STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on March 5, 2003

COMMISSIONERS PRESENT:

William M. Flynn, Chairman
Thomas J. Dunleavy
James D. Bennett
Leonard A. Weiss
Neal N. Galvin

CASE 02-E-0198 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service.

CASE 02-G-0199 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Gas Service.

ORDER ADOPTING RECOMMENDED DECISION WITH MODIFICATIONS

(Issued and Effective March 7, 2003)

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BY THE COMMISSION:

I. INTRODUCTION

On February 5, 2002, Rochester Gas and Electric Corporation (RG&E or the Company) filed revised tariff leaves designed to increase electric revenues by about $59.0 million (8.2%) and gas revenues by about $18.7 million (6.6%). The rates currently in effect for electric service were set in an order approving a five-year rate plan,[1] the term of which ended June 30, 2002. Natural gas rates currently in effect were set in an order dated April 2, 2001.[2] Gas rates were also intended to be effective through June 30, 2002.

By orders issued March 11, 2002 and July 3, 2002, we suspended the rate filings through January 14, 2003, the maximum statutory suspension period. At the request of RG&E, to accommodate settlement negotiations, the filing was further suspended through March 11, 2003, with the provision that the rates we approved in this order would be effective as of January 15, 2003.[3]

Hearings were held before Administrative Law Judge J. Michael Harrison on the Company's updated filing, Department of Public Service Staff (Staff) and intervenor evidence, and RG&E's rebuttal evidence. Public Statement hearings were held before Commissioner Neal N. Galvin and Administrative Law Judge Walter T. Moynihan on December 4, 2002, at two locations in Monroe County.

Judge Harrison's Recommended Decision in this proceeding was issued on December 17, 2002. Supplemental hearings on the revenue requirement effect of RG&E's proposal to close several customer service offices were held on December 6, 2002 and December 18, 2002.

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[1] Cases 94-E-0952, Matter of Competitive Opportunities Regarding Electric Service, and Case 96-E-0898, Matter of Rochester Gas and Electric Corporations Plans for Electric Rate/Restructuring Pursuant to Opinion No. 96-12, Order Adopting Terms of Settlement Subject to Conditions and Changes (issued November 26, 1997), confirmed in Opinion No. 98-1, Opinion and Order adopting Terms of Settlement Agreement Subject to Conditions and Changes (issued January 14, 1998) (the COB2 Orders). The five-year rate plan approved therein is typically referred to as "the COB2 Plan." The terms proposed by the parties were in their settlement document, dated October 23, 1997.

[2] Case 98-G-1589, Order Approving Terms of Joint Proposal (issued February 28, 2001), and Confirming Order (issued April 2, 2001).

[3] Untitled Order (issued December 3, 2002).

Briefs on exceptions to the Recommended Decision were filed on January 7, 2003, by RG&E, Staff, Multiple Intervenors (MI), Intervenor Charles A. Straka, The New York State Consumer Protection Board (CPB), and the Attorney General of the State of New York (Attorney General). Briefs opposing exceptions were filed on January 17, 2003 by RG&E, Staff, and MI. Supplemental briefs on the customer service center closings were also filed on January 17, 2003.

II. REVENUE REQUIREMENT

The Company based its revenue requirement on actual calendar 2001 (base year) data projected forward to the year ended June 30, 2003. At the time of its filing, the calendar 2001 data were ten months actual, and two months projected. In March 2002 RG&E made a supplemental filing to update the base year data to 12 months of actual data. At the time of its rebuttal filing on September 30, RG&E presented revisions and updates to its projections for the year ended June 30, 2003 (the "rate year").

As noted, rates are suspended through March 11, pursuant to the agreement of the Company. Previously, we suspended rates through January 14, 2003. In an order dated December 3, 2002, we ordered that RG&E would be "made whole" for the period of time between January 14, 2003 and the date new rates are set. This means that any annual revenue or revenue requirement change which would normally be accomplished during the first year of new rates will be compressed, so as to be fully realized by January 14, 2004. This would be accomplished, for a rate increase, through a surcharge mechanism.

Inasmuch as the rate year in this proceeding ends on June 30, 2003, it will be about two-thirds over when new rates are set. Although normally we allow projections of revenue requirements for the first full year of new rates (i.e., a fully forecasted rate year), in this instance the Company selected an earlier period. The Judge confined his analysis to the rate year ended June 30 2003, and we do as well.

A. Sales and Revenues

1. Electric Sales

The Recommended Decision adopted Staff's forecast of commercial sales, and rejected the Company's proposed rebuttal adjustment to industrial sales for the cessation of Eastman Kodak's operations at its Elmgrove site. RG&E takes exception to both recommendations.

a. Commercial Sales

The Judge concluded the difference between the RG&E and Staff commercial forecasts was caused mainly by use of different price deflators to convert the price of electricity into a real (i.e., inflation-adjusted) price. RG&E used a price index for personal consumption expenditures (PCE), while Staff used a broad GDP price deflator, and the Judge found the GDP deflator better encompasses the range of expenditures attributable to commercial enterprises. He also credited Staff's argument that an acknowledged double-count for weather normalization could have significantly distorted the Company's results. Finally, he rejected the Company's argument that Staff's forecast should be discounted (as too high) because the independent economic variables provided by DRI/McGraw Hill that Staff used were stale; the Company's own update using Economy.com data, he noted, effectively increased its commercial sales projection.

RG&E argues on exceptions that the weather normalization double-count has not resulted in significant distortions. Further, RG&E asserts, the difference between RG&E and Staff is due basically to the difference in gross regional product (GRP) which, in turn, is due to Staff's use of DRI/McGraw Hill data rather than the Economy.com data used by the Company. RG&E contends that the Staff GRP growth rate is 3.0%, higher than it would be if Staff's forecast were updated, and is higher than the forecast based on the Economy.com data.

Staff disputes RG&E's assertion that the difference between the Company and Staff forecasts is due mainly to the differing estimates of gross regional product. For one thing, Staff asserts, the Company only used a subset of the gross regional product, the non-manufacturing component. Regardless, Staff contends, "the forecast differences should be calculated with both the price deflator and the economic variables replaced simultaneously," and "the bias resulting from double counting weather normalization should also be estimated from a model corrected for the price deflator."[4]

RG&E has not challenged or answered the Judge's basic reason for concluding the DRI/McGraw Hill GDP deflator is preferable to the PCE index RG&E used. RG&E's exception is denied.

b. The Elmgrove Closing

The Judge also rejected RG&E's proposal on rebuttal to reduce the industrial sales forecast to reflect the closing of the Eastman Kodak Elmgrove facility. RG&E had introduced a dummy variable into its model, and then made a direct reduction when Staff objected to a belated change in the model. The Judge agreed with Staff that no adjustment was needed, since the reduction of demand at Elmgrove took place gradually over time before the end of 2001, and was reflected in the base data. He concluded that the model could have actually projected further reductions into the future that will not be taking place, and that in any event the impact of the Elmgrove closing on the forecast is at most statistically inconclusive.

On exceptions, RG&E contends that neither the cessation of Elmgrove operations nor the prior downward trend in consumption there was fully reflected in the sales forecast. RG&E points out that the system-wide growth rate does not identify specific components, and it argues that, although "[s]hown year by year, the most recent data would indicate the downward Elmgrove sales trend,"[5] nonetheless the sales forecast is overstated unless there is specific treatment of the Elmgrove

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[4] Staff's Brief Opposing Exceptions, p. 5.

[5] RG&E's Brief on Exceptions, p. 6.

closing. RG&E also argues that its presentation in brief overstated the industrial sales forecast by 68,166 mWh.

Staff replies that the use of the dummy variable is illogical and plagued with statistical problems that were discussed in Staff's presentation to the Judge.

The Company's position on Elmgrove is illogical and unacceptable. All of the reduction in demand there took place before the end of 2001 and is reflected in the historical data. There is no need for an additional adjustment. RG&E's exception is denied.[6]

2. Gas Sales and Revenues

The Company’s rate year forecasts for S.C. 1 and S.C. 5 retail gas sales were adopted in the Recommended Decision. Staff takes exception, arguing that the recommendation is in error with respect to both the projected number of customers and use per customer.

The Judge found that, although both Staff and RG&E predicted growth in the number of customers beyond calendar 2001, RG&E had shown flaws in Staff’s approach, while its own projection closely matched the .07% historical customer growth trend. On exceptions, Staff observes that the .07% is an annual growth figure, and argues that a higher growth should be reflected for the 18 months between the base period and the rate year. According to Staff, the Company's forecast has already been surpassed by the actual number of customers.

RG&E responds that Staff's argument about the 18-month period is "much ado about nothing."[7] With one exception (2000), RG&E continues, all of the annual growth rates from 1997 on have

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[6] The Company identifies a total of 123,956 mWh of adjustments to its industrial forecast, and indicates that the proper amount of the Elmgrove adjustment is 45,602 mWh, attributable to the dummy variable, not the 77,479 mWh that the Company identified as its hypothetical alternative. Since the RD accepted Staff's total industrial forecast, however, this modification merely changes the residual amount for "balance of adjustments," not the net result of the adjustments.

[7] RG&E's Brief Opposing Exceptions, p. 1.

been well below Staff's figures and closer to the Company's. RG&E asserts it demonstrated serious flaws in Staff's forecasting method. As to Staff's claim that the Company's forecast has been surpassed by actual amounts, RG&E points out that earlier Staff argued strenuously (and successfully) against admitting into evidence Exhibit 129 for identification, which RG&E had sought to introduce to demonstrate that actual rolling 12-month data were closely tracking the Company's forecast with respect to both the number of customers and use per customer.

The Judge also accepted the Company's forecast of use per customer, which was higher than 1998, 1999, and 2000 actual use per customer, concluding that its projection properly reflected a steady trend of declining use per customer since 1996. Staff, he concluded, placed too much reliance on 2000 use per customer, which he regarded as an abnormally high outlier. On exceptions, Staff argues that its forecast falls in the middle of the historical range, is less than 1% above the average, and properly discounts the very low usage in 2001, when gas prices were exceptionally high.

RG&E responds that Staff continues to ignore its own exhibits, which show use per customer declining each year since 1996 (except for 2000), to 127.27 Mcf/customer in 2001, which is less than RG&E's forecast of 128.38 Mcf/customer.

Current circumstances continue to support RG&E's projected use per customer. We agree with Staff, however, that more growth in the number of customers should be reflected, and that conclusion is consistent with the data on the proposed Exhibit 129. A figure of 290,000 customers appears reasonable for the rate year; it is more consistent with developing actuals than the 288,934 projected by the Company. To that extent, Staff's exception is granted.

3. Gas Late Payment Revenues

Staff, asserting there has been an increase in S.C. 1 late payments over the past three years, projects gas late payment revenue to reflect a consistent ratio, in excess of 2%, of late payment charges to net gas operating revenue. The

Company had proposed $229,000 less, pointing out that customers migrating from S.C. 1 retail to S.C. 5 transportation no longer have a billing relationship with RG&E under the single retailer model now in effect. The Judge believed both positions had merit and adopted a projection midway between the two parties' projections. Both Staff and RG&E except.

On exceptions, RG&E renews its assertion that customer migration to transportation only (S.C. 5) service will result in lower late payment revenues because RG&E does not continue to have a billing relationship with migrated customers. RG&E argues further that Staff's reliance on the spike in late payment revenues in the first half of 2001, which resulted from an unusually high cost of natural gas, is unreasonable. Moreover, RG&E continues, the late payment ratio has not increased in each of the last five years, but declined in 2000 from 0.74% to 0.68%.

Staff argues that actual late payment charge revenues have not been below 2.0% of new operating gas revenues during any of the last four years and have increased despite migration over this period. The Company's expectation that migration will reduce late payment charges, Staff asserts, has not been shown to be statistically accurate. The Company's arguments about 2001, Staff adds, do not explain the higher revenue levels also experienced in 2000.

Staff's position is consistent with actual experience, and the levels of migration under the single-retailer model have not been shown to affect late payment charge revenues significantly. Accordingly, we grant Staff's exception and adopt its entire adjustment.

4. <u>Gas Loss Factor</u>

The Judge accepted RG&E's gas loss factor of 1.68%, rejecting a 1.28% factor proposed by Staff. The choice was between Staff's use of a five-year average and the Company's use of a three-year average, and he determined that precedent favored use of a three-year average. The Judge concluded, as well, that the first two years of the five-year period skewed the results.

On exceptions, Staff argues that, since 1994, actual losses have been below the allowed factor, and further that the most recent factor (1.2706% for 2002) is consistent with its factor.

In reply, RG&E argues that Staff, which typically uses a three-year historical average loss factor, opted for a five-year factor in this proceeding because it produces a lower result.

The three-year loss factor in other circumstances might be more appropriate than the five-year factor, in view of loss factor variability, since the lower Staff factor is driven by the first two years of the recent five-year period. Despite that consideration, however, the main and service replacement programs which are being funded herein should reduce losses. For that reason, and because Staff's recommendation is similar to the most recent factor, Staff’s exception is granted.

B. Operating Expenses

1. Payroll Expense

A total of ten exceptions have been filed by RG&E and Staff to the Judge’s treatment of labor expenses. The Company’s position is that $128.5 million of payroll expenses should be included in rates for the test year, including proposed recovery of incentive compensation for management and other employees. Staff argues for a total of about $117.0 million. The Judge included $122.8 million in the Recommended Decision.

a. Base Period Payroll

The Judge accepted a Staff adjustment to base period payroll to remove the effects of an extra pay period recorded on the books in 2001 which, the Judge concluded, was improperly carried through to the rate year forecast. Since RG&E reclassified this expense in rebuttal to base year "Other" expenses, the effect of the Judge's adjustment was mostly to reduce rate year "Other" expenses; there is a net reduction of rate year expenses of $1.9 million. RG&E excepts, claiming that by reducing the Company's rebuttal O&M "Other" expense amount by the payroll adjustment the Judge has denied the Company two weeks' pay. Staff, however, excepts to the $1.9 million adjustment, claiming it is not large enough. According to Staff, the Judge erred in adding back $503,000 to base period payroll, and he should have eliminated the entire $2.4 million amount that was reflected in the Company's reclassification.[8]

In its exception, Staff also characterized as a "fiction" RG&E's claim that a credit of $1.719 million to reduce (electric) payroll was already embedded in the "Other" cost category.

We agree with Staff that there is no evidence, or reason to believe, that the rate year forecast was or could have been corrected by the Company's reclassification. RG&E's exception is denied, and we correct for the numerical error.

b. Productivity

The Recommended Decision addressed Staff productivity adjustments totaling $3.1 million. Payroll was reduced at Staff's request by $2.5 million to reflect productivity offsetting "market pay" increases, namely, wage and salary increases designed to bring compensation for some positions in line with comparable positions at other New York utilities. This uncontested productivity had not been reflected in RG&E's presentation. The Company does not take exception to this adjustment.

In addition, Staff proposed an additional $590,000 of rate year productivity, reflecting a traditional 1% productivity adjustment. The Judge rejected this adjustment, noting that RG&E claimed to have itself included an additional $613,000 of productivity in its rebuttal presentation--a point Staff appeared to concede when it argued it would simply rely on the asserted reasonableness of its proposed total payroll allowance.

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[8] As a result of an error in Staff's schedules, the Judge reported the adjustment as only $1.9 million. The correct figure is $2.4 million.

The Judge concluded that no further productivity allowance would be required, given this Staff "posture" and given the reflection of productivity offsetting the market pay increases.

Staff excepts, claiming the Judge has erroneously removed over $1.838 million of productivity forecasted by both the Company and Staff. Staff argues that the imputation of non-specific productivity is reasonable, claiming that the Company has forecasted as much as $23 million of expected labor productivity.

In reply, RG&E argues that we should uphold the rejection of Staff’s $590,000 productivity adjustment. RG&E maintains that the Judge properly concluded that an additional productivity adjustment would be superfluous, given the productivity gains imputed with respect to market increases. Moreover, RG&E argues, the Merger Joint Proposal has superceded and rendered moot the sole source of expected labor productivity alleged by Staff.

Both Staff and the Company reflected 1% productivity from the calendar 2001 test year through the rate year. The Company’s computation was $1.838 million, based on its payroll expense, and Staff’s was $1.771 million, based on its payroll expense. We conclude that the Judge should have included this standard productivity adjustment, despite his treatment of the market pay proposal. Staff’s exception on the 1% productivity is granted.

c. <u>Inflation/Merit Pay/Resource Requirements</u>

The Recommended Decision accepted a Staff adjustment reducing the Company’s proposed $3,400,000 addition to base payroll expense for merit pay increases by $520,000, and an additional adjustment eliminating $200,000 added by the Company for inflation. Staff argued to the Judge that because RG&E grants merit pay increases in lieu of COLAs, it is an improper double count to apply the additional $200,000 inflation factor. Staff also argued that applying the merit increase to the whole workforce is improper since merit increases are not awarded where salaries or wages are above market or frozen. RG&E did not respond to those arguments then, or on exceptions. Staff objected as well to an additional $723,000 for increased workforce (resource requirements) reflected in RG&E's rebuttal presentation, and the Judge also accepted that adjustment.

RG&E excepts, arguing for reversal of these three adjustments. Staff excepts as well, arguing that in addition to these adjustments, the Judge should have accepted its further adjustment to reduce payroll expense for "lump sum" payments in the amount of $778,000.

RG&E argues that the Recommended Decision improperly discounts its testimony showing that the rate year merit pay amount is supported by recent three-year average spending levels, as well as additional testimony sponsoring the resource requirements amount.

In reply, Staff argues that the record contains no evidence supporting the need for new hires (resource requirements), and that the evidence suggests RG&E's workforce is likely to decline. As to the merit pay increase, Staff indicates that it did not dispute the Company's projected $2.9 million projected increase, that this amount generously exceeds the rate of inflation, and that the Company improperly increased its request to $3.4 million in rebuttal.

In its exception, Staff argues that the Judge erred in assuming that Staff had withdrawn its $778,000 adjustment to eliminate lump sum payments; Staff argues that the lump sum payments are already in the base year payroll expense, so the Company is effectively double-counting them. In response, RG&E says the lump sum amount at issue is $400,000, and points to the Judge's conclusion that this is reasonably consistent with the three-year historical average lump sum payments of $423,000. RG&E also contests Staff's claim that lump sum payments were double-counted, maintaining that lump sum amounts have not been reflected in base payroll.

RG&E has not addressed or refuted the basis for Staff's inflation and merit pay adjustments, and its exception in that regard is denied. The Company reasonably requests inclusion of lump sum payments of about $400,000. The record does not show that these lump sum payments are reflected in base year base payroll as alleged by Staff. Accordingly, Staff’s exceptions regarding the lump sum amounts are also denied.

The Company’s exception regarding the resource requirements adjustment ($723,000) must be rejected as well, as there is no indication the Company is increasing its workforce.

d. Incentive Plans

RG&E takes exception to the disallowance of $865,000 it requested for its Executive Incentive Plan (EIP). Both RG&E and Staff take exception to the treatment of the requested $5,650,000 for the Performance Plus Plan (PPP), incentive compensation for other employees. The Judge allowed $2,815,000, treating the rest of the PPP request as being offset by productivity.

With respect to the EIP, the Company reasserts the argument that it made to the Judge, that the expenses should be allowed since incentive compensation plan (ICP) expenses are recognized as legitimate business expenses in the Commission’s charts of accounts (Account 920). Moreover, RG&E argues, the Judge erred in finding EIP expenditure recovery unprecedented, as such recovery had been approved in two cases involving Consolidated Edison Company of New York. The Company says it did not "concede" that 2001 EIP expenditures were recorded below the line, but merely mentioned that fact to correct a misunderstanding about the difference between base year and test year payroll expense.

In reply, Staff emphasizes that recovery of executive bonuses has not been approved in litigated cases. The two cases cited by RG&E involved settlements, and the joint proposals in those cases indicate that executive bonuses were offset with productivity gains. Moreover, Staff continues, RG&E has a long-standing policy of accounting for these costs below the line.

The Judge is correct that there is no precedent for recovery of executive incentive payments in a litigated rate case. They have been approved only twice in settlements, with associated productivity offsets. This is an expense that should not be charged to customers. RG&E’s exception is denied.

With respect to the PPP, the Judge noted the Company's practice of sharing excess earnings with its employees, but concluded that liberal employee bonuses over the past few years may have effectively transformed these payments into expected base compensation, and he recommended the Company review its program. On exceptions, RG&E asks for rate recovery of these costs based on its historical payout ratio of 4.63% and argues that at least its targeted 3% payout ratio should be allowed rather that the Judge's 2% ratio. Staff and MI argue that no PPP allowance should be made, since any PPP allowance should be offset by productivity. Moreover, they argue, if the Company needs rate relief, the excess earnings that justified the high historical awards cannot be expected. MI also asserts that the Judge's suggestion that the high bonuses of the past have effectively become base compensation is speculative. In response to these parties, the Company argues that the PPP program is not unique, that it is consistent with a philosophy of recognizing "performance above and beyond normal performance," and that it results in long-term benefits to customers.[9]

The high historical PPP payments have taken place in a multi-year plan in which considerable excess earnings were realized. We agree with the Judge's observation that it is improper, in principle, to allow recovery in a rate proceeding of rewards for excess profits that are not contemplated by the new rates. It is proper to expect bonuses to be funded from efficiency or productivity gains, as Staff and MI argue. The Judge erred in considering PPP payments to be effective pay increases because the liberal bonuses were allegedly rewards for earnings performance achieved during the multi-year plan. The Staff and MI exception is granted.

[9] RG&E's Brief Opposing Exceptions, p. 14.

e. <u>Payroll Related Overheads</u>

The Judge rejected Staff's tracking adjustment for employee benefits on the basis of the Company's contention that these benefits were estimated separate and independent of the payroll amounts. Staff excepts, arguing that this contention was raised for the first time in brief and is disingenuous.

According to Staff, although benefits are separately estimated, the amounts are dependent on the numbers of employees and the amount of wages paid. For example, medical costs are dependent on the number of employees multiplied by premiums, and 401(k) contributions depend upon a percentage of wages paid. The magnitude of Staff's 11% loading rate was the only subject of Company rebuttal on this score, Staff continues, and recent testimony pertaining to the proposed office closings indicates that the Company's loading rate is more than twice as high as Staff's.

The Company replies that the Judge correctly recognized that a benefits loading rate was inappropriate, because the Company estimated individual benefits separately. Staff's claim that 401(k) contributions depend upon a percentage of wages paid is misleading, RG&E continues, because 401(k) contributions will vary with the percentage of wages that each employee chooses to contribute to the 401(k) plan. Finally, RG&E asserts, the use of a loading rate in the context of the layoffs associated with office closings was the most efficient way to estimate savings in that context.

Although various benefits vary among employees, and although benefits estimates were made separately by RG&E, these estimates necessarily depended upon RG&E's sense of its total employees and payroll requirements. Any adjustment to the total should result in a corresponding change in benefits, however estimated. Accordingly, we are persuaded that a benefits loading factor should be applied to the payroll adjustments we make, and Staff's 11% factor appears conservative. Staff's exception is granted.

2. The PRIDE Project

The PRIDE project,[10] which appears to have an uncertain future, was intended to be a series of software improvements designed to enhance customer service, and employee and shareholder satisfaction. Installation of this project commenced during the year ended June 2001. Based on Company statements, MI concluded that some $8 million of PRIDE costs were included in rate year revenue requirement. RG&E states that $1.035 million is rate year expense, and the other $7 million represents plant that will not go into service until December 2003, beyond the rate year. Given substantial cost write-offs, MI argued to the Judge that it appears the project will be discontinued, and that there should be no funding of it in the rate year. MI asked for a prudence investigation of the project.

The Judge accepted the Company's explanation that the net rate year impact is a small revenue requirement reduction and declined to recommend a prudence investigation, suggesting the record did not include enough program information to demonstrate that prudence review was warranted.

On exceptions, MI renews its request for a prudence examination. Staff also notes that RG&E removed more than $4.747 million of PRIDE rate base savings in its rebuttal presentation, and argues it is unclear whether this change is acceptable, given that many other rebuttal modifications have been rejected, that the corresponding O&M savings were not also removed, and that at least one major PRIDE module is operational. Staff joins MI in also arguing that the electric portion of the $14 million of PRIDE write-offs may have been used to reduce excess earnings, the computation of which is discussed below, effectively allowing recoupment of these written off expenditures. Staff indicates it will address this matter during its review of the fifth-year COB2 Plan excess earnings filing.

[10] Process Reengineering Implementation for Delivery Energy.

RG&E responds at length, rejecting the suggestion that the Judge erred in finding in PRIDE project developments so far an insufficient basis for commencing a formal prudence review. The Company notes that its filing reflected a net revenue requirement reduction for the rate year. Although MI could have explored with Company witnesses PRIDE project details, RG&E continues, it declined to do so. Finally, RG&E submits, Staff is suggesting for the first time in brief that the removal of $4.7 million in plant savings in rebuttal updates was improper. RG&E says that adjustment was made when it became clear that capital savings would not occur in the rate year; moreover, that other updates were rejected by the Judge as belated and unsubstantiated does not mean that this one must also be rejected.

Like the Judge, we see no reason to commence a prudence review of the entire project. The write-offs do not portend abandonment of the entire project. Nor is there a basis at this point for reviewing any effects of PRIDE project write-offs on the excess earnings computation.

Any issues related to the impact of PRIDE cost write-offs on excess earnings will be addressed later, in our review of Staff's audit of the fifth-year COB2 Plan excess earnings. Finally, we cannot accept the Company's rebuttal update removing $4,747,000 of rate year rate base savings (with a revenue requirement impact of about $570,000). The rate year net effect of costs and savings, per the Company's initial filing, showed a virtual offset of expenses and expense savings, but include rate base savings of $4,747,000 following accumulation since July of 2000 of more than $29,000,000 of capital costs, which are not yet in rate base and presumably in construction work in progress (CWIP). Although we understand that some costs have been written off, there has been no demonstration that the remaining capitalized costs will not produce the projected savings.

3. Coal Costs

Staff offered a total downward adjustment of $2,048,800 to allowed rate year coal costs. RG&E challenged only one element of the multi-faceted adjustment--a reduction of $856,000 related to coal deliveries between July and December 2002, representing a 50% sharing of savings that Staff believed might have been realized had the existing contract prices been renegotiated. The Judge rejected the challenged component, finding it "akin less to a forecast than to an adjustment for imprudence, and [that] the record [is] inadequate for such a finding. Staff does not present information showing there actually are savings through replacement contracts for the last half of 2002."[11]

On exceptions, Staff argues that the distinction drawn by the Judge is unclear and that the portions of its adjustment that he did adopt were predicated on the same 50% sharing of savings between forecasted and adjusted coal prices. It notes as well that RG&E had reported in its initial brief that the contracts had in fact been renegotiated, and that while the specific dollar figure was not included, it would be wrong to allow the Company to capture 100% of the resulting savings. Staff continues to maintain its adjustment is conservative and prudent.

RG&E replies that Staff has failed to show that the replacement contracts will, in fact, produce savings; it notes that other factors, such as quantities purchased, could bear on overall costs. It supports the Judge's characterization of the adjustment as, in effect, an unproven imprudence adjustment; distinguishes the other adjustments on the grounds that they were uncontested; disputes Staff's premise that coal costs overall have been reduced and that there accordingly exist savings that should be shared with ratepayers; and suggests Staff disregards the benefit to ratepayers of providing a utility the incentive to pursue aggressive cost cutting.

[11] R.D., p. 19.

The Judge was wrong to conclude that the issue boils down to whether RG&E should have taken action it did not take to reduce coal costs. The Company concedes that two of its contracts, which had been the subject of Staff's adjustment, have been terminated, but it provides no information on how those terminations affect rate year costs. The credibility of RG&E's forecast is seriously undermined in these circumstances; it is reasonable to assume that replacement prices would reflect current market conditions. Staff's adjustment, which reduced coal costs by only 50% of the difference between contract prices and market price, is conservative and reasonable in these circumstances.[12]

4. Ginna and Beebee Station Costs

MI excepts to the recommended treatment of Ginna and Beebee station costs, objecting to accounting treatment which it contends improperly increases rate year costs for these facilities. With respect to Ginna, MI objects to depreciation on a schedule reflecting a 2009 retirement. With respect to the Beebee station, MI objects to recovery of $2.0 million during the rate year to fund decommissioning.

MI argues that we should expect approval of the Ginna license renewal application filed with the NRC, a decision on which is expected no later than 2005, in view of the facility’s

[12] Actual data on coal costs that have been submitted to us by RG&E further suggest the conservative and reasonable nature of Staff's adjustment. Each month the Department of Public Service receives the "Management Report" from RG&E which includes actual data on coal costs and electric output at the Russell coal station. Exhibit 15 shows RG&E's estimates of coal costs and MWHs for July through December 2002. These total $16,217,489 and 727,899, respectively. Subtracting Staff's adjustment of $856,000 would imply a Staff forecast of $15,361,489. The Company's unit cost forecast was approximately $22.28 per MWH, while Staff's was $21.10, or about 5% lower than the Company's. RG&E's "Management Report" shows actual total coal costs for July through December 2002 of $16,940,000 and total generation of 902,976 MWH. This implies unit coal costs of $18.76 per MWH, or 16% below RG&E's forecast and 11% below Staff's.

operating record and the current tight supply situation. RG&E is upgrading the plant, MI submits, in the expectation of license renewal. The Judge rejected MI's position, concluding that in a one-year rate case there is no need to begin decelerating the depreciation this far in advance of license renewal. On exceptions, MI maintains that rate moderation is sufficiently important to reduce depreciation expense. In reply, RG&E reiterates the rationale it presented to the Judge, arguing it is improper to prejudge the NRC ruling on the Ginna license extension request. Moreover, RG&E adds, the replacement of the reactor vessel head at a cost of $13 million will avoid future maintenance and outage expenses, and does not imply speculation about re-licensing.

As for Beebee, MI argues the decommissioning fund is unnecessary, for there are no current plans to decommission the facility, and it may never be decommissioned by RG&E. RG&E has accepted Staff's conditions for its support of the fund, including irrevocable dedication of the funds to decommissioning, the addition of any sale proceeds to the fund, and the return to ratepayers of any excess of funds over ultimate decommissioning costs; nonetheless, MI submits, the existence of adequate protections does not justify collecting these funds now. But RG&E argues that it is unreasonable to ignore the fact that the facility will inevitably be decommissioned, if not by RG&E then by another owner. There is no potential risk to customers, it maintains, because the fund will be returned to customers if the plant is sold, along with any proceeds of the sale.

We decline to reduce Ginna depreciation expense in this proceeding in anticipation of an extended service life. That possibility, however likely, remains premature by several years, and depreciation can be adjusted after a license renewal. We also find the Beebee decommissioning fund reasonable; if the facility is sold, the fund will be returned to ratepayers, and such a fund should be accumulated in advance to avoid an undue rate impact later. MI's exceptions are denied.

5. Ginna Refueling Outage
Replacement Purchased Power Costs

In its rebuttal presentation, RG&E requested consideration of a supply cost reconciliation adjustment (SCRA) mechanism, but refused to extend the suspension period to permit additional time for hearings and analysis of the controversial proposal when the Judge ruled that doing so was a precondition to consideration of the proposal in this proceeding. On exceptions, RG&E argues that the removal of the SCRA from consideration was not meant to affect its additional proposal--which was included in testimony but not advanced in brief for consideration by the Judge--for deferral of replacement purchased power costs during a regularly scheduled Ginna refueling outage scheduled to take place in the fall of 2003. The Company asserts that fairness requires deferral treatment of these costs, which will definitely be incurred during the first year after our decision in this case.

Staff responds that this request is on no different footing than other deferral and true-up requests the Judge rejected, and that these are costs that fall outside of the rate year and therefore are not properly recoverable in this proceeding. Moreover, Staff adds, no special mechanisms for Ginna outage cost recovery were included during the entire time it has had fixed, bundled electric rates (since 1996); in any event, had the matter been timely raised here the parties would have had a chance to consider alternatives, such as outage levelization or incentive mechanisms.

This proposal is improperly presented to us without being first made to the Judge in briefs, and it has not had his consideration. We note in any event, as discussed below, that we agree with the Judge's view that deferral and true-up mechanisms are generally inadvisable outside of the context of multi-year plans. No extraordinary circumstances have been shown or even alleged as a basis for considering this proposal. Moreover, it is improper to consider costs even for base rate recovery that are beyond the rate year, which in this instance will be over before the next Ginna refueling outage. This belated Company proposal is rejected.

6. Generation Outage Insurance Coverage

The Judge rejected as unsupported RG&E's proposed increase in generation outage insurance coverage. The Company had included $6 million for this item, but Staff proposed a downward adjustment of $4.1 million, to allow only for the cost of the existing contract.

On exceptions, RG&E argues that changes in the power market have increased the risk of high replacement costs associated with generation outages and that the Judge should not have rejected as inadequate its testimony that "discussions with other market participants" led to the conclusion that outage insurance costs are increasing. RG&E maintains that Staff could have investigated the basis for this testimony in discovery.

MI and Staff oppose this exception. MI argues that RG&E failed to establish any additional benefits associated with increased insurance coverage and failed to demonstrate that the existing level of insurance is unreasonable or inadequate for the rate year. RG&E's reliance on wholesale power costs as a basis for increased insurance, MI continues, is suspect given RG&E's reported decline in wholesale electric revenues during the first three quarters of 2002 due to lower wholesale market prices. Staff and MI both argue that the Company has the burden of proving that the requested $6 million is reasonable, and that RG&E's unelaborated reference to "discussions with other market participants" falls considerably short of meeting that burden.

We agree with the Judge that the Company's request here is unsubstantiated. No explanation for the Company's figure, and its associated claim that full insurance would cost $18 million in the rate year when current annual costs are $1.9 million, was ever advanced. Indeed, there is no evidence of any rate year insurance premiums in the record. The burden of proof is on RG&E, and it is not Staff's responsibility to elicit sufficient information to make the Company's case.

7. Medical Insurance

The Company's forecast that medical insurance would increase by 12.5% over 2002 actual premiums was accepted by Judge, who rejected Staff's proposal for a lower cost allowance based on the rate of inflation. Staff's proposed $288,000 adjustment was rejected, and Staff excepts.

Staff argues there is a clear, long-standing policy to apply the inflation rate to medical insurance cost escalation.[13] If these costs are to be accounted for separately, Staff continues, they should be removed from the inflation pool to avoid a double count. Accordingly, Staff urges a "corresponding adjustment of $490,000[14]" to reduce O&M expenses and "militate against RG&E's use of a clearly overstated overall inflation rate."[15]

RG&E replies that Staff has not justified retention of this item among those in a "pool" of costs presumed in rate cases to rise, as a group, in accordance with the rate of inflation. The advisory letter on this score, RG&E notes, is eighteen years old (1984), and its testimony indicated that health care costs have escalated much more rapidly in recent years. RG&E submits it also demonstrated that removal of medical care from the Consumer Price Index (CPI) did not produce a discernable decrease in that index, and that Staff provided no evidence that removal of medical care from other indices (such as the GDP implicit price deflators) would have a different result.

RG&E has not justified removing medical insurance cost from the inflation pool. It presented no evidence to suggest the mix of medical insurance among other costs in the inflation

[13] Staff cites Case 93-E-1123, Long Island Lighting Company, Opinion No. 958 (issued July 3, 1995), pp. 26-27, and Cases 92-E-1055 and 92-G-1056, Central Hudson Gas and Electric Corporation, Opinion No. 94-3 (issued February 11, 1994), pp. 12-13.

[14] This adjustment represents an alternative proposal to reflect removal of medical care from the inflation index.

[15] Staff's Brief on Exceptions, p. 9.

pool is not adequately represented in the GDP implicit price deflators or that the composition of the CPI makes it an adequate surrogate for the GDP price deflators. Thus, there is no basis for abandoning our long-standing policy regarding application of the inflation rate to a cost pool. Staff's exception is granted.

8. Insurance

The Company projects insurance expense of $1,422,000, while Staff projects ($1,271,000). The negative insurance expense reflects an excess of nuclear insurance dividends over premiums. The Company's figure consists of $1.7 million of non-nuclear insurance and ($.3 million) of nuclear insurance expense. The Judge adopted the Company's projection, noting the evidence showed a probable decrease in nuclear insurance dividends. He suggested the record could be updated when the 2002 dividend became known.

Staff excepts. Staff's recommendation was based on latest known insurance expense (2001) adjusted by the rate of inflation. Staff argues that the RG&E increases, $3.6 million in the filing and an additional $1.6 million in rebuttal, were simply unsupported, and Staff argues again for use of the inflation factor.

In response, RG&E argues that Staff has no basis for rejecting the expertise of the Company's Risk Management Department in assessing increases in premiums. Moreover, RG&E continues, Staff has completely ignored the advice from its insurer that a reduction in nuclear policy dividends is expected.

Staff's exception has merit as to the rebuttal increase. The Company's total increase of $5.2 million is greater than Staff's increase, which was made at the rate of inflation, by about $2.7 million. There should be an explanation for such a large increase, but other than the alleged potential decline in nuclear dividends, none has been provided. These big increases cannot be entirely justified on the ground of an expected decrease in nuclear insurance dividends, and the latest insurance dividend has not been revealed. As we can perceive no justification for the additional escalation alleged in rebuttal, and the 2002 dividend information has not been provided, we will reject the proposed additional increase in insurance expense proposed in the Company's rebuttal. This reduces the insurance expense from $1,422,000 to ($202,000). Staff's exception is partially granted.

9. Advertising

The Judge allowed the Company's proposed rate year advertising expense of $1,053,000, which approximates 0.1% of operating revenues, the upper end of the range of reasonableness set forth in the Commission's 1977 policy statement on advertising. The Judge credited RG&E's argument that advertising costs are more substantial today, in view of industry restructuring and increased responsibilities for customer awareness and education.

Staff takes exception, arguing for a 0.07% factor. Staff argued to the Judge that this percentage had been used in many previous cases, and it asserts that the 0.07% factor was set in order to avoid a tedious, detailed examination of actual advertising expense.

In reply, RG&E argues that the Judge properly recognized current conditions require relatively higher levels of advertising expense, and that Staff's method of estimating advertising expense is outdated. Regardless, the Company asserts, its request is consistent with the requirements of the Advertising Policy Statement.

The Judge's recommended advertising allowance is within a range of reasonableness established in the 1977 Advertising Policy Statement. Staff's exception is denied.

10. Updates and Reclassifications

The Company made substantial revisions to its revenue requirement presentation in its rebuttal case, revisions that necessitated a delay in hearings and that were the subject of a

Staff motion to strike. The Judge declined to exclude the newly proffered updates and cost reclassifications, and he considered them. RG&E argued that by reclassifying certain costs, it had obviated some Staff adjustments, although the Company pointed out that the reclassifications had a zero effect on revenue requirement. Staff, however, noting that expenses had not been reduced to reflect acceptance of its adjustments, argued that the reclassifications merely shifted the amounts to different categories and avoided accepting the Staff adjustments.

The Judge discussed three Staff adjustments the Company claimed had been obviated by reclassification: (1) a $2,456,000 adjustment to the Vouchers-Bank Services account; (2) a $3,420,000 adjustment to Competition Implementation Costs (under the "Other" cost category); and (3) a $4,046,000 adjustment to Uncollectible Reserve (under the "Other" cost category). In addition, updates in the amount of $1,553,000 were at issue, pertaining to Information Technology costs and retail access enhancements. The Judge accepted the Staff adjustments for the Competition Implementation costs and the Uncollectible Reserve, the latter of which had reflected an accounting double-count, but he accepted the RG&E position regarding staff’s adjustment to the Vouchers-Bank Services account. He also rejected the updates relating to Information Technology costs.

RG&E takes exception to the recommendations relating to the Uncollectible Reserve, Competition Implementation, and Information Technology costs, while Staff takes exception to the rejection of its adjustment to Vouchers-Bank Services.

Staff’s Uncollectible Reserve adjustment had been made to eliminate the double-count in the Company’s filing of a $4 million charge. The Company agreed that there had been a double-count, but argued that its reclassifications had mooted the adjustment. The Judge agreed with Staff that the reclassification, which netted to zero, effectively failed to make the needed adjustment. On exceptions, RG&E claims that the adjustment has now been made twice.

Staff replies that Staff's adjustment does not remove the charge twice, but only once, from uncollectible reserve. The Judge properly concluded, Staff submits, that the Company's reclassification improperly failed to reflect Staff's adjustment.

RG&E concedes that it agreed the Competition Implementation costs should be removed from its revenue requirement, because those were costs that no longer met the deferral requirements of the COB2 Plan. RG&E continues to assert, however, that its reclassification rendered Staff's adjustment moot. Staff argues that this issue is analogous to the other reclassification issues, and that the Judge correctly resolved this issue as well.

The Vouchers-Bank Services adjustment corrected for a radical overstatement of expense in that account. The Judge accepted the Company's position that this overstatement was a result of a misallocation, and was therefore corrected by the reallocation. On exceptions, Staff continues to maintain that the reallocation merely resulted in an unexplained 23% increase in the Vouchers-Outside Services account. In response, RG&E argues that the reclassification simply reflected certain accounting items on the correct expense lines.

RG&E argues that its update in rebuttal for Information Technology costs was proper and should have been accepted by the Judge. Although the Judge found that $1,533,000 was added in the rebuttal updates, and disallowed these costs, RG&E argues it did not actually add these costs in its rebuttal presentation. Staff responds that the Company did, indeed, add $1,719,000 of new, unsubstantiated Information technology costs, which the Judge properly rejected.

The Judge reached the correct result with respect to the Uncollectible Reserve and Competition Implementation cost adjustments. RG&E never claimed that the Competition Implementation costs at issue should be left in revenue requirement, or that they had already been removed prior to the reclassification. Its position on the Uncollectible Reserve adjustment implies that it had already somehow accepted Staff's adjustment, independent of the reclassification that, it claims, mooted the adjustment. RG&E simply offers no explanation as to how a reclassification, with zero revenue effect, could render these two adjustments "moot."[16] RG&E's exceptions on these two items are denied.

The Judge erred, however, in speculating, without proof, that the Vouchers-Outside Services account had been understated before the reclassification. The evidence presented by the Company does not so demonstrate. If that were true, RG&E was obliged to adjust that cost category in its initial filing; doing so in response to a Staff adjustment at the end of the case, when the basis for its reclassification cannot be audited, is improper. Staff's exception is granted.

The Judge properly rejected the balance of the Company rebuttal updates. RG&E refused to respond to Staff's request, in discovery, for information supporting its rebuttal updates. The Judge suggested that the late-filed update amounts could be considered if they were explained to Staff, but the Company has not done so, and it continues to adhere to its confusing and unsupported position. RG&E's exception on this score is denied.

11. Deferrals and True-ups

The Company excepts to the Judge's rejection of its proposed deferral and true-up mechanisms for insurance, security, property taxes, municipal work, and pension income. The Judge concluded, in general, that true-up mechanisms are inappropriate in a one-year rate case, although he did accept a Company proposal for deferral and true-up of variable rate interest expense, a recommendation to which no party takes exception. Staff opposed all of the proposals, except the one relating to pension income.

RG&E argues that even if it filed a new rate case immediately after rates went into effect in this one, that would be subject to the statutory suspension period, and the rates

[16] If the adjustments had already been independently accepted, RG&E surely could and would have pointed that out, and the adjustments would have appeared on their schedules.

approved here would remain in effect for at least eight or nine months after the end of the rate year in this proceeding (June 30, 2003). These mechanisms would apply only to specific costs that are beyond the Company's control, RG&E continues, and the mechanisms are reasonable because deferred costs are recovered in the future, and it will bear the burden of proving at that time that the costs are reasonable. Security cost and property tax deferral mechanisms are especially reasonable, RG&E posits, because in the current environment these costs, which are imposed by governmental action, are especially hard to predict.

As to pension income, RG&E submits that a true-up mechanism is distinguishable from the others the Judge rejected, in that the Commission's Statement of Policy on Pensions and OPEBs[17] explicitly provides for such a mechanism. Indeed, RG&E observes, Staff did not object to this proposal and argued merely that the true-up should commence, retroactively, at July 1, 2002. Although it stated in its reply brief to the Judge that "in light of Staff's recently revealed position regarding RG&E's true-up mechanism, the Company is withdrawing the mechanism from consideration,"[18] RG&E now argues the Judge "misconstrued RG&E's position"[19] when he concluded that the proposal had been withdrawn. The Company says it is still arguing for a deferral mechanism commencing January 15, 2003 (the effective date of new rates with a make-whole allowance), but will accept the timing of the mechanism proposed by Staff. RG&E proposes to use $20.9 million (the rate year actuarial estimate of pension income) as the base amount for true-up.

Staff replies that the Judge was correct in rejecting these deferral requests. The Company has been allowed its cost

[17] Case 91-M-0890, Accounting and Ratemaking Treatment for Pensions and Post Retirement Benefits other than Pensions, Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Post Retirement Benefits other than Pensions (issued September 7, 1993).

[18] RG&E Reply Brief, November 22, 2002, p. 30.

[19] RG&E's Brief on Exceptions, p. 16.

request in each instance, Staff continues, and these are benefits that should normally be entertained only in the context of multi-year agreements. Moreover, Staff states, it is not true that the Company has no control over any of these cost levels. Regarding pension deferrals, Staff says the Company's request is "blatantly one-sided."[20] Staff maintains that true-ups for both the rate year and the "short period"[21] are at issue, and it objects to both proposals. Staff argues that the $20.9 million pension income is the wrong base level for the short period: "The pension expense forecast in present rates must be used for the short period true-up and that forecast is $0."[22] Staff opposes the true-up for the rate year for the same reasons it generally objects to rate year true-ups. Given that RG&E will achieve merger synergy savings in part through employee severance, moreover, Staff objects as well to the lack of any proposals for accounting for merger complexities in connection with such a true-up mechanism.

We agree with the Judge and Staff that deferral mechanisms are generally inadvisable in the one-year rate context. Regardless of the degree of Company control over the levels of various costs, it has been our practice to project, using a fully forecast rate year, all revenues and costs.[23] Cost recovery guarantees reduce efficiency incentives. In this proceeding, the Company selected a rate year running from July 1, 2002 through June 30, 2003, perhaps with the expectation that it would agree with parties on terms for new rates to propose to the Commission that could go into effect by June 30, 2002. The fact that the rate year no longer corresponds with the first year of new rates, however, does not undermine the

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[20] Staff's Brief Opposing Exceptions, p. 12.

[21] Staff appears to refer the period July 1, 2002 through January 14, 2003.

[22] Staff's Brief Opposing Exceptions, p. 12 (original emphasis).

[23] In a multi-year context, where a company is given an earnings incentive to minimize the costs that are largely within its control, it may be appropriate to allow for deferrals and true-ups of costs that are largely outside of its control.

basic premise that outside of the context of multi-year plans deferral and true-up mechanisms are not desirable. Therefore, RG&E's exceptions are denied. With respect to the exception on pension income, moreover, we must deny the exception despite the Statement of Policy on Pensions and OPEBs, due to merger complexities.

12. Closing of Customer Service Centers

RG&E has customer service offices at eight locations, two of which are leased. On October 24, 2002, RG&E announced plans to close seven on the eight offices on January 31, 2003. Since then a proceeding was commenced to review that decision (Case 02-M-1465) and, as noted earlier, supplementary hearings were held to examine the revenue requirement implications for the rates being set in this case. The Company, Staff, and CPB comment in their supplementary briefs on this matter.

Staff argues that the annual savings to be realized by the closure of all seven service centers is $1.516 million and that the amount of rate year savings associated with the determinations made at the conclusion of Case 02-M-1465 should be deferred for recovery in the Company's next rate proceeding.[24] CPB supports Staff's proposal. RG&E opposes recognition of such cost savings here, arguing: (1) that any such savings are merger synergy savings and therefore already reflected in revenue requirement; (2) that Staff's adjustment is substantially overstated; and (3) that application of deferral accounting to these costs is inappropriate.

a. Synergy Savings

As to the first point, RG&E states: "That an office closing initiative could proceed without a merger is uncontested by the Company. That RG&E, faced with an alarming downturn in its financial condition, may have closed some offices as a means of achieving savings even without a merger is similarly

[24] Staff does not request deferral of annualized savings, just the amount of savings realized before June 30, 2003, if any.

undisputed."[25] Nonetheless, RG&E asserts, the Energy East merger was the "proximate cause" of the decision to close these offices. Its witness testified that these are merger related costs because the decision to close the offices was made following meetings between officials of Energy East and its subsidiaries to discuss "best practices."[26]

Staff and CPB dispute the claim these are merger synergy savings. While approval of the proposed merger was pending, Staff observes, RG&E took the position that it would not be closing the customer service centers; and the Joint Proposal does not suggest otherwise. Moreover, Staff continues, synergy is missing here because there is no combined action between RG&E and Energy East, or between RG&E and another subsidiary.[27] RG&E is simply trimming costs, Staff asserts, and CPB and Staff both emphasize that Energy East's CEO publicly announced that RG&E would take this action regardless of the merger.

The cost savings from the closing of these offices are not merger synergy savings. Although we certainly do not agree with RG&E's assertion that a marked deterioration of its "financial condition" requires such action, that is RG&E's claimed justification for doing so.[28] But even if the decision was based solely on a determination of "best practices," that would not mean the savings are "synergy" savings. Synergies are the result of combined operation and working together, and are in the nature of economies of scale. Synergy savings are those that would not be available <u>but for</u> the merger, <u>i.e.</u>, that become <u>possible</u> because of the merger, and it is both self-

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[25] RG&E’s Supplemental Brief, pp. 6-7.

[26] <u>Id</u>., p. 5. The witness testified it was possible to close the offices without the merger, and that what the merger did was advance or enhance consideration of the idea of closing the offices. Tr. 2283-2284.

[27] For example, Staff observes, there is no consolidation with NYSEG service centers, or other joint economies, reflected in these closures.

[28] RG&E’s Supplemental Brief, p. 6.

evident and conceded by RG&E that the closing of these offices was not in any way made possible by the merger. Accordingly, we conclude that these are not savings that are already reflected in revenue requirement.

b. Staff’s Proposed Adjustment

RG&E maintains that any rate year savings will be minimal and should not affect revenue requirement in this proceeding. First, RG&E asserts, first year net savings resulting from these office closings will be less than annual savings thereafter, because there will be first-year cost offsets associated with the closings, and these as yet undetermined cost offsets are not included is Staff’s annual savings figure.

Second, RG&E continues, the amount of gross savings realized in the rate year, even assuming it had closed its offices on January 31, 2003 as planned, would be minimal. Labor and labor-related cost savings would not occur until two months after that, on April 1, 2003; because the Company has been directed not to close its offices pending the conclusion of Case 02-M-1465, that date would have to slip; and the possibility that RG&E might not be permitted to close all seven offices adds additional uncertainty.

The annual cost savings, RG&E asserts, are overstated in any event. About five-sixths of the total annual cost savings, RG&E notes, are related to labor and fringe benefits. Although 21 full-time equivalent positions would be closed, RG&E argues, Staff’s figures overlook the fact that there would be a net reduction of only 11 positions. Another large item in Staff's computation is for rent at the two leased locations, and RG&E argues that continuing rate year rental obligations must not be ignored, for there is no showing that it was imprudent to enter into the leases in the first instance. Finally, other operating costs at the locations the Company owns are less significant, but cleaning and maintenance costs might not be fully avoided in any event. In addition, RG&E submits, there are incremental costs estimated at about $198,000 that also have not been taken into account.

Staff's adjustment is unknown at this time, RG&E observes, and in fact Staff is not now proposing an adjustment. Because the final determination of the Company's revenue requirement for the rate year is made in this order, RG&E submits, it is inappropriate to attempt to reserve any adjustment to that result in another proceeding.

We agree with the Company that no action should be taken now regarding the revenue requirement implications of customer service office closings. Any assessment of how many offices may be closed, and when, would be speculative at this time, and rate year net savings would probably be relatively minor under any scenario. Although Staff argued for a possible "placeholder" adjustment at the hearing, it has amended that request slightly, urging instead that we make a determination of rate year net savings at the end of the service proceeding. Given the lack of a record on likely rate year cost offsets here, that effort would not be productive. Moreover, we have eschewed reliance on deferral accounting for a number of cost items in the rate year, and we see no reason to make an exception for these costs. The net result of any customer service office closings, subject to our determinations in Case 02-M-1465, will be reflected in future rate proceedings.

C. Excess Earnings

The recently completed five-year COB2 electric plan, which ran from July 1, 1997 through June 30, 2002, included provisions for the sharing of excess earnings. It provided that, to the extent the net annual returns on common equity exceeded 11.8%: (1) 50% of the excess would be used to write down deferrals accumulated during the term of the plan, with any portion of that 50% of excess earnings greater than those deferrals to be kept by the Company as earnings; and (2) the other 50%, after applying a portion ($800,000) to reduce certain rates, would be used to write down deferrals or Sunk Costs (as defined in the plan agreement), with any excess earnings remaining after that to be disposed of as determined by the Commission. The Judge found that there was $44.8 million of excess earnings, with interest, and that deferred costs accrued during the five-year rate plan period exceeded 50% of the excess earnings, so that none would be retained by the Company. He recommends application of the excess earnings in the rate year to fully amortize the residual of Beebee station outage and storm cost deferrals, and to reduce the balance of the Nine Mile 2 deferrals.

There were numerous controversies with respect to excess earnings, and numerous exceptions are presented by RG&E and Staff.

1. Timing Issues

RG&E had urged that excess earnings not be reflected in revenue requirements in this proceeding, since Staff's audit of the fifth year had not been entirely completed, and any differences between Staff and the Company as to the fifth year had not been resolved through the applicable dispute resolution process. The Judge determined, however, that because recovery of deferred costs from the five-year period is included in this proceeding, it would be unreasonable not to recover excess earnings as well, particularly if there were any merit to Staff's claim that the amount of excess earnings is substantially greater than the amount computed by RG&E.

In view of the Judge’s conclusions on rate moderation (that electric rates should not be reduced despite a lower rate year electric revenue requirement, with the excess revenues applied to amortization of deferrals), RG&E does not take exception to the recommendation to use the excess earnings now.[29]

Staff takes exception to the Judge’s approach to computing excess earnings, which uses the Company’s amounts as a starting point for his adjustments. According to Staff, this "ignores many of the adjustments Staff made during years 1-4."[30] Accordingly, Staff suggests that we adopt its estimate of excess earnings now, subject to reconciliation upon completion of Staff’s audit.

RG&E replies that starting with Staff's estimate, which it says is "grossly bloated,"[31] creates a problem of undoing Staff's rate moderator later if Staff's positions are not all ultimately upheld.

The Judge resolved the excess earnings issues as they were presented to him by RG&E and Staff, and we will resolve the exceptions in the same way. We will not leave the major issues presented here to be decided in the audit process. If our figure for excess earnings does not agree with Staff’s, we will not adopt Staff’s estimate. The figure we adopt, however, will be subject to further possible modification, pending the result of the fifth-year excess earnings review process.

2. Temporary Cash Investments

Although it had not previously done so, RG&E in its rebuttal presentation, for COB2 years 1-4, included temporary cash investments (TCIs) in the excess earnings computation, placing TCI balances in rate base and including the interest

[29] RG&E had been concerned that using the excess earnings now, together with the rate reductions proposed by Staff, would result in rate disruptions later if the fifth-year results changed after any controversies pertaining to them were resolved.

[30] Staff’s Brief on Exceptions, p. 12.

[31] RG&E's Brief Opposing Exceptions, p. 23.

they generate in the return computations. The Judge resolved the issue in a traditional fashion, noting that in computing an allowed return for setting rates prospectively, TCIs are traditionally excluded from rate base, except in a limited circumstance where TCIs are appropriately generated to pre-finance construction, so that the excess financing undertaken for that purpose is reasonable.[32] He excluded TCIs from the excess earnings computation, on the grounds that at least some of the TCIs resulted from retained excess earnings, and that RG&E had not demonstrated a legitimate basis for inclusion of any of them.

On exceptions, RG&E argues that it is appropriate to include all TCIs in the excess earnings computation, but it offers an extra-record computation of amounts allegedly generated as a result of justifiable pre-construction financings. According to the Company, even TCIs that might not appropriately be included in rate base prospectively are properly included in rate base in the historic period for purposes of computing excess earnings. The determining factor, RG&E contends, should be that the TCIs were ultimately used to retire debt, common stock, or preferred stock, or were reinvested in the business.

Staff replies that it does not accept a general rule that even TCIs associated with common stock pre-financings should be included in rates. Regardless, Staff argues, the Company's analysis alleging the proportion of the TCIs that fall in that category is extra-record and cannot be considered, since its witness failed to provide that analysis at the hearing. Staff contends the Company should not be able to supply the analysis on exceptions, where there has been no opportunity for Staff to conduct discovery, cross-examine witnesses, or conduct its own analysis.

[32] As RG&E argued to the Judge, it can be economic to issue stocks or bonds in large lots, generating more cash than is immediately needed. The excess proceeds are then placed in TCIs, to partially offset the additional financial cost.

To begin, we reject RG&E's argument that the ultimate disposition of these funds is the determining factor. How these funds are eventually used has no bearing on how they should be treated for ratemaking purposes before they are disposed of.

The considerations applying to inclusion or exclusion in rate base of TCIs in computing excess earnings achieved during the historic rate plan period are, as the Judge concluded, the same as the considerations applying to TCIs prospectively (in setting rates). In setting rates, we estimate the working capital requirement necessary to run the business, and that amount is included in the rate base. Cash is not an efficient asset, for it generally earns low, taxable interest. Therefore, we do not require customers to provide a return on cash in excess of the measured working capital requirements, unless it can be shown that the excess was created by some activity that would save customers money or avoid higher cost in the future. An example might be an early financing, if interest rates are expected to rise, or a potential decline in bond rating.

There is no evidence in the record showing that any of the TCIs at issue are appropriate for inclusion in rates, or even establishing the source of the TCIs. We cannot accept the utility's belated presentation on exceptions. And that presentation, even had it been timely made, would fail, for it includes no assertions about how customers may have benefited from the excess cash.

In any event, the Judge’s disposition is a reasonable result. It allows RG&E to keep the interest earned on TCIs, including those generated by plant sales or excess earnings achieved during the plan, but holds the Company responsible for the actual cost of long-term debt and preferred stock while attributing the balance of earnings to common equity. RG&E’s exception is denied.

3. "Book-to-Regulatory" Adjustment

The "book-to-regulatory" adjustment was made by the Company for the first two years’ computation of excess earnings.

Essentially, it was done to remove items classified as non-operating income from regulatory equity balances. Since the regulatory equity balance is the denominator of the equity earnings ratio upon which the excess earnings determination is based, excess earnings would be improperly deflated unless these amounts were removed.

The Company discontinued the adjustment in years three and four, based on its conclusion that it produced a double-count. That is, its witnesses explained, the "Earnings Base-Capital allocation process already distributes the actual amount of capital being used to run the business between Electric Rate Base, Gas Rate Base, and items not in rate base."[33] Nonetheless, Staff made the adjustment in the third and fourth years. The Judge rejected the Staff's adjustment when it was discussed only by the Company in brief. On exceptions, Staff says the adjustment is still valid, as the Company's double-count argument does not encompass all of the book-to-regulatory adjustments.

The Company responds that Staff has not indicated any flaws in its double-count argument, or shown why examples RG&E advanced in support of it are flawed. Its witnesses had testified the "AFDC has already been excluded from the Common Equity Supporting Regulated Assets through the allocation of capital and the 'Book to Regulatory Adjustment' would be a double-count,"[34] and explained that the book-to-regulatory Adjustment would violate IRS and Commission regulations as to the amortization of deferred ITC."

Staff's adjustment remains unsupported, and its exception is denied.

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[33] Tr. 1089.

[34] Tr. 1090.

4. Incentive Compensation

RG&E takes exception to the exclusion of PPP costs from the excess earnings computation. The Judge partially included PPP costs in the rate year, on the ground that historical PPP awards may have become regarded by employees as effective base pay increases (See B.1.d. above). But he found improper inclusion of any PPP costs in the excess earnings computation.

RG&E advances the same argument for inclusion of PPP costs here that it makes for including them in rate year revenue requirement, contending that PPP costs are legitimate business expenses. The Company also argues that it is proper to recognize the employee role in achieving the historical excess earnings.

In reply, Staff maintains that only those payroll costs that would properly be recognized in rates should be reflected in the excess earnings computation. Staff states in its brief on exceptions, however, that the Judge deducted an excessive amount for PPP costs; the adjustment should be $1.9 million, not $2.4 million.

As discussed above, we are not providing rate year funding for this program given its amorphous and ill-defined character and the lack of any identified customer benefits from it. The Company explains its past PPP payments during the COB2 Plan as awards made to allow employees to share in, and presumably to some degree to recognize them for, its earnings success.

The following table compares PPP payments in each year with the excess earnings we have found the Company achieved in each year:

	PPP Payments ($ millions)	Excess Earnings ($ millions)
Year 1	2.9	11.8
Year 2	5.7	18.2
Year 3	3.0	34.4
Year 4	4.1	45.4
Year 5	3.1	(74.5)

As shown, the payments do not correlate well with excess earnings, and, in fact, substantial PPP payments were made in the fifth year, when earnings sharply declined. The Company itself considers its excess earnings to be even lower than we have found. In these circumstances, the Judge understandably found no coherent basis for these payments in the Company's presentation. There is no record basis for concluding that these historical awards reflected any specific aspects of employee performance, or even RG&E's financial performance. These were discretionary expenditures in excess of the base payroll used to set rates for the COB2 Plan period, and they have been directly attributed by RG&E to its earnings excess. Therefore, these costs are properly funded by shareholders, and should not be funded with the customers' share of excess earnings. RG&E’s exception is denied.

5. Items Deferred Prior to the Rate Plan

Staff sought to include in earnings gains taking place prior to the COB2 Plan, including certain Nine Mile 2 credits, gain on the sale of property, and Department of Energy (DOE) interest. The Judge agreed with RG&E that the COB2 Plan provided that all amounts due to customers as of June 30, 1997 were deemed eliminated as of the effective date of the COB2 Plan, and he disallowed the Staff adjustments.

Staff takes exception, denying that the COB2 Rate Order allows the Company to keep the DOE interest. As to the Nine Mile 2 credits and the gain on land sale, Staff reasons that the COB2 rate reductions were funded by these credits, and since the COB2 rate reductions are reflected in the regulatory earnings, so should be these offsetting credits. It argues that if a different result was intended the COB2 Order would have so stated.

RG&E replies that there is no ambiguity in the COB2 Plan as to the elimination of amounts owed customers prior to June 30, 1997. Thus, the Company argues, these amounts cannot be counted in the excess earnings computation.

The Company's position that the deferred amounts cannot be counted in the excess earnings computation does not follow from the provision that amounts previously owed to customers were eliminated in the COB2 Plan. The deferral amounts were extinguished and reported to earnings by RG&E during the COB2 Plan, and it benefited by eliminating debt it owed to ratepayers, making the debt no longer available to fund future rate decreases.

We must reject RG&E's argument that this benefit is somehow negated by the computation of excess earnings. The earnings computation is the "return on a regulatory basis for regulated operations," which means that it is conducted in the normal fashion, treating only certain specified items below the line.[35] The COB2 Plan, therefore, does not provide for below-the-line treatment of these IOUs, as requested by the Company.

The COB2 Plan provides a balance of benefits to and commitments from both the RG&E and its customers,[36] and further provides that the "commitments and assurances are inextricably interrelated."[37] It also provides for rates set at a level that is "just and reasonable to both customers and shareholders."[38] Among the several benefits received by RG&E is the elimination of the amounts at issue here, and among the several benefits received by customers is the right to share in excess earnings, computed as provided for in the COB2 Orders. Staff's exception is granted.

6. Nine Mile 2 Management Incentive

Staff proposed to exclude Nine Mile 2 management incentive costs. The Judge rejected this adjustment, noting that Staff had not addressed the Company’s position that these were legitimate operating costs that RG&E was obligated to pay

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[35] COB2 Agreement, ¶41.

[36] COB2 Agreement, ¶¶78(a) and 78(b).

[37] Id., at ¶78(c).

[38] Ibid.

as a Nine Mile 2 cotentant, and that they had been used in revenue requirements in the past. Staff, on exceptions, argues that these cost are no different from any of the other incentive compensation (ICP) costs that it has argued for disallowing, both in the rate year and in the excess earnings computation.

RG&E replies that its arguments for the inclusion of ICP costs in rates are sound. Moreover, RG&E argues, these costs are not within its control, as a cotenant of Nine Mile 2, and it could not have avoided them.

These payments were not discretionary to RG&E, as its own management bonus payments are, since they were required of co-tenants. Staff's exception is denied.

7. Common Expense Allocations

Staff argued that RG&E improperly applied to electric an increase in the allocation of common Administrative and General (A&G) expenses between electric and gas in the rate year ended June 2001. New allocation ratios were adopted effective January 1, 2001, and although Staff does not object to the prospective use of the new allocation ratios, Staff objects to using them for the regulatory earnings computations. The Judge rejected Staff's adjustment,[39] despite Staff's argument that our rules pertaining to accounting changes were not followed, on the ground that since the new allocations were used in the gas rate plan, they should be used here as well.

Staff excepts, arguing that the change was not authorized by either the electric or the gas plan. Staff maintains that the change, which was made two months before the gas rate joint proposal was approved, was not authorized or approved by the order in that proceeding. Staff asserts that this was "an unauthorized change in accounting that has significant adverse impacts,"[40] that RG&E's proposals violate our

[39] Staff testified the adjustment would be $2.2 million for the first half of 2001, and RG&E reported to the Judge that the amount for the fifth year would be $4.4 million.

[40] Staff's Brief on Exceptions, p. 14.

regulations, and that they constitute retroactive ratemaking.[41] Noting that RG&E reported the fifth-year allocation change to be $3.4 million ($5.2 million pre-tax), Staff requests a $4.8 million imputation to electric earnings.

RG&E responds that the Judge properly recognized that a change for one department requires a change for the other. Moreover, RG&E argues, merely updating rates is not a change in accounting requiring notification, since the "existing mechanism" was not changed.[42]

This is not a change of accounting, and, therefore, the Company did not violate our regulations by failing to report the change in allocation ratios. It is necessary to use the same ratios in both the gas and electric proceedings, and Staff accepts this allocation change going forward. Staff's exception is denied.

8. Out-of-Period Accounting Corrections

Staff proposed an adjustment relating to "Out-of-Period Accounting Corrections" which, according to the Judge, increased 1998 after-tax income by $1.3 million. RG&E claimed the adjustment to be improper, for it did not relate to 1998 (or later) operating costs. Finding no Staff refutation of the Company's argument, the Judge denied the adjustment. Staff excepts, stating that its adjustment related to the period July 1, 1997 through June 30, 1998, the first year of the COB2 Plan.

According to Staff, it continues to audit RG&E's latest claims regarding excess earnings, and while it could be true that the adjustments do not relate to 1998 and later years, they do relate to 1997, and at least the last six months of 1997 are part of the excess earnings filing.

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[41] What would have been retroactive ratemaking, Staff testimony indicates, was a Company suggestion that electric earnings for the entire five-year plan period be reduced by $22 million to reflect the changed allocation ratios. Tr. 1650.

[42] RG&E's Brief Opposing Exceptions, p. 28.

RG&E, however, points to the testimony of its witnesses that the corrections in question, although recorded in 1998, related to amounts recorded outside of the COB2 Plan period.

Staff's adjustment apparently relates to an out-of-period correction that should not affect excess earnings. Accordingly, we do not address Staff's exception here, but we may revisit this and similar items when Staff's audit is complete.

9. Other Staff Adjustments

The ALJ rejected two Staff adjustments to electric regulatory income, relating to OPEB carrying charges and inventory obsolescence. In each instance, Staff says that it continues to audit "late claims" made by the Company. Although it does not except to the rejection of the inventory obsolescence adjustment, Staff disagrees with the amount of the OPEB adjustment. The Company's adjustment for rate year 2 should be $900,000, not $569,000, Staff contends, because it should have used a 60% allocation factor to electric rather than 50%, and the amount of post-1997 OPEB carrying charges was verified to be $2.055 million, not $2.612 million.

RG&E responds that Staff appears to be correct as to the allocation factor, but incorrect as to the balance of the adjustment. Because the correct time reference is to post-1996, not post-1997, OPEB, the data support the figure of $2.612 million.

We accept the Company's explanation on the OPEB adjustment and adjust it accordingly.

10. Interest on the Customers' Share

The Recommended Decision includes interest, as proposed by Staff, on the customers' share of excess earnings. The Judge concluded that the absence from the COB2 Plan of a specific provision for interest on excess earnings is not controlling; that interest on deferrals is required by the plan; and that it is only reasonable to provide interest on excess earnings while deferred costs charged to customers are accumulating interest charges.

The Company excepts, repeating its argument to the Judge that because the total amount of excess earnings was to be determined after the end of the COB2 Plan's five-year term, the COB2 Order did not contemplate accumulated interest on excess earnings. RG&E also reiterates another argument, dismissed by the Judge as unsubstantiated, that the reacquisition of common stock with the excess earnings provided a benefit akin to interest to customers through the computation of the excess earnings,[43] with the result that there is no practical need for interest.

In response, Staff asserts that the parties to the COB2 proposal always intended to provide interest on excess earnings, and that Staff testified in the COB2 proceeding, without controversy, that excess earnings due customers would accrue interest at a 9% rate.[44]

The provision of interest on the customers' share of excess earnings is consistent with the language of the COB2 Plan and the intent of the COB2 Orders. There is no provision in the plan for considering stock reaquisition in the computation of excess earnings. Any effect on excess earnings of stock reacquisition is an unrelated matter having no bearing on the interest issue. The Judge’s interpretation of the COB2 Orders and his recommendation to accrue interest are reasonable, and the Company’s exception is denied.

11. Sunk Costs

In order for RG&E to share in the excess earnings, as noted at the beginning of this section, the cost deferrals accumulated during the term would have to be less than one-half of the excess earnings. The Company maintained that to be the case, but Staff objected that RG&E had improperly included

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[43] RG&E refers to the increase in the ROE when the denominator in the computation, regulated equity, is decreased.

[44] Case 96-E-0898, Tr. 404.

certain Nine Mile 2, Oswego 6, and Kamine Contract deferrals as "sunk costs," excluding them from the total of deferrals taking place during the COB2 Plan. The Judge agreed with the Company as to the Nine Mile 2 and Oswego 6 costs, but found that the Kamine Contract deferrals were not sunk costs and that they did not pre-date the electric plan's term.[45]

The Company excepts, arguing that the Kamine obligation arose earlier, though the actual agreement and its approval took place during the term of the COB2 Plan. The facility had stopped operating and RG&E had actually terminated its purchased power agreement earlier, RG&E maintains, effectively creating an obvious sunk cost, the need for recovery of which was understood to be inevitable before June 30, 1997.

Staff responds, arguing that the Kamine Contract costs at issue could not be characterized as sunk costs because they had not already been incurred prior to the COB2 Plan. Moreover, Staff continues, the COB2 Plan itself merely recognized a "purported" Kamine obligation, and provided for additional rate reductions if the Kamine costs turned out to be less than predicted.[46]

RG&E's position is contrary to the express terms of the COB2 plan since the Kamine regulatory deferral did not arise until during the plan. The expectation was that if there were excess earnings, they would be applied against deferred costs. The Company was afforded an opportunity to benefit by retaining some of the first 50% of excess earnings even if some of the deferred costs, those defined as "sunk costs," were not offset. We modified an earlier version of the rate plan which would have allowed that first 50% of excess earnings to the utility, because of our concern that provisions related to deferrals in that earlier version would lead to a need for rate increases at the end of the five-year plan. Accordingly, the deferrals subject to 50% sharing were broadly defined as including all

[45] The Judge found that the Kamine recovery commenced with execution of a Global Settlement Agreement (Kamine Settlement) in early 1998.

[46] COB2 plan, Par. 2, p. 12; p. 18.

deferrals during the period of the rate plan,[47] the concept of "sunk costs" was carefully defined in the rate plan, and both definitions reflected our equitable balancing of shareholder and customer interests. We also specifically provided for our review of any deferrals, under the plan, including the Kamine deferral, by requiring a petition prior to any deferral and recovery. The Judge correctly decided that the Kamine deferral was not booked, or even approved, prior to the COB2 Plan and, therefore, was not a "sunk cost." The Company's exception is denied.

D. Property Tax Deferrals

As explained in the Recommended Decision, the COB2 Plan provided that 50% of deviations from "base level" property taxes were to be deferred, for late recovery, as required. Staff computed that $4.1 million is owed customers ($5.4 million with interest, and excluding the fifth year), but the Company argued that it is owed about $1.35 million.

This controversy stems from the definition of "base taxes," which is actual tax costs for the twelve months ended February 28, 1997, less taxes related to assets sold after June 30, 1997. According to RG&E, base taxes (after adjustment for a sale of property) must be applied back to the start of the COB2 Plan, so that the Company would receive the benefit of the effect of the sale on deferrals throughout the term's entire five years. This would increase any deferred under-recovery, and decrease any deferred excess recovery. Staff argued that the adjustment to base taxes should be applied prospectively only. The Judge agreed with Staff, and RG&E excepts.

The Judge analyzed the COB2 Plan's terms, concluding that, although not directly addressing the issue, they support only a prospective application of adjustments to base taxes for property sales. RG&E's exception reiterates its position, but does not address the Judge's reasoning. In reply, Staff asserts that the Company's approach results in an unintended windfall,

[47] Id., at fn. 66.

and that RG&E itself had until recently computed the property tax deferral using Staff's approach.

The Judge's interpretation of the COB2 Plan is sound, and RG&E has not addressed his logic. As the Judge pointed out, moreover, to apply the adjustment retroactively would be tantamount to permitting the Company to recover the property taxes on any sold property twice, which would be a windfall to the Company. RG&E's exception is denied.

E. Merger Savings

The Energy East/RGS merger had not taken place when the Company filed the proposed rate increases in this case. The parties agree that net merger synergies, as approved in Case 01-M-0404, should be reflected in the revenue requirement in this case. Accordingly, Staff proposes to reflect $2.7 million of merger synergy savings ($1.9 million for electric and $0.8 million for gas), and would add the customer share of merger-related "costs-to-achieve" to rate base ($7.5 million for electric and $1.4 million for gas). Staff removed gas supply cost savings as an adjustment to revenue requirement, since such savings if achieved will automatically flow to customers through the gas adjustment clause (GAC) in the rate year.

The Judge adopted RG&E's proposal to put the shareholder share of costs-to-achieve in rate base as well as the customers' share, and Staff excepts. MI takes exception to the Judge's failure to recommend remedial action for alleged violation of merger promises, and Staff indicates its support for MI's position.

1. Deferral Before New Rates

Under the Merger Joint Proposal, all costs-to-achieve and gross savings attributable to the period prior to the effective date of new rates are to be deferred. The Recommended Decision reported an apparent controversy between RG&E and Staff, with the Company appearing to argue that Staff's rate case adjustment improperly reflected savings commencing on July 1, 2002. The Company argued that any costs and savings occurring before new rates are effective are to be deferred, with amortization to begin on the effective date of new rates (January 14, 2003).

On exceptions, Staff states that there is no issue, as it agrees with the Company on the amounts in rate base for merger costs. In its brief on exceptions, RG&E seeks to clarify the quantification and ratemaking treatment of net merger savings (gross savings minus costs-to-achieve), and it reports that there is no disagreement between the Company and Staff as to the rate treatment of net merger savings, other than the recovery of the shareholder portion of carrying costs, discussed in the next section.

According to RG&E, all of the actual costs incurred and savings realized through January 14, 2003 have been and will be deferred.[48] The net deferral will be a cost, since the costs-to-achieve will exceed the gross savings before January 14, 2003, and that cost is to be amortized over a five-year period from January 1, 2003 through December 31, 2007. RG&E continues:

> Commencing January 15, 2003, actual gross savings will no longer be deferred and amortized, but will be reflected in Income for financial and regulatory accounting purposes in the year they are realized. For the period January 15, 2003 through December 31, 2007, actual costs to achieve will be deferred and amortized using a remaining-life technique. . . The amortization of the actual deferred costs (and savings through January 14, 2003) will be reflected in Income and the unamortized net-of-tax balance of the actual deferred costs (and savings through January 14, 2003) will be included in Rate Base.[49]

In its brief opposing exceptions, Staff indicates it has several concerns about these clarifications. First, since

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[48] Pursuant to an order issued December 31, 2002 in this proceeding, although the proposed retail rates have been suspended through March 11, 2003 in this proceeding, the rates eventually approved will be compressed as if they became effective January 15, 2003.

[49] RG&E's Brief on Exceptions, p. 32. RG&E cites Cases 01-M-0404 et al., Energy East Corporation, et al., Order Adopting Provisions of Joint Proposal with Modifications (issued February 27, 2002).

the ratepayers' share of merger savings are capped at the amounts shown in Appendix A of the Merger Agreement, Staff argues, the amount of costs-to-achieve should also be capped. Moreover, Staff argues, the amortization of the merger costs should start at the beginning of the rate year, not January 2003. Thus, the controversy reported by the Judge does appear to exist between RG&E and Staff, and an additional issue has emerged as well.

First, we agree with Staff that, under the merger agreement's approved Joint Proposal[50] the costs-to-achieve are capped, as are the savings. We do not agree with Staff, however, that the amortization should begin retroactive to the beginning of the rate year in this proceeding. The deferral begins at the date of the merger, but actual recovery of the amortized costs-to-achieve begins with the effectiveness of new rates in this proceeding (January 14, 2003).

2. Deferral and Amortization After New Rates

Because customers cannot receive the Company's share of merger savings, Staff reasoned, they should not have to pay carrying charges on the costs incurred to achieve them. Therefore, Staff opposed the Company's proposal to include the shareholder as well as the ratepayer share of deferred costs-to-achieve in rate base. The Judge agreed with the Company that, with savings recognized currently and costs amortized over a five-year period, the shareholder portion should be included in rate base as well.

Staff excepts, arguing that the Joint Proposal does not provide for interest on the Company's share of merger costs. To provide interest, Staff asserts, would erode the customers' share of merger savings. Its position is "fair and balanced," Staff continues, because ratepayers pay for their share of the costs-to-achieve along with carrying charges, and RG&E should be treated the same.

[50] Ex. 171, App. A.

RG&E responds that while the Joint Proposal does not explicitly provide for carrying charges on the Company's share of costs, it does not preclude them either. Any lack of balance here, RG&E posits, stems from Staff's refusal to provide a return on deferred costs required to achieve the synergy savings Staff would pass through before they are actually achieved on a net basis. If it is not permitted to earn a return on its half of the deferred costs, RG&E asserts, then it should be permitted an equity return on the additional retained earnings that results from its half of the early sharing under Staff's approach.

There is no dispute that the customer half is treated properly, for if cost recovery is deferred, there must be carrying charges on the deferred balance. However, under the Merger Agreement, the Company's share of the costs-to-achieve are not to be recovered from customers at all. Therefore, although the Company may defer the write-off of these costs, we will not provide a return on them. The timing difference between recognition of the costs and the savings has no bearing on this conclusion. Staff's exception is granted.

3. Other Proposals

The Judge rejected a request by Staff and MI for action in response to the Company's alleged failure to live up to merger commitments, concluding: "Although vigilance is required where holding company commitments and responsibilities are concerned, the information provided in this case is inadequate to support any punitive action, or a recommendation that the merger savings computation be made the subject of a formal investigation."[51]

These parties except. Staff argues: "The failure by the Company to live up to its commitments has serious negative consequences, both financial and operational, and if left unchallenged will erode public confidence in the utility and the system of regulation. As a result, we urge the Commission to

[51] R.D., p. 62.

consider whether and under what conditions RG&E's shareholders should be allowed to retain merger savings."[52] MI argues that the Judge erred in concluding that the issue is not ripe for consideration in this proceeding, and that this is the proper forum for enforcing the merger promises. MI opposes recovery by RG&E of its share of merger savings before it demonstrates compliance.

According to MI, it appears the RG&E and Energy East are failing to honor many of the promises they made in support of approval of the merger. It asserts that: (1) the corporate headquarters of RGS Energy, NYSEG, and RG&E are not being relocated to Rochester as planned;[53] (2) RG&E is planning to close regional customer service centers, in contravention of assurances that the petitioning companies have no plans to reorganize of close them;[54] (3) RG&E expects to have involuntary workforce reductions, in contravention of assurances that there were no plans for involuntary workforce reductions;[55] (4) on information and belief, the former CEO of RG&E was forced out of RGS Energy and RG&E by Energy East, in contravention of its agreement that he would be appointed to the Board of Directors of Energy East along with two RGS Energy outside directors;[56] (5) the Board of Directors of RGS Energy was also to have included that individual, who would be in charge of RG&E and NYSEG,[57] and; (6) the promise to increase the level of charitable contributions to and community involvement with, Rochester has not been met.[58]

MI argues that RG&E has conceded that NYSEG's headquarters is still located in Binghamton, and that it plans to close customer service centers with potential involuntary

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[52] Staff's Brief on Exceptions, p. 18.

[53] Joint Petition, pp. 2, 9.

[54] Id., p. 16.

[55] Id., pp. 3, 18.

[56] Id., p. 9.

[57] Id., pp. 9-10.

[58] Id., p. 16.

layoffs. Moreover, MI continues, the Company would not respond to discovery questions concerning the composition of the RGS and Energy East Boards of Directors, and no plans have been revealed for greater community involvement in Rochester.

RG&E responds that it has abided by all of the commitments made in the Joint Proposal. Although the NYSEG corporate headquarters remains in Binghamton, RG&E states, NYSEG is without a CEO since the retirement of its CEO, and approximately 40 employees of Energy East (EEMC) are expected to be located in Rochester during 2003; Energy East's commitment to the Rochester area is evidenced by its decision to locate the consolidated Computer Data Center for all of Energy East in Rochester. Moreover, RG&E contends, RG&E must find about $117 million of merger-related synergy savings for the first five years of the merger, and the Company has been forced to respond to a deterioration of its financial condition since the filing of the merger petition. The closing of customer service offices and any workforce reductions, RG&E continues, are a response to these factors.

It is essential that Energy East, RGS Energy, and RG&E honor their merger commitments. However, we will not speculate as to the reasons for the retirement of a former RGS Energy CEO, and we would be reluctant in any event to interfere with high level management appointment decisions. It is also premature to conclude that Energy East has abandoned its commitment to Rochester, and we are investigating the planned customer service office closings, as noted above, in a separate proceeding. Although we will monitor these matters in the future, we will not revisit the merger savings sharing plan at this time. The Staff and MI exceptions are denied.

F. Rate Base

1. Working Capital/Dividends Declared

The Company increased its working capital allowance to include $6 million of retained earnings for amounts recorded in the dividends declared account. Staff sought to reject the adjustment, arguing that dividends declared do not have any impact on retained earnings balances and, therefore, should not be reflected in working capital. RG&E responded, however, that dividends reduce retained earnings when they are declared; and because dividends declared must be considered a part of capitalization supporting rate base until they are paid, they are properly included in capitalization for purposes of computing working capital. Persuaded by that analysis, and finding Staff’s adjustment unclear, the Judge accepted the Company’s position.

On exceptions, Staff argues that the lack of clarity lies in the Company’s approach, which it says adds dividends declared to a fictitious retained earnings balance. In argument to the Judge, Staff had contended that the Company’s retained earnings amount is a computed ("plug") figure, which does not appear on the Company’s books. Staff asserts it has now compared the Company’s derived retained earnings balance to the average amounts reported on the Company’s SEC 10K/10Q filings. According to Staff, the average of the five quarters ended December 2000 through December 2001 comes to $12.7 million less than the derived retained earnings amounts used by the Company for the historic test year. Similarly, for the last two quarters of 2002, Staff says, the reported amounts are lower than the derived amounts. Accordingly, Staff says, its adjustment is, if anything, conservative.

The Company responds that it computed its working capital allowance by subtracting the actual average earnings base for the 2001 historic test year from the actual average monthly capitalization for the same period. Since dividends declared support earnings base until paid, they were included in capitalization. Without disputing the theoretical propriety of including dividends declared in capitalization, RG&E continues, Staff offered an unsupported argument that dividends declared do not have any impact on retained earnings balances. Staff’s comparison is flawed, RG&E maintains,[59] and Staff's use of only five data points understated actual retained earnings by $4.3 million. Assuming agreement on the base amount of retained earnings, RG&E contends, the issue boils down to whether declared dividends must continue to be considered a part of capitalization supporting rate base until after they are paid.

Staff and the Company apparently agree on the theory underlying the book accounting for dividends declared and on the theory underlying a working capital modification for dividends declared. Under normal accounting, dividends declared reduces retained earnings and a liability is established until the dividend is actually paid. Under normal working capital calculations, dividends declared are added to retained earnings until such time as they are paid, since the dividend has no cash flow consequences until payment.

Staff and RG&E disagree about whether RG&E's rate case accounting actually produces a reduction to the retained earnings balance for dividends declared. Staff alleges it does not, because RG&E's retained earnings figure is a computed, or "plugged" amount, not an amount that appears on the Company's books, and dividends declared do not have any impact on retained earnings balances calculated in this manner.[60] RG&E conversely argues that its retained earnings figures are reduced for dividends, and it provides, in Schedule C of its Brief Opposing Exceptions, a schedule showing how retained earnings are reduced for dividends declared.

Schedule C shows per-book amounts, and it is not responsive to Staff's criticism that the retained earnings at issue in the rate case are a computed figure, not an amount that appears on the books. Given the relatively straightforward mechanics of this calculation described above, if the record

[59] Staff claims the reported test year average retained earnings is $182.2 million, $12.7 million less than the Company's "derived" $194.9 million; RG&E says it actually used $186.5 million plus $6.0 million for dividends declared, totaling $192.5 million.

[60] Tr. 1613.

contained information on the retained balances used in the working capital calculation, this issue could easily be resolved. Staff's testimony prevails on this issue, since the Company did not refute the Staff adjustment in its rebuttal. Staff's exception is granted.

2. Accumulated Deferred Income Taxes (ADIT) Updates

Staff requested rejection of some very large updates to Federal and State Accumulated Income Tax Balances that were presented at the time of the rebuttal filing. Staff asked for rejection of the updates because they were unexplained, and Staff could not verify or react to them. The Judge rejected the Company’s charge that Staff’s position was disingenuous, and he recommended that we consider the update adjustments only if the Company could demonstrate their validity to Staff.

No exception was filed to this result. However, Staff in its brief on exceptions denied the Company’s claim that this was a topic discussed with on-site Staff in April 2002 and in November 2002, after the hearings. In its Brief Opposing Exceptions, the Company states: "Since the parties have been unable to resolve the disputed adjustments, RG&E must now present its exceptions."[61]

According to RG&E, Staff has simply refused to take the time to understand what are valid and easily understood adjustments. One adjustment (to accumulated deferred investment tax credit (ADITC) as well as ADIT) was intended to replace ten-month actual and two-month estimated base year 2001 data with twelve months of actual data. According to the Company, these changes are consistent with already accepted test year ADIT levels. The balance of the update RG&E attributes to a change in the deductibility of the loss associated with the sale of the Nine Mile 2 nuclear facility.

As the Judge pointed out, the burden of proof is on the Company to show such an increase in costs, and that includes filing updates with a full explanation in testimony, at a time

[61] RG&E Brief Opposing Exceptions, p. 40.

affording Staff a reasonable opportunity to present any objections it may have. As explained by the Judge, that did not happen in this proceeding. Moreover, the Company did not take exception to the rejection of these updates, and only renewed its advocacy of them in response to a Staff challenge to related assertions made by the Company. RG&E's belated exception is denied.

3. <u>Construction Slippage</u>

Staff alleges that the Company's gas construction budget is overstated when viewed in light of historic experience, and it proposes an approximately $4 million rate-year rate base reduction, and a reduction in annual depreciation expense of $102,000.

The Company responds that these are adjustments that were not presented to the Judge, and cannot properly be made for the first time on exceptions.

Although there is evidently discussion of these proposals in Staff testimony, they were not briefed to the Judge. No reasonable exception can be taken to the Judge's failure to accept these adjustments when they were not presented to him in brief, nor can the Company be responsible for addressing adjustments that were not briefed and were, therefore, presumably withdrawn.

Accepting the Company's construction budget intact, which rejects a staff slippage adjustment relating to cast iron replacement, leaves the record in this proceeding unclear and we take this opportunity to clarify it and express our expectations of what we expect the Company to accomplish in the area of gas safety (reliability). The Judge rejected a staff proposal that would establish a rate adjustment if a certain level of unprotected steel services and miles of cast iron and base steel gas mains were not replaced. We agree. This conclusion is based in part upon a finding by the Judge that the record indicates RG&E's program is pretty much in line with the requirements of the gas agreement established in the prior proceeding, for the program was funded at an expected level of

$4.75 million per year. The record in this proceeding establishes that RG&E is replacing a greater amount of mains and expending considerably more capital dollars in so doing than previously required. In fact, in the year 2001 the Company replaced 13.2 miles of cast iron mains and 19.7 miles of bare steel pipe and replaced 609 unprotected steel services, at a cost of approximately $7 million. We are accepting a budget for these replacements in this case of $6.5 million for like work because of the high priority in which we hold gas safety. Therefore, we will not accept a contention that the targets established in the last proceeding are acceptable now.

At the level of funding RG&E has sought and is included in the revenue requirement for gas service, it should be able to replace the 1000 services originally proposed by Staff and approximately 25 miles of mains. Priority should be given to replacement of at least 1000 cathodically unprotected steel services and eight miles of small diameter high-pressure cast iron main. The remaining funds should be expended to replace as much other cast iron and cathodically unprotected steel main as possible. The Company should report to us its plans to accomplish these goals and reconcile the expenditures associated with service and gas main replacements described above along with associated numbers or mileage as appropriate.

4. Working Capital/Operating Reserves

Staff increased the amount of site remediation (SIR) reserve used to reduce rate base, and the Judge accepted Staff’s adjustment, as corrected by the Company, with one outstanding issue remaining to be resolved. Staff indicated it would agree to RG&E’s modification with respect to the application of insurance proceeds against the reserve, but only if it could be demonstrated that no further insurance proceeds were likely.

In its brief opposing exceptions, Staff reports that it has met with the Company and is persuaded that further insurance proceeds in the near future are unlikely. Accordingly, Staff agrees with the Company projections of growth in the SIR reserve. The Company’s projections are accepted in place of the Staff amounts used in the Recommended Decision.

G. Rate of Return

1. Capital Structure

The Judge recommended an overall rate of return of 8.26% based on a June 30, 2002 capital structure as shown in the table below. However, he further recommended that at the time we decide the case, we use RG&E's latest actual capital structure. He concluded that "an infusion of equity from the parent, Energy East, would be appropriate to counter the effect on capital structure of its acquisition of RG&E."[62] In their briefs on exceptions, RG&E, Staff and the Attorney General have challenged the recommended capital structure.

Recommended Decision's Capital
Structure and Cost Rates for RG&E

	Ratio	Cost Rate	Weighted Cost
Long term debt	54.2%	6.93%	3.76%
Preferred stock	4.3	5.24%	0.23
Customer deposits	0.1	4.70%	0.01
Common equity	41.4	10.29%	4.26
Total	100.0%		8.26%

RG&E accepts the Judge's recommendation to use the Company's latest capital structure and states that, in fact, Energy East has increased its equity holdings by investing an additional $50 million in RG&E.[63] The Company in turn has irrevocably committed itself to redeem $82 million of long-term debt. As a result, RG&E asserts the long-term debt ratio will decrease to approximately 49.5% and the equity ratio will increase to 46.1%. Inasmuch as no party has suggested using Energy East's capital structure, RG&E claims that Staff's references to Energy East's equity ratio are irrelevant.

[62] R.D., p. 82.

[63] RG&E states that Energy East had made a similar infusion over 16 months ago with respect to NYSEG, and Energy East has not attempted to recapture that equity infusion.

The Company also states that the cost of debt set forth in the Recommended Decision is in error. According to RG&E, it should be 7.14%, which will drop to 7.12% when adjusted for the anticipated redemption of debt.

Staff opposes the use of the updated capital structure, arguing that Energy East's equity ratio is only 36% and RG&E's bond rating and financial outlooks are directly tied to Energy East's low ratio. In addition, Staff maintains Energy East has a history of window dressing the equity ratio of its utility operations to fit the decisional dates in our proceedings. For example, Staff observed that in 1996 Energy East paid dividends to itself from NYSEG, dropping the ratio dramatically. Then a week before the hearing on NYSEG electric rates, Staff states, Energy East infused $100 million of equity into NYSEG to increase its "actual" equity level for the hearing.

On a different matter, Staff reiterates its call for an imputed capital structure to reflect separate operations for RG&E's transmission and distribution (T&D) and generation. For T&D, Staff advocated an equity ratio of 40% (with a 9.5% ROE) and, for generation, an equity ratio of 50% (with an 11% ROE) resulting in a 41.87% composite equity ratio and a 53.8% debt ratio for RG&E. Believing it is important to prepare for unbundling, Staff reasons that the rates of return and revenue requirements on T&D and generation should be separately determined. According to Staff, generation assets are riskier, the financial community differentiates the risk, and it should be reflected in this proceeding.

The Judge declined to use Staff's unbundled capital structure, noting that using it leads to the same result at this point as Staff's bundled capital structure. He concluded:

> It is not useful in the proceeding to separate the T&D and generation aspects of RG&E's business for ROE or capital structure purposes. In the rate year, RG&E will be a regulated

> consolidated enterprise. This issue can be revisited when rates are unbundled.[64]

On exceptions, Staff points out that the Judge said "I recommend that the Commission require RG&E to file proposed commodity-unbundled rates, in the manner suggested by Staff, by 90 days following the Commission's order in this case."[65] Staff explains that its method of unbundling included the division of the rate of return into two segments, one for generation and one for T&D. According to Staff, there is no reason why ESCO customers should pay for the risk of RG&E generation when they are buying supply elsewhere and have to pay for the risk of supply elsewhere. Staff notes the Judge agrees that the commodity-unbundled rates should include the separate returns of T&D and generation.

RG&E responds that (1) the Judge did not recommend that such unbundled rates should "include the separate returns of T&D and generation" or anything else about the returns for those rates;[66] (2) even if RG&E were to file unbundled rates as recommended (to which it has excepted), it is unlikely that hearings would be held, comments would be submitted, and an order implementing such rates would be issued during the rate year; and (3) even if rates were unbundled, RG&E will continue to be operated as an integrated entity for the full rate year.

We decline to update RG&E's capital structure for the recent $50 million equity infusion. Doing so would raise the requested equity ratio above RG&E's initially requested 44.1% target ratio. The Judge rejected RG&E's target ratio because it would tend to hold customers responsible for the implications of the Energy East goodwill created when it purchased RG&E's assets at $640 million above book value. The downrating of RG&E's debt by rating agencies has been attributed on this record to the merger and the implications of the goodwill.[67] The Judge adopted

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[64] R.D., p. 84.

[65] R.D., p. 94.

[66] R.D., p. 91.

[67] Standard & Poor's CreditWeek, April 11, 2001 (Ex. 65).

RG&E's 41.4% equity ratio based on its capital structure at the beginning of the rate year, June 30, 2002, emphasizing that RG&E's customers should not be held responsible for the cost of regaining an A rating.

We agree that the 41.4% ratio is appropriate for the rate year, and we agree with the Judge that it is improper to require customers to effectively compensate Energy East for its goodwill problem, and to overcome the decline in RG&E's creditworthiness caused by the merger. The capital structure we adopt reflects RG&E's underlying creditworthiness, unaffected by the merger.

We also note that Standard & Poor's bond rating reflects the fact that Energy East's corporate structure permits the free flow of funds throughout its organization, and Standard & Poor's assessment that default risk accordingly is the same throughout the organization.[68] Updating the capital structure as proposed by RG&E would be based on the false premise that RG&E would benefit from the financial support. However, since no new equity was actually issued by Energy East, given RG&E's lack of financial insulation, its bond rating would remain unchanged. In future cases, RG&E will have to demonstrate adequate structural insulation from Energy East to justify granting a rate of return based on a capital structure that exceeds the profile of Energy East.

We also agree with the Judge that the rate of return should be unbundled at the time of commodity rate unbundling.[69]

2. <u>Return on Equity</u>

The Company, Staff and the Attorney General have taken exception to the ROE recommendations. The Judge recommended a 10.29% ROE, which was based on analyses of proxy groups with a

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[68] Standard & Poor's CreditWeek, June 19, 2002 (Ex. 65).

[69] RG&E excepts to the Judge's recommendation that we require a filing of unbundled rates within 90 days of the date of this order. We will deny this exception, but accept RG&E's suggestion that the filing be incorporated in an electric rate proceeding, if one has been filed at that time.

2/3 weighting of the discounted cash flow (DCF) result (10.88%) and a 1/3 weighting of the capital asset pricing model (CAPM) result (9.13%). He did not adjust the ROE upward to reflect selling and issuance costs. Both Staff and RG&E used proxy groups, albeit different ones, to estimate their respective ROEs. RG&E noted that the use of a proxy group of companies satisfied the time-honored principle that allowed returns should be consistent with the returns on investment of comparable risk. Moreover, the Company noted that use of a proxy group avoids undue circularity that could be created by regulatory influence (through rate setting) on investors' expected returns for the specific common equity of the regulated Company.

RG&E's proxy group comprises gas and electric utilities that derive at least 80% of their operating revenues from electricity and gas operations and had total capital exceeding $10 billion, but it excludes companies whose ability to maintain dividend levels has been questioned by financial data sources and companies that are the known targets of possible takeovers.

Staff's proxy group included, among others, companies with less than 80% of their revenues from utility operations, but Staff limited its group to utilities carrying an A rating.

RG&E and Staff also employed different financial projections. The Company relied on an average of 20 days worth of data for the stock prices and data from Value Line and Zacks Investment Research (Zacks) for growth projections, while Staff used six months of data, and data from Value Line and Merrill Lynch for its growth projections.

a. <u>The DCF Computation</u>

The DCF model estimates the market-required return based on the ratio of the dividend to the stock price, plus expected growth. Of the three measures of growth presented by RG&E, namely, sustainable growth as estimated by Value Line, earnings per share estimates from Value Line, and analysts' earnings estimates as summarized by Zacks, the Judge largely discounted the Zacks data to estimate the appropriate ROE. He suggested that the Zacks data improperly reflect unsustainable earnings growth and are too diverse to inspire much confidence. Regarding Staff's proxy groups, the Judge expressed concern about bias in Staff's dividend-per-share projections. The Judge recommended that an average ROE of the two proxy groups be used after excluding the Zacks data. Five exceptions were taken.

First, RG&E excepts, claiming that the Judge should have relied on a diversity of estimates of expected growth, including Zacks, instead of estimates from just one source, Value Line, because expected growth in the DCF analysis is difficult to ascertain, in light of the current regulatory and financial uncertainties plaguing the industry. According to RG&E, Zacks earnings growth projections reflect a compilation of projections from numerous sources that produce a consensus of growth projections for the companies in the proxy group. Further, the Company argues that Zacks summarizes the earnings growth rates of a number of disinterested analysts, which influence both the current stock price and the DCF cost of equity. Believing that investors often employ the forecasts published by both Zacks and Value Line as long-term growth rates, RG&E claims that they thus represent the most current estimate of long-term growth, which should be used in calculating the cost of capital.

MI supports the Judge's decision that the Zacks earnings growth data should not be used; it buttresses its opinion that dividend growth estimates should be employed by citing the Recommended Decision in the Generic Financing case, which states:

> The proponents have adopted a two-stage DCF calculation. The first stage growth rate is the dividend stream implied by a comparison of the first-year dividends forecast by Value Line with the dividend projected by Value Line for three to five years into the future. The second stage growth rate is also derived from Value Line projections, picking up from the end of the three-to-five year period in the first stage and going out indefinitely.[70]

Second, with respect to the dividend payout ratio, RG&E claims the Judge understated the impact of such declining ratios. According to RG&E, payout ratios have declined since 1997, a trend it expects will continue into the foreseeable future. Under these circumstances, the Company contends, growth in dividends will be less than the growth in earnings because the proxy group companies are retaining a greater fraction of their earnings internally. Accordingly, RG&E reasons, this visible trend in the proxy group's dividend payout policies causes Staff's proposed growth rates to diverge from the underlying growth rate for the proxy companies. Therefore, RG&E would discount Staff's growth rate in deriving a DCF ROE in these proceedings. The Company calculates that inclusion of the Zacks growth rate and elimination of the Staff's growth rate raise the Recommended Decision's DCF estimate by 70 basis points, to 11.58%.

Staff claims there is no bias attributable to the use of data with declining payout ratios because investors price stock on the basis of expected future dividends. According to Staff, the Judge's criticism basically implies that when the dividend payout is increasing, and therefore short-run dividend growth is higher than long-run sustainable growth, it is wrong to recognize this higher short-run growth. Staff agrees that the higher short-run growth should not be recognized, for it comes at the cost of lower long-run sustainable growth. Similarly, Staff reasons, when the dividend payout is decreasing and short-run dividend growth is declining, the offsetting

[70] Case 91-M-0509, supra, Recommended Decision, p. 11.

effect is that long-run sustainable growth will be higher than it would have been had dividend growth not declined. Staff advocates reliance exclusively on Value Line Dividend growth estimates to determine the short-run DCF growth rate.

According to MI there is no support for RG&E's assertion that a decline in payout ratios is expected to continue into the foreseeable future. Indeed, MI asserts, if President Bush's proposed elimination of the double taxation on dividends is adopted, dividend growth rates may increase. In any event, MI believes RG&E has failed to demonstrate why dividend growth rates should be ignored when we have relied upon them in DCF analyses for decades.

Third, RG&E observes that the Recommended Decision declined to adjust the ROE for the credit quality difference between the Company's equity and that of the proxy groups proposed by Staff and recommended by the Judge. Instead, the Judge attributed RG&E's downgrading to BBB to its recent merger, consistent with the expressed opinions of bond rating agencies. The Company claims that its downgrading is consistent with repeated observations in the financial press that rating agencies have become stricter in the evaluation of utilities and that downgrades have recently far outnumbered upgrades. Moreover, RG&E submits, Staff concedes that one reason for the downgrade is RG&E's ownership of generation, particularly the Ginna nuclear plant, which presents unique risks for regulated utilities.

RG&E cites the recommended decision issued in the Generic Financing case to support an adjustment reflecting the risk difference between the subject Company and the proxy group used to determine that Company's cost of equity.[71] Over the past several months, RG&E notes, the spread between Baa-rated and A-rated utility bonds has ranged from 50 to 80 basis points. Therefore, it requests that an adjustment of at least 50 basis

[71] Case 91-M-0509, Proceeding on Motion of the Commission to Consider Financial Regulatory Policies of New York Utilities, Recommended Decision (issued July 19, 1994).

points be added to the proxy group cost of equity to reflect RG&E's higher risk.

Fourth, Staff criticized the Judge's position that a nine-basis-point ex-dividend adjustment is needed. Staff concedes that in the past it supported the use of ex-dividend adjustments to remove the known effect that the next quarterly dividend payment has on the stock price. Staff explains that the ex-dividend adjustment was a necessary element of the DCF in the late 1980s, when the price component of the DCF dividend yield was computed based on prices over a 20-day time period. But, Staff asserts, the generic return approach adopted by the electric and gas industry group in the Generic Financing proceeding[72] dispensed with the ex-dividend adjustment. One of the major arguments against the DCF approach in the past, Staff asserts, was the idea that the use of a 20-day average price could, for a variety of reasons (including the ex-dividend effect), produce volatile DCF results. As a result, Staff states, the electric and gas group opted to use a DCF price component based upon six months of data, which would smooth the effects of this approach and obviate any ex-dividend adjustment.

Fifth, the Attorney General points out that on November 6, 2002, the Federal Open Market Committee lowered its target for the federal funds rate by 50 basis points, to 1 1/4%, the Board of Governors of the Federal Reserve Bank approved a 50 basis point reduction in the discount rate, to 3/4%, and other interest rates have fallen in tandem with these declines in the Fed Funds rates. The Attorney General asserts that the authorized ROE should be reduced to reflect this further decline in interest rates, which occurred after the close of the record and was not adopted by the Judge.

RG&E notes that the Attorney General referred to its post-record figures in its Initial Brief, but the Judge found that there was an inadequate record basis for further reducing the fair return on equity to reflect recent declines in interest

[72] Case 92-M-0509, Return on Equity Consensus Document, Appendix A, page 7.

rates.[73] In fact, RG&E explained on the record that interest rate movements alone are not a good indicator of movements in the cost of equity, especially in times of a volatile stock market. According to RG&E, the federal funds rate and the discount rate that the Attorney General cited are overnight or very short term interest rates, and their change by administrative fiat cannot be considered evidence of a change in investor requirements for utility common stock.

We agree in principle with the Judge's recommendation to use the Staff's and the Company's DCF model estimates after excluding the Zacks earning growth data. As noted above, we have employed dividend growth rates in the past, and we see no reason to overturn the Judge's conclusions that Zacks earnings growth estimates are simply not credible. After adjusting the Company's return to 11.5% to give some weight to Staff's proxy group, the Judge reduced the return by 70 basis points, as discussed, to reverse the effect of the Zacks data. The Company's update evidence shows the Zacks data to be even less reliable, and, in fact, a steeper decline in the cost of equity is reflected in the non-Zacks data. The distortion created by the Zacks data that should have been reflected by the Judge is 121 basis points.[74] Accordingly, we adjust his DCF cost of equity by an additional 51 basis points, bringing it down to 10.37%. Staff's corrected DCF equity cost is very close at 10.34%, confirming the reasonableness of that result.

We will not adjust the DCF results for a credit quality difference between RG&E and Staff's proxy group because the downgrading is due primarily to Energy East's influence and because the proxy groups used by both the Company and Staff include the risks of RG&E's utility business. However, we will let stand the Judge's use of an ex-dividend adjustment because it was applied to RG&E's study, which employed only 20 days worth of price data, which could be influenced by the declaration of a dividend.

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[73] R.D., p. 79.

[74] Ex. 82.

Finally, we will not further adjust the return on equity downward to reflect recent trend in short term interest rates. It is premature to try to anticipate its effect, if any, on investors' requirements for utility common stock.

b. The CAPM Computation

The CAPM model develops a ROE based upon the measure of volatility of a particular stock relative to the volatility of the market as a whole (beta coefficient). The proxy group's required return based on the CAPM is computed from the risk-free rate, the market return, and the average proxy group beta. The Judge recommended that we employ an average of RG&E's and Staff's proposals.

RG&E points out that the approach recommended in the generic financing case called for a CAPM that relied on the Ibbotson risk premium rather than the Merrill-Lynch-based estimate that Staff used in these proceedings. Substituting the Ibbotson risk premium for Staff's risk premium, RG&E claims, would raise the Staff CAPM from 8.90% to 10.62%.

According to the Company, the Merrill Lynch-based market risk premium is understated when compared with the Ibbotson market risk premium. In addition, RG&E asserts that the Merrill Lynch market return is inherently suspect when compared with the average 11.12% returns recently allowed for electric utilities, which is at the high end of the range Merrill Lynch calculates for the market as a whole (10.9% to 11.3%). Given the higher risks for the market as a whole compared with regulated utilities (as measured by beta), the Company reasons that it does not seem likely investors would require a return for the market as a whole only equal to, or below, that for "lower-risk" utilities.

Staff and MI support the use of the Merrill Lynch data. Staff notes that the Merrill Lynch data are prepared for market participants and portfolio managers. MI emphasizes that the Ibbotson data relied upon by RG&E date back to the 1920's and can be considered stale. On the other hand, MI states, we have expressed a preference for the more current risk premium data published by Merrill Lynch.[75]

We agree with Staff and MI that sole reliance on the Ibbotson data would overly reflect stale data. In the instant case, we will adopt the Judge's recommendations to rely on an average of the Company's Ibbotson based study and Staff's Merrill Lynch based study to give due weight to the more recent data in the latter study.

c. Issuance Costs

The Judge rejected the Company's allowance of 29 basis points for selling and issuance costs because he found no reason to expect RG&E to issue equity in the rate year. RG&E takes exception, noting that we have authorized selling and issuance cost adjustments. According to RG&E, a decision to deny selling and issuance costs because the Company is not likely to issue equity in the rate year focuses on prospective costs only. Instead, RG&E proposes that it be compensated for accumulated issuance costs that have never been recovered in rates. Absent such an adjustment, the Company argues, the allowed ROE will understate its fair rate of return.

Staff and MI respond that the Judge's recommendation to exclude selling and issuance costs is sound because RG&E is not forecasting a market equity issuance. According to MI, RG&E's claim that the return should reflect accumulated issuance costs, which have never been expressed or recovered in rates, smacks of retroactive ratemaking and should be rejected.

We agree with the Judge's recommendation to exclude a separate adjustment for selling and issuance costs, because our policy has been to allow recovery of such expenses when they are incurred and there has been no assertion by the Company in this case of an external equity issuance.

[75] Case 95-G-1034 - Central Hudson Gas & Electric Corporation - Rates, Opinion No. 96-28 (issued October 3, 1996) p. 14.

3. Summary of Rate of Return

A fair equity return, derived by weighting the DCF result (10.37%) two-thirds and using a one-third weighting of the CAPM result (9.13%), is 9.96%. The overall rate of return, reflecting the update of the cost of debt filed in the Company's rebuttal submission and the latest customer deposit rates and consistent with the record in this proceeding, is shown in the following table:

	Ratio	Cost Rate	Weighted Cost
Long Term Debt	54.2%	6.93%	3.76%
Preferred Stock	4.3%	5.24	0.23
Customer Deposits	0.1	3.85	0.00
Common Equity	41.4	9.96	4.12
Total	100.0%		8.11%

H. Revenue Requirement and Rate Moderation

With respect to gas, the determinations above result in the need for a rate year increase in revenues of $5.078 million. The increases in the minimum charge as adopted herein for Service Classifications (S.C.) 1, 3 and 5, using Staff's customer count, will generate approximately $6.2 million, or some $1.1 million in excess of the revenue requirement. The excess revenues will be returned to customers by allocating a uniform credit (net of gas costs) to the usage blocks after the minimum charge in S.C. 1, 3, and 5.

The Company will determine the revenue shortfall from January 15, 2003 to the effective date of the new rates, on a class-by-class basis, and surcharge customers' bills for the remainder of the first year of new rates (i.e., until January 14, 2004).

The above determinations resolve to a rate year reduction of $15.6 million in electric revenue requirement. The Judge elected to freeze electric base rates, while permitting a temporary surcharge to recover deferred retail access backout credits in the amount of $6.8 million. The additional revenues resulting from freezing rather than reducing base rates, in these circumstances, would fund a reduction in deferred costs of $15.6 million.

It is important to amortize the deferred costs, but given current economic conditions in RG&E's service territory, we would prefer to freeze electric revenues rather than base rates, so we will not impose a revenue increase for the retail access backout credits.

Our rate determination means that deferred costs will be amortized by $47.0 million per year, including the $15.6 million revenue requirement reduction. To make the revenue requirement reduction effective January 14, 2003, as required by our December 3, 2002 order, we will apply the revenue reduction accruing from then until this date against deferred cost balances. This will require RG&E to amortize the full $15.6 million during the first ten months of new rates. At the end of the rate year, the balance of deferred costs is expected to be approximately $276.8 million.

We resolved several issues involving ratemaking deferral mechanisms, and as described above, and further accelerated the amortization of regulatory IOUs by adopting a rate freeze. We decided that deferred costs related to Beebee shutdown costs, storm costs and property taxes were overstated by $6.6 million. We also determined that excess earnings from the COB2 Order were understated by $45.3 million. We also determined that the Case 96-E-0898 service quality adjustment of $249,000 will reduce one-time costs, and accordingly it will be used to further write-down deferred costs. As a result of these decisions, RG&E is required to immediately write-down an additional $52.1 million of deferred costs due from customers. This write-down permanently reduces RG&E's annual amortization expense by $2.6 million. Our decisions in this case produce a total base rate revenue requirement reduction of $15.6 million. Our decision to freeze base rates therefore requires an additional write-down of deferred costs due from customers by $15.6 million, which will reduce RG&E's future ongoing amortization expense by approximately $0.8 million.

III. COST OF SERVICE AND RATE DESIGN

A. Cost of Service Studies - Revenue Allocation

According to the Recommended Decision, Staff's proposed revenue allocations should be adopted. For electric service, this would entail a proportionate increase to all classes with the exception of S.C. 6 - Area Lighting. For gas service, Staff proposed a proportionate revenue allocation to all classes.

Staff's proposals to proportionally change electric rates (except for S.C. 6 - Area Lighting) are based on the revenue-to-revenue-requirement ratios of RG&E's filed marginal and embedded cost of service studies. According to Staff, a tolerance band of +/-20% should be applied to these ratios to reflect the fact that much judgment is often exercised in preparing cost analyses, and, therefore, the results of cost studies are not precise. If both ratios for any of the service classes fall outside of the +/-20% tolerance band, Staff would subject those classes to something other than an across-the-board revenue allocation. Inasmuch as the ratios for S.C. 6-Area Lighting exceeded the 20% tolerance band, Staff proposed no increase in revenues for this classification. RG&E agrees with Staff's proposal.

Similarly, for gas service, Staff and RG&E propose that any increase or decrease be allocated to the service classes on a uniform percentage basis. The application of a +/-20% tolerance band to the results of the marginal and embedded cost of service studies, they say, justifies a proportional revenue allocation across all gas service classes.

No party took exception to the recommended method for revenue allocation. The Judge noted that RG&E's gas and electric rate structures are being reviewed in the unbundling proceeding.[76] Thus, he urges adoption of Staff's wide tolerance

[76] Case 00-M-0504, Proceeding Regarding Provider of Last Resort Responsibilities, the Role of Utilities in Competitive Energy Markets, and Fostering the Development of Retail Competitive Opportunities - Unbundling Track, Order Instituting Proceeding (issued March 21, 2000).

band of 20% to avoid rate changes in the instant case that might need to be reversed in the unbundling proceeding. We agree and adopt the Recommended Decision's revenue allocation method.

B. Rate Design

Exception was taken to the recommended rate design changes with respect to the residential minimum charge and the retail access back-out credits. In addition, MI seeks clarification of the Recommended Decision's rate design changes for two classifications.

1. Minimum Charges

In the Recommended Decision, it is suggested that the monthly minimum charge be increased by $1.50 for the electricity and gas residential and small commercial classes. The Judge concluded that the $1.50 increase strikes a fair balance between the desire to move the minimum charges closer to the marginal costs in order to send the proper pricing signals, and the resulting impacts on customers' bills. The Judge further noted that the monthly increase of $1.50 for these classes is consistent with the increase that was approved in RG&E's last major electric rate proceeding.[77] The CPB and Mr. Straka take exceptions.

The CPB opposes the $1.50 monthly increases, which would result in an electric service minimum charge of $19.00 and a gas service minimum charge of $13.50. The CPB argues that the electric cost studies relied upon by the Judge are approximations and a 20% tolerance band should be applied to the account for their inexact nature.[78] According to the CPB, if a 20% band were applied to the S.C. 1 electric customer costs computed by Staff of $22.22, a minimum charge of only $17.78 would be justified.

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[77] Case 96-E-0898, Rochester Gas and Electric Corporation - Electric Rates and Restructuring, Opinion No. 98-1, (issued January 14, 1998), p. 26.

[78] CPB does not address the gas marginal cost of service study.

Use of a 20% tolerance band is also important, CPB maintains, because we are in the process of establishing unbundled rates in Case 00-M-0504, the unbundling proceeding. To avoid the possibility that rate design decisions made in the instant case may be contradicted in a few months based on the result of the unbundling proceeding, CPB would allow no increase in the S.C. 1 electric minimum charge at this time.

CPB also alleges that an offsetting decrease in the volumetric charge would result in an increase in consumption, which may contravene NYSERDA's and our policies to mitigate energy and environmental problems.

Finally, CPB notes that the Company's current S.C. 1 - Residential electric minimum charge is the highest in the State and that RG&E's electric residential minimum charge would be increased from $10.00 five years ago to $19.00 or 90%. For gas service, the CPB makes a similar argument, noting that RG&E's proposed residential minimum charge would increase this rate from $5.81 to $13.50, or 131% in a two-year period.[79]

Mr. Straka observes that the Recommended Decision quantifies the estimated impacts on the basis of average rate charges. For example, he points out, the Recommended Decision states that, over the past six years, average residential bills have declined 10%. Mr. Straka emphasizes that many low-usage customers may have actually seen bill increases in the same six-year period. Mr. Straka believes that RG&E's bill comparison study, which was predicated on its original filing, should have been updated to reflect the currently proposed changes in the basic service charges, the usage charges, and taxes. In the absence of updated bill comparisons, Mr. Straka urges us to adopt the position espoused by Staff for both the revenues and rate reductions.[80]

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[79] CPB notes that the rate order in Case 98-G-1589 (the Company's gas rate and restructuring case) recently raised the minimum charge from $5.81 to $12.00.

[80] Staff had originally proposed a $1.50 per month increase in the minimum charge for the residential and small customer classes for electric service and no increase for the comparable gas service.

Staff and RG&E respond to the CPB arguments by noting that RG&E's minimum charge ideally should be based on the Company's underlying customer costs and not other utilities' minimum charges. Furthermore, Staff states, minimum charge increases not based on sound cost principles will uneconomically discourage energy conservation as well as investment in energy efficient technology; the concern, Staff claims, is reflected in the 2002 New York State Energy Plan:

> The State supports expediting efforts to have electricity distribution and customer service prices to consumers reflect the true cost of service and eliminate inter-class and intra-class subsidies to the extent practicable.[81]

With respect to CPB's arguments concerning the +/-20% tolerance band, both Staff and RG&E observe that tolerance bands are used for the purpose of revenue allocation, not rate design. Moreover, Staff points out that the Recommended Decision correctly finds that revenues that must be collected from the embedded S.C. 1 electric residential customers exceed by approximately 19% the revenues that would be produced if each rate element were set at its underlying marginal costs, but the volumetric charge exceeds the marginal costs per kWh by over 60% --well in excess of any reasonable tolerance band. So as not to exacerbate this situation, Staff advocates an increase in the fixed minimum charge.

With regard to Mr. Straka's concern that increasing the minimum charge ignores the impact on low-usage customers, RG&E states that these customers do not necessarily predominate in the very low-use blocks.

We will adopt the Judge's recommendation to increase residential minimum charges by $1.50 per month. First, we note that RG&E's charges must be based on RG&E's costs and the impacts to RG&E's customers, and not the charges of other utilities. Thus, the fact that RG&E has made more progress in

[81] 2002 New York State Energy Plan, section 1.3, subparagraph 5B (p. 1-44).

moving its rates closer to its marginal costs than other utilities should not preclude us from taking steps that we would otherwise deem reasonable. The increase of $1.50 per month will move this rate closer to marginal costs, which is in accordance with sound ratemaking principles and the 2002 New York State Energy Plan's goal of reflecting the true cost of service in the rates, as set forth above.

2. Retail Access Backout Credits

RG&E's proposed electric rates provide for recovery of $6.56 million in electric retail access backout credits (net lost revenues). Staff proposes that retail access back-out credits (currently 4 mills/kWh) not be collected in base rates, but rather that actual lost revenues associated with customer migration to retail access be deferred for future recovery. Accordingly, Staff reduced RG&E's revenue requirement by $6.56 million.

The Judge recognized that the issues of retail access credits, the creation of stranded costs, and utilities' ability to recover such costs from customers, are being addressed in the unbundling proceeding--Case 00-M-0504. He recommended that the credits (or net losses) be excluded from base rates, and that the Company be allowed to recover the retail access backout credits (or net losses) through a surcharge mechanism until the appropriate treatment for competitive losses is resolved in the unbundling proceeding. This treatment, he reasoned, would protect consumers if we modify or eliminate the credit mechanism in the unbundling proceeding.

MI takes exception to the Judge's recommendation. MI acknowledges that the issues surrounding retail access backout credits are being addressed in the unbundling proceeding, but it nonetheless opposes the surcharge mechanism because utilities have an obligation to reasonably mitigate their costs[82] and are not guaranteed recovery of any shortfall.[83]

Furthermore, MI claims that we addressed a similar issue when we modified NYSEG's retail access backout credits. In that proceeding, MI states, NYSEG argued that it should be permitted to recover, through a surcharge, the "costs" associated with its retail access backout credits, or adders, of 2 and 4 mills per kWh. According to MI, we rejected NYSEG's arguments in their entirety:

> NYSEG's ordinary tariff filing in Case 01-E-0217 would establish an energy rate surcharge of .03¢ per kWh, purportedly needed to recover the costs of the 2 and 4 mill adders. Neither the Market RAC Order nor any other prior Order justifies this surcharge of costs to customers. As decided in the Market RAC Order, NYSEG avoids costs when customers move to retail access. To surcharge customers for those same costs would double recover them. Moreover, NYSEG was invited to submit evidence on cost impacts during the course of this proceeding, but it failed to do so. As a result, there is no evidentiary basis for imposing the costs of the adders on customers through a surcharge.[84]

Finally, if the Judge's recommended surcharge were to be adopted, MI would request two clarifications. First, it seeks to establish that the RG&E's recovery under that surcharge is conditional, and the Company has no claim to such recovery if: (a) its reasonably avoided costs equal or exceed the amount of the credit; or (b) its sales or number of customers exceed the projections upon which rates are based herein. Second, MI

[82] Case 00-M-0504, supra, Order Establishing Parameters for Lost Revenue Recovery and Incremental Cost Studies (issued March 21, 2002) at 23.

[83] Case 00-M-0504, supra, Order on Rehearing and Clarification Petitions (issued May 30, 2002) at 6.

[84] Cases 01-E-0217, et al., New York State Electric & Gas Corporation - Ordinary Tariff Filing to Establish a Separate Energy Rate Surcharge to Establish the Projected Costs of the 2 Mill and 4 Mill Additional Component of the Market-Based Retail Access Credit, Order on Tariff Compliance Filings, Canceling Ordinary Tariff Filing, and Rejecting Other Requests for Relief (issued April 26, 2001) at 14 (footnote omitted).

seeks to clarify how the recommended surcharge would be imposed, i.e., if it would follow Staff's proposal that a surcharge be applied to RG&E's customer classes based upon migration levels, and then recovered from each class on a volumetric basis.[85]

RG&E would reject MI's position, asserting that none of the orders issued in the unbundling proceeding directed any utility to absorb incremental costs and net lost revenues associated with retail access, as MI would require. Rather, RG&E claims that we rejected proposals for partial or total disallowance of revenue shortfalls[86] and instead expressly stated that utilities would be authorized recovery of net lost revenues and costs through mechanisms that include both a prospective and retroactive element. Also, RG&E states,[87] we provided for periodic reconciliation and flexibility in the design of the individual utility recovery mechanisms,[88] and in denying MI's petition for rehearing in the unbundling track, we reaffirmed our intention that utilities should be permitted recovery subject to the parameters set forth in our orders.[89]

We agree with the Recommended Decision's finding that the issue of retail access credits will be addressed in Case 00-M-0504. However, we will not adopt the Judge's recommendation to reflect retail access credits (or net losses) in a surcharge. As discussed above, we have decided to freeze electric base rates, and not to increase revenues with such a surcharge. We are not with this decision limiting our authority to create such a surcharge in the unbundling proceeding.

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[85] See R.D., p. 107.

[86] Case 00-M-0504, supra, Order Establishing Parameters for Lost Revenue Recovery and Incremental Cost Studies (issued March 21, 2002) at 23.

[87] Id. at 25.

[88] Id.

[89] Case 00-M-0504, supra, Order on Rehearing and Clarification Petitions (issued May 30, 2002).

3. Clarifications

For the reasons set forth below, MI requests clarification of electric and gas intraclass rate design recommendations with respect to S.C. 8 Large General Service electric customers and S.C. 3 Gas Transportation Customers. The Judge recommended that Staff's general approach to electric rate design be adopted, i.e., after first excluding the effect of the revision to the customer service charge, Staff would reduce the class' energy charges on an equal per-kWh basis if the balance of the revenue charges were negative.[90]

MI understands that the Recommended Decision: (a) advocates freezing RG&E's electric base rates; (b) adopts an across-the-board electric revenue allocation; and (c) adopts Staff's S.C. 8 minimum charges. Under those circumstances, MI calculates that the balance of the changes to S.C. 8 customers should be negative and, therefore, under Staff's approach, the increased revenues resulting from the new minimum charges should be applied toward a reduction in energy charges. MI does not oppose applying the increased revenues from the new S.C. 8 minimum charges, and perhaps any moderate rate reduction, to reducing S.C. 8 energy charges. However, to the extent RG&E's electric rates were substantially reduced in this proceeding, MI would request that at least an equal percentage share of that reduction be allocated so as to reduce demand and energy charges.

Staff agrees that adoption of its residual rate design proposal as applied to the Recommended Decision's revenue requirement, revenue allocation, and minimum charges would result in a freezing of the existing demand charges for S.C. 8. Nonetheless, Staff continues to support its residual rate design proposals in the event that we substantially reduce RG&E's electric rates.

With respect to S.C. 3 gas transportation rates, the Judge recommended that the increase to the monthly minimum charge advocated by RG&E be adopted and that any residual

[90] R.D., p. 110.

increase to S.C. 3 rates be spread on a uniform basis pending the outcome of RG&E's unbundling proceeding.[91] MI seeks clarification as to whether that "uniform increase" would apply to all S.C. 3 rate blocks including the minimum charge.

With respect to the S.C. No. 8 electric demand charge, the issue is moot since we have not authorized a revenue reduction. For all electric classes, we direct RG&E to increase the minimum charges as set forth in the Recommended Decision and reduce the remaining rate blocks as proposed by Staff, which would preserve each class's revenue responsibility by applying a class-specific uniform per-kWh reduction.

As far as the gas rates are concerned, for S.C. 3 and the other gas service classes, we will require RG&E to increase the minimum charges as set forth in the Recommended Decision and adjust the rates in the remaining blocks on a uniform percentage basis (net of gas costs) in each class to produce the authorized revenue requirement set forth in this order.

IV. CUSTOMER SERVICE AND POLICY ISSUES

A. Service Quality Measures and Incentives

RG&E proposed a "Service Quality Performance Program" (SQPP) that incorporated six measures of service quality: Retail Billing Accuracy, PSC Complaint Rate, Estimated Meter Reads, Calls Answered Within 30 Seconds, Appointments Kept, and Customer Interaction Service Index. Performance below specified levels would result in rate adjustments and performance above specified levels would be rewarded; between those two levels would be a "dead band" in which there would be neither reward nor adjustment.

Staff agreed with the service quality measures (though modifying the calculation of Retail Billing Accuracy) but objected to rewards for service above specified levels, noting that no other major gas or electric utility in the State had the opportunity to earn such rewards. It increased the rate

[91] R.D., p. 110.

adjustment associated with below-target service, and it recommended resetting the target levels for PSC Complaint Rate, Estimated Meter Reads, and Calls Answered in 30 Seconds.

The Judge adopted Staff's view that rewards for special excellence were unnecessary and that the plan should be limited to rate adjustments for failure to meet the targets. But he regarded Staff's proposed adjustment as too high, reducing its potential magnitude by $1.5 million; and he accepted the Company's proposed targets except with respect to PSC complaint rate, where he recommended a compromise between RG&E's position and Staff's. Staff excepts on both issues, and a number of matters related to the plan's term and administration require clarification.

1. Magnitude of Rate Adjustment

RG&E proposed a maximum downward adjustment of $1.5 million; Staff would increase it to $3.0 million--equivalent to about $10 a customer and 31 basis points of equity return, using Staff's rate base and capital structure. RG&E contended Staff's maximum adjustment could cost the Company over $8 million; that a rate adjustment should not be an earnings erosion formula; and that Staff had failed to recognize the costs involved in making the service improvements Staff advocates. The Judge, as noted, rejected Staff's proposal and set the maximum adjustment at $1.5 million.

On exceptions, Staff contends that the Company's $8.0 million figure includes potential safety and reliability rate adjustments (discussed separately below) as well as the customer service rate adjustments at issue here. It suggests a maximum adjustment of only $1.5 million may provide inadequate incentive to improve service quality and that, in any event, the Company is at less risk of service quality deterioration during the term of the rates set here than it would be under a multi-year plan. Finally, Staff argues that its proposed rate adjustment is in line with the 42-basis-point (on gas rate base) exposure associated with RG&E's existing service quality plan adopted in Case 98-G-1589 and with those of other utilities. It cites our recent adoption of joint proposals related to NYSEG's electric and gas rates, under which that utility is subject to annual revenue adjustments of $4.8 million--47 basis points on electric equity and 15 basis points on gas equity--related to service quality, as well as additional adjustments with respect to service quality and gas safety.[92] Staff cites as well a joint proposal adopted for National Fuel Gas Distribution Corporation, which includes a maximum rate adjustment related to customer service of 29 basis points.[93]

RG&E replies that it was the $3.0 million service quality rate adjustment--not the total $8.0 million figure--that the Judge found overly aggressive. It distinguishes the other cases cited by Staff, noting that they involved multi-year negotiated arrangements that should not serve as precedent in a one-year litigated case.

While the Company is right that the exposure to rate adjustments in multi-year negotiated cases does not serve as direct precedent here, Staff makes the valid observation that in a one-year case, there is less risk that service quality will deteriorate within the time being considered. To balance these considerations, the maximum customer service adjustment exposure will be set at $2.0 million; to that extent, Staff's exception is granted.

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[92] Cases 01-E-0359 et al., New York State Electric & Gas Corporation, Order Adoption Provisions of Joint Proposal With Modifications (issued February 27, 2002); Cases 01-G-1668 et al., New York State Electric & Gas Corporation, Order Establishing Rates (issued November 20, 2002).

[93] Case 00-G-1858, National Fuel Gas Distribution Corporation, Order Adopting Terms of Joint Proposal (issued April 18, 2002).

2. Service Quality Targets

Of the six service metrics, three were disputed. As a general matter, Staff favored taking account of recent historical performance; RG&E objected, suggesting that doing so would risk creating an incentive to avoid superior service lest it become the basis for raising the bar even further. Staff responded that Company-specific historical data better reflected a Company's individual circumstances than would national or regional benchmarks.

The Judge generally agreed with RG&E that it would be unfair to keep raising the bar as service improved and that the targets should be based primarily on objective industry standards--specifically, the 1999 AGA/EEI Best Practices. He therefore adopted the Company's proposed targets of 77% of calls answered within thirty seconds (rather than Staff's 78%) and no more than 10% estimated meter reads (rather than Staff's 8%). With respect to the PSC Complaint Rate, however, he recommended that the threshold for incurring a penalty be set at 5.0 per 100,000 customers, the mid-point of the range between Staff's 3.0 rate and the Company's 7.0.

Staff excepts with respect to the PSC Complaint Rate. It notes that in June 2002, our Office of Consumer Services (OCS) instituted a new complaint handling procedure, under which fewer calls are logged in as complaints. In the six ensuing months, all utilities have experienced dramatic reductions in their PSC complaint rates; RG&E's rate for the 12 months ended November 30, 2002 was 1.9, in contrast to 4.0 for the 12 months ended November 30, 2001. Staff therefore believes a rate of 3.0 would not be onerous, and that the rates in place for other companies, having been set before OCS changed its procedures, as well as RG&E's own historical data, compiled on the basis of the old procedures, are not pertinent here. It urges that its 3.0 rate be assessed on its own merits, rather than being compared to historical or other utility numbers, and it asserts it is beginning to renegotiate complaint rate target levels for other utilities.

In reply, RG&E supports what it terms the Judge's "compromise" recommendation, insisting that the record does not warrant use of the 3.0 rate. The Company argues, among other things, that it is premature to set a target on the basis of the new OCS procedures, arguing that at least twelve months' worth of experience should first be compiled. It disavows any knowledge of Staff efforts to renegotiate target levels for other utilities, but contends that this case, in any event, is not the proper forum for addressing matters of such statewide applicability.

The records maintained by our Office of Consumer Services show that as of December 31, 2002, RG&E's complaint rate for the preceding 12 months--comprising five months under the old procedures and seven months under the new--was 1.8. And while recorded customer contacts increased during the final seven months, the new recording procedures resulted in a substantially reduced number of complaints.

In view of these data, a target rate of 5.0 would be almost meaningless and could not be expected to provide the needed incentive to maintaining the level of service quality to which the Company's ratepayers are entitled. The target rate will be set, in accordance with Staff's exception, at 3.0. It will be subject to further adjustment after June 2003, when we have data on the new procedures' first full year; Staff should monitor those data and report to us promptly on the changes that might be warranted.

3. Clarifications

The plan will go into effect when the rates set here take effect, and will remain in force unless and until changed by order of the Commission. For purposes of applying the maximum annual rate adjustment, a "year" will be the twelve-month period beginning on the first day of the calendar month following the month in which the rates here set take effect.

B. Electric Reliability

With respect to electric reliability, RG&E proposed a System Average Interruption Frequency Index (SAIFI) and a Customer Average Interruption Duration Index (CAIDI). Each index would have a threshold that, if exceeded by 10%, would subject the Company to a rate adjustment; rewards would be available for performance well below the threshold. For SAIFI, the threshold would be 1.0 annual interruptions per customer; adjustments would apply if the index exceeded 1.10; a reward would be available for an index of 0.65 or less. For CAIDI, the threshold would be 1.73 hours per interruption; rate adjustments would be imposed at 1.90; a reward would be available at 1.64 or less.

As in the case of the SQPP, Staff objected to rewards for superior service and the Judge agreed with Staff. Staff also proposed more rigorous adjustment thresholds--0.80 for SAIFI and 1.85 for CAIDI--and it proposed a maximum rate adjustment of $5.34 million, in contrast to the Company's $500,000. The Judge rejected the more rigorous targets, finding they were too close to average experience and imposed too great a risk of incurring adjustments even with continued good performance. He also found Staff's increased rate adjustment amount excessive and not justified by experience; he recommended a potential adjustment of $1 million.[94] Staff excepts.[95]

With respect to the SAIFI, Staff notes that the 0.03 margin that separates its recommended 0.80 rate adjustment threshold from the Company's ten-year average experience is in line with the margins for other companies--0.03 for Orange and Rockland Utilities, Inc. (Orange and Rockland), 0.04 for Niagara Mohawk Power Corporation, and 0.07 for Central Hudson Gas & Electric Corporation--and that our Office of Electricity and Environment (OEE) has had a policy of tightening reliability targets. It discounts the Company's observation that its

[94] RD., p. 116.

[95] Staff does not except to the Judge's rejection of its suggestions to modify the company's proposals related to gas reliability.

reliability is the third best in the State, contending that the lowered adjustment threshold is needed to prevent deterioration of that performance and consequent customer dissatisfaction. If a rate adjustment threshold of 0.80 is too stringent, Staff would suggest a figure of 0.90, representing an 18% margin above the ten-year average.

As for CAIDI, Staff notes that its proposed penalty threshold of 1.85 would have resulted, like RG&E's proposed 1.90, in only one penalty over the last ten years. Staff sees its figure as no riskier for the Company, but it regards the 1.90 figure as acceptable if the SAIFI of 0.90 is adopted. With respect to both indices, Staff clarifies that it intends the rate adjustment to be imposed if the index is "greater than or equal to" the appropriate level, not only if the level is exceeded; it notes the threshold is applied in that manner for other utilities and that it favors uniformity in this regard.

Finally, Staff contends the Judge's maximum rate adjustment of $1 million represents only nine basis points of return, in contrast to the 25 to 35 basis points at risk in other utilities' arrangements. It suggests the adjustment be no less than $3 million pre-tax (33 basis points), equal to $1.75 million post-tax.

In response, RG&E contends that Staff's exception, as in other instances, relies on extra-record material related to other utilities rather than on the record in this case. It dismisses Staff's reference to an OEE "policy," asserting that only the Commission, and not Staff offices, may issue policies and that a Staff predilection is no substitute for evidence. It sees no stronger record basis for Staff's "fall-back" SAIFI threshold of 0.90 than for its initial proposal of 0.80.

The Company objects as well to Staff's pursuit of consistency in applying a rate adjustment when the rate is "equal to or greater than" the threshold figure. It contends that position was advanced for the first time on exceptions, and that statewide uniformity is unnecessary--given the inter-utility variation in threshold levels--and does not warrant adopting a proposal introduced so late in the game.

Finally, RG&E insists there is no record basis for Staff's five-fold increase in the Judge's recommended adjustment level, which it characterizes variously as "Draconian" and "absurd."[96] The Company suggests Staff's recognition of that "absurdity" underlies its proposal on exceptions to set the penalty at $3.0 million rather than $5.0, but it sees no more basis for that "slightly less punitive proposal" than for the original one.

OEE's movement toward tightened reliability targets, even if not a formally adopted policy, properly reflects our interest in service reliability and in measures to promote it. Setting the target levels that best advance that goal without being unrealistic and punitive is not an exact science, but the data before us suggest that a SAIFI target of 0.90 and a CAIDI target of 1.90, as suggested by Staff on exceptions, would be reasonable. Rate adjustments should be incurred when the target is exceeded; RG&E fairly argues that Staff's "equal to or greater than" clarification was advanced here too late to be adopted. With respect to adjustment exposure, the much higher levels set for other utilities (in terms of basis points of risk) are not directly precedential, given that they resulted from multi-year negotiated plans. But a one-year arrangement, as already noted, entails less risk to the Company of service deterioration, and a maximum rate adjustment level greater than the Judge's would not be unreasonable. Taking all these factors into account, we will set the maximum adjustment level at $2.0 million.

C. Low-Income Residential Energy Consumer Assistance Program

RG&E's Residential Energy Consumer Assistance Program (RECAP) provides qualified low-income heating customers a more affordable payment plan for utility bills and offers them household budget counseling and related services; for low-income non-heating customers, it provides a reduced monthly minimum charge. RG&E proposed continuation of the program, but Staff

[96] RG&E's Reply Brief on Exceptions, p. 55.

offered several modifications with respect to heating customers.[97] Staff favored cutting the per-customer benefit by half and doubling, from 900 to 1,800, the targeted number of participants. In addition, Staff would cap the administrative costs of the program at 20% of the sum of counseling costs, arrears forgiveness and budget reduction amounts provided to customers. Staff also called for continuation of the program's existing reporting requirements.

The Judge found the 20% cap on administrative costs "troublesome in light of the Staff proposal to double the participants and halve the benefits."[98] He recommends instead the Company's proposal to allow administrative costs of 46%.

Staff excepts to the 46% cap on administrative costs. In addition, it asserts the Recommended Decision is unclear with regard to the disposition of its proposed program changes, which it continues to advocate.

Noting both the 20% cap in the Joint Proposal approved in the Company's last gas rate proceeding (Case 98-G-1589) and the Company's claim that it is in fact experiencing administrative costs of 70%, Staff asserts that its program modifications were designed to make the program more efficient and reduce the drop-out rate to which RG&E attributes its high administrative costs. Staff explains that the current program--in contrast to analogous programs at other utilities--is limited to customers who have already been issued a termination notice on account of their arrears. Because such customers will be unlikely to be able to pay their future monthly bills--as the program requires for continued participation--many such customers tend to drop out, thereby raising administrative costs. If the program is opened to low-income customers who have some resources (such as many of the working poor and senior citizens), the dropout rate and administrative costs can both be

[97] The program for non-heating customers was unopposed and the Judge recommends its adoption.

[98] R.D., p. 119.

expected to decline. Staff therefore asks that its program change be reconsidered.

In response, RG&E argues that Staff's proposals to reduce monthly benefits and increase enrollment are not revenue-neutral and therefore should be rejected. If they are adopted, it continues, reporting requirements should be reduced. Finally, the Company opposes Staff's exception on the administrative expense cap, distinguishing the situation of the other utilities Staff cited as precedent and contending Staff's program changes would increase administrative costs.

Staff proposed its program changes at least in part to reduce administrative costs, now said by the Company to be running as high as 70%; RG&E claims Staff's changes will have the opposite effect and raise those costs even higher. There is no way to be certain of the result, but the changes, for the reasons outlined in Staff's Brief on Exceptions, appear worth trying and seem more likely to reduce administrative costs than to raise them. Accordingly, we adopt Staff's changes with respect to number of participants and magnitude of the benefit. With regard to reporting requirements, we are unpersuaded that all the existing requirements are needed, but the record does not provide a basis for determining which, if any, should be removed. Staff and the Company should confer within 30 days of the issuance of this order and attempt to agree on changes to the existing reporting regime. If they cannot reach agreement, Staff should bring the matter to us again with further recommendations.

With respect to the administrative costs themselves, the Company's claims that they are running at 70% is at odds with its "Report Regarding Low-Income Program" filed on June 28, 2002, which suggests administrative costs of about 27%. More fundamentally, administrative costs of 70%, or even 46%, are unprecedented and unacceptable; our Office of Consumer Education and Advocacy advises that no utility programs now in effect have administrative costs exceeding 20%. Taking account of these considerations but also recognizing that RG&E's costs are running above that level and may have to be reduced gradually, we will set an administrative cost cap of 25%. If that cap cannot be met and then reduced, Staff and the Company should revisit the issue and consider the need for further program recommendations.

D. Bill Format

Staff proposed that the Company's electric bills, like its gas bills, be reformatted to separate delivery and supply into distinct sections and to include a statement that customers may shop for commodity. The Judge agreed, rejecting RG&E's argument that such bill unbundling would make sense only if rates were unbundled and that rate unbundling was being pursued in a separate generic proceeding. According to the Judge, the proposed bill format would assist customers in making competitive choices even before rate unbundling.[99]

RG&E excepts, asserting that it does not object in concept to unbundled billing but that it simply cannot develop an accurate unbundled electric bill format before rates are unbundled and that the schedule in the unbundling proceeding makes it unlikely that rates will be unbundled until well after the effective date of the rates being set here. It notes as well its exception to the Judge's recommendation in this case that it be required to file commodity-unbundled rates within 90 days of the order in this case and suggests that even if its exception is denied, the timing of that filing and its ensuing review make it unlikely that unbundling would take place before the end of the rate year. Accordingly, bill unbundling during that year would be unfeasible.

In response, Staff acknowledges the merit of RG&E's point with respect to timing of the bill format change. It suggests the Company's submission of a revised bill format be tied to the recommended filing of unbundled rates. That resolution of the issue is reasonable.

[99] R.D., p. 121.

E. Retail Access Issues

1. Transition to Multi-Retailer Model

The Judge noted that Staff's $2.8 million estimate of the cost of moving from a single-retailer to a multi-retailer retail access model was included in the revenue requirement.[100] RG&E, which had suggested the transition cost might be $4.2 million - $6.8 million, excepts.

RG&E contends the Judge presented no assessment of the two cost estimates. Staff's estimate, it continues, unexplained in Staff's testimony, is said in an interrogatory response to be based on costs incurred by Orange and Rockland in introducing a single-bill process. RG&E sees no reason to regard the costs as comparable, and asserts it fully explained its own estimate, which should be adopted.

RG&E also cautions against underestimating the time needed to move to the new model. It notes the Judge's statement that the Company had estimated the transition period to be about a year and compares that to its testimony that the transition period would be at least a year and could be substantially longer.[101]

MI urges denial of the exception, contending there is no evidence to support the Company's cost estimate, which was first offered on brief. It argues as well that the Company has overstated the costs of the transition, disregarding, for example, potential synergies that it could realize by adopting the same retail access model as its affiliate, NYSEG. MI suggests further that transition costs should not be allowed in rates at all, since the transition is necessitated by RG&E's

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[100] R.D., p. 129. Under a single-retailer model, the customer deals with a single entity for both delivery and commodity; a multi-retailer option permits a customer taking commodity from an ESCO to nevertheless take distribution directly from the utility, freeing the ESCO of responsibility for the transmission and distribution portion of customer accounts. The Judge recommended that the company move from its current single-retailer model to a multi-retailer model but that it not be required to offer both.

[101] Tr. 1043.

past advocacy of the failed single-retailer model, the costs of moving to which ratepayers have already paid. MI sees no reason why ratepayers should pay again to correct RG&E's misjudgment; at a minimum, it urges that the Company bear the risk that costs will exceed those recommended by the Judge.

Finally, MI notes the need for a smooth transition to the multi-retailer model, including arrangements to ensure that no customer find itself contractually bound to pay both an ESCO and the utility for the same delivery service. It notes RG&E's acknowledgement on the record that is was willing to work toward resolving those concerns.

As MI correctly argues, RG&E's high cost estimate is unsupported. The Judge's recommendation provides a reasonable allowance and it is adopted. Staff should work with the Company and other parties to ensure a smooth transition.

2. Purchase of Accounts Receivable

Because many customers prefer receiving a single bill, Staff urged that the multi-retailer model include an offer of consolidated billing by the utility. The Judge noted that proposal was unopposed.[102]

Staff further proposed that in conjunction with consolidated billing, the Company purchase ESCOs' accounts receivable; RG&E and the Attorney General objected. Citing the substantial unresolved issues related to accounts receivable, the Judge recommended that their purchase "be left to RG&E's discretion in the first instance, subject to subsequent review."[103]

On exceptions, the Attorney General objects to affording RG&E the discretion to purchase ESCOs' accounts receivable, calling for an outright ban. Without such a ban, it sees a risk that RG&E could purchase the receivables of its affiliated ESCOs, thereby reducing their collection costs and shifting risks to the utility's ratepayers.

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[102] R.D., p. 129.

[103] Id.

Inasmuch as RG&E objected to the purchase of accounts receivable, it seems to matter little, as a practical matter, whether we ban it outright or leave it to the Company in the first instance, subject to subsequent review. But the latter course of action is more consistent with general principles of regulation, which avoid micromanaging the Company. The Judge's recommendation is reasonable and the exception is denied; Staff should report to us promptly if the Company should begin purchasing accounts receivable in a manner that warrants concern.

3. Aggregation Program

Staff advocated support by RG&E of aggregation programs for both electric and gas customers, which could reduce ESCOs' acquisition costs and lead to better price offerings. In particular, Staff urged a series of steps to facilitate use by the Monroe County Aggregation Program of the Department of Social Services (DSS) Energy Procurement Model that had been devised by a working group comprising the Company, Staff and other interested entities. Staff suggested the program, which serves customers on DSS vouchers, was impeded by RG&E not being obligated to provide billing and customer service functions for customers purchasing commodity from competitive suppliers. Staff believed only RG&E could provide those services, since the Uniform Tape Exchange (UTX) billing system was within its control. Staff therefore recommended that the Company be required to provide those services for the vouchered customers, noting that Monroe County was willing to pay $5.75 per customer per month for that service, and that it develop a needed Supplier Invoice and Billing System (SIBS). For doing so, it would be granted a rate allowance of $555,000, offset by a service quality adjustment of $249,000 that had been assessed in Case 96-E-0898.

RG&E objected to Staff's proposal as unnecessary, noting that aggregation is well under way in its service territory, and as too ill-defined to be assessed. It favored leaving the aggregation function to third parties. With specific reference to the Monroe County program, RG&E objected to being required to provide customer support service to the County. It contended as well that the UTX system resides at DSS, not at RG&E, and that DSS had announced plans to replace or modify it.

The Judge credited RG&E's objections. Noting that the need for a SIBS was unclear on the record, as was the manner in which it might be affected by consolidated billing, he suggested the matter might be clarified on exceptions.[104]

On exceptions, Staff describes several instances in which we have directed utilities to cooperate in the development of aggregation programs with interested entities. It urges a similar directive here, given Monroe County's interest in aggregation for vouchered customers; the program should be in place by the end of the rate year unless the parties otherwise agree. Specifically, Staff recommends that RG&E be required to provide billing services for the Monroe County program, for a fee to be negotiated, regardless of where the UTX billing system is physically located. It asks as well that RG&E and other interested parties be required to reexamine the requirements for the program's billing system under a multi-retailer model and in view of the forthcoming introduction of EDI.

As for how to treat the service quality adjustment of $249,000 assessed in Case 96-E-0898, Staff now recommends that rates be reduced by that amount.

RG&E responds that the practices of other utilities, adopted in the context of multi-year negotiated rate plans, are of no precedential value here. Moreover, RG&E asserts Monroe County has backed away from pursuing an aggregation program, concerned about its likely cost. The costs for the County can be expected to decline under a multi-retailer model, but the transition will take time; and the lower costs will not be realized during the rate year in this proceeding.

We have expressed a strong interest in promoting aggregation programs that can bring the benefits of competition

[104] R.D., p. 130.

to small customers in general and low-income customers in particular. The record here provides no basis for directing the specific measure Staff urges, but in view of our commitment to aggregation programs that include utility involvement, we direct RG&E to resume, without delay, collaborative discussions of aggregation with the Monroe County Department of Social Services, Staff, and other interested parties. The discussions should be directed toward developing a mutually acceptable aggregation program for the 6,000 low-income, vouchered customers of Monroe County that could be put into effect for the 2003-2004 heating season. The program should be designed so that the Company and its other ratepayers do not subsidize its development or operating costs. Staff should report back to us on the progress that is made and on any unreasonable barriers to progress.

Finally, as Staff proposes, the $249,000 adjustment assessed in Case 96-E-0898 will be applied here; of course, it will be applied in a manner reflecting its status as a one-time adjustment rather than a recurring adjustment built into rates.

4. Market Match Program

RG&E notes the Judge's adoption, over its objection, of Staff's proposal that it conduct a Market Match program.[105] It therefore asks that Staff include the revenue requirement impact of the program in its Brief Opposing Exceptions.[106]

In response, Staff reiterates its view that the reasonable costs of the program should be minimal and that it would not object to their recovery. It declines to provide a specific estimate, suggesting RG&E use the estimated costs for this program of its affiliate, NYSEG.

MI objects to any recovery of program costs, contending they will be de minimis and that RG&E's request to recover them is a petty expression of its objection to being required to do anything to promote retail access.

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[105] R.D., p. 131.

[106] RG&E's Brief on Exceptions, p. 43.

Although these costs are small, they are nonetheless real. NYSEG's costs provide a reasonable proxy estimate, as Staff suggests, and RG&E will be allowed recovery of $7,500 per year.

F. Outreach and Education

The Judge found that the record did not provide a suitable basis for evaluating RG&E's outreach and education programs or taking any specific actions, but he called for Staff to continue to review those programs.

Staff should indeed continue to review the programs and report to us on any needed changes. For now, we clarify that the Company should continue all existing programs, including its retail access education effort and its annual survey of customers with respect to retail access. RG&E should continue to include the results of that survey in its annual submittal to Staff with respect to its Outreach and Education Plan.

G. Economic Development-Incremental Manufacturing Load Rate

The Judge recommended that RG&E's proposed changes to its Incremental Manufacturing Load Rate (IMLR) to be reviewed in a separate filing and that the costs of continuing the existing program be deferred for later recovery, something to which Staff had not objected.

We recently determined that the Company should, in fact, be allowed to recover lost revenue associated with extension of the IMLR.[107] Accordingly, RG&E is directed to maintain the IMLR rate for existing customers at its current rate level until we consider its status as part of our overall review of the Company's Economic Development Plan.

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[107] Case 96-E-0898, Rochester Gas and Electric Corporation, Order Granting Petition for Clarification and Rehearing (issued February 6, 2003).

V. CONCLUSION

We authorize a $1.50 increase in the monthly minimum charge for gas service which, together with gas usage rate changes, would generate an additional $5.078 million. We also freeze electric rates, and increase the amortization of deferred electric costs to reflect the reduced revenue requirement we have found herein. Both the electric rate amortization and the gas rate increase are effective, as provided in our December 3, 2002 order, as of January 15, 2003. The compressed gas rate increase will be recovered through a surcharge, and the electric revenue requirement reduction accruing from January 15, 2003 until this date will be applied against deferred cost balances.

Other issues are resolved as discussed herein. The Recommended Decision issued on December 17, 2002 in these proceedings, to the extent not inconsistent herewith, is adopted as part of this order and incorporated herein by reference.

The Commission orders:

1. Rochester Gas and Electric Corporation is directed to file cancellation supplements, effective on not less than one day's notice on March 11, 2003, canceling the tariff amendments and supplements listed in Appendix C.

2. Rochester Gas and Electric is directed to file on not less than one day's notice, to become effective on a temporary basis on March 12, 2003, such further tariff revisions as are necessary to effectuate the provisions adopted in this order. The company shall serve copies of its filing upon all parties to these proceedings. Any comments on the compliance filing must be received at the Commission offices within ten days of service of the company's proposed amendments. The amendments specified in the compliance shall not become effective on a permanent basis until approved by the Commission, and shall be subject to refund if any showing is made that the revisions are not in compliance with this order. The requirement of Section 66(12)(b) of the Public Service Law that newspaper publication be completed prior to the effective date of the proposed amendments is waived, provided that the company files with the Commission, not later than six weeks following the amendments' effective date, proof that a notice to the public of the changes proposed by the amendments and their effective date has been published once a week for four successive weeks in newspapers having general circulation in the areas affected by the amendments.

3. Rochester Gas and Electric is directed to surcharge through the year ending January 14, 2004 the gas revenue shortfall from January 15, 2003 to the effective date of new rates, on a class-by-class basis. Any overcollection or undercollection of revenues will be recovered through the gas cost adjustment and transportation adjustment clauses.

4. Rochester Gas and Electric Corporation is directed to file, within 90 days from the date of this Opinion and Order, tariffs and supporting workpapers that result in the unbundling of commodity charges and create commodity options for all customers consistent with the discussion in the Administrative Law Judge’s recommended decision. As part of its unbundling filing, the Company is directed to include an unbundled rate of return, one for generation and one for transmission and distribution. The filing will be incorporated in an electric rate proceeding, if one has been filed at that time.

5. Rochester Gas and Electric Corporation is directed to complete its transition to a multi-retailer model within 12 months of the date of this Opinion and Order. Within 30 days, Rochester Gas and Electric Corporation is directed to notify the Secretary of the consolidated billing option it intends to offer in a multi-retailer model. Regarding Electronic Data Interchange, Rochester Gas and Electric Corporation is directed to commence Phase 2 (EDI) testing for all non-billing EDI Transaction Set Standards within 45 days of the date of this Opinion and Order and be prepared to commence Phase 1 (EDI) testing, for the transactions associated with its chosen billing model, within 6 months of the date of this Opinion and Order.

6. Rochester Gas & Electric Corporation is authorized to use Account 186, Miscellaneous Deferred Debits, and Account 253, Other Deferred Credits to record the principal amount and carrying charges, if any, for items which deferred accounting has been provided for in this Order. The associated federal income tax impacts shall be recorded in accordance with the Commission’s interim policy regarding Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes, unless modified by the Commission in Case 92-M-1005. The amounts deferred for each item shall be recorded in a separate subaccount and the company shall maintain proper and easily accessible supporting documentation for each entry made.

7. Rochester Gas & Electric shall make a compliance filing with the Director of the Office of Accounting and Finance within 60 days of the date of this Order providing proposed

accounting entries to implement the accounting described in this Order.

8. Nuclear Decommissioning

a. It is agreed that the projected cost of decommissioning Rochester Gas & Electric’s 100% owned Ginna Nuclear Power Plant shall be based on site-specific studies and methods submitted by the Company.

b. The study for Ginna estimates that the decommissioning of Ginna will cost $391,094,100 in 2001 dollars. If this amount is inflated by 4.83% annually, the projected cost of decommissioning the facility in 2009 is $570,382,183.

c. The after-tax interest rates projected to be earned by the amounts collected for decommissioning these plants are 6.40% for each plant's external fund established to qualify for a current tax deduction under Internal Revenue Service ("IRS") rules and 4.44% through 2005 and 4.60% thereafter for the non-IRS qualified external fund. The rates established pursuant to the Settlement to which this Schedule is attached are based on funding the contaminated portions of the units, as required by the Nuclear Regulatory Commission ($525,327,290 for Ginna), using external funding methods.

d. The annual expense allowance incorporated in rates for Ginna, based on external funding, is $17,310,997 for the rate year ending June 2003. These amounts are to be deposited in separate external funds set up solely for the purpose of accumulating decommissioning funds for each plant.

e. Additional annual expense allowances incorporated in rates for Ginna, based on internal funding is $1,645,576 for rate year ending June 2003. This additional amount is for the decommissioning and removal of non-contaminated facilities at Ginna.

9. Rochester Gas & Electric shall accrue $2 million annually to fund the decommissioning of Beebee Station. These funds are granted on the condition that they are irrevocably dedicated to decommissioning, any sales proceeds must be added to the fund, and any excess of funds over ultimate decommissioning costs must be returned to ratepayers.

10. Excess Earnings

a. Estimated deferred costs related to Beebee Station shutdown costs, Labor Day windstorm costs have been recovered through offset with Excess Earnings. To the extent that final amounts approved by the Commission for Beebee or wind storm costs differ from estimated amounts, such variance will be charged or credited to the Nine Mile #2 regulatory asset.

b. As a result of this decision, concerning Excess earnings, Rochester Gas & Electric is required to immediately write down deferred Nine Mile #2 regulatory assets as described above. The amount we adopt for excess earnings, however, will be subject to further possible modification, pending the result of the fifth-year excess earnings review process.

c. Rochester Gas & Electric Corporation is directed to apply the $249,000 service quality rate adjustment assessed in Case 96-E-0898 as an offset to deferred costs as described above.

d. To make the revenue requirement reduction effective January 14, 2003, as required by our December 3, 2002 order, we will apply the revenue reduction accruing from then until this date against deferred cost balances. Rochester Gas & Electric is ordered to amortize the full $15.6 million during the first ten months of new rates.

11. Costs to achieve the merger between RGS Energy and Energy East will be deferred beginning on the date of the merger. Such deferred costs will be amortized in a manner consistent with this Order beginning with the effectiveness of new rates in this proceeding (January 14, 2003). Further, the costs-to-achieve merger synergies are capped at the amounts shown in Appendix A to the merger Joint Proposal (see Cases 01-M-0404 et al., Energy East Corporation, et al., Order Adopting Provisions of Joint Proposal with Modifications (issued February 27, 2002).

12. Economic Development

a. Rochester Gas & Electric is directed to continue its Incremental Manufacturing Load Rate (IMLR) and Empire Zone rate programs.

b. Rochester Gas & Electric will be allowed to defer lost revenue associated with extension of the IMLR in accordance with the Commission's February 6, 2003 Order.[108]

c. Any portion of the $13 million included for an Economic Development Fund in Rochester Gas & Electric's electric revenue requirement unspent for economic development will be deferred.

d. Within 45 days from the issuance of this Opinion and Order, Rochester Gas & Electric Corporation is directed to conduct a full review of its current economic development programs. The review shall include an examination of program enrollment levels, discounts provided, administrative costs, benefits to customers, and program effectiveness. Results of the review shall be submitted to Staff and interested parties and Rochester Gas & Electric Corporation is directed to collaborate with staff and interested parties to devise a Plan for submission to the Commission.

e. As part of its Economic Development Plan submission, the company shall review the IMLR and Empire Zone rates as directed in ordering clause 12 d.

f. Within 75 days of conducting its review, Rochester Gas & Electric Corporation is directed to submit an Economic Development Plan (Plan) to the Commission for review and approval.

13. Within 30 days from the issuance of this Opinion and Order, Rochester Gas & Electric Corporation is directed to confer with Staff to agree on modifications to the existing reporting requirements for its Residential Energy Consumer Assistance Program.

[108] Case 96-E-0898, Rochester Gas and Electric Corporation, Order Granting Petition for Clarification and Rehearing (issued February 6, 2003).

14. Rochester Gas and Electric Corporation must conduct an annual ESCO/Marketer survey, to be developed in consultation with staff and implemented by an independent third party, within 30 days following the end of the rate year.

15. Rochester Gas & Electric Corporation will continue all existing outreach and education programs, including its retail access education effort and its annual survey of customers with respect to retail competition. The company will file its annual outreach and education plan 30 days following the end of the rate year. The plan will include the previous year's activities and budget, the results of the competition survey, and a plan and budget for the upcoming.

16. Within 60 days from the issuance of the Opinion and Order in this case, Rochester Gas & Electric Corporation will resume collaborative discussions with Monroe County Department of Social Services, Staff and interested parties on the aggregation of low-income vouchered customers.

17. Except as herein granted, all exceptions to the Administrative Law Judge’s recommended decision are denied.

18. Except as herein modified, the Administrative Law Judge’s recommended decision is adopted as part of this Opinion and Order.

19. These proceedings are continued.

By the Commission,

(SIGNED) JANET HAND DEIXLER
Secretary

APPEARANCES

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Rochester Gas & Electric Corporation
Electric Income Statement
For the Rate Year Ending June 30, 2003
($000)

	Per RD	Adjust. No.	Commission Adjustments	As Adjusted Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Operating Revenues						
Retail Customers	$ 492,958	(1)	$ (6,560)	$ 486,398	$ (0)	$ 486,398
Distribution Customers	148,069		0	148,069		148,069
Off System Sales	73,563		0	73,563		73,563
Other Revenues	9,903		0	9,903		9,903
Total Operating Revenues	724,493		(6,560)	717,933	(0)	717,933
Operating Deductions						
Supply Costs	221,965	(2)	(856)	221,109		221,109
Revenue Taxes	10,181		0	10,181	(0)	10,181
Total Operating Deductions	232,146		(856)	231,290	(0)	231,290
Gross Margin	**492,347**		**(5,704)**	**486,643**	**(0)**	**486,643**
Total Other Operating Expenses (From Page 2)	189,863	(3)	(7,334)	182,529	(0)	182,529
Depreciation/Amortization						
Amortization	40,991	(4)	5,966	46,957		46,957
Depreciation	67,359		0	67,359		67,359
Decommissioning	18,957		0	18,957		18,957
Total Depreciation/Amortizations	127,307		5,966	133,273	0	133,273
Taxes Other Than Income						
Property Taxes	37,855		0	37,855		37,855
Payroll Taxes	7,076	(5)	(121)	6,955		6,955
Other Taxes	2,537		0	2,537		2,537
Taxes Other Than Income	47,468		(121)	47,347	0	47,347
Total Operating Revenue Deductions	364,638		(1,489)	363,149	(0)	363,149
Net Operating Revenues	**127,709**		**(4,215)**	**123,494**	**(0)**	**123,494**
Income Taxes						
Federal - Current	29,809	(6)	(1,289)	28,520	(0)	28,520
Federal - Deferred	533		0	533	0	533
NYS Income Tax	2,958	(7)	(180)	2,778	(0)	2,778
Total Federal Income Taxes	33,300		(1,469)	31,831	(0)	31,831
Net Income Available for Return	**$ 94,409**		**$ (2,746)**	**$ 91,663**	**$ (0)**	**$ 91,663**
Rate Base	**$ 1,144,776**	(8)	**$ (14,807)**	**$ 1,129,969**		**$ 1,129,969**
Rate of Return	**8.25%**			**8.11%**		**8.11%**
Return on Equity	**10.29%**			**9.96%**		**9.96%**

Rochester Gas & Electric Corporation
Electric Operating & Maintenance Expense
For the Rate Year Ending June 30, 2003
($000)

	Per RD	Adjust. No.	Commission Adjustments	As Adjusted Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Operating & Maintenance Expenses						
Payroll	$ 91,606	(3a)	$ (1,706)	$ 89,900		$ 89,900
Employee Benefits	17,529	(3b)	(567)	16,962		16,962
Pension Income	(16,449)		0	(16,449)		(16,449)
PPP/EIP	1,835	(3c)	(1,835)	0		0
Vouchers Other	26,497		0	26,497		26,497
Vouchers Bank Services	4,229	(3d)	(1,572)	2,657		2,657
Postage	1,013		0	1,013		1,013
Telephone	437		0	437		437
Materials & Supplies	8,576		0	8,576		8,576
Vouchers-Outside Services	28,508		0	28,508		28,508
Vouchers-Travel	1,555		0	1,555		1,555
Voucher-Legal	1,763		0	1,763		1,763
Uncollectibles	5,500		0	5,500	(0)	5,500
Low Income	243		0	243		243
Research & Development	2,062		0	2,062		2,062
Systems Benefit Charge	8,579		0	8,579		8,579
Insurance	1,279	(3e)	(1,663)	(384)		(384)
NMP II	0		0	0		0
Advertising	697		0	697	0	697
PRIDE	(778)		0	(778)		(778)
Other	5,182	(3f)	8	5,190		5,190
Total O&M Expense	**189,863**		**(7,334)**	**182,529**	**(0)**	**182,529**
Amortizations						
Nuclear Fuel /DOE Liability	1,986		0	1,986		1,986
Plant Acquisition	78		0	78		78
Oswego 6 Plant	6,476		0	6,476		6,476
Enrichment Decommissioning	1,843		0	1,843		1,843
Nine Mile II Regulatory Asset	21,653	(4)	5,966	27,619		27,619
Allegany Contract Buyout	9,222		0	9,222		9,222
Beebee Decommissioning	2,000		0	2,000		2,000
Labor Day Storm	0		0	0		0
Contractor Settlement	(361)		0	(361)		(361)
COB2 Property Tax	0		0	0		0
COB2 ROE Sharing	0		0	0		0
Merger Synergy Savings	(1,906)		0	(1,906)		(1,906)
Other	0		0	0		0
Total O&M Amortizations	**40,991**		**5,966**	**46,957**	**0**	**46,957**
TOTAL O&M and Amortization	**$ 230,854**		**$ (1,368)**	**$ 229,486**	**$ (0)**	**$ 229,486**

Rochester Gas & Electric Corporation
Electric Federal & State Income Taxes - Current
For the Rate Year Ending June 30, 2003
($000)

	Per RD	Adjust. No.	Commission Adjustments	As Adjusted Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Net Operating Income Before FIT	$ 127,709		$ (4,215)	$ 123,494	$ (0)	$ 123,494
Interest - LTD	42,998		(531)	42,467		42,467
Interest - Customer Deposits	59		0	59		59
Operating Income Before FIT	84,652		(3,683)	80,969	(0)	80,968
Additional Income - Non-Deductions						
Construction Contribution	0		0	0		0
Mirror CWIP	1,051		0	1,051		1,051
Business Expense	0		0	0		0
Other	0		0	0		0
Total Additions	1,051		0	1,051	0	1,051
Additional Deductions & Non-Taxable						
Additional Property Tax Deduction	4,523		0	4,523		4,523
Cost of Removal	(5,057)		0	(5,057)		(5,057)
Amortizations	0		0	0		0
Excess Earnings PassBack	0		0	0		0
Total Deductions	(534)		0	(534)	0	(534)
Taxable Income	85,169		(3,683)	81,485	(0)	81,485
Net FIT @ 35% - Current	$ 29,809		$ (1,289)	$ 28,520	$ (0)	$ 28,520
NYS State Income Tax	$ 2,958		$ (180)	$ 2,778	$ (0)	$ 2,778

Rochester Gas & Electric Corporation
Electric Federal Income Taxes - Deferred
For the Rate Year Ending June 30, 2003
($000)

	Per RD	Adjust. No.	Commission Adjustments	As Adjusted Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Provision for Deferred FIT						
Nuclear Fuel	0		0	0		0
Cost of Removal	167		0	167		167
Accelerated Depreciation	366		0	366		366
Excess Earnings Passback	0		0	0		0
Amortization	0		0	0		0
Other	0		0	0		0
Total Provision for Deferred FIT	**$ 533**		**$ -**	**$ 533**	**$ -**	**$ 533**

PSC Case No. 02-E-0198

Rochester Gas & Electric Corporation
Electric Rate Base
For the Rate Year Ending June 30, 2003
($000)

	Per RD	Adjust. No.	Commission Adjustments	As Adjusted Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Net Utility Plant	**$ 920,677**		**$ -**	**$ 920,677**	**$ -**	**$ 920,677**
Decommissioning - Ginna	$ (34,396)		0	(34,396)	0	(34,396)
Decommissioning - NM2	0		0	0	0	0
NM2 Deferred Projects	25,054		0	25,054	0	25,054
Plant Held for Future Use	940		0	940	0	940
Plant Acquisition Adjustment	2,067		0	2,067	0	2,067
Filed Completed Projects	51,293		0	51,293	0	51,293
Net Nuclear Fuel - Ginna	23,299		0	23,299	0	23,299
Allegany Plant - Net	11,917		0	11,917	0	11,917
PRIDE - Plant Adjustment	0	(8b)	(2,795)	(2,795)	0	(2,795)
Accrued Pension Costs	13,172		0	13,172	0	13,172
Ginna Outage	(5,688)		0	(5,688)	0	(5,688)
Site Remediation	(10,843)	(8a)	1,748	(9,095)	0	(9,095)
Other Post Employment Benefits	(50,171)		0	(50,171)	0	(50,171)
Total Other Plant	**26,644**		**(1,047)**	**25,597**	**0**	**25,597**
Working Capital						
M&S	5,505		0	5,505	0	5,505
Fuel Stocks	4,183		0	4,183	0	4,183
Prepayments	18,697		0	18,697	0	18,697
SO2 Allowances	790		0	790	0	790
O&M Expense	10,983		0	10,983	0	10,983
Total Working Capital	**40,158**		**0**	**40,158**	**0**	**40,158**
Accumulated Deferred FIT	**(144,869)**	(11)	**4,713**	**(140,156)**	**0**	**(140,156)**
Accumulated Deferred ITC	**(11,730)**		**0**	**(11,730)**	**0**	**(11,730)**
EBCAP Adjustment	**0**	(9)	**(4,888)**	**(4,888)**	**0**	**(4,888)**
Amortization Charges						
Nuclear Fuel/DOE Liability	(103,135)		0	(103,135)	0	(103,135)
Plant Acquisition Adjustment	940		0	940	0	940
Oswego 6 - Plant	61,518		0	61,518	0	61,518
Enrichment Facility Decommissioning	1,350		0	1,350	0	1,350
Nine Mile II Regulatory Asset	240,878	(10)	(13,585)	227,293	0	227,293
Allegany Contract Buyout	106,049		0	106,049	0	106,049
Labor day Storm	0		0	0	0	0
Contractor Settlement	(181)		0	(181)	0	(181)
COB2 Property Tax	0		0	0	0	0
Beebee Decommissioning	(1,000)		0	(1,000)	0	(1,000)
Merger Synergy Savings	7,477		0	7,477	0	7,477
Total	**313,896**		**(13,585)**	**300,311**	**0**	**300,311**
Total Average Rate Base	**$ 1,144,776**		**$ (14,807)**	**$ 1,129,969**	**$ -**	**$ 1,129,969**

PSC Case No. 02-E-0198

Rochester Gas & Electric Corporation
Computation of Electric Revenue Requirement
For the Rate Year Ending June 30, 2003
($000)

Average Rate Base	**$**	**1,129,969**
Rate of Return on Rate Base		**8.11%**
Required Net Income		**91,663**
Net Income Before Revenue Requirement		**91,663**
Earnings Deficiency (Excess)		**(0)**
Retention Factor		**57.947%**
Revenue Increase (Decrease)	**$**	**(0)**

Retention Factor Calculation

Sales Revenues	**100.000%**	**$**	**(0)**
Revenue Taxes	**2.130%**		**(0)**
Advertising	**0.000%**		**0**
Uncollectibles	**1.500%**		**(0)**
Retention Factor Before FIT/SIT	**96.370%**		**(0)**
Income Tax FIT@35% & SIT @4.875%	**38.423%**		**(0)**
Retention Factor	**57.947%**	**$**	**(0)**

COMMISSION CAPITAL STRUCTURE	**RATIO**	**COST**	**WEIGHTED COST**
Long Term Debt	54.2%	6.93%	3.76%
Preferred Stock	4.3%	5.24%	0.23%
Common Equity	41.4%	9.96%	4.12%
Customer Deposit	0.1%	3.85%	0.01%
Total Capital	**100.0%**		**8.11%**

ROCHESTER GAS & ELECTRIC CORPORATION
CASE 02-E-0198
SCHEDULE OF COMMISSION ADJUSTMENTS
ELECTRIC DEPARTMENT
FOR THE RATE YEAR ENDED June 30, 2003
($000)

	Explanation		Amount	
	Revenues			
(1)	To remove surcharge for retail access backout credits.		(6,560)	
(2)	**Supply**			
	To adopt Staff adjustment to coal expense.	$	(856)	
	TOTAL MARGIN	**$**	**5,704**	
(3)	**O&M Expense**			
(3a)	**Payroll**			
	To adopt Staff's adjustment for extra pay period .		(352)	
	To accept 1% Productivity adjustment of adjusted wages.		(1,354)	
	Total Payroll			(1,706)
(3b)	**Benefits**			
	To accept Staff's adjustment for 11% benefit loading on wages.		(325)	
	To reflect inflation on medical insurance.		(242)	
	Total Benefits			(567)
(3c)	**PPP**			
	To accept Staff's elimination of Performance Plus Plan payout .		(1,835)	
	Total EIP/PPP			(1,835)
(3d)	**Vouchers - Bank Services**			
	To accept Staff's adjustment to Bank Services expense.			(1,572)
(3e)	**Insurance**			
	To eliminate Company's Rebuttal change for insurance expense.			(1,663)
(3f)	**Other Expense**			
	To increase allowance for Market Match Program.			8
	TOTAL O&M			(7,334)

ROCHESTER GAS & ELECTRIC CORPORATION
CASE 02-E-0198
SCHEDULE OF COMMISSION ADJUSTMENTS
ELECTRIC DEPARTMENT
FOR THE RATE YEAR ENDED June 30, 2003
($000)

	Explanation	Amount	
(4)	**Amortization Expense**		
	To reduce Nine Mile 2 Amortization to reflect COB2 offset to balance.	(530)	
	To reflect one time Special Amortization for Revenue Requirement - Nine Mile 2.	6,496	
	Total Amortization Expense		**5,966**
	Total O&M and Amortizations		**(1,368)**
(5)	**Taxes Other Than Income**		
	To reflect a 7.109% loading associated with payroll adjustments.	**(121)**	
(6)	**Federal Income Taxes**		
	To reflect Federal Income Tax effect of adjustments.	**(1,289)**	
(7)	**State Income Taxes**		
	To reflect New York Income Tax effect of adjustments.	**(180)**	
(8)	**RATE BASE**		
	Other Plant		
(8a)	To reflect Company's forecast of Site Remediation Reserve.	1,748	
(8b)	To reflect PRIDE plant adjustment.	(2,795)	
	Total Other plant		**(1,047)**
(9)	**Working Capital**		
	To reflect Staff's adjustment for dividends declared.		**(4,888)**
(10)	**Rate Base Amortizations**		

ROCHESTER GAS & ELECTRIC CORPORATION
CASE 02-E-0198
SCHEDULE OF COMMISSION ADJUSTMENTS
ELECTRIC DEPARTMENT
FOR THE RATE YEAR ENDED June 30, 2003
($000)

	Explanation	Amount	
	To reflect adjustment to Nine Mile 2 Asset for COB2 offset	(10,337)	
	To reflect special one time amortization for revenue requirement (NM2).	(3,248)	
	Total Rate Base Amortizations		(13,585)
(11)	**Accumulated Deferred Income Taxes**		
	To reflect adjustment to Nine Mile 2 regulatory asset for COB2 offset	4,052	
	To reflect ADFIT associated with special one time amortization (NM2).	1,273	
	To recognize Accumulated Deferred Federal Income Tax effect of Site Remediation Reserve Adjustment. (SIRC).	(612)	
	Total Accumulated Deferred Income Taxes		4,713
	Subtotal Rate Base Amortizations		
	TOTAL RATE BASE		$ (14,807)
	RETURN ON EQUITY		
	To reflect the estimate of ROE.	9.96%	

PSC Case No. 02-G-0199	Rochester Gas & Electric Corporation	Appendix B
	Gas Income Statement	Schedule B
	For the Rate Year Ending June 30, 2003	Page 1 of 6
	($000)	

	Per RD	Adjust. No.	Commission Adjustments	As Adjusted Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Operating Revenues						
Retail Customers	$ 240,617	(1)	$ 903	$ 241,520	$ 5,078	$ 246,598
Distribution Customers - Net	41,272		0	41,272		41,272
Other Revenues	1,888		0	1,888		1,888
Total Operating Revenues	283,777		903	284,680	5,078	289,758
Operating Deductions						
Purchased Gas	157,519		0	157,519		157,519
Revenue Taxes	6,659		0	6,659	118	6,777
Total Operating Deductions	164,178		0	164,178	118	164,296
Gross Margin	**119,599**		**903**	**120,502**	**4,960**	**125,462**
Total Other Operating Expenses (From Page 2)	55,721	(2)	(2,179)	53,542	76	53,618
Depreciation/Amortization						
Amortization	(787)		0	(787)		(787)
Depreciation	16,833		0	16,833		16,833
Total Depreciation/Amortizations	16,046		0	16,046	0	16,046
Taxes Other Than Income						
Property Taxes	12,703		0	12,703		12,703
Payroll Taxes	2,293	(3)	(41)	2,252		2,252
Other Taxes	832		0	832		832
Taxes Other Than Income	15,828		(41)	15,787	0	15,787
Total Operating Revenue Deductions	87,595		(2,220)	85,375	76	85,451
Net Operating Revenues	**32,004**		**3,123**	**35,127**	**4,884**	**40,011**
Income Taxes						
Federal - Current	4,531	(4)	1,129	5,660	1,709	7,370
Federal - Deferred	2,986		0	2,986	0	2,986
NYS Income Tax	698	(5)	157	855	238	1,093
Total Federal Income Taxes	8,215		1,287	9,502	1,947	11,449
Net Income Available for Return	**$ 23,789**		**$ 1,836**	**$ 25,625**	**$ 2,936**	**$ 28,562**
Rate Base	**$ 354,991**	(6)	**$ (2,751)**	**$ 352,240**		**$ 352,240**
Rate of Return	**6.70%**			**7.27%**		**8.11%**
Return on Equity	**6.56%**			**7.95%**		**9.96%**

PSC Case No. 02-G-0199

Rochester Gas & Electric Corporation
Gas Operating & Maintenance Expense
For the Rate Year Ending June 30, 2003
($000)

	Per RD	Adjust. No.	Commission Adjustments	As Adjusted Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Operating & Maintenance Expenses						
Payroll	$ 28,837	(2a)	$ (578)	$ 28,259		$ 28,259
Employee Benefits	5,441	(2c)	(148)	5,293		5,293
Pension Income	(5,194)		0	(5,194)		(5,194)
PPP/EIP	588	(2b)	(588)	0		0
Vouchers Other	10,205		0	10,205		10,205
Vouchers Bank Services	530	(2d)	(884)	(354)		(354)
Postage	766		0	766		766
Telephone	219		0	219		219
Materials & Supplies	1,476		0	1,476		1,476
Vouchers-Outside Services	6,568		0	6,568		6,568
Vouchers-Travel	414		0	414		414
Voucher-Legal	741		0	741		741
Uncollectibles	4,500		0	4,500	76	4,576
Low Income	198		0	198		198
Research & Development	497		0	497		497
Insurance	162	(2e)	20	182		182
Advertising	356		0	356	0	356
PRIDE	(334)		0	(334)		(334)
Other	(249)		0	(249)		(249)
Total O&M Expense	**55,721**		**(2,179)**	**53,542**	**76**	**53,618**
Amortizations						
Contractor Settlement	0		0	0		0
Excess Reserve Amortization	0		0	0		0
Gas Revenue Stabilization	0		0	0		0
Merger Synergy Savings	(787)		0	(787)		(787)
Other	0		0	0		0
Total O&M Amortizations	**(787)**		**0**	**(787)**	**0**	**(787)**
TOTAL O&M and Amortization	**$ 54,934**		**$ (2,179)**	**$ 52,755**	**$ 76**	**$ 52,831**

PSC Case No. 02-G-0199

Rochester Gas & Electric Corporation
Gas Income Taxes - Current
For the Rate Year Ending June 30, 2003
($000)

	Per RD	Adjust. No.	Commission Adjustments	As Adjusted Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Net Operating Income Before FIT	$ 32,004		$ 3,123	$ 35,127	$ 4,884	$ 40,011
Interest - LTD	13,334		(104)	13,230		13,230
Interest - Customer Deposits	19		0	19		19
Operating Income Before FIT	18,651		3,227	21,878	4,884	26,762
Additional Income - Non-Deductions						
Other	0		0	0		0
Total Additions	0		0	0	0	0
Additional Deductions & Non-Taxable						
Preferred Stock Dividend	0		0	0		0
Additional Property Tax Deduction	(4,019)		0	(4,019)		(4,019)
Tax Depreciation	0		0	0		0
Nuclear Fuel Storage	0		0	0		0
Cost of Removal	(1,686)		0	(1,686)		(1,686)
Amortizations	0		0	0		0
Excess Earnings PassBack	0		0	0		0
Total Deductions	(5,705)		0	(5,705)	0	(5,705)
Taxable Income	12,946		3,227	16,173	4,884	21,057
Net FIT @ 35% - Current	$ 4,531		$ 1,129	$ 5,660	$ 1,709	$ 7,370
NYS Income Tax	$ 698		$ 157	$ 855	$ 238	$ 1,093

PSC Case No. 02-G-0199

Rochester Gas & Electric Corporation
Gas Federal Income Taxes - Deferred
For the Rate Year Ending June 30, 2003
($000)

	Per RD	Adjust. No.	Commission Adjustments	As Adjusted Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Provision for Deferred FIT						
Cost of Removal	56		0	56		56
Accelerated Depreciation	2,930		0	2,930		2,930
Excess Earnings Passback	0		0	0		0
Amortization	0		0	0		0
Other	0		0	0		0
Total Provision for Deferred FIT	$ 2,986		$ -	$ 2,986	$ -	$ 2,986

Rochester Gas & Electric Corporation
Gas Rate Base
For the Rate Year Ending June 30, 2003
($000)

	Per RD	Adjust. No.	Commission Adjustments	As Adjusted Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Net Utility Plant	**$ 364,318**		**$ -**	**$ 364,318**	**$ -**	**$ 364,318**
Field Completed Projects	17,586		0	17,586	0	17,586
PRIDE - Plant Adjustment	0	(6b)	(1,952)	(1,952)	0	(1,952)
Gas Cost Adjustment	(6,084)		0	(6,084)	0	(6,084)
Accrued Pension Costs	4,160		0	4,160	0	4,160
Other Post Employment Benefits	(15,843)		0	(15,843)	0	(15,843)
Site Remediation	(3,425)	(6a)	553	(2,872)	0	(2,872)
Amortization Items	1,378		0	1,378	0	1,378
Total Other Plant	**(2,228)**		**(1,399)**	**(3,627)**	**0**	**(3,627)**
Working Capital						
M&S	1,739		0	1,739	0	1,739
Gas Storage	16,685		0	16,685	0	16,685
Prepayments	5,904		0	5,904	0	5,904
O&M Expense	2,746		0	2,746	0	2,746
Total Working Capital	**27,074**		**0**	**27,074**	**0**	**27,074**
Accumulated Deferred FIT	**(28,412)**	(6d)	**(194)**	**(28,606)**	**0**	**(28,606)**
Accumulated Deferred ITC	**(5,761)**		**0**	**(5,761)**	**0**	**(5,761)**
EBCAP Adjustment	**0**	(6c)	**(1,158)**	**(1,158)**	**0**	**(1,158)**
Amortization Charges						
Other Miscellaneous	0		0	0	0	0
Total	**0**		**0**	**0**	**0**	**0**
Total Average Rate Base	**$ 354,991**		**$ (2,751)**	**$ 352,240**	**$ -**	**$ 352,240**

Rochester Gas & Electric Corporation
Computation of Gas Revenue Requirement
For the Rate Year Ending June 30, 2003
($000)

Average Rate Base	$	352,240
Rate of Return on Rate Base		8.11%
Required Net Income		28,562
Net Income Before Revenue Requirement		25,625
Earnings Deficiency (Excess)		2,937
Retention Factor		57.833%
Revenue Increase (Decrease)	$	5,078

Retention Factor Calculation

Sales Revenues	100.000%	$	5,078
Revenue Taxes	2.320%		118
Advertising	0.000%		0
Uncollectibles	1.500%		76
Retention Factor Before FIT	96.180%		4,884
Income Tax @FIT 35% & SIT @ 4.875%	38.347%		1,947
Retention Factor	57.833%	$	2,936

Per COMMISSION CAPITAL STRUCTURE	RATIO	COST	WEIGHTED COST
Long Term Debt	54.2%	6.93%	3.76%
Preferred Stock	4.3%	5.24%	0.23%
Common Equity	41.4%	9.96%	4.12%
Customer Deposit	0.1%	3.85%	0.00%
Total Capital	100.00%		8.11%

ROCHESTER GAS & ELECTRIC CORPORATION
CASE 02-G-0199
SCHEDULE OF COMMISSION ADJUSTMENTS
GAS DEPARTMENT
FOR THE RATE YEAR ENDED June 30, 2003
($000)

Adj. #	Explanation		Amount	
(1)	**Revenues**			
	To accept full Staff adjustment for Late Payments revenues	$	101	
	To increase SC #1 and SC #5 customer count to 290,000.		802	
	Total Margins			**$ 903**
(2)	**O&M Expense**			
(2a)	**Payroll**			
	To accept Staff adjustment for extra pay period		(151)	
	To accept 1% Productivity adjustment of adjusted wages		(427)	
	Total Payroll			**(578)**
(2b)	**PPP**			
	To accept Staff's elimination of Performance Plus Plan payout .		(588)	
	Total EIP/PPP			**(588)**
(2c)	**Benefits**			
	To reflect employee benefit loading associated with wage adjustments		(102)	
	To reflect inflation on medical insurance.		(46)	
	Total Benefits			**(148)**
(2d)	**Vouchers - Bank Services**			
	To accept Staff's adjustment to Bank Services expense.			**(884)**
(2e)	**Insurance**			
	To eliminate Company's Rebuttal change for insurance expense.			**20**
	Total O&M Expense			**(2,179)**
	Total O&M and Amortization Expenses			**(2,179)**

ROCHESTER GAS & ELECTRIC CORPORATION
CASE 02-G-0199
SCHEDULE OF COMMISSION ADJUSTMENTS
GAS DEPARTMENT
FOR THE RATE YEAR ENDED June 30, 2003
($000)

Adj. #	Explanation	Amount
(3)	**Taxes Other Than Income**	
	To reflect a 7.109% loading associated with payroll adjustments.	(41)
(4)	**Federal Income Taxes**	
	To reflect Federal Income Tax effect of various adjustments.	1,129
(5)	**State Income Taxes**	
	To reflect New York Income Tax effect of various adjustments.	157
(6)	**RATE BASE**	
	PLANT	
	Other Plant	
(6a)	To reflect Company's forecast of Site Remediation Reserve	553
(6b)	To reflect PRIDE plant adjustment	(1,952)
	Total Other Plant	(1,399)
(6c)	**Working Capital**	
	To reflect Staff's adjustment for dividends declared adjustment.	(1,158)
(6d)	**Accumulated Deferred Federal Income Taxes**	
	To adjust Accumulated Deferred FIT to track Site Remediation adjustment.	(194)
	Total Accumulated Deferred Taxes	(194)
	TOTAL RATE BASE	(2,751)

ROCHESTER GAS & ELECTRIC CORPORATION
CASE 02-G-0199
SCHEDULE OF COMMISSION ADJUSTMENTS
GAS DEPARTMENT
FOR THE RATE YEAR ENDED June 30, 2003
($000)

Adj. #	Explanation	Amount
	RETURN ON EQUITY	
	To reflect the estimate of ROE.	**9.96%**

ROCHESTER GAS AND ELECTRIC CORPORATION
COB 2 EXCESS EARNINGS

Appendix B
Schedule C
Attachment 1

	Year 1 7/97 - 6/98	Year 2 7/98 - 6/99	Year 3 7/99 - 6/00	Year 4 7/00 - 6/01	Year 5 7/01 - 6/02	5 Year Total
Per Book Earnings	78,071	82,508	76,529	74,589	(30,334)	281,363
Company Adjustments						
Synchronize interest expense	(5,050)	(5,001)	852	2,749	4,436	(2,014)
Synchronize preferred dividends	63	95	65	168	293	684
Interest on TCIs	240	340	212	495	571	1,858
Pension Income Charged to Other Income	3,252					3,252
Uncollectible Charged to Other Income	569					569
Interest on Regulatory Assets/Liabilities		3,190	7,300	7,619	7,349	25,458
Property tax deferral adjustment					2,169	2,169
Correct Departmental Income Tax Allocation			5,600			
Adjust amortizations to COB2 schedule	(1,542)	(3,552)	(1,579)	(2,323)	(3,424)	(12,420)
Income tax corrections					32,825	32,825
Exclude Esco Start-up costs above limit	198					
Book deferral of excess earnings				10,595	6,381	16,976
Sub-Total Company Adjustments to ROE	(2,270)	(4,928)	12,450	19,303	50,600	75,155
PSC Adjustments						
Exclude Interest on TCIs (Year 2 net of DOE)	(240)	(159)	(212)	(495)	(571)	(1,677)
Adjust Property tax deferral adjustment					(3,538)	(3,538)
Add Nine Mile 2 credits	2,113	1,730				3,843
Add gain on property		1,069				1,069
Adjust Uncollectible Charged to Other Income	157					157
Exclude PPP costs	1,729	3,450	1,817	2,470	1,885	11,351
Sub-Total RD Adjustments to ROE	3,759	6,090	1,605	1,975	(2,224)	11,205
Total Earnings - Per Commission	79,560	83,670	90,584	95,867	18,042	367,723
Per Book Common Equity	641,682	635,351	612,513	596,160	540,374	
Company Adjustmnents						
Book deferral of excess earnings				7,689	14,511	
PSC Adjustments						
Exclude TCI Capital	(11,719)	(2,995)	(4,754)	(7,528)	(8,658)	
Total Electric equity - Per RD	629,963	632,356	607,759	596,321	546,227	
Equity Return - Per Commission	12.63%	13.23%	14.90%	16.08%	3.30%	
Allowed Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	
Equity Return Shortfall - Per Commission	1.13%	1.73%	3.40%	4.58%	-8.20%	
Earnings Shortfall	7,114	10,949	20,692	27,290	(44,774)	21,271
Pre-tax Amount of Excess (Shortfall) @ 60.125%	11,832	18,210	34,414	45,389	**(74,469)**	**35,377**
Amount applied to Beebee & Storm Costs Residual						(10,349)
Interest						**19,791**
Residual Applied to Nine Mile 2 Deferral						**44,819**

ROCHESTER GAS AND ELECTRIC
REGULATORY ASSETS/LIABILITITES AND AMORTIZATIONS
$(000)

Appendix B
Schedule C
Attachment 2

	RG&E	Adjustment	Recommended Decision	Adjustment	Commission
RG&E Pre-Rate case balance	**386,530**	**0**	**386,530**	**0**	**386,530**
Adjustments					
Property Tax Reconciliation	0	(6,604)	(6,604)	0	(6,604)
COB earnings sharing	(9,900)	(34,915)	(44,815)	(10,353)	(55,168)
Customer Service Quality Penalty	0	0	0	(249)	(249)
One-time Write Down	(9,900)	(41,519)	(51,419)	(10,602)	(62,021)
Merger costs reconciling	0	(755)	(755)	0	(755)
Storm cost reconciling	0	35	35	0	35
Opening Balance Rate Case	376,630	(42,239)	334,391	(10,602)	323,789
Amortizations					
Uncontested amortizations	21,244	0	21,244	0	21,244
COB2 deferrals	1,404	(1,404)	0	0	0
Merger savings	(397)	0	(397)	0	(397)
Merger Savings SCRA	0	(1,509)	(1,509)	0	(1,509)
Subbtotal Non- Nine Mile 2 Amortizations	22,251	(2,913)	19,338	0	19,338
Nine Mile 2 Amortization - Per RG&E	14,309	0	14,309	0	14,309
Nine Mile 2 Amortization - COB 2	0	(1,723)	(1,723)	(530)	(2,253)
Nine Mile 2 Rate Moderator	0	9,068	9,068	6,495	15,563
Subbtotal Non- Nine Mile 2 Amortizations	14,309	7,345	21,654	5,965	27,619
Total Amortizations	**36,560**	**4,432**	**40,992**	**5,965**	**46,957**
Ending Balance	**340,070**	**(46,671)**	**293,399**	**(16,567)**	**276,832**

Amendments to Schedule P.S.C. No. 11 - Gas
19th Revised Leaf No. 87
13th Revised Leaf No. 88
Supplements Nos. 61, 63, and 65 to Schedule P.S.C. No. 11 - Gas

Amendment to Schedule P.S.C. No. 12 – Gas
3rd Revised Leaf No. 136
Supplements Nos. 2, 4, 6 to Schedule P.S.C. No.12 - Gas

Amendments to Schedule P.S.C. No. 13 – Electricity
37th Revised Leaf No. 21
41st Revised Leaf No. 22
28th Revised Leaf No. 22-A
52nd Revised Leaf No. 23
43rd Revised Leaf No. 30
18th Revised Leaf No. 38
Supplements Nos. 53, 54, 55 to Schedule P.S.C. No. 13 - Electricity

Amendments to Schedule P.S.C. No. 14 – Electricity
29th Revised Leaf No. 96
24th Revised Leaf No. 97
26th Revised Leaf No. 99
15th Revised Leaf No. 100
24th Revised Leaf No. 101
16th Revised Leaf No. 104
30th Revised Leaf No. 105
2nd Revised Leaf No. 105-A
25th Revised Leaf No. 106
20th Revised Leaf No. 115
10th Revised Leaf No. 115-A
23rd Revised Leaf No. 118
7th Revised Leaf No. 120-A
25th Revised Leaf No. 121
22nd Revised Leaf No. 122
7th Revised Leaf No. 123
19th Revised Leaf No. 125
2nd Revised Leaf No. 125-B
2nd Revised Leaf No. 125-C
2nd Revised Leaf No. 125-D
26th Revised Leaf No. 126
22nd Revised Leaf No. 128
22nd Revised Leaf No. 129
Supplements Nos. 89, 91 and 95 to Schedule P.S.C. No. 14 - Electricity

Amendments to Schedule P.S.C. No. 15 – Electricity
6th Revised Leaf No. 112
5th Revised Leaf No. 114
11th Revised Leaf No. 115-A
15th Revised Leaf No. 129
15th Revised Leaf No. 130
13th Revised Leaf No. 131
17th Revised Leaf No. 132
9th Revised Leaf No. 133
Supplements Nos. 17, 19, 23 to P.S.C. No. 15 -Electricity