NATIONAL GRID
RHODE ISLAND GAS

REQUEST FOR CHANGE OF
GAS DISTRIBUTION RATES

RIPUC DOCKET NO. 3943

BEFORE THE
RHODE ISLAND PUBLIC UTILITIES COMMISSION

TESTIMONY AND EXHIBITS
OF DAVID J. EFFRON

ON BEHALF OF THE

DIVISION OF
PUBLIC UTILITIES AND CARRIERS

JULY 25, 2008

RIPUC DOCKET NO. 3943
DIRECT TESTIMONY
OF DAVID J. EFFRON

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is David J. Effron. My business address is 12 Pond Path, North Hampton, New Hampshire, 03862.

Q. What is your present occupation?

A. I am a consultant specializing in utility regulation.

Q. Please summarize your professional experience.

A. My professional career includes over thirty years as a regulatory consultant, two years as a supervisor of capital investment analysis and controls at Gulf & Western Industries and two years at Touche Ross & Co. as a consultant and staff auditor. I am a Certified Public Accountant and I have served as an instructor in the business program at Western Connecticut State College.

Q. What experience do you have in the area of utility rate setting proceedings?

A. I have analyzed numerous electric, gas, telephone, and water filings in different jurisdictions. Pursuant to those analyses I have prepared testimony, assisted attorneys in case preparation, and provided assistance during settlement negotiations with various utility companies.

I have testified in over two hundred cases before regulatory commissions in Alabama, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maryland, Massachusetts, Missouri, Nevada, New Jersey, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, and Washington.

Q. Please describe your other work experience.

A. As a supervisor of capital investment analysis at Gulf & Western Industries, I was responsible for reports and analyses concerning capital spending programs, including project analysis, formulation of capital budgets, establishment of accounting procedures, monitoring capital spending and administration of the leasing program. At Touche Ross & Co., I was an associate consultant in management services for one year and a staff auditor for one year.

Q. Have you earned any distinctions as a Certified Public Accountant?

A. Yes. I received the Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 certified public accounting examination in New York State.

Q. Please describe your educational background.

A. I have a Bachelor's degree in Economics (with distinction) from Dartmouth College and a Masters of Business Administration Degree from Columbia University

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Rhode Island Division of Public Utilities and Carriers ("the Division").

Q. What is the purpose of your testimony?

A. I am addressing the revenue requirement of the Rhode Island gas operations of The Narragansett Electric Company, d/b/a National Grid ("National Grid" or "the Company") based on a test year consisting of the twelve months ended September 30, 2007 and a rate year consisting of the twelve months ending September 30, 2009. I also address the Company's proposed reconciliation mechanism for pensions and postretirement benefits other than pensions ("PBOP"), the proposal to implement annual rate adjustments for the revenue requirement impact of capital additions related to the Accelerated Replacement Program ("ARP"), and the alternative three-year rate plan proposed by the Company.

Q. Please summarize your testimony.

A. I have calculated a base rate revenue requirement of $131,225,000 for gas distribution service provided by National Grid in Rhode Island. The Company's revenue deficiency is $8,527,000, which is 6.95% greater than the revenues produced by the base rates presently in effect (Schedule DJE-1).

With regard to the rate reconciliation mechanisms and rate plan being proposed by the Company:

- The Commission should not approve the pension/PBOP reconciliation mechanism proposed by the Company.
- The Commission should not approve the annual ARP rate adjustment mechanism as presented by the Company. However, with certain modifications,

implementation of a mechanism for reconciling the revenue requirement effect of actual ARP expenditures, with annual rate adjustments, should be considered.

- The Commission should not approve the alternative three-year rate plan proposed by the Company.

III. REVENUE REQUIREMENT

A. SUMMARY

Q. Have you prepared a summary of the Company's net revenue requirement?

A. Yes, I prepared a summary on Schedule DJE-1. On this schedule, I compare the Company's presentation of its revenue deficiency to the Division's recommendation. I have begun with the Company's base rate cost of service. The base rate cost of service comp is comprised of operating expenses plus the return on rate base, as shown on my Schedule DJE-2. Next costs that are recovered through certain riders are added. I then subtract the miscellaneous revenues earned by the Company, including rider revenues (which are assumed to be equal to the costs subject to recovery through the riders), interruptible firm revenues, and other miscellaneous revenues. The total cost of service net of miscellaneous revenues is the revenue requirement from services that are provided pursuant to Commission approved base rates. The difference between the net revenue requirement and the rate year revenues earned from tariff services is the Company's revenue deficiency.

National Grid has calculated a revenue deficiency of $20,036,000, which is equal to 16.33% of rate year tariff revenues. I have calculated a revenue deficiency of $8,527,000, which is equal to 6.95% of rate year tariff revenues

B. COST OF SERVICE

Q. What are the elements of the cost of service?

A. The elements of the rate year cost of service are operation and maintenance expenses (with uncollectible accounts expense, which is derived from the other elements of the revenue requirement, shown separately), depreciation, taxes other than income taxes, income taxes, and return on rate base. These elements of the total cost of service are summarized on Schedule DJE-2.

Q. Are you proposing adjustments to the rate year cost of service calculated by the Company?

A. Yes. The Company has calculated a pro forma rate year net revenue requirement of $142,734,000. Based on the adjustments to the Company's position that I have identified, I am proposing a net base rate revenue requirement of $131,225,000. I address the individual adjustments to the Company's calculated cost of service in the following testimony.

1. Operation and Maintenance Expenses

a. Medical and Dental Expenses

Q. How did the Company determine pro forma rate year medical and dental expense?

A. The Company's calculation of pro forma medical and dental expense is .shown on Attachment NG-MDL-1, Page 8. First, the medical and dental expenses were estimated for calendar year 2008 based on the employee enrollment selections made in November 2007. Then, the estimated 2008 medical and dental costs were escalated by 8% to project the 2009 costs. The medical and dental costs for the twelve months ending September 30, 2009 consist of three months of the 2008 estimated costs and nine months of the projected 2009 costs. The pro forma rate year National Grid RI medical and dental expense of $4,614,000 represents a 21.4% increase over the actual test year expense.

Q. Have the Company's estimates of the increases in the medical and dental expense subsequent to the end of the September 2007 test year been borne out by actual experience?

A. No. In response to Division Data Request 4-11, the Company provided the actual medical and dental costs for each month from October 2006 through April 2008 The actual costs for the seven months ended April 2008 were actually less than the actual cost for the seven months ended April 2007, even with a significant credit to expenses that was recorded in October 2006. For the first four months of calendar 2008, the actual medical and dental costs were approximately 29% less than the costs in the corresponding months of 2008.

Q. Should the pro forma rate year medical and dental expense calculated by the Company be modified?

A. Yes. The actual experience in the months immediately after the test year does not support the Company's forecast of medical and dental expenses. As noted above, the costs in the first four months of 2008 were actually lower than the actual costs in the first four months in the corresponding months of 2007. Although four months of data might not offer conclusive evidence, the increases in expenses forecasted by the Company do not appear to be taking place. Therefore, I recommend that the Company's pro forma adjustment of $907,000 to medical and dental expenses be eliminated (Schedule DJE-4). This results in the pro forma rate year medical and dental expense being set at the same level as the actual test year expense. As the actual medical and dental expenses have decreased from 2007 to 2008, this allowance provides for escalation in the actual medical and dental costs incurred since the end of the test year.

b. Gas Marketing Expense

Q. Has the Company included expenses associated with its proposed gas marketing program in pro forma rate year operating expenses?

A. Yes. As shown on Attachment NG-MDL-1, Page 5, the Company includes $1,377,000 of gas marketing program costs in pro forma rate year operation and maintenance expenses. Additional support and explanation of the gas marketing program and the associated expenses are provided in the testimony of Company Witness Mongan.

Q. How have you treated these expenses in your determination of the Company's revenue requirement?

A. Division Witness Oliver addresses these programs and the associated expenses in his testimony. Consistent with that testimony, I have eliminated all but $148,000 of the expenses associated with the gas marketing programs. This adjustment results in a $1,229,000 reduction to pro forma rate year operation and maintenance expenses (Schedule DJE-4).

Q. Have you eliminated the incremental rate year sales that the Company has estimated will be produced by the gas marketing programs?

A. No. Given the present cost of gas of relative to the price of alternative fuels such as heating oil, I do not believe that it is unreasonable to expect that such growth in sales will be achieved even in the absence of the programs described by the Company. Mr. Oliver addresses this matter further in his testimony. In addition, I have also included the future additions to plant in service associated with the incremental sales in my calculation of rate base, and inclusion of the incremental sales in the rate year billing determinants is consistent with the recognition of these plant costs.

c. Encroachment Expense

Q. Has the Company included increased expenses related to "encroachment activity" in pro forma rate year expenses?

A. Yes. The Company has included $1,034,000 of additional test year operation and maintenance related to the encroachment activities in pro forma rate year expenses. As explained in the response to Division Data Request 1-11, this additional expense is inadvertently labeled as Accelerated Replacement Program expense on Attachment NG-MDL-1, Page 5. The Company further described the "increased encroachment activity" as referring to additional work resulting from increased public works activities and third party excavations (response to Division Data Request 4-10). The Company also explained that the increased expense is based on the backlog existing in early 2008 plus new encroachment anticipated in fiscal year 2008/2009. The Company's adjustment is based on its estimated increase from the $21,000 of expense actually incurred in the test year to a forecasted annual level of $1,054,000.

Q. Has the Company actually experienced an increase in spending on encroachment activity?

A. Yes. In the five months ended February 2008 the actual expense was $124,000 (response to Division Data Request 4-10). This is a significant increase in the rate of spending over the actual spending incurred in the test year; however it is still well short of the annual spending rate of $1,054,000 reflected by the Company in pro forma rate year expenses.

Q. Should the pro forma level of expenses relate to encroachment activity included by the Company in its revenue requirement be adjusted?

A. Yes. The actual experience cited by the Company does not support the annual level of expense of $1,054,000. If the actual expense of $124,000 for the five months ended February 2008 is annualized, the result is $298,000. This is $756,000 less than the pro forma expense reflected by the Company (Schedule DJE-4). Accordingly, I recommend that pro forma rate year operation and maintenance expense be reduced by $756,000, in order to reflect a rate of spending that is more in line with the Company's actual experience since the end of the test year.

d. Distribution Maintenance

Q. What amount of distribution maintenance expense did the Company incur in the twelve months ended September 30, 2007?

A. The Company incurred actual distribution maintenance expense of $16,804,000 in the test year.

Q. Did this maintenance expense include catch-up activities necessary to reduce backlogs of work existing prior to the beginning of the test year?

A. Yes. As explained in the responses to Division Data Requests 1-28 and 9-3, the actual test year maintenance expense included costs incurred to reduce the backlog of work associated with Grade 2 leaks and paving restoration existing prior to the beginning of the test year. The reduction in these backlogs was cited by the Company as one reason for the increase in distribution maintenance expense in the test year over prior periods.

Q. Should the pro forma distribution maintenance expense be adjusted?

A. Yes. In response to Division Data Request 9-4, the Company provided the distribution maintenance expense by month from October 2006 through May 2008. Based on this response, the increase in maintenance expense related to the backlog reduction does not appear to be continuing in nature. For example, the distribution maintenance expense for the twelve months ended March 31, 2008, the Company's latest fiscal year, was nearly $1 million less than the distribution maintenance in the test year. The expense for the twelve months ended May 31, 2008 was $539,000 less than the test year expense.

Q. What do you recommend?

A. The increased distribution maintenance expense related to the backlog reduction incurred in the test year does not appear to be continuing. I recommend that the pro forma distribution maintenance expense be reduced to reflect the actual expense for the twelve months ended May 31, 2008. This adjustment reduces pro forma operation and maintenance expense by $539,000 (Schedule DJE-4).

e. Merger Synergies and Costs to Achieve

Q. Has the Company included expense adjustments related to merger synergies and costs to achieve ("CTA") those synergies in its pro forma cost of service?

A. Yes. In August 2006, Narragansett Electric Company acquired the Rhode Island assets and operations of the former New England Gas division of Southern Union ("National Grid/Southern Union transaction"). The Company has quantified what it believes to be the synergy savings from that transaction and has included the Company share, or 50%, of those quantified savings in its revenue requirement in this case. This adjustment to expenses is $1,141,000. The assumptions underlying this expense adjustment are that 1) the synergies resulting from the Southern Union transaction are implicitly reflected in test year operating expenses, 2) the synergy savings would not have been possible in the absence of the transaction, and 3) shareholders are entitled to a share of the demonstrated savings in order to cover the costs of the transaction not explicitly included in the revenue requirement. The Company also includes the recovery of the CTA over ten years, with return, in pro forma expenses, resulting in an additional expense adjustment of $158,000. Thus the total expense adjustment related to the National Grid/Southern Union transaction is $1,299,000.

The Company has also reflected synergies and CTA associated with the acquisition of KeySpan by National Grid USA ("National Grid/KeySpan transaction"). The synergies from the National Grid/KeySpan transaction are not included in the actual test year cost of service, because the synergy savings had not been achieved in the test year. The Company has estimated annual synergy savings of $6,400,000 and annual CTA of $1,500,000 (again reflecting a ten year recovery of the total CTA, with return). The Company reflects 50% of the annual net savings of $4,900,000, or $2,450,000, as a credit to the pro forma cost of service (Attachment MDL-1, Page 5).

Q. How did the Company calculate the synergies from the National Grid/Southern Union transaction?

A. The Company's calculation of the synergies from the National Grid/Southern Union transaction is shown on Attachment NG-MDL-1, Page 20. The gross merger savings are calculated based on the reduction in the employee complement attributable to the transaction and the savings from the sale of the Providence office building, which the Company treats as having been made possible by the merger. These gross merger savings are offset by increases in non-labor customer accounting and A&G expenses from the twelve months ended June 30 2006 (pre-merger) to the twelve months ended September 30, 2007 (post-merger) and the costs to achieve the synergies. The calculated net synergies are $2,281,000, of which the Company's share is 50%, or $1,141,000.

Q. Should the Company share of synergies and the CTA associated with the National Grid/Southern Union transaction be included in the Company's pro forma test year revenue requirement?

A. No. The Company uses an after-the-fact method that takes into account only selected changes in expenses in order to calculate achieved synergies. This is not to say that the Company intentionally contrived a method of measurement to show synergy savings when no such savings actually exist. However, when the method of measuring savings is determined after the transaction has taken place, it is not unlikely that the method selected from a number of possible different methods is going to show the results of the merger in the most favorable light. The method of measuring the savings on Attachment NG-MDL-1, page 20 should not be accepted for the purpose of measuring synergy savings from the National Grid/Southern Union transaction.

The Commission has already adopted a method of measuring synergy savings achieved by the former New England Gas, which was formed by the merger of the former Providence Gas Company and the former Valley Gas Company and the acquisition of those companies by Southern Union. I have replicated this method, which is substantially the same as the method used to measure synergies achieved by the merger of the former Blackstone Valley Electric Company and Newport Electric Company into Narragansett Electric Company, on Schedule DJE-4.1. This method considers changes in the total cost of service, not just changes in selected expenses. This is the method of measuring achieved synergies that should be used to measure the synergies achieved by the National Grid/Southern Union transaction because: 1) it has already been approved for this Company, 2) it was already in existence prior to the transaction, and 3) and it is a broad measure of changes in the cost of service.

If the method on Schedule DJE-4.1, rather than the method on Attachment NG-MDL-1, Page 20, is used to measure synergies achieved by the National Grid/Southern Union transaction, there are no synergies. Accordingly, the Company share of the synergies and the associated CTA should be eliminated from the Company's revenue requirement. This elimination of the Company's adjustment reduces pro forma operation and maintenance expense by $1,299,000 (Schedule DJE-4).

Q. Should the synergies net of CTA associated with the National Grid/KeySpan transaction be included in the determination of the Company's test year revenue requirement in this case?

A. Because the effect of the National Grid/KeySpan transaction is not already reflected in the test year cost of service, this adjustment is a credit to the Company's revenue requirement. As this treatment is beneficial to customers, there is no reason to oppose the Company's adjustment to recognize these synergy savings in this case.

However, in future cases, the full savings from National Grid/KeySpan transaction will already be included in the test year cost of service. In those future cases, the Company will therefore be seeking to include its retained share of the savings and the CTA as a pro forma expense to be recovered in its revenue requirement (in the same manner that it seeks to include its share of the claimed National Grid/Southern Union synergies and CTA in this case). The inclusion of the expected synergy savings in the present case should not be deemed to be a finding that the savings have actually been achieved *and* will continue in effect in future years. In response to Division Data Request 9-2, the Company stated that its share of the calculated savings and the CTA, $2,450,000, is a fixed amount that will be included in the cost of service in future rate cases. The Commission should not approve the inclusion of this pro forma expense in future rate cases unless the Company can demonstrate, using a method similar to that on Schedule DJE-4.1, that the synergies have been achieved and are actually continuing. In addition, there should be a time limit of ten years on the inclusion of this item in the Company's revenue requirement.

f. Uncollectible Accounts Expense

Q. Have you also adjusted the uncollectible accounts expense included in the Company's revenue requirement?

A. Yes. The allowance for uncollectible accounts is calculated as a percentage of the other components of the cost of service. Therefore, the pro forma uncollectible accounts expense is affected by the other adjustments to the Company's revenue requirement. My calculation of the adjustment to the uncollectible accounts expense related to the other revenue requirement adjustments is shown on Schedule DJE-3. I also reflect the adjustment to uncollectible accounts expense related to the Company's proposed rate discounts for low income customers, which is addressed in the testimony of Mr. Oliver.

2. Depreciation Expense

Q. Have you reflected an adjustment to test year depreciation expense in you calculation of the rate year cost of service?

A. Yes. As depreciation expense is calculated by applying the relevant depreciation accrual rates to the depreciable plant in service, my proposed adjustment to plant in service (addressed in my testimony on rate base) affects the rate year depreciation expense. The adjustment to depreciation expense resulting from my proposed adjustment to plant in service is shown on Schedule DJE-5.

4. Income Tax Expense

Q. Have you calculated the pro forma income tax expense to be included in the Company's revenue requirement?

A. Yes. I have calculated the pro forma income tax expense on my Schedule DJE-6. I have used what is commonly referred to as the "return method" of calculating pro forma income tax expense. This method begins by calculating the taxable income base (that is, the net income after income tax expense) by applying the weighted return on equity to the rate base and adjusting the product of that calculation by permanent tax reconciling items. To determine the taxable income, the adjusted net income must then be grossed up, as the income tax expense itself is not deductible for federal income taxes. Finally, the income tax rate of 35% is applied to the taxable income to calculate the pro forma income tax expense to be included in the Company's revenue requirement.

5. Return on Rate Base

Q. How is the return on rate base to be included in the total revenue requirement calculated?

A. The return on rate base is calculated by multiplying the rate of return by the rate base. The rate base is the net investment in facilities necessary to provide utility service. I am proposing adjustments to rate base, and I have incorporated the recommendation of Mr. Rothschild on rate of return into my calculation of the required return on rate base.

a. Rate Base

Q. How did the Company determine the balance of gross utility plant that it is proposing to includes in its pro forma rate base?

A. The gross utility plant included in rate base is the forecasted average balance for the twelve months ending September 30, 2009, the Company's rate year. The Company began with the actual balance of plant as of September 30, 2007, the end of the test year, and then adjusted that balance for forecasted additions to and retirements from plant in through September 30, 2009. The average balance of gross utility plant forecasted by the Company for its rate year is $589,769,000.

Q. Have you analyzed the Company's forecast of gross utility plant for the twelve months ending September 30, 2009?

A. Yes. I have reviewed the budgeted additions to plant for fiscal years 2008, 2009 and 2010[1] and the conversion of the budgets for those fiscal years to the forecasts of additions for the twelve months ending September 30, 2008 and the twelve months ending September 30, 2009. I have also compared the Company's forecasts of additions and retirements in those fiscal years to actual additions and retirements in recent years, and I have reviewed the actual and budgeted additions to plant in service from October 2007 through March 2008.

Q. Based on your analysis, are you proposing any adjustments to the forecasted plant balance included in rate base by the Company?

A. Yes. Referring to Attachment NG-MDL-1, it can be seen that the Company is forecasting additions to plant in service of $36,679,000 in the twelve months ending September 30, 2008 and $60,780,000 in the twelve months ending September 30, 2009. These forecasts, even exclusive of the effect of new programs such as the ARP, exceed the level of additions to plant in service in recent years and also the rate

[1] I refer to the twelve months ending March 31 of a given year as the Company's fiscal year.

of actual additions to plant in service since the end of the test year. Accordingly, I recommend that the Company's forecast of additions to plant in service subsequent to the end of the test year be modified.

Q. How are you proposing to modify the Company's forecast of plant additions through the end of the rate year?

A. My proposed adjustments to the Company's forecast of rate year plant in service are shown on Schedule DJE-7.1, Page 2. My adjustments can be broken out into four separate six-month time periods: October 2007 – March 2008, April 2008 – September 2008, October 2008 – March 2009, and April 2009 – September 2009.

Q. Please explain your proposed adjustment to the Company's forecast of plant additions for the period October 2007 – March 2008.

A. The Company's estimate is based on its forecasted plant additions in its 2008 fiscal year. The forecasted plant additions for that fiscal year were $31.2 million. However, the actual rate of spending through September 30, 2007, the end of the test year, was only $13.4 million. The Company assumed that the slower rate of spending in the first six months of the 2008 fiscal year would be made up by a higher rate of spending in the last six months of the fiscal year, resulting in forecasted average spending of $2,968,000 per month for the six months October 2007 – March 2008, or a total of $17,909,000 for that period.

The response to Division Data Request 1-2 provided the actual plant additions by month for the six months October 2007 – March 2008. This response shows that the actual spending for that six month period was $14,360,000. Not only was the actual spending below the Company's revised forecast of increased spending for the last six months of fiscal 2008, it was also below the average forecasted rate of spending for fiscal year 2008 as a whole. As we now have the actual plant additions for the six months October 2007 – March 2008, those actual additions should be substituted for the Company's forecast, which was clearly overstated. This adjustment reduces the plant in service by $3,449,000. I show this adjustment by month on Schedule DJE 7.1, Page 2.

Q. Please explain your proposed adjustment to the Company's forecast of plant additions for the period April 2008 – September 2008.

A. The Company's forecast of spending for this period is shown in the response to Division Data Request 1-1, Page 2 of the Attachment. The forecast is based on the fiscal year 2009 budget. Other than the Accelerated Pipe Replacement Program ("the ARP", only $86,000 per month in this period) and spending related to the marketing program (which, as I explained above, I am not challenging) the budgeted routine capital spending is $2,699,000 per month.

I recommend that the routine plant additions included in rate base for this period reflect the actual experience for the six months October 2007 – March 2008, or $2,393,000 per month. First, based on the comparison of actual plant additions to budgeted plant additions in fiscal year 2008, the Company has demonstrated a tendency to over-estimate future plant additions, so downward adjustment to the Company's budget is warranted on these grounds. Second, the budgeted additions of

$2,699,000 per month are well in excess of the average rate of actual plant additions in recent years, and a downward adjustment would bring the projection more into line with recent experience.

Reducing the projected plant additions from $2,699,000 per month to $2,393,000 per month decreases the total plant addition for the six month period by $1,831,000. Again, this adjustment is shown on Schedule DJE-7.1, Page 2.

Q. Please explain your proposed adjustment to the Company's forecast of plant additions for the period October 2008– March 2009

A. The Company's forecast of spending for this period is also based on the fiscal year 2009 budget. However, the spending on the ARP is budgeted to increase from $86,000 per month to $1,691,000 per month[2] for this period. With regard to the routine plant additions (other than ARP and spending related to the marketing program), I recommend that the estimated additions be assumed to continue at $2,393,000 per month. With regard to the ARP, I believe that it is difficult to know at this time just what the rate of spending will be. However, the Company's forecast of $1.7 million per month is well in excess of the rate of spending that the Company itself is forecasting over time. For example, the budgeted ARP replacement in fiscal 2010 is $1.1 million per month. For the purpose of calculating the rate year rate base, I have reflected ARP spending of $1,000,000 per month for the period October 2008– March 2009. However, as I explain in my testimony on

[2] This amount and the amount for the first six months of the fiscal 2009 represent the true acceleration of the pipe replacement program. The routine capital spending also includes $10.8 million for mains and services replacement.

the Company's proposed reconciliation mechanisms, the Commission should consider reconciling actual ARP spending against the assumed level of ARP spending included in rate base in this case and implement appropriate rate adjustments.

Reducing the projected monthly spending on routine plant additions by $305,000 and the projected ARP monthly spending by $691,000 decreases the total plant addition for this six month period by $5,977,000. This adjustment is also shown on Schedule DJE-7.1, Page 2.

Q. Please explain your proposed adjustment to the Company's forecast of plant additions for the period April 2009 – September 2009.

A. The Company's forecast of spending for this period is based on the fiscal year 2010 budget (response to Division Data Request 1-1, Attachment, Page 3). In addition to the spending categories in fiscal year 2009, the fiscal year 2010 spending includes $4,600,000 of spending on automatic meter reading equipment, all of which is in the first three months of the fiscal year. The routine spending is forecasted to increase from $2,699,000 per month to $3,048,000 per month, and the ARP sending is forecasted to decrease to $1,115,000 per month.

I am proposing to increase the forecast of routine capital spending from $2,393,000 per month in fiscal 2009 to $2,500,000 to in fiscal 2010. I believe that this is a reasonable allowance for inflation and system growth from fiscal 2009 to fiscal 2010. It is a reduction of $548,000 per month to the Company's forecast. I am also proposing to maintain the ARP spending at a rate of $1,000,000 per month, which is $115,000 per month less than the Company's forecast. Together, these adjustments represent a decrease of $663,000 per month, or $3,977,000 from the Company's forecast of additions for the six month period.

Q. What is the effect of your proposed adjustments to the Company's forecast of plant additions through the end of the rate year?

A. The effect of my proposed adjustments to the Company's forecast of capital additions is summarized on Schedule DJE-7.1, Page 1. I am proposing to reduce the Company's forecast of plant additions for the twelve months ending September 30, 2008 by $5,282,000. This adjustment results in a reduction to the rate year rate base by the same amount. I am also proposing to reduce the Company's forecast of plant additions for the twelve months ending September 30, 2009 by $9,954,000. As the rate year rate base reflects the forecasted average balance of plant in service for the twelve months ending September 30, 2009, this adjustment to plant additions reduces the rate year rate base by one-half of the amount of the adjustment, or $4,977,000. My proposed adjustment to the Company's forecast of plant additions reduces the plant in service included in the rate year rate base by $10,259,000.

As the pro forma rate year depreciation expense is calculated by applying the composite depreciation rate to the average balance of rate year plant, my proposed adjustment to plant in service also affects the pro forma depreciation expense. On Schedule, DJE-5, I have calculated a reduction of $347,000 to pro forma rate year depreciation expense related to the adjustment to plant in service.

The adjustment to plant additions also results in a reduction of $279,000 to the balance of accumulated depreciation deducted from plant in service in the determination of rate base. This adjustment is shown on Schedule DJE-7.1, Page 1.

b. Rate of Return

Q. What rate of return have you used to calculate the return requirement to be included in the total cost of service?

A. I have used the rate of return of 8.56% proposed by Mr. Rothschild to calculate the required return on rate base.

Q. What return on rate base have you calculated?

A. I have calculated a required return on rate base of $23,734,000 (Schedule DJE-7) and included this return component in the Company's total revenue requirement.

IV. RECONCILIATION MECHANISMS

A. PENSION/PBOP RECONCILIATION MECHANISM

Q. Please describe the pension/PBOP reconciliation mechanism being proposed by the Company.

A. The pension/PBOP reconciliation mechanism will allow the Company to recover changes in pensions and postretirement benefits other than pension ("PBOP") through a reconciling mechanism that will be included in the distribution adjustment clause ("DAC"). The mechanism would reconcile the future actual pension and PBOP expenses recorded by the Company to the pension and PBOP expenses included in its revenue requirement in this case. Any difference between the actual expenses and the amounts included in the revenue requirement would be recovered or refunded to customers through the Company's DAC in the following year. In addition, if the amount contributed to the pension and PBOP funds differs from the actual expense accruals, ratepayers would pay carrying costs (at the authorized pre-tax rate of return) on any excess funding or be credited for carrying costs on any under-funding.

Q. What objectives does the Company seek to achieve by implementing this reconciling mechanism?

A. The Company cites two objectives. First, the proposed mechanism would provide adequate funding to support the pension and PBOP obligations. Second, the proposed mechanism would ensure that customers pay the amounts necessary to provide pension and PBOP benefits to employees.

Q. Has National Grid established that the proposed pension and PBOP reconciliation is a necessary and appropriate mechanism to implement at this time?

A. No. As a general matter, reconciliation mechanisms are contrary to sound ratemaking practice, as such mechanisms tend to either reduce or eliminate incentives to control costs that exist under traditional ratemaking practices. National Grid presents the reconciling mechanism as a means of addressing the volatility of pension and PBOP costs and mitigating potential financial concerns resulting from such volatility. However, the Company has not provided any measurement of the volatility of pension and PBOP costs or any measurement of how the magnitude of changes in these expenses relate to overall revenue requirements; nor has the Company compared the magnitude or volatility of pension and PBOP costs relative to other costs for which there is no adjustment mechanism.

Q. Has the Company presented any data or analysis that establishes the potential for the volatility of the pension/PBOP expense to impair its financial integrity?

A. No. Pension costs are accrued pursuant to Statement of Financial Accounting Standards 87 and PBOP expenses are accrued pursuant to Statement of Financial Accounting Standards 106. Both of these accounting standards require certain actuarial and financial assumptions. While it is true that changes in those assumptions can cause pension and PBOP expenses to fluctuate, just about all other expenses included in the Company's base rate cost of service are also subject to fluctuation. The Company has not adequately explained why pension and PBOP costs should be treated differently from these other expenses that go into the base rate revenue requirement. Further, the Company has not presented any analysis showing that the fluctuations in pension and PBOP costs are of such a magnitude that they have the potential to impair its financial integrity.

Q. Is the proposed mechanism necessary to achieve the objectives cited by the Company?

A. No. The funding for the pension and PBOP programs is provided by the inclusion of the accruals in the cost of service, regardless of whether those accruals are subject to reconciliation. That is, the Company gets the cash from customers to pay for these programs by including the expenses in the revenue requirement. The expense accruals are already calculated in a manner so as to provide adequate funding of the programs, even without any reconciliation mechanism. With regard to the second objective, the amounts to pay pension and PBOP benefits to employees come from the separate funds from those programs. The contributions to those funds come from the recovery of the expense accruals in rates. The Company has presented no evidence that the present method has resulted in inadequate funding of the pension and PBOP programs.

Q. If the Company could demonstrate that, absent the implementation of the proposed mechanism, the fluctuations in the pension and PBOP pose a significant risk, is its proposal complete?

A. No. The Company does not presently have any pension and PBOP reconciliation mechanism in place, nor were any such mechanisms in place at the time of the last base rate case. Thus, to the extent the volatility of pension and PBOP expense causes financial risks, such risks are implicitly incorporated into the cost of common equity. If a reconciliation mechanism is approved, then such financial risks are transferred to the Company's customers, and the authorized return on common equity should be reduced to incorporate that reduced level of risk.

Q. Should the pension and PBOP reconciliation mechanism proposed by the Company be approved?

A. No. The Company has not established that the pension and PBOP expenses should be treated differently form the other expenses that go into its revenue requirement, or that such a mechanism is necessary to assure adequate funding of the pension and PBOP programs.

B. ARP RATE ADJUSTMENT MECHANISM

Q. Please describe the Accelerated Replacement Program ("ARP") annual rate adjustment mechanism being proposed by the Company.

A. As referenced in my testimony on rate year plant in service, National Grid is proposing to accelerate the replacement of bare steel and cast iron mains and high pressure bare steel services. The Company is requesting authorization to implement annual rate adjustments for the revenue requirement effect of the capital additions related to this program to the extent that the additions exceed the amounts included in the rate year rate base. The rate adjustments would include the effect of the return on cumulative incremental investment, incremental depreciation, and property taxes.

Q. Should the ARP rate adjustment mechanism as proposed by the Company be approved?

A. No. First there are several mechanical problems with the mechanism as proposed by the Company. For example, as the title implies the ARP is a *replacement* program, not just a capital additions program. That is, as plant is added, other plant will be retired. However, the calculation of the revenue requirement effect, while recognizing the increase in depreciation expense related to plant additions, does not recognize reductions to depreciation expense related to associated plant retirements (Attachment NG-MDL-5). Further, the calculation of the additional depreciation expense applies the proposed composite depreciation expense on all plant in service, although the depreciation rates on the mains and services are somewhat lower than the average composite rate. Finally, the Company calculates the incremental property taxes by applying the composite municipal property tax rate to the gross plant additions (without consideration of plant retirements or growth in accumulated depreciation). However, as can be seen on Attachment NG-MDL-1, page 22, the pro forma municipal property tax expense included in the Company's revenue requirement is not calculated as a percentage of plant in service, but rather is a projection of the trend in the expense in recent years, without explicit regard to plant additions.

There are two more basic problems with the ARP rate mechanism proposed by the Company. First, as described by Mr. Laflamme at pages 52 – 55 of his testimony, the ARP rate adjustment would apply to *all* main and service replacement expenditures, not just the *acceleration* of such expenditures. For example, the fiscal year 2009-2010 capital spending budget reflects $26.7 million for main and service replacements (Attachment NG-SLF-2), substantially all of which would be subject to the ARP rate adjustment mechanism. However, as can be seen in the response to Division Data Request 1-1, only about half that amount, $13.4 million, relates to the *accelerated* replacement program. Based on the Company's capital budget for fiscal year 2009-2010, the remaining $13.3 million would be spent on main and service replacements, even in the absence of the accelerated pipe replacement program. The Company's proposal is especially problematical in the fiscal years subsequent to 2010, when the rate adjustments would apply to the full amount of the main and service replacements[3], even though a substantial portion of those replacements would be routine replacements unrelated to the program to accelerate the replacement of mains and services

Second, the mechanism as proposed by the Company would allow for rate increases for main and service replacements, even if the additions did not result in an overall revenue deficiency. Thus, the ARP rate adjustment mechanism as proposed by the Company could lead to, or even enhance, an excess earnings situation.

Q. Should the Commission approve the annual ARP rate adjustment mechanism as proposed by the Company?

A. No. However, the Division believes that the ARP is a beneficial program, and to the extent that any disincentives to incurring necessary and prudent expenditures can be removed by means of an appropriately designed rate adjustment mechanism, the Commission should not reject the implementation of such a mechanism out of hand. However, the ARP rate adjustment mechanism proposed by the Company should be modified to address the above described technical issues, should apply only to the *acceleration* of main and service replacements, and should be subject to an earnings test so that any resulting rate increases do not result in excess earnings.

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[3] Actual replacements in fiscal years 2009 and 2010 would be reconciled to the main and service

V. ALTERNATIVE THREE-YEAR RATE PLAN

Q. Please describe the alternative three-year rate plan ("Rate Plan") being proposed by the Company.

A. The proposed three-year rate plan would implement annual rate increases of approximately $13.8 million per year for three years beginning with the conclusion of this case, rather than a one-time increase of $20.0 million. The annual rate increases are based on the Company's calculated revenue deficiency for the rate year and its projected revenue requirements for the two years following the rate year. The stated purpose of the three-year rate plan is to mitigate the initial rate increase and to smooth the revenue requirements over three years. The three year rate plan would subsume the ARP rate adjustment mechanism during its term, as the ARP capital expenditures would be included in the rate base, along with all other capital additions, over the course of the plan. The proposed ARP rate adjustment would be replaced by a more comprehensive Capital Tracker, which would reconcile *all* capital expenditures, including the Accelerated Pipe Replacement Program, against the capital additions forecasted in the calculation of the three year revenue requirement.

Q. Should the Commission approve the alternative three-year rate plan proposed by the Company?

A. No. First, the Division is proposing a substantial reduction to the initial rate increase being requested by the Company. To the extent that the rate increase is

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replacements included in the rate year rate base in this case.

reduced, the effect of mitigating that rate increase by phasing it in over three years is of less benefit.

Second, as noted above, the three year rate plan is based on a projection of the revenue requirements in the rate year plus the two following years. I believe that it is difficult enough to forecast the revenue requirement for the rate year, much less the two years after the rate year. In my opinion, it is not possible to project the Company's revenue requirements in the twelve months ending September 30, 2012 with any reasonable degree of certainty to the extent that such projections can be used to establish rates going into effect in 2008.

Third, as a practical matter, the three year rate plan works only if the Commission accepts the Company's calculation of its rate year revenue deficiency exactly as presented, which in my experience would be highly unusual. If the Commission were to modify any of the elements of the Company's calculated revenue deficiency, then ancillary issues would arise as to how such modifications should be incorporated into the projections of the revenue requirements in the two years following the rate year, or if they should be incorporated at all. I believe that these practical considerations would make the three-year rate plan extremely difficult, if not impossible, to implement.

Over its proposed term, the Company's alternative three year rate plan, with the three annual rate increases, would, on a cumulative basis, provide it with approximately $23 million of revenues in excess of the revenues produced by its requested one time increase of $20 million (excluding the effect of any ARP rate adjustments). I do not believe that such a plan is beneficial to customers, and the Commission should not approve it

Q. Does this conclude your direct testimony?

A. Yes.

Schedule DJE-1

NATIONAL GRID - RI GAS
RATE YEAR REVENUE REQUIREMENT
($000)

	(A) Company Position	(B) Adjustments	Division Position
Base Rate Cost of Service	$ 146,501	$ (11,510)	$ 134,992
Costs Subject to Rider Recovery	3,385	-	3,385
Total Cost of Service	149,886	(11,510)	138,377
Rider Revenues	3,385		3,385
Interruptible Firm Revenues	1,600		1,600
Other Miscellaneous Revenues	2,167	-	2,167
Base Rate Revenue Requirement	$ 142,734	$ (11,510)	$ 131,225
Base Rate Revenues, Present Rates	122,698	-	122,698
Revenue Deficiency	$ 20,036	$ (11,510)	$ 8,527
Percentage Rate Increase	16.33%		6.95%

Notes:

(A) NG-MDL-1, Page 1
(B) Schedule DJE-2

NATIONAL GRID - RI GAS
COST OF SERVICE
($000)

	(A) Company Position	Adjustments		Division Position
Uncollectible Accounts Expense	$ 3,595	$ (688)	(B)	$ 2,907
Other Op & Maint Expense	78,105	(4,730)	(C)	73,375
Depreciation and Amortization	20,310	(347)	(D)	19,963
Taxes Other Than Income Taxes	10,021	-		10,021
Income Taxes	8,029	(2,862)	(E)	5,167
Return on Rate Base	26,442	(2,883)	(F)	23,559
Total Base Rate Cost of Service	$ 146,501	$ (11,510)		$ 134,992
Costs Subject to Rider Recovery	3,385	-		3,385
Total Cost of Service	$ 149,886	$ (11,510)		$ 138,377

Sources:

(A) NG-MDL-1, Page 1
(B) Schedule DJE-3
(C) Schedule DJE-4
(D) Schedule DJE-5
(E) Schedule DJE-6
(F) Schedule DJE-7

NATIONAL GRID - RI GAS
ADJUSTMENTS TO UNCOLLECTIBLE ACCOUNTS EXPENSE
($000)

Other Adjustments to Revenue Requirement:

Other Op & Maint Expense		(A)	$ (4,730)
Depreciation and Amortization		(A)	(347)
Taxes Other Than Income Taxes			-
Income Taxes		(A)	(2,862)
Return on Rate Base		(A)	(2,883)
Total			(10,822)
Adjustment to Uncollectible Accounts Expense	2.46%	(B)	(273)
Adjustment for Low Income Rate Discounts		(C)	(415)
Total Adjustment to Uncollectible Accounts Expense			$ (688)

Sources:
- (A) Schedule DJE-2
- (B) NG-MDL-1, Page 32
- (C) Testimony of Mr. Oliver

Schedule DJE-4

NATIONAL GRID - RI GAS
OPERATION AND MAINTENANCE EXPENSE
($000)

Medical and Dental Expenses	(A)	$	(907)
Gas Marketing Expense	(B)		(1,229)
Increased Encroachment Activity Expense	(C)		(756)
Distribution Maintenance Expense	(D)		(539)
National Grid/Southern Union Synergies and CTA	(E)		(1,299)
Total Adjustment to Operation and Maintenance Expense		$	(4,730)

Sources

(A)	NG-MDL-1, Page 5			
(B)	Testimony of Division Witness Oliver		148-1377	
(C)	Encroachment Spending 10/07-02/08		124	DIV 4-10
	Annualized Spending	12/5	298	
	Company Pro Forma Expense		1,054	DIV 4-10
	Adjustment to Company Expense		(756)	
(D)	Distribution Maint. 12 Mos 5/31/08		16,265	DIV 9-4
	Distribution Maint. 12 Mos 9/30/07		16,804	DIV 9-4
	Adjustment to Test Year Expenses		(539)	
(E)	NG-MDL-1, Page 5 -1141-158			

Schedule DJE-4.1

NATIONAL GRID - RI GAS
TEST OF ACHIEVED SAVINGS - DOCKET NO. 3401 FORMULA
($000)

1	Benchmark Cost of Service					127,700
2	GDPIPD Growth Y/E 6/30/2004	2.98%	*	50%	1.0149	
3	GDPIPD Growth Y/E 6/30/2005	3.29%	*	50%	1.0164	
4	GDPIPD Growth Y/E 6/30/2006	3.19%	*	50%	1.0160	
5	GDPIPD Growth Y/E 6/30/2007	2.39%	*	50%	1.0120	
6	GDPIPD Growth 3 Mos. 9/30/2007	0.60%	*	50%	1.0030	
7	Escalated Benchmark COS					135,847
8	2003 Therm Sales from Settlement (000)				345,400	
9	Weather Adjusted Y/E 9/30/2007 Therm Sales (000)				342,685	
10	Weather Normalized Sales Growth				-0.786%	
11	Cost Growth Factor				30%	
12	Adjustment for Growth					(320)
13	Adjusted Benchmark Cost of Service					135,526
14	Normalized Cost of Service - Year Ended 9/30/2007					147,928
15	Proved Savings					-

Line Notes

1,8,11	Docket No. 3401, Settlement Appendix D		
2-6	Implicit Price Deflator for Period		
7	Product, Lines 1-6		
9	Attachment NG-PCC-2, Page 1		
10	Line 8/Line 9 -1		
12	Line 10/Line 11 * Line 7		
13	Line 7 + Line 12		
14	Attachment NG-MDL-1, Page 1		
	Other Operation and Maintenance Expenses		77,899
	Uncollectible Accounts Expense		9,005
	Depreciation and Amortization Expense		21,221
	Taxes Other Than Income		9,995
	Rate Base	252,408	
	ROR, w/ FIT Gross-up (Docket 3859)	11.81%	
	Return Requirement, Including Income Taxes		29,808
	Normalized Cost of Service		147,928
15	Line 13 - Line 14, not Less than Zero		

NATIONAL GRID - RI GAS
ADJUSTMENTS TO DEPRECIATION EXPENSE
($000)

Adjustment to Plant in Service	(A)	$	(10,259)
Composite Book Depreciation Rate	(B)		3.38%
Adjustment to Pro Forma Depreciation Expense		$	(347)

Sources:
- (A) Schedule DJE-7.1
- (B) NG-MDL-1, Page 31

NATIONAL GRID - RI GAS
INCOME TAX EXPENSE
($000)

Rate Base	DJE-7	$ 275,261
Weighted Return on Equity	DJE-8	3.76%
Preliminary Taxable Income Base		10,345
Tax Reconciling Items	NG-MDL-1, Page 31	(749)
Taxable Income Base		9,596
Taxable Income	Taxable Income Base/.65	14,763
Income Tax Rate		35%
Income Tax Expense		5,167

Schedule DJE-7

NATIONAL GRID - RI GAS
RETURN ON RATE BASE
($000)

		(A) Company Position	Adjustments		Division Position
Gas Plant in Service		$ 589,769	(10,259)	(B)	$ 579,510
CWIP		8,981			8,981
Contributions in Aid of Construction		(99)			(99)
Accumulated Depreciation		(284,402)	279	(B)	(284,123)
Net Plant		314,249	(9,980)		304,269
Materials and Supplies		2,227			2,227
Prepaid Expenses		46			46
Deferred Debits		1,440			1,440
Cash Working Capital		11,144	-		11,144
Sub-total		14,857	-		14,857
					-
Accumulated Deferred FIT		8,952			8,952
Merger Hold Harmless Deferred FIT		30,337			30,337
Customer Deposits		3,736			3,736
Injuries and Damages Reserve		840			840
Sub-total		43,865	-		43,865
Net Rate Base		285,241	(9,980)		275,261
Rate of Return	(C)	9.27%	-0.71%		8.56%
Return on Rate Base		$ 26,442	$ (2,883)		$ 23,559

Sources
- (A) NG-MDL-1, Page 24
- (B) Schedule DJE-7.1, Page 2
- (C) Schedule DJE-8

NATIONAL GRID - RI GAS
ADJUSTMENT TO RATE YEAR PLANT IN SERVICE
($000)

Adjustment to Plant Additions 10/01/07 - 9/30/08		(A)	$ (5,282)
Adjustment to Plant Additions 10/01/08 - 9/30/09		(A)	(9,954)
Effect on Average Rate Year Rate Base	50%		$ (4,977)
Total Adjustment to Rate Year Rate Base			$ (10,259)
Adjustment to Rate Year Depreciation Expense		(B)	$ (347)
Adjustment to Accumulated Depreciation 9/30/2008		(C)	(105)
Adjustment to Accumulated Depreciation 9/30/2009		(C)	(173)
Adjustment to Rate Year Accumulated Depreciation			$ (279)

Sources:
- (A) Schedule DJE-7.1, Page 2
- (B) Schedule DJE-4
- (C) Adjustment to Plant Additions * Depreciation Rate * 1/2

NATIONAL GRID - RI GAS
RATE YEAR PLANT IN SERVICE
($000)

	Company Forecast Plant Adds	Adjstmt.	Adjusted Plant Adds		Company Forecast Plant Adds	Adjstmt.	Adjusted Plant Adds
Oct-07	2,968	(180)	2,788	Oct-08	4,749	(996)	3,753
Nov-07	2,968	883	3,851	Nov-08	4,749	(996)	3,753
Dec-07	2,968	(352)	2,616	Dec-08	4,749	(996)	3,753
Jan-08	2,968	(1,063)	1,905	Jan-09	4,749	(996)	3,753
Feb-08	2,968	(2,148)	820	Feb-09	4,749	(996)	3,753
Mar-08	2,968	(590)	2,378	Mar-09	4,749	(996)	3,753
Apr-08	3,145	(305)	2,840	Apr-09	6,147	(663)	5,485
May-08	3,145	(305)	2,840	May-09	6,147	(663)	5,485
Jun-08	3,145	(305)	2,840	Jun-09	6,147	(663)	5,485
Jul-08	3,145	(305)	2,840	Jul-09	4,614	(663)	3,951
Aug-08	3,145	(305)	2,840	Aug-09	4,614	(663)	3,951
Sep-08	3,145	(305)	2,840	Sep-09	4,614	(663)	3,951
Totals	36,679	(5,282)	31,397		60,781	(9,954)	50,827

Notes on Adjustments

Oct 07 -Mar 08 Adjustment reflects actual plant adds, per DIV 1-2

	Apr-08 Sep-08	Oct-08 Mar-09	Apr-09 Sep-09
Base Spend per Company	2,548	2,548	2,838
New Program Spend per Company	150	150	210
Total	2,699	2,699	3,048
Monthly Avg. 10/07-03/08 and FY 09-10 Est.	2,393	2,393	2,500
Adjustment	(305)	(305)	(548)
Recommended Pipe Replacement		1,000	1,000
Company Proposed Pipe Replacement		1,691	1,115
Adjustment to Pipe Replacement		(691)	(115)
Total Adjustment		(996)	(663)

Sources: Responses to DIV 1-1, DIV 1-2

NATIONAL GRID - RI GAS
RATE OF RETURN
($000)

Company Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	40.63%	7.99%	3.25%
Short Term Debt	11.66%	4.59%	0.54%
Common Equity	47.71%	11.50%	5.49%
Total Capital	100.00%		9.27%

Division Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	59.06%	7.99%	4.72%
Short Term Debt	3.17%	2.58%	0.08%
Common Equity	37.77%	9.95%	3.76%
Total Capital	100.00%		8.56%

Sources:
Attachment NG-MDL-1, Page 32
Testimony of Mr. Rothschild