformed by arithmetic into a healthy reported earnings growth.

The table shows that Value Line's five-year earnings growth for the 13- company proxy group is projected to increase slightly above the 7.1% historical five-year average. This seems to mitigate Mr. Rothschild's concern that the Value Line earnings forecasts are overstated. At the same time, though, nine of eleven earnings projections (including CTG's) exceed book value projections, while none of them are less than projected rates of growth in book value. Although not included in this analysis, the earnings growth forecast for SEMCO in Revised Exhibit FJHG-13 was raised to 15.5%, a 3% increase from Value Line's forecast just six months earlier. [FN13] The Department concludes that it is inadequate to rely solely on Value Line's earnings forecasts as indicators of cash flow growth due to the volatility of earnings, the extent to which earnings are affected over the short run by changes in the return on equity, and because sustainable growth in the long run is also a function of growth in book value. The Department will accept Value Line's earnings growth projections for the first five years of the investment horizon.

Beyond that, however, the Department will assume that cash flow growth will occur at Value Line's projected book value growth rates. The growth rates used in the DCF model to help determine the Company's investor-required return on equity will represent a blend of Value Line's forecast earnings and book value growth. The Department will not make use of the I/B/E/S earnings forecasts included in Mr. Hanley's FJH-13 exhibits because I/B/E/S does not provide book value growth rates.

The following table provides Value Line's five-year earnings and book value growth rate forecasts from Exhibit FJH-13 of Mr. Hanley's original prefiled testimony.

	EPS 5 Yr. Proj.	BVPS 5 Yr. Proj
Atmos Energy	11.5%	8.5%
*CNE	4.0%	4.0%
Energen Corp.	9.0%	10.0%

*Indiana Energy	6.0%	5.0%
*Laclede Gas	4.0%	3.5%
NJ Resources	7.5%	7.0%
*NW Nat'l Gas	6.0%	4.5%
*Piedmont Nat'l	7.0%	5.5%
Prov. Energy	8.0%	5.0%
So. Jersey Inds.	7.5%	4.5%
13-Company Proxy Group Avg.	7.1%	5.8%
* 5-Company Proxy Group Avg.	5.4%	4.5%

A comparison of the two growth summary tables shows the changeability of the growth forecasts. In view of this, the Department believes it is prudent to average both sets of earnings and book value growth projections for use in the DCF model. Therefore, the average projected growth rate based on earnings and book value for the proxy group of five gas distribution companies is 5.2% [(5.9% + 4.9% + 5.4% + 4.5%)/4]. The rate of projected growth ascribed to the proxy group of 13 gas distribution companies (excluding SEMCO) is 6.5% [(7.4% + 5.5% + 7.1% + 5.8%)/4]. It is interesting to note that the average forecast book value growth indicated for the proxy groups across the two sets of projections is the same. Value Line's updated earnings forecasts produce change in the average growth rate indicated for the two proxy groups, again highlighting the subjective nature of the earnings measure.

Mr. Rothschild computed growth rates in his DCF analyses by a method referred to as retention growth. The Department finds that retention growth is a poor choice to rely upon solely or to include in an averaging scheme with earnings and book value, because it is not a complete measure of the growth portion of return realized by investors. The part of capital appreciation it reflects is the portion of net income retained that flows back into the total of shareholders' equity, or the growth of shareholders' equity that occurs from one period to the next. However, retention growth ignores the fact that firms have the ability to enhance the magnitude of shareholders' equity not just by retaining net income, but by successfully reinvesting such net income and realizing higher levels of return in subsequent periods. It also ignores the fact that investors' return is also a function of the interaction of buyers and sellers in the marketplace that causes market-to-book ratio changes. The problematic assumptions of a static expected return on book equity (i.e., 12.5% in the second stage) and unchanging market-to-book ratios (i.e., 1.77 and 1.75) are evident in the non-constant version of Mr. Rothschild's DCF methodology, in which he calculated a cost of equity of 9.45% (based on the average of stock prices for the year ending 1/31/00) and 9.5% (based on stock price as of 1/31/00) for the universe of Value Line gas distribution companies, respectively. Rothschild PFT, Schedule JAR-4, pp. 1-2 Revised. Mr. Rothschild alludes to these particular difficulties with the retention growth calculation in footnotes 6 and 7 of his testimony. Id., p. 31. The Department regards Mr. Rothschild's entire DCF analysis as ambitious and detailed, but finds that use of the retention growth measure, either in the constant or non-constant DCF model, imposes a downward bias in determining CNG's appropriate cost of equity.

The following table illustrates the aforementioned flaws with the retention growth statistics, and its tendency not to capture a portion of return realized by investors. The first column repeats Value Line's five-year historical growth rates in book value from the first growth rate summary table above, while the second column shows the arithmetic average retention growth rates based on the data reported in Value Line for the LDCs comprising the two proxy groups. In eight of the ten instances, retention growth is less than the reported growth in book value.

	Value Line 5-Yr. Historical BVPS Growth	Avg. Arithmetic (1994-1998) Retention Growth
Atmos Energy	4.0%	3.5%
CT Energy Corp.	4.5%	2.5%
Energen Corp.	9.5%	5.0%
Indiana Energy	4.5%	4.5%
Laclede Gas Co.	3.5%	2.5%
NJ Resources Corp.	2.5%	3.5%
NW Natural Gas Co.	5.0%	2.5%
Piedmont Natural Gas Co.	6.5%	4.0%
Providence Energy Corp.	3.5%	1.5%
So Jersey Industries	3.0%	0.5%

Source: 1994-1998 DPS, EPS, and BVPS data from Hanley PFT, Exhibit FJH-13, pp. 3-11, 13.

iv. DCF Yield

It is typically the Department's practice to use a six-month averaging period to determine the yield component of the DCF model. The Department has utilized the six-month average yields summarized in Mr. Hanley's updated and original testimony, for the periods ending July 31, 1999, and December 31, 1999, for consistency with the growth rate analysis. Mr. Rothschild criticized Mr. Hanley's approach to establishing the dividend yield as 'overly complex.' Rothschild PFT, p. 44. However, the Department finds that the information contained in Exhibit FJH-11 and Revised Exhibit FJH-11 provides a sound basis by which to characterize the Company's yield, and regards the details as useful. For example, the data in updated Exhibit FJH-11 illustrate the tendency for the spot yield not to be entirely representative of a longer-term average.

Mr. Hanley's six-month average yield for the proxy group of five LDCs is 4.8% in his original testimony and 4.7% for the six-months ending December 31, 1999. The combined average of 4.75% is essentially the identical yield value determined by Mr. Rothschild in his DCF analyses using the gas distribution companies selected by CNG's witness. Mr. Hanley's six-month average yield for the 13-company proxy group for the period ending July 31, 1999, is 4.7%; in his updated filing the six-month average yield is 4.4%. Excluding SEMCO, the average dividend yield rates for the 13-company proxy group are 4.65% and 4.3%, respectively. [FN14] The combined average yield for the 13-company proxy group (SEMCO excluded) is 4.5%.

v. DCF Summary

As indicated from the two growth rate summary tables above, the average projected growth rate based on earnings and book value for the proxy group of five gas distribution companies is 5.2%; for the proxy group of 13 gas distribution companies (excluding SEMCO) it is 6.5%. The average dividend yield rate for the five-company group is 4.75%. For the 13-company group, the average dividend yield rate (with SEMCO excluded) is 4.5%. The indicated DCF equity cost rates for the two proxy groups are determined as follows:

	Adjusted Div. Yield [FN15]		Growth		Indicated Equity Cost
5-company proxy group	(4.9%	+	5.2%)	=	10.1%
13-company proxy group	(4.6%	+	6.5%)	=	11.1%

The Department finds that these equity cost rates establish an appropriate range for CNG's investor-required return. It is noteworthy that the Department's independently determined growth rate range of 5.2% to 6.5%, midpoint at 5.85%, is very much in synchrony with Zacks' consensus 5-year growth rate forecast ranging from 5.76% to 6.14%, midpoint at 5.95%. Rothschild PFT, Schedule JAR-6, p. 3.

vi. Risk Premium Synopsis

Risk premium is an alternative approach for estimating common equity cost rates. The implementation and interpretation of any risk premium study is subjective, and a great amount of professional judgment is required to transform historical risk premium data into a meaningful forward-looking estimate. Some of the problems with the methodology include: (1) the amount of risk differential that may apply at a given time to a given utility; (2) the period of time over which the stock-bond yield spread should be established; (3) what debt and equity securities should be used in the risk premium's assessment; (4) the value of historical data in times of economic uncertainty or unstable earnings; and (5) changes in the relative level of risk between the asset classes of stocks and bonds that may occur over time. Nowhere are these problems, and the difficulty they impose in determining a risk premium reasonably matched with investors' current expectations, more apparent than from the analyses and arguments of the two witnesses. With equity risk premiums ranging from approximately 100 to 470 basis points, it would be

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reasonable to conclude that the risk premium approach suffers from so much subjectivity that it can essentially be used to show whatever the user wants. Rothschild PFT, Schedule JAR-9; Hanley PFT, Exhibit FJH-14, p. 1.

Mr. Hanley used a period of more than 70 years to determine historical risk premium. Hanley PFT, Exhibit FJH-14. Mr. Rothschild suggests it is appropriate to consider centuries of data. Rothschild PFT, p. 38. The former develops a risk premium based on an arithmetic mean for one-year holding period returns. Hanley PFT, pp. 55-57. The latter strongly advocates use of a geometric approach. Rothschild PFT, pp. 69-71. Debt instruments used to establish a risk premium range from 90-day T-bills, to long-term inflation-indexed treasury securities, to corporate bonds and public utility bonds. Rothschild PFT, pp. 40-41; Hanley PFT, Exhibit FJH-14. The forecasted three-year to five-year total annual market return, a subjective estimate, changes from 14.4% to 16.4% from one Value Line issue to another, and is then used in Mr. Hanley's beta-derived risk premium analysis that mismatches geometric and arithmetic return data. Hanley PFT, Exhibit FJH-14, p. 6 and Exhibit FJH-14 Revised and Exhibit FJH-15, p. 4; Response to Interrogatory OCC-37.

Mr. Hanley described how investors would have reduced insight into the potential variance of expected future returns if their risk analysis involved a process whereby year-to-year fluctuations, or variance, of returns were smoothed out. Response to Interrogatory GA-198. He stated that the smoothing out of returns and reduced insight would be transacted either by calculating a geometric mean or by selecting any arbitrary, or arbitrarily short, period of time to determine the equity risk premium. Tr. 1/19/00, pp. 946, 949, and 953. He also stated that calculating the arithmetic mean risk premium over a long period of time, of taking the individual yearly highs, the lows, the negatives, and the positives, provides the insight critical to understanding what the return on an investment should be. Tr. 1/19/00, pp. 945-947 and 953-954.

Mr. Hanley's argument in support of an arithmetic mean risk premium is not unsound. A problem, however, is that the equity risk premiums he calculates, ranging from 400 to 470 basis points, appear to constitute broad-brush estimates for utilities generally. Hanley PFT, Exhibit FJH-14, pp. 5-6, and 8. The methodology does not explore the equity risk premium that may attach specifically to CNG or to CNG at this time. In regard to the latter, the Department finds that any endeavor to use risk premium methodology for investment policy-setting requires, at a minimum, that an attempt be made to distinguish between risk premium deviations from normality or shifts in that normality. Mr. Rothschild identified this issue, but neither he nor Mr. Hanley accommodates it in their analyses. Rothschild PFT, p. 33.

These shortcomings affect the risk premium representations of both Mr. Hanley and Mr. Rothschild. Whereas Mr. Hanley's risk premium calculations overstate CNG's cost of equity, Mr. Rothschild's understates it. In the case of the OCC witness, this should be clear by comparing Mr. Rothschild's recommendation of 8.85% to the Company's pro forma embedded cost of debt of 7.88%. The difference, or equity risk premium, is barely 100 basis points. The Department adds that the inflation-based risk premium approach and the actual level of historical returns (net of inflation) for common stock (i.e., 6.6% to 7.2%) used within Mr. Rothschild's analysis (Schedule JAR-9) appear ill-suited to deriving a risk premium cost of equity applicable to CNG. In the case of the Company's witness, comparing CNG's rate of return on average common equity with its average cost of long-term debt from 1994 through 1999, the average differential or risk premium over the six-year period is 2.88%. This is substantially below the average equity risk premium of 4.4% to 4.7% ascribed by Mr. Hanley to the various proxy groups. Late Filed Exhibit No. 48 (Revised Exhibit FJH-3, p. 2); Hanley PFT, Exhibit FJH-14, p. 5 and Revised Exhibit FJH-14, p. 5.

vii. Risk Premium Summary

The Department allows that a risk premium applies to the Company's equity. In the Previous Rate Decision, the Department established a forward-looking risk premium range of 2.25% to 2.75% and selected 2.75% as the proper risk premium. Decision, p. 78. Based on the evidence presented in this proceeding, it may be concluded that a forward-looking risk premium in the range of 2.0% to 3.5% is appropriate. The Department finds that 2.75% to 3.0% represents a prospective, best estimate of CNG's equity risk premium.

Based on the average of all the adjusted prospective bond yields listed in Exhibit FJH-14 and Exhibit FJH-14 Revised, the Department finds that a 7.8% prospective yield is applicable to the Company at this time. [FN16] Adding 2.75% to 7.8% indicates a risk premium cost of equity of 10.55%. Adding a risk premium of 3.0% indicates a risk premium cost of equity of 10.8%. These results, calculated without DCF considerations, fall squarely within the DCF equity cost rate range shown above. Thus they are credible outcomes that also support the established DCF equity cost range.

viii. Conclusion

Mr. Hanley cautioned about the tendency of the DCF model to mis-specify investors' required return rate. Hanley PFT, pp. 41-43. The rebuttal to his argument is that the prices being paid by investors for utility stock reflect the understanding that these entities are subject to regulation. Furthermore, the DCF range 10.1% to 11.1% is sufficiently broad to minimize error resulting from excessive reliance on it. The Department's independent risk premium findings ranging from 10.55% to 10.8% fall within that range. The range incorporates Mr. Hanley's updated DCF testimony and, as such, is responsive to current and ongoing changes with respect to capital costs. Of all the methodologies employed by the cost of capital witnesses, the DCF approach is the only one that attempts to consider investors' future earnings expectations, namely, the expected cash flow from dividends and the expected market appreciation of stock. Thus it represents a concept that at least tries to predict future conditions expected to exist when related rates are in effect.

A review of Mr. Hanley's summary Exhibit FJH-1, p. 2 and Exhibit FJH-1, p. 2 Revised shows that 10.5% represents the exact average of his DCF results for the proxy group of five gas distribution companies. His testimony identifies this as being close to CNG's investment risk and as representative a group as possible, passing all the criteria tests established for comparability to CNG. Response to Interrogatory GA-191; Tr. 2/10/00, p. 1498. Under the risk premium approach, it is possible that the Company's equity premium may be as high as 3.0%. In that circumstance, the cost of equity is 10.8% which, in view of all the considerations discussed herein, the Department regards as representative of CNG's investor-required rate of return. No further specific risk adjustment is warranted.

A final check as to the overall reasonableness of this conclusion can be found by the pre-tax interest coverage a 10.8% equity cost would impute to the Company. Mr. Hanley stressed CNG's need for a reasonable opportunity to achieve a pre-tax interest coverage of 3.6 times. Hanley PFT, pp. 77-79. In this regard, the Department believes that his testimony is compelling. In contrast, Mr. Rothschild does not address the issue of whether or not his recommendation would provide a reasonable opportunity for CNG to achieve S&P's financial target guidelines relative to a bond rating within the A category, or with respect to the business risk position/profile assigned by S&P to the Company.

Schedule F-5.0 of the Company's Application shows a pre-tax interest coverage of 3.9 based upon Schedule C-1/C-2. Response to Interrogatory GA-182. In the same way as that calculation, which utilizes actual numbers from the pro forma income statement and also recognizes higher embedded marginal tax rates from prior periods, a cost of equity of 10.8% achieves a pre-tax interest coverage of approximately 3.6 times on revised Late Filed Exhibit No. 4, Attachment B, p. 2.

5. Overall Rate of Return

[84] On a test year basis, projected to the mid-point of the upcoming rate year, the Company requested an overall rate of return of 10.1% reflecting a return on equity of 12.4%. Hanley PFT, Exhibit FJH-1, p. 1, Revised. After diligent study and deliberation of all issues presented in this rate proceeding, the Department finds that 9.3% is a fair rate of return. This return is calculated for gas-regulated operations only, using the approved capital structure and capital costs, as follows:

[Note: The following TABLE/FORM is too wide to be displayed on one screen. You must print it for a meaningful review of its contents. The table has been divided into multiple pieces with each piece containing information to help you assemble a printout of the table. The information for each piece includes: (1) a three line message preceding the tabular data showing by line # and character # the position of the upper left-hand corner of the piece and the position of the piece within the entire table; and (2) a numeric scale following the tabular data displaying the character positions.]

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Class of Capital	Amount	% of Total	Cost	Weighted Cost
Short-Term Debt	$ 6,760,000	2.41	6.64%	0.16%
Long-Term Debt	$131,153,846	46.74	7.88%	3.68%
Total Debt	$137,913,846	49.15		3.84%
Customer Deposits	$ 532,469	0.19	2.30%	0.00%
Preferred Stock	$ 879,381	0.31	6.96%	0.02%
Common Equity	$141,303,000	50.35	10.80%	5.44%
				Total Capitalization

1...+...10....+...20....+...30....+...40....+...50....+...60....+...70....

(Publication page references are not available for this document.)

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******* This is piece 2. -- It begins at character 75 of table line 1. ********
****

$280,628,696 100.00 9.30%

75..80....+...90....+....0..

(Publication page references are not available for this document.)

The Department finds that these rates, when applied to the rate base found reasonable for the Company, should produce operating income sufficient for CNG to operate successfully and serve its ratepayers, maintain its financial integrity, and compensate its investors for the risk assumed.

6. Weather Normalization Adjustment

[85, 86] A WNA is a rate mechanism by which actual heating-related consumption is adjusted to a normal weather pattern during the winter period, so that customers' bills and the Company's revenues and earnings are subject to less weather-related volatility. Bryant PFT, p. 16. The WNA adjusts the non-gas portion of customers' bills to offset the influence of weather. If the weather is warmer than normal, the adjustment is upward (customers are charged a higher unit non-gas charge); if weather is colder than normal, the adjustment is downward (customers are charged a lower unit non-gas charge). Tr. 1/12/00, p. 390. The Company stated that the intent of the WNA is to achieve revenue neutrality and not to increase or decrease what is allowed in base rates. Tr. 1/12/00, p. 403.

The Department has reviewed the Company's request for a WNA mechanism in the context of its overall revenue requirement and the ROE authorized and finds that it is not appropriate for this Company at this time.

K. ORDER COMPLIANCE

For reasons of administrative efficiency and streamlining the regulatory process, the Department considered whether or not the Company's outstanding orders and directives from other dockets are outdated or no longer applicable. The Department analyzed each of the Orders and directives from the Company's docketed cases. Late Filed Exhibit No. 6.

Order No. 9 in the Previous Rate Decision provides that:

No later than December 31, 1995, and each quarter thereafter, the Company shall file a status report on the computer contracts.

CNG has complied with this order filing status reports at the end of each calendar quarter. CNG believes that this order is no longer applicable since it has met the intent of the order. Late Filed Exhibit No. 6. The Department agrees with the Company that further reporting is not necessary and Order No. 9 is hereby rescinded.

III. FINDINGS OF FACT

1. The Company proposed an increase of $16,536,609 to produce revenues at proposed rates of $294,315,742.

2. The test year is the 12 months ending June 30, 1999.

(Publication page references are not available for this document.)

3. CNG included $472,666,612 of plant in service in its rate base.

4. The Company based its pro forma plant additions on its 2000 capital budget and 2001 forecast, and reduced these amounts by 9% to reflect the historical relationship between budgeted and actual capital expenditures.

5. Hardship forgiveness portions of FAS 106 costs, amortization and uncollectibles are non-cash expenses.

6. The Company included non-cash operating expenses in the calculation of its daily cash requirement.

7. CNG did not include any prepaid insurance or prepaid property taxes in its rate base.

8. The Company did not include the load and revenue from an additional large use firm customer in its pro forma data.

9. The Company assumed that the existing 500 Mcf usage cap for FTS-3 customers would be eliminated in August 2000.

10. The Company proposed to lower the interruptible target margin to $4,400,000 from its previous target of $8,833,575.

11. The Company originally estimated that Downtown Cogeneration Associates would be shut down in September 2000.

12. The Company submitted a depreciation study for property in service at September 30, 1997 that uses the straight-line method and remaining life technique.

13. The relevant difference between Average Life Group and Equal Life Group is that ALG uses a direct weighting of the remaining lives of each average life group, whereas ELG uses a reciprocal weighting procedure.

14. The Hardship Arrearage Forgiveness Program provides low-income customers with an affordable mechanism to make consistent monthly payments, reduce arrearages and maintain service year round.

15. The Company used a 2.944% composite inflation factor to adjust a pool of unadjusted expenses having a balance of $6,314,135 to produce an inflation expense of $185,869.

16. CNG stated that it used interest synchronization to determine the interest expense used in the calculation of its state and federal corporate income tax liabilities.

17. The Company based its pro forma Connecticut Corporation Business Tax of $1,872,945 on its projected financial operations at the rate of 7.5%.

(Publication page references are not available for this document.)

18. The Company based its pro forma federal income tax of $11,547,544 on its projected financial operations at a rate of 35%.

19. The majority of Deferred Federal Income Taxes of $297,000 is a result of timing differences between book and tax depreciation expense.

20. CNG's initial Application included pro forma property taxes of $4,550,207 that included a City of Hartford increase of $807,768 based on an estimated mill rate.

21. The Company indicated that 52 employees earned more than the social security wage limit in the test year.

22. Gas distribution companies are subject to 4% and 5% Connecticut gross receipt tax rates on residential and commercial/industrial sales, respectively.

23. CNG has included the cost of Directors and Officers liability policies, which provide the Company with coverage for certain types of wrongful acts by directors or officers of the corporation, in pro forma insurance expense.

24. CNG sought recovery of $993,063 in premiums for a weather stabilization insurance policy covering the 2000/2001 heating season.

25. Injuries and Damages is a self-insurance mechanism that covers deductibles, and its $568,000 cost is included in total pro forma insurance expense of $2,455,067.

26. The Company projected repairs of $162,500 and repaving costs of $60,000 for its headquarters within its pro forma Maintenance of General Plant expenses.

27. CNG's pro forma payroll expense includes a short-term incentive plan (STIP) amount of $273,910, or 50% of the projected incentive of $547,820, which covers mid and senior-level managers, including officers.

28. Under the Financial Accounting Standard No. 106 -- Employers' Accounting for Post-Retirements Benefits Other Than Pensions, the Company is required to recognize these benefits during the working career of employees, not after they retire.

29. CNG has projected a $849,847 pro forma regulatory commission expense for the proposed rate year which included a 2% inflation factor to the Department's $833,183 most recent assessment for the July 1, 1999, through June 30, 2000 period.

30. CNG's total costs of $1,076,000 of rate case expenses included an estimated $245,000 for rate design.

31. The Company employed a revenue conversion factor of 1.73781 to determine the change necessary in revenues to produce the required change in allowed operating

income.

32. The Company reported that, despite a reduction in its total cost of gas, its base gas cost increased because of the migration of some of its customers from firm sales service to transportation services.

33. The Company made a number of adjustments in its gas supply pipeline capacity portfolio since its last rate case that have a total estimated value of $ 6,885,000.

34. Department guidelines to evaluate the response of gas utilities to gas odor complaints are 30 minutes during normal business hours and 45 minutes at other times.

35. Estimated expenditures for safety education have been approximately $70,000 per year from 1995 through 1999.

36. The Company is wholly owned by CTG Resources, Inc., which also owns The Energy Network, Inc.

37. Positive time reporting requires employees to account for all of their time, rather than just the time that they spend working for one or more of the affiliates.

38. The Company does not automatically return deposits to residential or commercial customers who have paid their monthly bills on time for 12 months and 18 months, respectively.

39. The Company does not hold anyone other than the customer of record responsible for paying the bill and will not deny service to a new applicant at premises where service had been shut off for nonpayment.

40. The Company does not use the date the customer pays an agent as the date the bill is paid.

41. A stock repurchase executed in October 1997 changed the debt and equity ratios between CNG and CTG.

42. A WNA is a rate mechanism by which actual heating-related consumption is adjusted to a normal weather pattern during the winter period.

43. The WNA adjusts the non-gas portion of customers' bills to offset the influence of weather. If the weather is warmer than normal, the adjustment is upward if weather is colder than normal, the adjustment is downward.

IV. CONCLUSION AND ORDERS

A. CONCLUSION

[87, 88] Based on the evidence presented in this proceeding, the Department concludes that the Company's total estimated gas cost is $157,420,830, and its new base cost of gas for firm customers is $4.776 per Mcf. Further, the Department concludes that revenues of $282,263,346 will be sufficient to enable CNG to operate successfully, maintain its financial integrity, attract capital, and compensate its investors for the use of their money and the risks assumed. Therefore the Department decreases the Company's revenue requirements by $117,062 or .04%.

Given the limited effect a decrease of this amount would have on customer bills, the Department believes the public interest is better served by applying it to the Company's cast iron and bare steel pipe replacement program.

The Department is deferring its Decision on alternative ratemaking plans to Phase II of this proceeding.

B. ORDERS

1. The Company shall continue to defer hardship arrearage forgiveness expenses that exceed the amount allowed by the Department.

2. No later than May 25, 2000, the Company shall automatically return all security deposits, with interest, to residential and commercial customers who have made 12 and 18 consecutive monthly payments, respectively, on time.

3. No later than June 1, 2000, the Company shall codify in its Rules and Regulations its policy concerning denial of service as described above in Section II.I.3., and file it for the Department's approval.

4. No later than June 1, 2000, the Company shall submit a detailed proposal to amend its Rules and Regulations to provide for a 3-day grace period before assessing a late payment charge on payments received through the U.S. Postal Service and payments received through payment agents. The filing shall include examples that demonstrate when a late payment will be assessed and how the charge will be calculated.

5. No later than June 1, 2000, the Company shall submit a revised credit rating agency reporting policy that comports with Conn. Gen. Stat. §16- 262d(g).

6. No later than June 30, 2000, the Company shall file a plan for implementing positive time reporting. This plan should provide for fully operational positive time reporting by the beginning of the Company's next fiscal year (October 1, 2000).

7. No later than June 30, 2000, the Company shall file procedures for cost allocations and affiliate transactions. These procedures shall address all areas covered by the NARUC Guidelines, and shall address all of the cost allocations and

affiliate transactions between Energy East and CTG, between CTG and all of its subsidiaries, and among CTG's subsidiaries.

8. No later than August 1, 2000, the Company shall implement the two proposed programs for handling customer leak calls.

9. No later than August 15, 2000, and quarterly thereafter, the Company shall provide a report to the Department showing the amount of retained earnings, dividends paid to CTG and the resulting dividend payout ratio.

10. No later than September 1, 2000, the Company shall submit a proposed code of conduct governing relationships of its officers and directors with unregulated affiliates for the Department's review and approval.

11. No later than November 1, 2000, the Company shall provide a report describing its analysis of its service department to find improvements in productivity that will result in improved leak response times. The report shall include but not be limited to a plan to improve productivity and leak response time in its service department.

12. No later than November 1, 2000, the Company shall develop a program and provide a report to the Department's Gas Pipeline Safety Unit on the means to measure achievement of the goals of its public safety education program.

13. The Company shall notify the Department in writing within 10 business days whenever a monthly average speed of answer is more than 30 seconds. The notice shall include the reasons for the higher rate and how it was addressed.

14. The Company shall notify the Department in writing within 10 business days whenever the abandoned call rate is more than 3% per month.

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FOOTNOTES

FN1 Public Act 93-417 is an act concerning energy efficiency standards and design proposals for State of Connecticut major capital projects. The cost of these programs is shared equally by the public service companies and the State.

FN2 A Class 1 leak is '[a] leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.' Guide for Gas Transmission and Distribution Piping Systems 1995-98, American National Standard Z380.1, pp. 340-341. A Class 2 leak is '[a] leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.'Id., pp. 341-342. A Class 3 leak is '[a] leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.'Id., pp. 342-343. Connecticut gas companies routinely report Class 1 and Class 2 leaks to the Department. Decision, dated December 15, 1995, Docket No. 95-09-25, DPUC Ninth Annual Report Regarding Compliance with and Enforcement of Provisions Contained in Chapter 293 (Excavation, Demolition or Discharge of Explosives) of the Connecticut General Statutes, p. 9.

FN3 'Guidelines for Cost Allocations and Affiliate Transactions,' adopted by the Board of Directors of NARUC at its meetings in July 1999.

FN4 On March 3, 2000, the Company submitted a modified credit bureau reporting policy in Late Filed Exhibit 43 Revised. The revised exhibit was submitted after the close of hearings and was not subject to cross-examination; therefore, it cannot be accepted into the evidentiary record of this proceeding.

FN5 Decision dated November 27, 1996, in Docket No. 96-09-10, Application of Connecticut Natural Gas Corporation and CTG Resources, Inc. for Approval of Reorganization and Formation of a Holding Company.

FN6 The extent to which the additional eight LDCs in the proxy group of 13 do not share the selection characteristics (or criteria) of the LDCs included in the proxy group of five is detailed in the response to Interrogatory GA-189.

FN7 The initial consensus forecast was for the six calendar quarters ending with the fourth quarter of 2000 as reported in the August 1, 1999, issue of Blue Chip Financial Forecasts. The updated forecasts were for the six calendar quarters ending with the second quarter of 2001 as reported in the January 1, 2000, issue of Blue Chip Financial Forecasts.

FN8 Mr. Rothschild takes earnings, dividends and book value projections out to 40 years since calculations longer than this into the future have minimal present value. Rothschild PFT, p. 31.

FN9 The 6.6% is for the period 1871 through 1925, while the 7.2% historical return (net of inflation) is since 1926. Rothschild PFT, p. 38.

FN10 The other two are Atmos Energy Corporation and Indiana Energy, Inc.

FN11 The growth rate projections in this table are taken from the most recent Value Line sheets included in Mr. Hanley's Exhibit FJH-13 Revised. The historical data in the table are taken from the Value Line sheets included in Hanley PFT, Exhibit FJH-13. The observations and conclusions drawn from the historical growth rates in the table would have been exactly the same if it had been updated per the more recent Value Line sheets in revised Exhibit FJ H-13.

FN12 Although referred to as the 13-company proxy group, it is recognized that there are just 10 LDCs listed in the table. Value Line did not provide information for Public Service Co. of North Carolina or Yankee Energy System, Inc., and SEMCO is excluded.

FN13 The Value Line sheets included in Mr. Hanley's original PFT in Exhibit FJH-13 were dated June 25, 1999. Those appearing in Revised Exhibit FJH-13 were dated December 24, 1999.

FN14 From column (3) of Exhibit FJH-11 for the 13-company proxy group: ((13x4.7%)-5.3%)/12 = 4.65%. From column (3) of Exhibit FJH-11 Revised for the 13-company proxy group: ((13x4.4%)-5.9%)/12 = 4.3%.

FN15 The adjusted dividend yields reflect a growth rate component equal to one-half the average projected five-year growth rate in EPS and BVPS, as discussed, times the respective dividend yields to reflect the periodic payment of dividends as opposed to the continuous (4.75% X (1+(0.5x5.2%)) = 4.9%; and 4.5% X (1+(0.5x6.5%)) = 4.6%).

FN16 The consensus forecast found in Blue Chip Financial Forecasts at the time of the prior rate case proceeding applicable to A-rated utilities was 8.1%. See previous rate Decision, p. 77.

EDITOR'S APPENDIX

PUR Citations in Text

[CONN.] Re Connecticut-American Water Co., 142 PUR4th 62, Docket No. 92-06- 12, April 14, 1993.

[CONN.] Re Connecticut Nat. Gas Corp., 148 PUR4th 239, Docket No. 93-02-04, Dec. 15, 1993.

[CONN.] Re Connecticut Nat. Gas Corp., 166 PUR4th 491, Docket No. 95-02-07, Oct. 13, 1995.

[CONN.] Re Southern Connecticut Gas Co., 198 PUR4th 233, Docket No. 99-04- 18, Jan. 28, 2000.

[CONN.] Re Unbundling of Natural Gas Services by Connecticut Local Distribution Companies, 187 PUR4th 452, Docket No. 97-07-11, Phase I, July 23, 1998.

[U.S.Sup.Ct.] Federal Power Commission v. Hope Nat. Gas Co., 51 PUR(NS) 193, 320 U.S. 591, 88 L.Ed.2d 333, 64 S.Ct. 281 (1944).

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