ROCHESTER GAS AND ELECTRIC CORPORATION • 89 EAST AVENUE, ROCHESTER, N.Y. 14649

JOHN L. KENNEDY
VICE PRESIDENT

TELEPHONE
AREA CODE 716 546-2700

May 26, 1978

Mr. Samuel R. Madison, Secretary
Public Service Commission
Empire State Plaza
Albany, New York 12223

Dear Mr. Madison:

The enclosed leaves, issued by Rochester Gas and Electric Corporation, are transmitted for filing in compliance with the requirements of the Public Service Commission of the State of New York:

P.S.C. No. 9 - Electricity	P.S.C. No. 13 - Electricity
2nd Revised Leaf No. 19	1st Revised Leaf No. 3
15th Revised Leaf No. 31	Original Leaf No. 11-A
15th Revised Leaf No. 33	1st Revised Leaf No. 21
15th Revised Leaf No. 35	1st Revised Leaf No. 22
8th Revised Leaf No. 36	1st Revised Leaf No. 23
15th Revised Leaf No. 38	1st Revised Leaf No. 24
14th Revised Leaf No. 45	1st Revised Leaf No. 25
9th Revised Leaf No. 46	1st Revised Leaf No. 26
9th Revised Leaf No. 47	

P.S.C. No. 10 - Gas
5th Revised Leaf No. 40
5th Revised Leaf No. 42

Effective June 26, 1978

The above revisions are being filed for the purpose of increasing revenues approximately $34,999,000, or 18.2%, from our electric operations and $9,997,000, or 9.1%, from our gas operations, based on sales data for the 12-month period ended December 31, 1977. The average number of customers served during the 12-month period ended December 31, 1977 was 277,540 electric customers and 206,479 gas customers. The proposed rates would have resulted in increases for all bills rendered during that period.

In accordance with 16 NYCRR 2.3, the Company submits herewith twenty-four copies of the prepared written testimony and exhibits which will comprise its direct case in support of this electric and gas rate filing. This material clearly demonstrates that rate relief is necessary if the Company is to remain in a viable position to provide the quality of service our customers expect.

DATE May 26, 1978
TO Mr. Samuel R. Madison

In view of the Commission's Order, issued March 8, 1978, in Case 27301, allowing the use of experimental hearing procedures, the Company supports the concept of using written interrogatories and responses, together with a consolidated hearing procedure, to expedite the development of a clear and concise record. The Company is of the opinion that revised procedures, such as those used in Cases 27094 and 27095, will reduce the time required to complete the record enabling the Commission to reach a final decision more efficiently. Accordingly, the Company hereby requests that the experimental procedures, including the advance use of appropriate data requests and interrogatories, and the filing of all testimony and exhibits prior to any hearings for cross-examination, be used in these proceedings.

A notice to the public regarding these revisions will be made in accordance with 16 NYCRR 136.70 and 16 NYCRR 270.70.

Very truly yours,

ROCHESTER GAS AND ELECTRIC CORPORATION

John L. Kennedy
Vice President

JLK:mjr
Encls.

GENERAL INFORMATION

3. EXTENSION OF COMPANY FACILITIES TO SERVE CUSTOMER (Cont'd)

3.5 TRANSFORMER VAULTS

Whenever a transformer vault is necessary to supply a Customer with alternating current service in the network district, the Customer will provide space satisfactory to the Company in which space the Company will construct, at its expense, a transformer vault for housing its transformers and necessary switching equipment. These transformers may, if desired by the Company, be tied in with the Company's secondary distribution system.

Where a transformer vault already available or in service on the Customer's premises is adequate for service in the judgment of the Company's engineers, and the Customer requires a change in the location of the vault, such a change will only be made at the expense of the Customer.

3.6 STANDBY: AUXILIARY OR BREAKDOWN SERVICE

Customers operating power generating equipment and having equipment that may be operated by privately generated power or by purchased power, may contract for service under an applicable Service Classification, but shall pay an annual minimum bill of not less than $50.88 per year per kilowatt of service capacity.

The service capacity may not be reduced during a yearly period and shall be during the term of agreement the kilowatts of maximum demand specified by the Customer or the highest registered demand if this be greater.

Any deficiency under this provision for annual minimum charge shall be billed on the last monthly bill of each annual period.

Term of Service shall be for yearly periods until terminated by 30 days' written notice before the expiration of a yearly period.

The Customer shall not operate his own power generating equipment in parallel with the Company's service except under control by, and with the Company's consent.

Filed with but not as yet acted upon by the P. S. C.

ROCHESTER GAS AND ELECTRIC CORPORATION

ORIGINAL LEAF NO.....
.....15th..... REVISED LEAF NO.....31.....
SUPERSEDING ...13th..... LEAF NO.....31.....

14th Revised Leaf No. 31 Pending

SERVICE CLASSIFICATION NO. 1

RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

All purposes, in Entire Territory, by single family residential Customers in single family dwellings, individual flats or apartments, and also for all electricity utilized exclusively in connection with religious purposes by any corporation or association organized and conducted in good faith for religious purposes. This classification is available to all such Customers providing but one meter for the above service is used.

CHARACTER OF SERVICE:

Continuous, Alternating Current - 60 cycle; 120/240, 120/208 volts, single phase. Three phase service will not be rendered under this Service Classification except to religious organizations receiving such service hereunder at existing locations as of November 11, 1977.

RATE: (Per Month)

Energy Charge:	Late Payment Rate	Rate
First 12 kilowatthours, or less	$3.65	$3.50
Next 488 kilowatthours, per kwh	.0444	.0436
Next 500 kilowatthours, per kwh	.0398	.0391
Over 1,000 kilowatthours, per kwh	.0326	.0320

Fuel Cost Adjustment:

The energy charges set forth herein shall be increased or decreased when changes from the base cost of $.002374 per kilowatthour occur (as explained in Rule 4.8).

Increase in Rates and Charges:

The rates and charges under this Service Classification, including fuel adjustment and minimum charge, are increased by the applicable percentage shown in Rule 4.9 for service supplied within the municipality where the Customer is taking service.

MINIMUM CHARGE:

The minimum monthly charge, exclusive of fuel cost adjustment charges, is $3.50, $3.65 including late payment charge.

(Continued on next leaf)

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14th Revised Leaf No. 33 Pending

SERVICE CLASSIFICATION NO. 1 (Cont'd)

RESIDENTIAL SERVICE

SPECIAL PROVISIONS: (Cont'd)

3. "Off-peak" Service

a. Service under this provision will be available only to those Customers, at their existing location, taking service hereunder prior to August 30, 1967. The Company will meter and bill all energy used during the time controlled "off-peak" hours of approximately 10:30 pm to 7:00 am, at the following energy charge per month:

	Late Payment Rate	Rate
First 100 kilowatthours, or less	$4.08	$4.00
Over 100 kilowatthours, per kwh	.0226	.0222

Fuel Cost Adjustment:

The energy charges set forth herein shall be increased or decreased when changes from the base cost of $.002374 per kilowatthour occur (as explained in Rule 4.8).

Increase in Rates and Charges:

The rates and charges under this Service Classification, including fuel adjustment and minimum charge, are increased by the applicable percentage shown in Rule 4.9 for service supplied within the municipality where the Customer is taking service.

b. For Customers taking service under this provision, there shall be a separate minimum charge, exclusive of fuel cost adjustment charges, of $4.00, $4.08 including late payment charge, per month, applicable to the service used during "off-peak" hours only.

c. Electric storage water heaters which are under control of the time switch in the "off-peak" meter must have two thermostatically controlled heating elements, so wired that the lower element shall be operable only during the "off-peak" hours. Such lower element shall not have a demand exceeding 50 watts per gallon of tank capacity.

(Continued on next leaf)

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ROCHESTER GAS AND ELECTRIC CORPORATION

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.....15th..... REVISED LEAF NO.....35.....
SUPERSEDING .....13th..... LEAF NO.....35.....

14th Revised Leaf No. 35 Pending

SERVICE CLASSIFICATION NO. 2

GENERAL SERVICE - SMALL-USE

APPLICABLE TO USE OF SERVICE FOR:

All purposes, in Entire Territory, by any customer whose consumption does not exceed 2,000 kwh in each of two consecutive monthly billing periods.

CHARACTER OF SERVICE:

Continuous, Alternating Current - 60 cycle; voltage and phase at the Company's option, as available and appropriate for the Customer's requirements.

RATE: (Per Month)

Energy Charge:	Late Payment Rate	Rate
First 12 kilowatthours, or less	$3.65	$3.50
Next 588 kilowatthours, per kwh	.0677	.0664
Over 600 kilowatthours, per kwh	.0371	.0364

Fuel Cost Adjustment:

The energy charges set forth herein shall be increased or decreased when changes from the base cost of $.002374 per kilowatthour occur (as explained in Rule 4.8).

Increase in Rates and Charges:

The rates and charges under this Service Classification, including fuel adjustment and minimum charge, are increased by the applicable percentage shown in Rule 4.9 for service supplied within the municipality where the Customer is taking service.

MINIMUM CHARGE:

The minimum monthly charge, exclusive of fuel cost adjustment charges, is $3.50, $3.65 including late payment charge.

TERMS OF PAYMENT:

All bills are rendered at the above rate. The late payment rate shall become due and payable if payment is not made on or before the "last day to pay rate total" date specified on the bill in accordance with the provisions of Rule 4.3.

TERM:

Service may be discontinued upon three days' written notice to the Company.

(Continued on next leaf)

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ORIGINAL LEAF NO.....
8th REVISED LEAF NO. 36
SUPERSEDING 7th " LEAF NO. 36

SERVICE CLASSIFICATION NO. 2 (Cont'd)

GENERAL SERVICE - SMALL-USE

SPECIAL PROVISION:

The Company will install a demand measuring device and provide service under Service Classification No. 7 - General Service - 5 kw Minimum:

a. Whenever it is determined that the Customer is using, or might use, more than 5 kw of billing demand, or

b. Whenever the Customer's consumption during the preceding 12 months has exceeded 2,000 kwh in each of two consecutive monthly billing periods or 4,000 kwh in one bimonthly billing period.

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.....15th..... REVISED LEAF NO.....38.....
SUPERSEDING ..13th. ..." ..... LEAF NO.....38.....

14th Revised Leaf No. 38 Pending

SERVICE CLASSIFICATION NO.3

GENERAL SERVICE - 100 KW MINIMUM

APPLICABLE TO USE OF SERVICE FOR:

All purposes, in Entire Territory, by any Customer guaranteeing a billing demand of not less than 100 kilowatts.

CHARACTER OF SERVICE:

Continuous, Alternating Current - 60 cycle; voltage and phase at the Company's option, as available and appropriate for the Customer's requirements.

RATE: (Per Month)

	Late Payment Rate	Rate
Demand Charge:		
First 500 kw of billing demand, per kw	$7.54	$7.40
Over 500 kw of billing demand, per kw	4.32	4.24
Energy Charge:		
First 200 hours' use of billing demand, per kwh	$ .0193	$ .0190
Next 200 hours' use of billing demand, per kwh	.0166	.0163
Over 400 hours' use of billing demand, per kwh	.0138	.0136

Fuel Cost Adjustment:

The energy charges set forth herein shall be increased or decreased when changes from the base cost of $.002374 per kilowatthour occur (as explained in Rule 4.8).

Increase in Rates and Charges:

The rates and charges under this Service Classification, including fuel adjustment and minimum charge, are increased by the applicable percentage shown in Rule 4.9 for service supplied within the municipality where the Customer is taking service.

MINIMUM CHARGE:

The minimum monthly charge is $4.24, $4.32 including late payment charge, per kw of service capacity contracted for, but not less than $740.00, $754.00, including late payment charge.

(Continued on next leaf)

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SERVICE CLASSIFICATION NO. 6

AREA LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Annual outdoor lighting, in Entire Territory, installed on wood poles, when requested by property owners for private areas or within the area of an adjacent highway, subject to permission of the State of New York or other municipal authority having jurisdiction over the highway. This classification is not available for seasonal use.

CHARACTER OF SERVICE:

Unmetered service for dusk-to-dawn illumination, approximately 4,200 hours per year. Company will own, operate and maintain the facilities required. Customer may designate lamps and facilities as provided under Rate below.

RATE: (Per Month)

Lighting Units

Type of Luminaire	MV175	MV400	MV1000
Lamp Size (Nominal Lumens)	6,000	20,000	54,000
Bracket Length	30"	8'	8'
Rate	$6.11	$11.60	$20.25
Added Facilities			
Additional Wood Pole Installed for Luminaire	$2.38	$2.38	$2.38
Wire Service (Per Foot of Extension)	.0099	.0099	.0099

(Continued on next leaf)

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9th REVISED LEAF NO. 46
SUPERSEDING 7th " LEAF NO. 46

8th Revised Leaf No. 46 Pending

SERVICE CLASSIFICATION NO. 7

GENERAL SERVICE - 5 KW MINIMUM

APPLICABLE TO USE OF SERVICE FOR:

All purposes, in Entire Territory, by any Customer guaranteeing a billing demand of not less than 5 kilowatts.

CHARACTER OF SERVICE:

Continuous, Alternating Current - 60 cycle; voltage and phase at the Company's option, as available and appropriate for the Customer's requirements.

RATE: (Per Month)

	Late Payment Rate	Rate
Demand Charge:		
All kilowatts, per kw	$6.78	$6.65
Energy Charge:		
First 200 hours' use of billing demand, per kwh	$ .0323	$ .0317
Next 200 hours' use of billing demand, per kwh	.0193	.0190
Over 400 hours' use of billing demand, per kwh	.0138	.0136

Fuel Cost Adjustment:

The energy charges set forth herein shall be increased or decreased when changes from the base cost of $.002374 per kilowatthour occur (as explained in Rule 4.8).

Increase in Rates and Charges:

The rates and charges under this Service Classification, including fuel adjustment and minimum charge, are increased by the applicable percentage shown in Rule 4.9 for service supplied within the municipality where the Customer is taking service.

(Continued on next leaf)

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SERVICE CLASSIFICATION NO. 7 (Cont'd)

GENERAL SERVICE - 5 KW MINIMUM

MINIMUM CHARGE:

1. The minimum monthly charge is $21.20, $21.60 including late payment charge.

2. Where the Customer's equipment and/or method of operation requires the installation of service facilities (transformers, etc.) in excess of that considered by the Company's engineers as required for normal utilization of service, a special service capacity shall be determined, based either on 80% of the transformer installation required, or 80% of the maximum 15-second load in kilovoltamperes. Such service capacity multiplied by $4.24 per kw shall determine the Minimum Charge and shall remain in force for each month until there is a change in the Customer's equipment or method of operation.

DETERMINATION OF DEMAND:

1. The demand will be the measured maximum 30-minute integrated demand occurring during the monthly period for which bill is rendered, but in no case shall the billing demand be taken as less than 5 kilowatts.

2. Whenever a Customer's metered demand has been 5 kw or less and the energy consumption has been 2,000 kwh or less per month for 12 consecutive monthly billing periods, the Customer will be transferred to Service Classification No. 2 - General Service - Small Use.

TERMS OF PAYMENT:

All bills are rendered at the above rate. The late payment rate shall become due and payable if payment is not made on or before the "last day to pay rate total" date specified on the bill in accordance with the provisions of Rule 4.3.

TERM:

One month and thereafter until terminated by three days' written notice. However, when the amount of investment required or other conditions of service are such as to warrant, the Company may, with the permission of the Public Service Commission, require that the initial term be longer than one month.

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ROCHESTER GAS AND ELECTRIC CORPORATION

ORIGINAL LEAF NO.....
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TABLE OF CONTENTS

PART II - RULES AND REGULATIONS

Rule		Leaf No.
1.	Definitions.	6
2.	How to Obtain Service	
	2.1 Application for Service	7
	2.2 Limitation of Service Offer	7
	2.3 Kind of Service	7
3.	Extension of Company Facilities to Serve Customer	
	3.1 Facility Extensions	8
	3.2 Temporary Service	8
4.	Metering and Billing	
	4.1 Billing Determinants.	9
	4.2 Billing Period.	9
	4.3 Charges for Special Services.	9
	4.4 Adjustment of Rates Due to Changes in Cost of Fuel. . .	9
	4.5 Increase in Rates Applicable in Municipality Where Service is Supplied	11-A
5.	Discontinuance of Service	
	5.1 Discontinuance of Service Due to Default.	12
6.	Liability	
	6.1 Continuity of Supply.	14
	6.2 Customer's Equipment.	15
	6.3 Company Equipment and Use of Service.	15
7.	Customer Inquiries and Complaints.	16
8.	Application Forms	
	8.1 Street Lighting Service	17

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GENERAL INFORMATION

4. METERING AND BILLING (Cont'd)

4.5 INCREASE IN RATES APPLICABLE IN MUNICIPALITY WHERE SERVICE IS SUPPLIED

The rates and charges for service under all Service Classifications, including fuel cost adjustment and minimum charge, shall be increased by the aggregate percentage rate of the taxes imposed on the Company's electric revenues pursuant to Sections 186 and 186-a of the Tax Law; Section 20-b of the General City Law; and Section 5-530 of the Village Law.

The respective percentage increases applicable in the municipalities served by the Company are as follows:

	Percentage Increase
City of Canandaigua	4.75
City of Rochester	4.75
Village of East Rochester	4.75
Village of Geneseo	4.75
Village of Hilton	4.75
Village of Manchester	4.75
Village of Mt. Morris	4.75
Village of Nunda	4.75
Village of Pittsford	4.75
Village of Shortsville	4.75
Village of Sodus Point	4.75
Village of Wolcott	4.75
All other villages and towns	3.75

Refund of such increase will be made to a Customer who is a vendor of electricity to the extent that revenue derived from such vendor to which such increase was applied is not taxed to the Company under such statutes, as shown by the Customer's Report of Electric Current Resold filed with the Company.

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ROCHESTER GAS AND ELECTRIC CORPORATION

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SERVICE CLASSIFICATION NO. 1 (Cont'd)

STREET LIGHTING SERVICE

RATE:

Circuit Charge (Per Year):

Description	Unit Rates per Foot of Street Lighted(1) (Except as Noted)
Overhead wire	$ 0.064
Street lighting wood poles, Company owned, per pole	14.72
Street lighting wood poles, jointly owned by Company and third party, per pole	7.37
Conduit and cable or direct buried cable	0.486
Direct buried cable in URD subdivisions	0.486
Cable in conduit owned by others	0.281

(1) "Per Foot of Street Lighted" shall be determined by measuring along the center line of the street between the center lines of intersecting streets. On dead end or partially lighted streets, the measurement shall be taken to the last lamp. When lighting is installed in parks, playgrounds or on school properties, the measurement shall be taken along the circuit route.

(Continued on next leaf)

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SERVICE CLASSIFICATION NO. 1 (Cont'd)

STREET LIGHTING SERVICE

RATE: (Cont'd)

Fixture Charge (Per Year):

Unit Type(1)	Rate Per Unit
1(2)	$ 47.36
2	81.32
2a	126.09
2b(2)	147.21
2c(2)	129.92
3(2)	71.04
3-2(2)	103.05
5	18.76
6(2)	35.20
9	28.62
9a(2)	14.72
10	84.99
10a(2)	186.90
10-2	116.49
11	114.73
11-2	140.92
13	29.34
20	27.61
20a	107.87
20b	100.19
20c	33.89
21	37.31
C-5(2)	131.84
C-4a	114.42
C-5a	140.10

(1) Detailed descriptions of unit types contracted for will be made a part of the Application for Service.

(2) Not available for new installations.

(Continued on next leaf)

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.....1st..... REVISED LEAF NO.....23.....
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SERVICE CLASSIFICATION NO. 1 (Cont'd)

STREET LIGHTING SERVICE

RATE: (Cont'd)

Lamp Charge (Per Year):

Lamp Size	Light Source	Wattage	Rate Per Unit
2500 Lumen	Incandescent	166	$ 33.92
4000 " (1)	"	261	47.36
6000 " (1)	"	366	62.72
10000 " (1)	"	621	96.64
200 Watt	Mercury Vapor	133	25.60
175 "	" "	210	39.68
250 "	" "	290	55.04
400 "	" "	460	74.24
1000 "	" "	1102	156.17
70 "	High Pressure Sodium	81	44.79
100 "	" " "	116	53.12
150 "	" " "	171	57.59
250 "	" " "	300	78.72
400 "	" " "	457	97.28

(1) Not available for new installations.

Fuel Cost Adjustment:

The energy charge included in the lamp rate set forth herein shall be increased or decreased when changes from the base cost of $.002374 per kilowatthour occur (as explained in Rule 4.4).

Determination of Kilowatthour Consumption:

The kilowatthours consumed during the month shall be determined by multiplying the number of lamps in service for the full calendar month by the "Wattage" shown for each lamp by the number of burning hours in the month shown below and dividing by 1000, plus or minus the kilowatthours for lamps reported in or out of service for periods greater or less than a month on a pro rata basis.

(Continued on next leaf)

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SERVICE CLASSIFICATION NO. 1 (Cont'd)

STREET LIGHTING SERVICE

RATE: (Cont'd)

Determination of Kilowatthour Consumption (Cont'd):

Monthly Burning Hours(1)

Month	Hours	Month	Hours
January	448	July	264
February(2)	383	August	300
March	364	September	335
April	306	October	395
May	275	November	424
June	246	December	460

(1) For 24-hour burning lamps multiply number of days in month by 24.

(2) Use 395 hours during leap year.

Increase in Rates and Charges:

The monthly charge under this Service Classification, including fuel cost adjustment, shall be increased by the applicable percentage shown in Rule 4.5 for service supplied within the municipality where the Customer is taking service.

MONTHLY CHARGE:

The monthly charge shall be 1/12 the sum of the lamp, fixture and circuit charges for units in service at the beginning of the month, plus or minus the pro rata charge for lamps, fixtures and circuits installed or removed for periods greater or less than a month, plus the Fuel Cost Adjustment charge.

TERMS OF PAYMENT:

All bills are due when rendered and customer is in default unless payment is received within 30 days after rendition of bill.

(Continued on next leaf)

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ROCHESTER GAS AND ELECTRIC CORPORATION

ORIGINAL LEAF NO. .....
1st REVISED LEAF NO. 25
SUPERSEDING Original LEAF NO. 25

SERVICE CLASSIFICATION NO. 1 (Cont'd)

STREET LIGHTING SERVICE

TERM:

Five years from the initial rendering of service, including service previously rendered under contract, and thereafter until terminated on one year's written notice by either Company or customer. However, if customer elects to terminate service, Special Provision 2c shall be fully applicable notwithstanding termination and provided further that the rules, rates and charges for service shall be subject to changes at any time when such changes are filed with, and accepted by the Public Service Commission.

SPECIAL PROVISIONS:

1. The Company agrees, subject to its ability to obtain needed materials, to:

   a. Furnish, install and operate the street lighting system as now obtains, or as may be hereafter changed by written request of the customer, within the jurisdictional limits of customer.

   b. Furnish all materials and do all work and provide all labor necessary to perform Special Provision 1a above. The materials shall be of high quality and kind and all equipment shall be installed, and operated in accordance with the latest rules of the National Electric Safety Code, as approved by the American National Standards Institute.

   c. Maintain the street lighting system so that it is wholly serviceable in function and presentable in appearance (provided however, that maintenance of customer owned equipment shall be performed pursuant to Special Provision 3a). Said maintenance shall include, but not be limited to, an efficient system of lamp replacement so that any lamps which fail to burn properly shall be promptly put in order or replaced with new lamps. Upon receiving notice from the customer that there is a defective lamp, the Company will put the same in order or replace the lamp within 24 hours, except that Saturdays, Sundays and holidays shall be excluded in computing the 24-hour period.

      For each night the lamp is not lighted in accordance with the first paragraph of this Special Provision 1c, the customer shall be credited an amount equal to 1/365 of the total rate for that lamp and fixture. No credits shall be allowed for outages due to fire, strikes, acts of God or public enemy or circumstances and conditions over which the Company has no control.

(Continued on next leaf)

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SERVICE CLASSIFICATION NO. 1 (Cont'd)

STREET LIGHTING SERVICE

SPECIAL PROVISIONS: (Cont'd)

Subject to the availability of manpower, equipment and materials, the customer can require Company to perform additional maintenance, over and above the Company's standard maintenance, on those facilities which Company is to maintain under this Service Classification; provided, however, that such additional maintenance shall not impair the value of such facilities. Customer shall pay for such additional maintenance pursuant to Rule 4.3.

d. Remove existing lamps, fixtures and circuits (except poles and conduit system installed, owned or maintained by customer) upon written request of the customer, provided that, for those items which have been installed on or after July 1, 1971 and for a period of ten years or less, the customer shall pay to the Company the actual cost of labor and material, including applicable overhead expenses, incurred in such removal, plus the unamortized investment for the removed items less salvage equipment value.

e. Make changes in the location of existing lamps, fixtures and circuits (except poles and conduit system installed, owned or maintained by customer) upon written request of the customer, provided customer shall pay to the Company the actual cost of labor and material, including applicable overhead expenses incurred in such relocation. Customer shall not be required to pay the cost of relocating lamps, fixtures or circuitry from locations other than those theretofore approved by the customer.

f. Upgrade the existing street lighting system (except poles and conduit system installed, owned or maintained by customer), by replacing any of the lamps, fixtures and circuitry at the written request of the customer. However, the foregoing (1) shall not be applicable to existing items which have been installed on or after July 1, 1971 and for a period of ten years or less, unless customer agrees to pay Company's cost of removal in accordance with Special Provision 1d; and (2) shall not obligate the Company to expend in any calendar year, for any customer, an amount greater than 5% of its existing investment (on an original cost basis) in street lighting plant installed for such customer for all costs in connection with such replacements, including labor, materials, applicable overheads and additions of conduit, cable, poles, wire and other appurtenances.

(Continued on next leaf)

Filed with but not as yet acted upon by the P. S. C.

Date of Issue: May 26, 1978 Date Effective: June 26, 1978

Issued by: John L. Kennedy, Vice President, Rochester, New York

ROCHESTER GAS AND ELECTRIC CORPORATION

ORIGINAL LEAF NO.....
.....5th..... REVISED LEAF NO.....40.....
SUPERSEDING .....3rd..... " LEAF NO.....40.....

4th Revised Leaf No. 40 Pending

SERVICE CLASSIFICATION NO. 1

GENERAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

All purposes.

CHARACTER OF SERVICE:

Continuous; natural gas or a mixture of natural gas and other gas of not less than 1000 Btu per cubic foot, supplied at pressures within the limits prescribed by the Public Service Commission.

RATE: (Per Month)

		Late Payment Rate	Rate
First	3 Ccf or less	$3.65	$3.50
Next	27 Ccf, per Ccf	.3548	.3479
Next	970 Ccf, per Ccf	.2800	.2746
Next	99,000 Ccf, per Ccf	.2423	.2376
Next	200,000 Ccf, per Ccf	.2214	.2171
Over	300,000 Ccf, per Ccf	.2045	.2005

Gas Cost Adjustment: The charges set forth herein shall be subject to a gas cost adjustment per Ccf of gas supplied hereunder when changes from the base cost of $.15228 per Ccf of gas occur (as explained in Rule 4.7).

Increase in Rates and Charges: The rates and charges under this Service Classification, including gas cost adjustment and minimum charge, are increased by the applicable percentage shown in Rule 4.8 for service supplied within the municipality where the customer is taking service.

MINIMUM CHARGE:

The minimum monthly charge, exclusive of gas cost adjustment charges, is $3.50, $3.65 including late payment charge.

(Continued on next leaf)

Filed with but not as yet acted upon by the P. S. C.

Date of Issue: May 26, 1978 Date Effective: June 26, 1978

Issued by: John L. Kennedy, Vice President, Rochester, New York

ROCHESTER GAS AND ELECTRIC CORPORATION

ORIGINAL LEAF NO.....
.....5th..... REVISED LEAF NO.....42.....
SUPERSEDING ..3rd..... " LEAF NO.....42.....

4th Revised Leaf No. 42 Pending

SERVICE CLASSIFICATION NO. 2

GAS LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Outdoor gas lighting service to post standards owned and installed by the customer. Limited to service rendered hereunder at existing locations and to existing units in service as of April 28, 1972.

CHARACTER OF SERVICE:

Continuous; unmetered, 24 hour burning service; natural gas or a mixture of natural gas and other gas of not less than 1000 Btu per cubic foot, supplied at pressures within the limits prescribed by the Public Service Commission.

RATE: (Per Month)

$4.70 for each orifice supplying an incandescent mantle, such orifice being adjusted to pass, per hour, approximately 2 cubic feet of natural gas.

Increase in Rates and Charges: The rates and charges under this Service Classification are increased by the applicable percentage shown in Rule 4.8 for service supplied within the municipality where the customer is taking service.

TERMS OF PAYMENT:

All bills are due when rendered and customer is in default unless payment is made on or before the "last day to pay rate total" date specified on the bill; such date shall be at least 20 days after rendition of the bill.

TERM:

One year, and thereafter until discontinued on 30 days' written notice.

SPECIAL PROVISION:

The customer shall own and maintain the post, lamp fixture and mantles.

Filed with but not as yet acted upon by the P. S. C.

Date of Issue: May 26, 1978 Date Effective: June 26, 1978

Issued by: John L. Kennedy, Vice President, Rochester, New York

Rochester Gas and Electric Corporation

Direct Testimony

of

WILLIAM W. STODDART

Assistant Division Manager
General Accounting Department

Q: Would you please state your name and business address?

A: My name is William W. Stoddart. My business address is 89 East Avenue, Rochester, New York 14649.

Q: Mr. Stoddart, what is your position with Rochester Gas and Electric Corporation?

A: I am Assistant Division Manager of the General Accounting Department.

Q: How long have you held that position?

A: Since 1970.

Q: What are the duties and responsibilities of that position?

A: I am responsible for coordinating the activities of the General Accounting Department relative to the collection and preparation of data utilized to maintain the financial records of the Company. The Property Records, Stores Records, Accounts Payable, Payroll, Accounting Control and other General Accounting functions come within the scope of my responsibilities.

Q: How long have you been employed by the Company?

A: Approximately 19 years.

Q: Will you briefly outline your experience and qualifications?

A: I am a graduate of the State University of New York at Buffalo. In 1959 I was employed by the Company as an

accountant in the General Accounting Department. Subsequently I have held the position of Corporate Tax Representative and now my present position.

Q: Mr. Stoddart, are you generally familiar with the requests for additional revenue in the Company's electric and gas filings?

A: Yes, I am.

Q: Have you prepared certain exhibits of a financial and accounting nature in conjunction with and support of these proposed increases?

A: Yes. Exhibits 1 through 7 were prepared by me or under my supervision and direction utilizing data taken from the books and records of the Company.

Q: Will you describe Exhibit 1 and state what it purports to show?

A: Exhibit 1 sets forth the comparative balance sheets for the Company as of December 31, for the years 1974, 1975, 1976 and 1977, in the form prescribed by the Commission. These balance sheets are stated on a corporate basis and include data applicable to all of the operating departments of the Company.

Q: Does the Company maintain its accounting records in accordance with the Uniform System of Accounts prescribed by the Commission?

A: Yes.

Q: Are there any particular accounts upon which you wish to comment?

A: The balances in account 101, Electric Plant in Service, increased by $81,540,839 over the three year period. The majority of the plant additions have been for the Company's transmission and distribution system to meet the reliability and growth needs of our system. During 1977 there were also major additions to our nuclear production plant.

The balances in account 101, Gas Plant in Service, increased by $4,000,985 between December 31, 1974 and December 31, 1975, decreased by $1,499,088 between December 31, 1975 and December 31, 1976 and then increased by $4,492,009 between December 31, 1976 and December 31, 1977. Plant additions for the three year period were for improvement of distribution facilities necessary to assure reliability of service and for continued improvement in safety standards. The decrease at December 31, 1976 reflects the retirement from service of the Company's gas manufacturing facilities totalling $5,350,924.

Account 118.1, Common Utility Plant in Service, consists of office buildings, operations and service

centers and transportation, tools, office, communications and other equipment. The amounts applicable to the Electric Department are shown in Exhibit 6 and the amounts applicable to the Gas Department are shown in Exhibit 7.

The balance in Account 105, Plant Held for Future Use, is made up of $306,365 representing land located south of the City of Rochester and $33,765 representing land located adjacent to Station #5. The current balance in this account is applicable to the Electric Department.

The Electric Department portion of accounts 107 and 118.1, Construction Work in Progress, at December 31, 1974, 1975, 1976 and 1977 was $36,757,449, $77,134,659, $118,228,084 and $158,673,781, respectively. The increases in this balance through December 31, 1977 primarily reflect the Company's share of expenditures incurred for three new generating facilities. Expenditures for licensing and preliminary engineering for its 28% interest in the 1150 MW nuclear plant to be located in Sterling, New York and to be owned by the Company jointly with Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc. and Central Hudson Gas and Electric Corporation amounted to $29,054,512 including

fuel at December 31, 1977. The Company is also participating in the ownership of two Niagara Mohawk generating stations: Oswego #6, an 850 MW fossil unit in which the Company will have a 24% ownership interest and Nine Mile Point #2, an 1100 MW nuclear unit in which the Company will have a 14% ownership interest. Expenditures on these two units through December 31, 1977, including fuel, totalled $43,589,026 and $54,774,342, respectively.

The Gas Department Construction Work in Progress balance at December 31, 1974, 1975, 1976 and 1977 was $1,645,707, $1,228,345, $1,255,286 and $1,395,385. The lower balances in 1975 through 1977 compared to 1974 are due primarily to reduced distribution main construction.

There are also small balances of Common Utility Plant - Construction Work in Progress applicable to the Electric Department and Gas Department. These amounts are shown in Exhibits 6 and 7, respectively.

Account 114, Plant Acquisition Adjustment, does not appear in the balance sheet at December 31, 1974. At that point in time, $3,132,171, representing the value of certain water rights on the Genesee River which were acquired on June 11, 1904 in the consolidation of Rochester Light and Power Company and Rochester Gas and Electric Company, was reflected in Account 101,

Plant in Service. The Commission ordered the Company, in a prior Electric rate case, Case 26522, to begin amortizing these water rights over a forty year period. The Company transferred the $3,132,171 to Account 114, Plant Acqusition Adjustment, on January 1, 1975 and commenced amortization in accordance with the order in Case 26522. The balances are applicable to the Electric Department.

The balances in Account 120, Nuclear Fuel, at December 31, 1976 and December 31, 1977, represent the original cost of the nuclear fuel components for the Ginna nuclear plant. The balance at December 31, 1974 includes the Company's share of prepayments for nuclear fuel applicable to the Sterling nuclear plant in the amount of $438,167. The balance at December 31, 1975 includes the Company's share of prepayments for nuclear fuel applicable to the Sterling and Nine Mile Point nuclear plants in the amounts of $736,120 and $1,131,017, respectively.

The balances in Account 120.5 reflect the accumulated provision for amortization of fuel applicable to Ginna Station.

Q: Turning now to Account 108, Accumulated Provision for Depreciation of Electric Plant in Service, will you

comment on the balances shown?

A: Accumulated Provision for Depreciation of Electric Plant in Service was $109,396,951 at December 31, 1974 and $138,106,010 at December 31, 1977. The ratio of this provision to Plant in Service at December 31, 1974, 1975, 1976 and 1977 was 25.0%, 25.7%, 26.6% and 26.6%, respectively.

Account 108, Accumulated Provision for Depreciation of Gas Plant in Service was $33,663,094 at December 31, 1974 and $35,049,799 at December 31, 1977. The ratio of this provision to Plant in Service at December 31, 1974, 1975, 1976 and 1977 was 23.0%, 23.2%, 21.3% and 22.8%, respectively. The reduction in this account from December 31, 1975 to December 31, 1976 reflects the retirement of the Company's gas manufacturing facilities in the amount of $5,350,924.

Depreciation accruals are provided by applying 1/12 of the annual depreciation rates to the monthly book balances of the primary plant accounts. The Company reviews annually its rates used for depreciation accruals. Depreciation studies are made each year to help the Company gauge the appropriateness of its book accruals. These studies are based, in part, on an actuarial analysis of plant history to determine average

service lives. The annual accrual rates used are based upon these actuarial studies, salvage studies, theoretical reserves and managerial judgment. These studies have been regularly made available to the staff of the Commission. The balances shown in Exhibit 1 result from accrual rates approved by the Commission in several proceedings, commencing with Case 16510 through, most recently, the Company's last electric and gas rate cases, Cases 27108 and 27109.

Q: Would you please continue with your explanations of this exhibit?

A: The balances in Account 123.1, Investment in Subsidiary Companies, represents our investment in Canadea Power Corporation computed under the equity method of accounting. The Company adopted the equity method of accounting for its investment in this wholly-owned subsidiary, effective January 1, 1973, pursuant to the Federal Power Commission Order No. 469.

Account 131, Cash, has fluctuated between a high balance of $5,912,089 and a low balance of $4,844,109 at the year end dates shown in the exhibit. The variations in cash balances between balance sheet dates occur for several reasons such as cash collections, bill payments and prospective bills due and compensating balance

requirements. These changing conditions are reflected in the balances shown.

Account 133, Dividend Special Deposits, represents funds on deposit for payment of dividends on common and preferred stock. The balance in this account increased $322,079 between December 31, 1974 and December 31, 1975. This increase primarily reflects the increase in dividends due to the October 1975 sale of 220,000 shares of preferred stock. The balance in this account decreased by $1,622,729 at December 31, 1976. This was caused by eliminating a one month lag in reporting of disbursements by the disbursing agent which was reflected in the prior year balances. The increase in this balance of $27,782 at December 31, 1977 primarily reflects the issuance of 1,000,000 shares of common stock on September 29, 1977.

The balances in Account 134, Other Special Deposits, at December 31, 1974 and 1975 reflect funds advanced by the participants in the Sterling nuclear unit for its construction. The balance at December 31, 1976 represents a deposit in lieu of mortgaged property sold. The large increase at December 31, 1977 represents the par value, call premium and accrued dividends on the Company's Series "O" preferred stock which was called for redemption

subsequent to a request by the Company and approval by the Commission in Case 27269. These amounts totalled $28,131,950.

Account 142, Customer Accounts Receivable, decreased by $2,161,285 from December 31, 1974 to December 31, 1975, increased $10,485,155 at December 31, 1976 and then decreased by $3,064,937 at December 31, 1977. These changes were due primarily to the variance in sales in the month of December of each year. For instance, December 1977 sales were approximately $3,000,000 lower than December 1976 sales which, in turn, were over $10,000,000 higher than December 1975 sales.

Account 143, Other Accounts Receivable, increased by $1,026,617 to $1,119,364 at December 31, 1975 and then decreased to $318,287 and $105,994 at December 31, 1976 and 1977, respectively. The 1975 and 1976 balances primarily related to amounts due from other utilities participating in the construction of the Company's Sterling nuclear generating facility.

The balances in Account 144, Accumulated Provision for Uncollectible Accounts - Credit, have increased by approximately $97,000 in 1976 and $250,000 in 1977. The Company determined that this provision should be increased due to increases in the amount of customer

billings and its history of uncollectibles. Prior to 1976 the Company had maintained the reserve at the $100,000 level for a considerable number of years.

Q: Would you please continue with your explanation of this exhibit?

A: Account 150, Materials and Supplies, increased by approximately $2,660,000 from December 31, 1974 to December 31, 1975. This net increase was due primarily to a $3,360,000 increase in fuel stock due to higher unit costs and a $700,000 decrease in other materials and supplies. The balance in this account decreased by approximately $1,467,000 at December 31, 1976 due primarily to a decrease in fuel stock, while the balance at December 31, 1977 increased approximately $303,000 due primarily to an increase in other materials and supplies.

The balances in account 165, Prepayments, decreased approximately $200,000 at December 31, 1975 and $11,000 at December 31, 1976. The balance increased approximately $280,000 at December 31, 1977.

The 1975 decrease resulted from the elimination of a prepayment of $262,000 for poles offset by an increase in prepayments for insurance under the Employees Welfare Association Plan and general insurance. The increase

at December 31, 1977 results primarily from increases in general insurance. Excess public liability insurance premiums, for instance, doubled during 1977 due to general premium increases and our recent experience of claims reserved and paid by our insurance carriers.

Account 181, Unamortized Debt Discount and Expense, has increased from December 31, 1974 to December 31, 1975 by $302,283 reflecting a change in method of reporting. Prior to the latter date Unamortized Discount was included in Account 181. However, effective with that date, it is now reported in Account 226. Likewise, Unamortized Premium on Debt, previously reported in Account 251, is now reported in Account 225 as shown on page 2 of this exhibit. The further increases in the balance of this account at December 31, 1976 and December 31, 1977 reflect $514,600 of expense incurred in the issuance of $50,000,000 of Series BB 9 1/4% bonds in June 1976 and $896,700 of expense incurred in the issuance of $50,000,000 of Series CC 8 3/8% bonds in November 1977.

Account 183, Preliminary Survey and Investigation Charges, decreased from a balance of $1,796,503 at December 31, 1974 to $1,159,495 at December 31, 1975 and then increased to $1,604,033 at December 31, 1976

and $2,304,943 at December 31, 1977. Expenditures incurred in obtaining environmental certification of our proposed 765 KV transmission line comprised a large portion of the balance in each year shown. The December 31, 1974 balance also reflects substantial expenditures incurred to review piping system designs at Ginna Station.

The balance in Account 186, Miscellaneous Deferred Debits, increased from a balance of $3,851,923 at December 31, 1974 to $3,895,452 at December 31, 1975, then decreased to $3,807,897 at December 31, 1976 and increased to $6,665,154 at December 31, 1977. Of the $3,851,923 balance at December 31, 1974, $3,736,605 is applicable to fuel costs deferred resulting from the adoption of deferred fuel cost accounting by the Company in 1974, in accordance with the Statement of Commission Policy Concerning Fuel Adjustment Clauses of Electric Utilities. The Order in Case 26547 extended the accounting provision to Steam Utilities.

The balances of $3,895,452 at December 31, 1975, $3,807,897 at December 31, 1976 and $6,665,154 at December 31, 1977 further reflect the Commission's Opinion No. 75-10 issued May 1, 1975 together with a Resolution adopted April 29, 1975 whereby 16 NYCRR 270 was changed to require a surcharge-refund provision for

over or under-recoveries of Gas Adjustment Clause Revenues. Also included in the latter three balances are Steam Department deferrals arising from a reduction in fuel cost adjustment revenues which are being amortized pursuant to the Commission's Order in PSC Case 26766. These items together with the aforementioned fuel cost deferrals total $3,739,009 at December 31, 1975, $3,451,627 at December 31, 1976 and $6,338,424 at December 31, 1977.

The deferred Federal income taxes applicable to the deferred steam fuel currently being amortized are likewise reflected in the December 31, 1975, 1976 and 1977 balances in Account 253, Other Deferred Credits, in the respective amounts of $1,016,200, $902,800 and $779,100.

Account 190, Accumulated Deferred Income Taxes, has a balance only at December 31, 1976 and December 31, 1977. The balance at December 31, 1976 reflects deferred tax accounting applicable to Contributions in Aid of Construction, in accordance with the accounting prescribed by the Commission in PSC Case 26848 and 26849, and to over-recoveries of Gas Adjustment Clause Revenues. The balance at December 31, 1977 increased $3,424,600 from December 31, 1976 including a $3,346,000 deferral

representing the adoption of deferred tax accounting for nuclear fuel storage costs. This change will be further described in Exhibit 8. The remainder of the balance primarily reflects deferred tax accounting applicable to Contributions in Aid of Construction.

Q: Turning to Page 2 of this exhibit, will you continue with your comments?

A: Account 201, Common Stock Issued, has increased from $47,346,950, at December 31, 1974 to $54,399,465 at December 31, 1975, then increased to $56,830,555 at December 31, 1976 and $64,448,155 at December 1, 1977. Credits to this account from common stock issuances during this period from new offerings and under our Automatic Dividend Reinvestment Plan were: 1974, 38,511 shares for $192,555; 1975, 1,126,457 shares for $5,632,285; 1976, 159,784 shares for $798,920 and 1977, 1,182,536 shares for $5,912,680.

Stock dividends were issued totalling 274,690 shares in 1974, 284,082 shares in 1975, 326,398 shares in 1976 and 340,984 shares in 1977. Transfers from Unappropriated Retained Earnings in connection with the stock dividends were credited to this account in the amount of $1,373,450, $1,420,410, $1,631,990 and $1,704,920 for the years 1974 through 1977, respectively.

Account 204, Preferred Stock Issued, increased by $22,000,000 from December 31, 1974 to December 31, 1975, increased an additional $3,000,000 to December 31, 1976 and then decreased $24,720,000 at December 31, 1977. These changes reflect the sale of 220,000 shares of Series O, 11% preferred stock in October 1975, the delayed sale of an additional 30,000 shares of Series O preferred stock in March 1976 and the announced call of the Series O, 11% preferred stock and sale of 280,000 shares of Series A, 7.60% preference stock, par value $1, in December 1977.

As a result of common stock issuances during this period from new offerings and under our Automatic Dividend Reinvestment Plan, Account 207, Premium on Capital Stock, was credited with the following amounts: 1974, $301,889; 1975, $11,625,384; 1976, $1,826,515 and 1977, $18,666,651. Transfers from Unappropriated Retained Earnings in connection with the stock dividends were credited to this account as follows: 1974, $3,570,970; 1975, $1,704,492; 1976, $3,590,328 and 1977, $5,114,760. An amount totalling $27,720,000 was also credited to this account in 1977 as a result of the issuance of preference stock.

The balances in Accounts 211, Miscellaneous Paid

in Capital, and 216.1, Unappropriated Undistributed Subsidiary Earnings, reflect equity accounting for the Company's investment in Canadea Power Corporation.

The increase in the debit balance of Account 214, Capital Stock Expense, from December 31, 1974 to December 31, 1976 reflects the expenses of issuance of common and preferred stock and for stock dividends during that period. The increase in this balance from December 31, 1976 to December 31, 1977 primarily reflects a $2,750,000 call premium on the Series O, 11% preferred stock and $105,008 issuance cost of the Series A, 7.60% preference stock. These amounts, totalling $2,855,008, will be amortized in equal annual installments to the maturity of the Series A, 7.60% preference stock in 1985 as authorized by the Commission in Case 27269.

The increases during the past two years in the balances of Account 221, Bonds, have resulted from the sale of $50,000,000 of 9 1/4% Bonds in June 1976 and $50,000,000 of 8 3/8% Bonds in September 1977, offset by the redemption of $333,000 of 10 3/4% Bonds and $6,000,000 of matured 4 1/2% Bonds in August and September 1977, respectively.

The balances in Account 224, Other Long Term Debt, represent the non-current liability for deferred purchase

contracts for land at Sterling.

The balances in Account 225, Unamortized Premium on Debt, and Account 226, Unamortized Discount on Debt, reflect a change in the method of reporting as stated previously in my explanation of Account 181, Unamortized Debt Discount and Expense. The increase in the balance of Account 225 at December 31, 1976 reflects the premium received from the sale of bonds in June 1976 in the amount of $117,500.

The balance in Account 231, Notes Payable, fluctuates between $9,000,000 and $21,500,000 at the balance sheet dates shown. When it is necessary for us to go into the open market to obtain funds, we first issue either commercial paper which generally matures in 30-45 days or notes to banks which usually mature in 9 months. Subsequently, we issue long-term securities and use the proceeds to the extent necessary to extinguish the outstanding short-term borrowings. This procedure provides us a degree of flexibility in the timing of long-term financing.

The balance in Account 232, Accounts Payable, was $9,286,801 at December 31, 1974. The balance increased by $3,469,850 during 1975 with $1,756,617 of that increase representing the Company's obligations in

jointly owned generation facilities. The balance increased an additional $3,371,395 during 1976. This increase was primarily due to an increase of $3,077,575 in the balance payable to the Company's natural gas supplier and an increase of $996,399 in the balance owed for coal, freight and demurrage. During 1977, the increase of $618,517 was caused primarily by an amount payable of $2,997,148, representing a liability for repayment of nuclear materials to Combustion Engineering Corporation, coupled with decreases of $2,195,443 and $597,020 in the balances payable to various coal companies and to our natural gas supplier, respectively.

The balance in Account 236, Taxes Accrued, increased from $2,427,741 at December 31, 1974 by $4,077,033 to $6,504,774 at December 31, 1975, decreased by $3,545,499 in 1976 and then increased by $1,651,680 at year end 1977. The changes in the balances in this account over the period shown are due primarily to changes in Federal income tax accrued, which, at December 31, 1974, was approximately $6,700,000 lower than the prior year. The Company operated at a tax loss for the year 1974 and accrued a negative income tax which, together with a March 1974 payment on the 1973 Federal income tax liability, caused the decrease in this account during

1974. The balance in this account at December 31, 1975 was approximately $4,000,000 higher than 1974 reflecting current year accruals offset by refunds applicable to the 1974 loss of $630,000. The balance at December 31, 1976 was approximately $3,750,000 lower than 1975 due to investment tax credit carrybacks to prior years, refunds received applicable to 1974 and 1975 and a March 1976 payment on our 1975 income tax liability. The December 31, 1977 balance in Federal income tax accrued increased approximately $1,650,000 reflecting 1977 accruals offset by refunds applicable to previous years.

Taxes accrued other than Federal income taxes increased over this period from a balance of $1,393,873 at December 31, 1974 to a balance of $1,714,594 at December 31, 1977. Balances at December 31, 1975 and 1976 were $1,509,432 and $1,714,542, respectively.

Account 237, Interest Accrued, shows a decrease of $667,233 at December 31, 1975 from the balance at December 31, 1974, due primarily to a decrease of interest accrued on notes payable. The balances in this account showed increases of $205,533 at December 31, 1976 and $1,049,498 at December 31, 1977 reflecting accrued interest on Series BB 9 1/4% Bonds issued in

1976 and Series CC, 8 3/8% Bonds issued in 1977.

Q: Would you please continue by explaining the changes in the balances of Account 238, Dividends Declared?

A: This account represents the balance of dividends declared but not paid. The increase at December 1975 results from an increase of dividends due to the additional preferred stock sold in 1975. The large decrease at December 31, 1976 was primarily caused by the elimination of a one month lag in the recording of the bank statement, as suggested in my testimony concerning Account 133, Dividend Special Deposits. Prior to 1976, the balances in these accounts did not reflect dividend checks presented for payment in the month of December due to the timing of the receipt of December bank statements. Commencing in 1976, December activity is reflected in the year end balances.

The increase in the balance at December 31, 1977 reflects the declaration of a dividend on the Company's Series "O" preferred stock for the period January 1 through January 19, 1978. The Series "O" preferred stock was called for redemption on December 20, 1977 with a January 20, 1978 redemption date.

The balances in Account 241, Tax Collections Payable, have remained relatively constant over this

period. The increase of approximately $230,000 from December 31, 1975 to December 31, 1976 was primarily due to the New York State Sales and Use Tax payable, as was the approximate decrease of $120,000 at December 31, 1977.

Q: Would you please explain the large increase in the balance of Account 242 at December 31, 1977?

A: The balance in Account 242, Miscellaneous Current and Accrued Liabilities, increased by about $27,800,000 at December 31, 1977. This increase includes $27,750,000 reflecting the principal and call premium of the Company's Series "O" preferred stock redeemed January 20, 1978.

Q: Would you please continue by explaining the balance in Account 255, Accumulated Deferred Investment Tax Credit?

A: The Company adopted deferred tax accounting for the increase in investment tax credits arising from the Tax Reduction Act of 1975 in accordance with the statements of policy issued by the Commission. The balance in this account of $6,247,400 at December 31, 1977 reflects the deferrals applicable to these increased investment tax credits arising from that act.

Q: Would you comment on Account 282, Accumulated Deferred Income Taxes - Liberalized Depreciation and Account 283, Accumulated Deferred Income Taxes - Other?

A: The Company adopted deferred tax accounting for ADR depreciation in 1971, removal costs in 1972, fuel costs in 1974 and 1975, and mortgage recording taxes in 1976, all in accordance with the Commission's statements of policy for these items. In addition, in 1975 the Public Service Commission approved a Company petition to adopt deferred tax accounting for liberalized nuclear fuel depreciation. The balance appearing in Account 282 for the first time at December 31, 1975 reflects the transfer of deferred taxes relating to ADR depreciation from Account 283 in accordance with amendments to the Uniform System of Accounts and also includes deferred taxes resulting from nuclear fuel depreciation. At December 31, 1977 the respective deferred tax balances for ADR depreciation and nuclear fuel depreciation were $4,918,200 and $787,100. The December 31, 1977 balance in Account 283 includes $1,475,700 of deferred taxes related to cost of removal, $2,264,100 of deferred taxes related to fuel costs, $2,160,000 of deferred taxes related to the Sterling fossil plant and $342,400 of deferred taxes related to the mortgage recording tax on the Company's 1976 and 1977 bond issues.

Q: Will you please describe Exhibit 2 and state what it purports to show?

A: Exhibit 2 sets forth Statements of Income for the twelve months ended December 31, 1974, 1975, 1976 and 1977, respectively, in the form prescribed by the Commission. This exhibit has been prepared to show Company-wide operating income as well as the operation of each of the Company's operating departments. Below-the-line items are shown on a Company-wide basis.

Q: Are details of certain of the accounts shown in Exhibit 2 given in later exhibits as they relate to the Electric and Gas Departments?

A: Yes. Account 400, Operating Revenue, Account 401, Operating Expense, Account 402, Maintenance Expense, Account 402.1, Joint Expenses and Account 408.1, Taxes - Other Than Income Taxes are detailed in Exhibit 4 for the Electric Department and in Exhibit 5 for the Gas Department. I should point out that certain account numbers and the format of the Statement of Income changed throughout the period. However, these changes are readily apparent and are not commented upon further.

Q: Will you refer now to Accounts 419.1, Allowance for Other Funds Used During Construction and 432, Allowance for Borrowed Funds Used During Construction, (Account

419.1, Allowance for Funds Used During Construction) and indicate the amounts which are applicable to the Electric and Gas Departments?

A: Allowance for Funds Used During Construction (AFUDC) applicable to the Electric Department was $1,717,994, $3,549,033, $7,512,067 and $11,297,104, for the twelve months ended December 31, 1974, 1975, 1976 and 1977, respectively. The increases in the amount of AFUDC over the periods shown primarily reflect AFUDC interest accrued on the Sterling, Nine Mile Point and Oswego plants.

AFUDC applicable to the Gas Department was $24,691, $20,789, $13,584 and $17,304 for the four periods.

Over the period shown in this exhibit the rate used in AFUDC was 8% through May 31, 1974, 10% effective June 1, 1974, 8.25% effective July 1, 1975 and 8.75% effective May 1, 1976. Account 419.1, Allowance for Funds Used During Construction, was used for recording AFUDC in the years 1974 through 1976. In 1977, Account 432, Allowance for Borrowed Funds Used During Construction, and Account 419.1, Allowance for Other Funds Used During Construction, were utilized to record AFUDC. Also, commencing in December 1977, amounts recorded in Account 432 reflected AFUDC on the Nine Mile Point

and Oswego projects on a net of tax basis as provided in Case 27108. This rate was 7.04% in that month. Nuclear fuel for the Sterling and Nine Mile Point projects is included in the base for determining AFUDC as provided in Case 26848.

Q: Will you comment on the interest charges beginning with Account 427?

A: Charges to Account 427, Interest on Long-Term Debt, totalled $14,965,352 for the twelve months ended December 31, 1974. This amount reflects the partial year's interest of $1,227,292 on our Series AA, 10 3/4% Bonds issued in August 1974 plus the annual interest on the other bond issues outstanding at year end 1974. At the end of 1975 these charges had increased by $1,997,708 reflecting a full year's interest on the 1974 bonds.

The charges to this account increased by $2,415,278 during 1976 as a result of the issuance in June 1976 of Series BB, 9 1/4% Bonds. A further increase of $3,163,313 occurred in 1977 reflecting annual interest on the 1976 issue together with a partial year's interest on our Series CC, 8 3/8% Bonds issued in September 1977.

Account 431, Other Interest Expense, had charges for the twelve months ended December 31, 1974, 1975, 1976 and 1977 of $2,369,990, $2,659,701, $1,154,156 and

$1,657,048, respectively. These charges primarily represent interest on short-term borrowings during this period. Interest on notes payable and commercial paper were $2,255,000 in 1974, $1,568,000 in 1975, $1,054,000 in 1976 and $1,319,000 in 1977. These changes are attributable to variations in the balances of short-term borrowings outstanding and in interest rates.

Other interest charges, in addition to interest on short-term borrowings, reflected in the yearly amounts shown included $966,079 in 1975 representing interest expense on payments to Niagara Mohawk Power Corporation for the Company's purchase of a partial ownership of Nine Mile Point #2 and Oswego #6 generating stations. Also included is $258,837 in 1977 representing interest expense pertaining to leased nuclear fuel.

Q: Will you describe Exhibit 3 and state what it purports to show?

A: Exhibit 3 is a Statement of Unappropriated Retained Earnings for the twelve months ended December 31, 1974, 1975, 1976 and 1977. The exhibit shows the balance of retained earnings at the beginning of each period, the addition of net income which has been transferred to retained earnings, the appropriations for cash dividends on preferred and common stock, the common stock dividends and the balance of retained earnings at the end of each period.

In addition, the exhibit shows the adjustments to retained earnings in connection with the adoption of equity accounting for Canadea Power Corporation and, in 1977, a charge to retained earnings pursuant to the order in Case 27269 for the capital stock expense of our Series "O" Preferred Stock which was called for redemption.

Undistributed subsidiary earnings reflects the annual earnings of Canadea Power Corporation less dividends paid to the Company.

Q: Will you discuss Exhibit 4 and state what it purports to show?

A: Exhibit 4 is a Statement of Electric Department Operating Income and Detail of Revenues, Expenses and Taxes, in Amount and Equivalent Cents for the twelve months ended December 31, 1974, 1975, 1976 and 1977. The exhibit is designed to facilitate comparison of the revenues and operating expenses of the Electric Department by primary accounts for the periods shown. I would like to explain the methods used in preparing this exhibit by referring to pages 1 and 2. A summary of the Operating Revenues, Operation and Maintenance Expenses, Depreciation, Taxes and Operating Income for each of four periods is shown on the upper portion of page 1. You will note that I have not made any equivalent cent computation for the various components. The reason for this, is that because of the large variations in contract and incidental power sales, it was not meaningful to utilize a single unit basis such as total kilowatt hours sold to arrive at equivalent cents for the four periods for the detail of revenues, expenses and taxes. Therefore, in order to obtain a meaningful comparison of the details of operating revenues, expenses and taxes, it was necessary to use different bases to determine the equivalent cents.

For example, the lower portion of page 1 shows operating revenues by accounts, and the upper portion of page 2 shows equivalent cents per kilowatt hour sold for operating revenues. The kilowatt hours sold applicable to each revenue account is shown on the lower portion of page 2. Page 4 shows Steam Power Generation operation and maintenance expenses on the basis of the equivalent cents per kilowatt hour of net steam generation. Likewise, page 6 details Nuclear Power Generation operation and maintenance expenses on the basis of equivalent cents per kilowatt hour of net nuclear generation. Page 8 shows the detail of Hydraulic Power Generation expenses on the basis of equivalent cents per kilowatt hour of net hydro generation. Page 10 shows Other Power Generation expenses on the basis of equivalent cents per kilowatt hour of other generation, and Other Power Supply Expenses on the basis of equivalent cents per kilowatt hour of energy purchased. Pages 11 through 19 detail the other expense subdivisions for the Electric Department with the dollar amounts being shown first, followed by the equivalent cents per kilowatt hour sold, less kilowatt hours sold for resale. Pages 20 and 21 are a detail of Taxes Other than Income Taxes and equivalent cents per kilowatt hour sold less

sales for resale.

Q: Do you have any comments relative to the summary of operating income or any of the detail account figures for operating revenues or expenses shown in this exhibit?

A: Electric operating revenues have increased by $64,086,182 from 1974 to the twelve months ended December 31, 1977. During this period the Company has received annual increases in permanent electric rates of $11,002,000 effective April 21, 1976 and $10,186,000 effective November 11, 1977.

Revenues also increased during this period because of revenues collected under our fuel cost adjustment and due to growth and increases in customer loads. You will note that there is a decline of total KWH sales for the twelve months ended December 31, 1976 and that 1977 KWH sales are approximately equal to 1975 KWH sales. This is primarily attributable to a variance in sales for resale. KWH sales for each of the other classifications have increased year to year throughout the period shown in the exhibit.

Turning to Page 3 of this exhibit, Account 500, Supervision and Engineering, Operation, has increased approximately $30,000 from December 31, 1976 to December 31, 1977 while Account 510, Supervision and Engineering,

Maintenance, has decreased approximately $20,000 over the same period. These changes have occurred due to a reallocation of payroll between operation and maintenance.

Account 501, Fuel, increased annually over the period shown from $33,869,919 in 1974 to $42,002,252 in 1977. The increases between each of the twelve month periods shown result from changes in the unit price as well as in the quantity of fuel purchased by the Company.

Stated in terms of Btu, these dollars represent 25,244,758 million Btu in 1974, 22,506,938 million Btu in 1975, 25,698,109 million Btu in 1976 and 27,581,463 million Btu in 1977. Cost per million Btu increased from 130.06 cents in 1974 to 151.35 cents in 1975, decreased to 145.83 cents in 1976, then increased to 147.65 cents in 1977.

Account 504, Steam Transferred - Credit, reflects the cost of steam produced at Beebee Station No. 3 which is subsequently transferred as a by-product to the Steam Department where it is utilized for commercial steam sales. These credits have remained relatively constant over the period shown having decreased slightly from 1974 to 1975 and from 1975 to 1976 followed by an increase from 1976 to 1977. However the average high pressure steam transfer rate per M lbs. was $3.93,

$4.16, $4.29 and $4.92 for 1974, 1975, 1976 and 1977, respectively, reflecting a steady increase primarily due to fuel costs. The average low pressure steam transfer rate per M lbs. was $3.54, $3.75, $3.84 and $4.44 for the respective periods.

Account 506, Miscellaneous Steam Power Expenses, shows increases approximating $150,000 in 1976 and $80,000 in 1977. These were caused primarily by research and development expenditures of $99,000 and $37,000 concerning suspension burning of refuse derived fuel in conventional boilers in 1976 and 1977, respectively. Also, beginning in 1976, expenses for the heating of Station No. 7 which had previously been charged to Account 501, Fuel Expenses, were charged to this account.

Turning to pages 5 and 6 of this exhibit, Nuclear Power Generation Expenses, you will notice a considerable increase in total cost of operation in 1975 when compared to 1974 and in 1977 when compared to 1976. This is primarily due to the fact that Ginna Station was shutdown for 125 days for refueling, maintenance and replacement of a broken turbine blade in 1974 and was shutdown twice in 1976 for a total of 99 days for refueling, maintenance and repairs to the turbine necessitated by further turbine blade damage. The plant was down for

more normal refueling and maintenance for 69 and 38 days during 1975 and 1977, respectively, as compared to the 125 and 99 days in 1974 and 1976. A substantial increase is shown in Account 518.1, Nuclear Fuel, between the 1976 and 1977 periods. This increase was caused by the interaction of approximately fifty per cent greater generation and increased amortization rates during 1977 compared to 1976.

The differences in shutdown periods and nuclear fuel cause variations within total nuclear power generation expense. Deducting Account 518.1, Nuclear Fuel, from total nuclear power generation expense is helpful in discerning the trend of expense other than nuclear fuel. This calculation shows total nuclear power generation expense, exclusive of nuclear fuel, of $5,396,166, $6,600,299, $7,360,701 and $7,944,138 for the years 1974 through 1977, respectively.

There are, of course, variations within the operation and maintenance accounts. Account 517, Supervision and Engineering, increased approximately $165,000 in 1976 and $56,000 in 1977. The 1976 variance included increases of about $10,000 in operator training costs, $21,000 for engineering and consulting costs to evaluate nuclear fuel bids and $43,000 from a reallocation of the Electric

System Planning and Operation Department payroll. The 1977 variance included a $40,000 increase in operator training costs.

Account 519, Coolants and Water, increased about $166,000 during 1977 due primarily to increasing costs associated with environmental studies. We expect this trend to continue as these studies continue to become more sophisticated and require more detailed analysis.

Account 524, Miscellaneous Nuclear Power Expenses, increased approximately $600,000 during 1977. The variance was primarily caused by an increase of $291,000 in plant security expenses together with an increase of $168,000 in research and development expenses.

Account 528, Supervision and Engineering, increased approximately $79,000 during 1977. This was caused primarily through payroll charges which increased over $72,000. Approximately $52,000 of the payroll increase represents increased labor charges of plant personnel while the remaining $20,000 represents increased labor charges to this account by employees assigned to other departments.

Account 531, Electric Plant, indicates a marked increase during 1975. This change reflects increased costs for maintenance of the turbo-generator during

overhaul, maintenance of accessory electric equipment during overhaul and inspection and testing of the intake heating screens and power cable to the screens. These 1975 job costs reflect increased expenditures over the year 1974 in the amounts of $201,000, $43,000 and $134,000, respectively.

Q: Would you please continue with your explanations of this exhibit?

A: Account 543, Reservoirs, Dams and Waterways, increased approximately $99,000 in 1977. Hydro Station #5 expenditures increased about $93,000 due mainly to costs associated with maintenance on the tunnel at that station.

Account 547, Fuel, reflects the cost of #2 oil and natural gas used in our gas turbine operations at Station #3 and Station #9. Total MWH generated from these peaking units was 12,806 in 1974, 2,198 in 1975, 2,797 in 1976 and 850 in 1977.

On page 9, Account 555, Purchased Power, increased by approximately $6 million from 1975 to 1976 and then decreased about $4.6 million from 1976 to 1977. The variations in this account are primarily due to changes in the quantities and unit costs of power purchased from other utilities as a result of maintenance requirements on the Company's generating plant.

Account 559, Fuel Costs Deferred - Net, reflects the accounting for deferred fuel costs adopted by the Company in January 1974. The difference in amounts for the periods shown is the result of the price of fuel and the generation mix.

Q: Will you continue with your comments on this exhibit?

A: Looking at Account 561, Load Dispatching and Account 562, Station Expenses, you will notice an increase approximating $128,000 in the former account between 1975 and 1976 while the latter account shows a decrease of around $41,000 for the same period. This was partially caused by an amount of $34,904 erroneously being charged to Account 562 in 1975. A correcting entry in 1976 properly charged that amount to account 561. The increase in Account 561 from 1976 to 1977 also reflects increased payroll charges approaching $64,000 together with an increase in payments of about $56,000 to the New York Power Pool representing the increase in this Company's share of NYPP expenses.

Account 563, Overhead Line Expenses, reflects a substantial increase in 1976 while 1977 expenditures have remained at the same approximate level. Both years reflect increased expenses for tree trimming.

Account 566, Miscellaneous Transmission Expenses,

shows a credit amount in 1976. This resulted primarily from charges of $30,814 to a research and development job for accoustical research offset by a refund of $51,000 from the Empire State Electrical Energy Research Corporation for amounts expended in 1976 and prior years on the accoustical research study. Research and development expenditures charged to this account decreased in 1977 with only minor amounts charged for biological assessment of electrical and magnetic fields and for soil investigation.

Account 570, Station Equipment, increased about $104,000 during 1977 due mainly to $48,000 increased charges for transformer repairs.

Account 583, Overhead Line Expenses, also reflects increased tree trimming activity the past two years and charges for removing and resetting transformers which represent approximately $53,000 of the $59,000 increase in 1977.

Account 585, Street Lighting and Signal System Expenses, reflects a decrease in charges during 1975. The decrease resulted from an austerity program in effect at that time whereby globe washing by contractors was eliminated, bulb life was extended from twelve months to eighteen months and overtime work was discontinued.

Account 586, Meter Expenses, decreased about $17,000 in 1976 and increased almost $70,000 in 1977. The 1976 decrease was caused predominately by a reduction in expense of testing watthour meters located on customers' premises due to a lengthening of the period between required tests (16 NYCRR 92.12). The 1977 increase reflects increased turn on and shut off activity.

Account 587, Customer Installation Expenses, reflects a reduction in expense of $93,000 in 1977. This reduction was due primarily to the discontinuation of servicing television, radio, hi-fi and small appliances on June 14, 1976. Expenses of paid servicing were $25,000 lower in 1977 while charges to Company Account 587-31, All Other Services on Customers Premises, were $54,000 below 1976.

Account 590, Supervision and Engineering, decreased $171,000 during 1976. This decrease resulted from a reallocation of labor costs between capital and expense. Company studies indicated that a significant amount of engineering labor costs related to construction were being charged to expense as, in many cases, construction jobs were not issued until much of the preliminary engineering work was completed. Effective January 1, 1976 we began charging construction related engineering

costs to a permanent job from which an engineering overhead charge is allocated to construction jobs.

Account 592, Station Equipment, increased $119,000 in 1977. The increase was primarily due to increased payroll charges and a $25,000 repair of a transformer which failed at Substation #56.

Account 904, Uncollectible Accounts, increased $240,000 in 1975, $925,000 in 1976 and then decreased slightly in 1977. The 1975 and 1976 increases were primarily caused by the implementation of an accelerated write-off program to more accurately reflect our accounts receivable. We now charge off as uncollectible any accounts receivable which have aged over 120 days. The 1977 decrease reflects a return to more normal write-offs tempered by a $150,000 increase in the reserve balance.

Account 906, Rents, reflects a large decrease in 1975. This resulted from a transfer of charges from this account to Account 903, Customer Records and Collection Expenses, representing rental costs of data processing equipment.

Q: Will you continue with your comments on this exhibit?

A: Turning to page 18, Administrative and General Expenses, I would like to comment upon the basis for the charges

to these accounts. Costs applicable to these accounts are charged directly to the class of operation involved whenever possible. However, where costs are non-direct, 60% of the charges to the respective accounts are generally allocated to the Electric Department. This percentage was derived as a matter of judgment after considering the number of customers, distribution operating expenses, the trend of the Company's operations and the time expended for each department. Account 926.1, Employee Pension, and Account 926.2, Employee Welfare Expense are an exception to the 60% allocation of non-direct charges. All of Account 926.1 and a portion of Account 926.2 is allocated monthly to the Electric Department on the basis of the ratio of Electric Department operating expense payroll to the total operating expense payroll for the prior twelve months. The average percentages used were 67.4%, 65.3%, 66.1% and 65.9% for the years 1974, 1975, 1976 and 1977, respectively.

Account 925, Injuries and Damages, increased $158,000 in 1976 and $64,000 in 1977. The 1976 change was predominately due to a $65,000 increase in Workmen's Compensation premiums resulting from the elimination of the $300 per employee deductible feature coupled with a

rate increase. The 1977 change was due mainly to a $46,000 increase in the cost of excess public liability insurance.

Q: Turning to page 20 and 21 of this exhibit, are there any comments you would like to make?

A: Yes. Total taxes other than Federal income taxes for the year 1974 totalled $22,783,829. Increases occurred in each year shown on the exhibit in the amount of $2,586,015 for 1975, $3,173,203 for 1976 and $2,986,646 for 1977. These increases evolve primarily from additions to the Company's electric plant coupled with increases in property tax rates and from growth in the taxable base upon which revenue taxes are determined. Property taxes increased $5,443,704 over the three year period while gross income and gross earnings taxes increased $2,322,435 over the same period. These amounts represent increases of 35.9% and 43.4%, respectively.

Q: Will you describe Exhibit 5 and state what it purports to show?

A: Exhibit 5 is a Statement of Gas Department Operating Income and Detail of Revenues, Expenses and Taxes in Amount and Equivalent Dollars per Therm (000's) Sold for the twelve months ended December 31, 1974, 1975, 1976 and 1977. This exhibit has been prepared in a manner similar to Exhibit 4.

Page 1 of this exhibit shows the details of operating income in summary form. Page 2 shows a breakdown of operating revenues by account. Pages 3 through 14 details operating expenses by functional accounts while pages 15 and 16 are details of Account 408.1, Taxes Other Than Income Taxes. The exhibit is self explanatory for the most part and is designed to facilitate the comparison of the revenue and operating expense of the Gas Department for the period shown.

Q: Do you have any comments concerning the summary of operating income on page 1 of this exhibit?

A: Operating revenues have increased from $75,462,995 in 1974 to $105,796,864 in 1977, an increase of $30,333,869 over that period. During this period the Gas Department has received permanent rate increases on an annual basis of $4,854,000 effective October 23, 1974, $4,983,000

effective April 20, 1976 and $2,536,000 effective November 11, 1977. A temporary rate increase of $2,497,000, on an annual basis, was received effective July 25, 1974 and subsequently made part of the October 23, 1974 permanent increase. Revenues were reduced $1,536,370 in 1977 as a result of a decision by the Company to provide a $10 credit on the billing of each residential gas spaceheating account. Revenue deductions have increased by $30,884,560 over the same period from $66,727,356 in 1974 to $97,611,925 in 1977. Operating income decreased $550,691 from $8,735,630 in 1974 to $8,184,939 in 1977.

Revenue deductions in 1977 included amortization in the amount of $154,706 representing the net loss from the abandonment of our manufactured gas facilities. This charge was recorded pursuant to a Commission order dated April 12, 1977.

The Company completed the conversion of all of its manufactured gas customers to straight natural gas effective June 30, 1976. Therefore no expenses relating to the production of manufactured gas appear on pages 3, 4 and 5 for the year 1977 and those expenses recorded in 1976 are below those balances shown for 1974 and 1975. Besides the accounts on those pages, the use of

Accounts 812 and 840 through 846 on pages 6 and 7 and Accounts 872 and 873 on pages 8 and 9 were terminated due to the cessation of manufactured gas production.

As shown on page 6 of this exhibit, Account 804, Natural Gas City Gate Purchases were $37,341,565 in 1974, $47,247,241 in 1975, $56,191,880 in 1976 and $62,085,820 in 1977. The changes in these amounts reflect the increase in the cost of this gas to the Company and volume variations due to weather. The average cost per therm of gas purchased increased from 7.80¢ in 1974 to 9.53¢ in 1975, to 11.05¢ in 1976 and to 14.42¢ in 1977.

Turning now to page 8, many of the account variations are primarily due to the conversion of the Company's mixed gas system to natural gas in connection with the phasing out of the manufactured gas plant.

Account 878, Measuring and Regulating Station Expenses, reflects a $30,000 decrease in 1977. This reduction was the result of the cessation of manufactured gas production.

Account 879, Customer Installation Expenses, increased $571,000 in 1975, increased $225,000 in 1976 and decreased $735,000 in 1977. This reflects the increased costs incurred in converting our mixed gas

customers to natural gas during 1975 and 1976.

Account 894, Other Equipment, increased $34,300 in 1977. This was primarily caused by expenditures incurred in moving propane gas tanks from our Blossom Road holder to other locations.

Turning to page 10, Account 904, Uncollectible Accounts, increased substantially in 1975 and 1976 and then decreased in 1977. As stated in my testimony on this account in the Electric Department, these changes were caused by an accelerated write-off program which was in effect in 1975 and 1976. The year 1977 reflects a return to more normal write-offs offset by a $98,750 increase in the reserve.

The reduction from the 1974 level in Account 906, Rents, reflects the transfer of data processing rental costs from this account to Account 903, Customer Records and Collection Expenses.

Q: Will you continue with your comments on this exhibit?

A: Pages 13 and 14 is a schedule of Administrative and General Expenses. As I discussed in connection with Exhibit 4, the amounts represent both direct and non-direct charges applicable to this group of accounts. The non-direct charges, except for Account 926.1 and portions of Account 926.2, were allocated to the Gas

Department by utilizing 39.5% of the total amount charged to these accounts, such percentage based on the criteria previously described. Account 926.1 and a portion of Account 926.2 are allocated monthly to the Gas Department on the basis of the ratio of the Gas Department operating expense payroll to the total operating expense payroll for the previous twelve months. The average allocation percentages used for 1974, 1975, 1976 and 1977 were 29.3%, 28.4%, 27.9% and 28.0%, respectively.

Account 925, Injuries and Damages, reflects an increase of $76,000 in 1976 and $133,000 in 1977. The 1976 change was composed primarily of a $28,000 increase in premiums for excess public liability insurance, a $23,000 increase in Workmen's Compensation premiums and an $11,000 increase in allocations of non-direct charges. The 1977 change reflects a $93,000 increase in excess public liability insurance premiums, an $18,000 increase in Workmen's Compensation costs and a $23,000 increase in allocated expenditures.

Account 930, Miscellaneous General Expenses, shows a $126,000 increase in 1976 and a decrease of $64,000 in 1977. An amount of $47,909 was incorrectly charged to this account in 1976 which should have been charged

to Account 928, Regulatory Commission Expenses. A correcting entry was made in 1977. Absent the incorrect charge, the 1976 and 1977 expenditures in this account would have been approximately $598,000 and $630,000, respectively, rather than the $646,337 and $582,582 shown.

Q: Turning to pages 15 and 16 of this exhibit, are there any comments you would like to make?

A: Total operating taxes for the year 1974 were $7,937,088. These increased by $777,485 for 1975, $1,014,527 for 1976 and $360,254 for 1977. The decrease in property tax from 1976 to 1977 was primarily caused by the physical removal of our former gas manufacturing facility. The year to year increases in total operating taxes reflect some additions to the Company's gas plant but, more significantly, reflect increases in tax rates and an expanding revenue tax base derived from customer charges including GCA revenues. Property taxes increased $741,102 while gross income and gross revenue taxes increased $1,245,304 over the three year period. These amounts represent increases of 18.7% and 39.7% respectively.

Q: Will you describe Exhibit 6 and state what it purports to show?

A: Pages 1 and 2 of this exhibit show the book cost of Electric Plant in Service by primary accounts and the Electric Construction Work in Progress as of December 31, 1974, 1975, 1976 and 1977. Pages 3 and 4 show the Accumulated Provision for Depreciation of Electric Plant in Service by primary accounts and the amount of Retirement Work in Progress for the Electric Department. Page 5 shows the Electric portion of Common Utility Plant in Service by primary accounts and the Electric portion of Common Construction Work in Progress. Page 6 shows the Accumulated Provision for Depreciation of the Electric portion of Common Utility Plant in Service by primary accounts and the amount of Retirement Work in Progress for that plant. The methods of allocation of Common Utility Plant and the Accumulated Provision for Depreciation of Common Utility Plant in Service will be explained in conjunction with a later exhibit. I believe this exhibit is self explanatory.

Q: Will you describe Exhibit 7 and state what it purports to show?

A: Page 1 of this exhibit shows the book cost of Gas Plant in Service by primary accounts and the Gas Construction Work in Progress as of December 31, 1974, 1975, 1976 and 1977. Page 2 shows the Accumulated Provision for Depreciation of Gas Plant in Service by primary accounts and the amount of Retirement Work in Progress for the Gas Department. Page 3 shows the Gas portion of Common Utility Plant in Service by primary accounts and the amount of Retirement Work in Progress for that plant. The methods of allocation of Common Utility Plant and the Accumulated Provision for Depreciation of Common Utility Plant in Service will be explained in conjunction with a later exhibit. The December 31, 1976 and 1977 balances on pages 1 and 2 reflect the retirement of our gas manufacturing facilities. I believe this exhibit is also self explanatory.

Rochester Gas and Electric Corporation

Direct Testimony

of

ROBERT C. HENDERSON

Assistant Controller

DIRECT TESTIMONY
OF
ROBERT C. HENDERSON

Q: Would you please state your name and business address?

A: Robert C. Henderson. My business address is 89 East Avenue, Rochester, New York 14649.

Q: Mr. Henderson, what is your position and what are your responsibilities with Rochester Gas and Electric Corporation?

A: I am an Assistant Controller. I am responsible for accounting and financial research, analysis of financial and accounting problems, federal income taxes, long range financial planning and studies and the planning and preparation of financial and accounting data required for rate increase applications. I also participate in the determination and implementation of the Company's financing plans and goals.

Q: Would you briefly outline your experience and qualifications?

A: I received a bachelors degree in accounting from the University of Rochester in 1962 and I am presently completing the requirements for a masters degree in business administration from the University of Rochester's Graduate School of Management. In 1963, I was employed

by the Company as an accountant in the general accounting department. Subsequently, I have held the position of tax analyst, corporate tax representative, senior staff assistant and manager of the financial analysis department. In October, 1976, I was elected to my present position. I have testified in our last five rate case proceedings. I have also testified before the Nuclear Regulatory Commission in relation to the Company's application to build the Sterling Nuclear Plant as well as other proceedings before the PSC.

Q: What is the purpose of your testimony in this proceeding?

A: First, I will discuss exhibits 8 and 9 relating to the Electric and Gas Departments, respectively. These exhibits cover revenues and expenses for the historical test year (calendar 1977), and set forth known, pro forma adjustments to establish the impact of changes in the rate year, that is, the first year in which rates would be effective. Secondly, I will discuss Exhibits 10 and 11, the forecast exhibits prepared in response to the Commission's "Statement of Policy on Test Periods in Major Rate Proceedings". My testimony will also include a discussion of the manner in which we have addressed the subjects of executive compensation and labor produc-

tivity. Lastly, I will introduce an exhibit (Exhibit 13), which contains projections of Source and Disposition of Funds, Capitalization, and Interest Coverage Ratios, and I will indicate how this data bears on the Company's need for additional revenues.

Q: Will you describe and explain Exhibit 8 and state what it purports to show?

A: This exhibit develops for the electric department a rate of return per books and pro forma for the 12 months ended December 31, 1977, as summarized on the first and second page. On the first page, column 1, is a statement of Electric Department revenues and expenses, operating income and rate of return per books. Column 2 contains known pro forma adjustments to these book figures. These adjustments are generally described along the left hand side of the page and each is cross-referenced to a schedule which provides details of the adjustment. Column 3 is the pro forma result of applying the adjustments in column 2 to the book figures in column 1. Column 4 reflects the proposed electric rate increase sought in this proceeding and column 5 reflects the adjusted Pro Forma Income Statement and Rate of Return including the proposed increase.

Q: Will you now refer back to column 1 of page 1 and

explain the information shown there?

A: Column 1 is a statement of the revenues and expenses per books for the 12 months ended December 31, 1977. The balance for return of $36,444,476 applied to the average rate base of $425,848,853 produces a rate of return per books of 8.56%.

Q: Would you please explain column 2 of this exhibit labeled "Pro Forma Adjustments"?

A: The first adjustment labeled "Annualization of rate increases" in the amount of $12,557,104, is summarized on the upper portion of Schedule A. This adjustment reflects annualization of the rate increases which became effective in November 1977 and February 1978, and annualization of the rate increase under our street lighting tariffs which became effective in March 1978. The second adjustment of $21,990, labeled "PASNY credits," adjusts the test year PASNY credits to the annual amount under PASNY contracts effective during the rate year. The third revenue adjustment, a decrease in revenues of $975,800, labeled "Fuel cost adjustment revenues on the basis of December 1977 cost of fuel," reflects fuel cost adjustment revenues that would have resulted from using, for the entire year, the December 1977 cost of fuel. This adjustment is summarized on the

lower portion of Schedule A.

Q: Turning back to the first page of Exhibit 8, would you explain the adjustments under the heading "Normalization of generation, purchases and sales"?

A: If you will turn to page 1 of Schedule C, the first adjustment under the heading "Normalization of generation, purchases and sales" labeled "Sales to Other Utilities", results in a decrease in revenues of $3,963,221. This adjustment has been made to reduce test period incidental sales to a level consistent with normalized generation. As a result of this adjustment, corresponding adjustments were also made to expenses to reflect normalization of Generation and Purchases as shown on pages 2 and 3 of Schedule C. The adjustment in incidental sales results in a 336,798 megawatt hour reduction in generation, which, after changes in transmission and distribution losses are taken into account, yields a reduction in incidental sales of 331,590 megawatt hours, as shown on the upper portion of page 1 of Schedule C. The pro forma level of incidental sales of 1,122,000 megawatt hours was then priced out on the basis of December 1977 costs of $15 per megawatt hour plus a return of $5 per megawatt hour, to determine the pro forma sale price to other utilities of $20 per mega-

watt hour. This results in pro forma revenues of $22,440,000, a $3,963,221 reduction from actual test period revenues.

The second adjustment under this heading, labeled "Fuel Cost Adjustment," showing an increase in revenues of $104,410 is summarized on the lower portion of page 1 of Schedule C. This adjustment has been made to reflect the increase in fuel cost adjustment revenues that will occur as a result of the normalization of generation, purchases and sales.

Q: Turning back to the first page of Exhibit 8 would you please continue with your explanation by describing the adjustments to expenses?

A: The first adjustment, labeled "Fuel at December 1977 Cost," detailed on page 1 of Schedule B, reprices test year fuel costs at the December 31, 1977 cost. On Schedule B, I have first shown test period generation and purchases in megawatt hours, the fuel cost per megawatt hour, and the total fuel expense consisting of fuel expenses and deferred fuel reinstatements totalling $48,999,118. Repricing test period generation and purchases at the December 31, 1977 fuel costs results in a pro forma fuel expense of $52,796,308, an increase in fuel expense of $3,797,190.

The next two adjustments to expense are under the heading "Steam Produced by the Electric Department. " The first, labeled "Steam Transferred," reflects reduction in expense of $1,773, and the second, labeled "Fuel used for steam production," a reduction of $246,340. Both adjustments are shown on page 2 of Schedule B. The adjustment labeled "Steam transferred" is made to reprice, at the December 1977 cost, the test year steam produced by the electric department and transferred as a by-product to the Steam Department. On the lower portion of the page, I have shown the adjustment to reprice, at the December 1977 fuel costs, the fuel used for steam production.

Two adjustments under the heading "Normalization of Generation, Purchases and Sales" are shown on Schedule C. The first adjustment, labeled "PASNY Capacity and Transmission Charges", reflects an increase of $389,932 in capacity and transmission charges for firm capacity purchases under our Niagara, Gilboa and Fitzpatrick contracts. Schedule C, page 2, shows the per book expenses in 1977 for the PASNY capacity and transmission charges. The lower portion of the page sets forth the contractual charges under our contracts effective during the rate year. The pro forma Niagara "firm demand" and

transmission charges reflect a contractual reduction in purchases to 130,000 Megawatts, effective March 1, 1978. The pro forma FitzPatrick demand charges reflect an increase in the contract rates from $3.50 to $6.00 per megawatt per month, effective September 1, 1977.

An expense adjustment of $3,999,265 attributable to "Generation and energy purchases", is summarized on page 3 of Schedule C. This adjustment is based upon pro forma changes in the levels of generation and purchases. Mr. Laniak will explain the basis for these adjustments. I have simply priced the normalized generation and energy purchases, as shown on the lower portion of page 3, at the December 1977 cost. This results in a pro forma expense of $52,088,069, which, when subtracted from the test period generation and purchases expenses at December 1977 costs of $56,087,334, produces a pro forma reduction of $3,999,265.

Q: Will you continue with your explanation of the adjustments to expenses?

A: The next adjustment, in the amount of $6,571,611, labeled "Wage and Salary Adjustments," is detailed on Schedule D. This item adjusts test period payroll charged to the Electric department to reflect current complement at estimated wage rates and fringe benefit

costs that will be effective in the rate year. If you will turn to Schedule D, you will notice that line 1 reflects the company's current annual payroll on the basis of the February 1978 complement and wage rates. Line 2 reflects the company's actual 1977 overtime expenses. Lines 3 and 4 develop the increase in expense currently estimated for wage increases effective on February 1, 1979 and 1980. Line 5 reflects the test period part time and miscellaneous payroll. The $63,729,993 shown on line 6 is our estimated pro forma annual payroll for the rate year. Of this amount, 81.14% is applicable to operating expense (line 7), and 66.35% of this operating expense payroll is applicable to the Electric Department (line 8). The difference between the pro forma estimated wage expense of $34,309,927 and actual test period payroll expense of $28,617,753 is $5,692,174. The adjustments to the related welfare expenses shown on lines 11 through 13, reflect the net increase attributable to three changes: First, an adjustment to reflect current allocations; second, an adjustment to reflect cost consistent with the wage levels for the rate year; and third, in the case of hospitalization insurance, to reflect the current cost for this insurance. These adjustments total

$879,437 and, when added to the wage and salary adjustment, result in the total adjustment of $6,571,611.

Q: Mr. Henderson, you indicated that these increases for wages effective February 1979 and 1980 are estimated, is that correct?

A: That is correct. Our company has historically given a cost of living, or inflation, increase in wage rates to hourly paid employees on February 1st of each year. In addition, certain of our hourly employees are eligible for merit increases during the year. Salaried employees are evaluated on this date for merit increases. While our salaried employees do not get a general increase, their merit increases approximate the overall percentage increase achieved by hourly employees.

Q: Mr. Henderson, how and when are the wage and salary increases actually established?

A: The increases are established in December prior to the granting of the wage increase based on data prepared by our Employee Relations Department and recommended by management to the Board of Directors. The Board of Directors can approve or modify the proposed increase. The increase will, of course, vary depending on several factors. Recently, inflation has had the most significant effect on the raises awarded our employees.

Therefore, for rate purposes, I have estimated these increases at 8% or slightly over 1% in excess of the inflation rate I am using for expense escalation in this proceeding. The derivation of this inflation rate will be explained later in my testimony.

Q: Will you please continue with your explanation of the remaining expense adjustments?

A: The next adjustment, labeled "Account 426.10 Donations," in the amount of $298,564, is detailed at Schedule E. On Schedule E, I have shown total company test period charges to Account 426.10 in the amount of $369,053. Of these charges, 80.9%, or $298,564, has been allocated to the electric department, on the basis of net plant as of December 31, 1977.

The next adjustment summarized on Schedule E, labeled "PSC Assessment," shows a decrease of $75,993 to reflect the current annual assessment of the Public Service Commission.

The next adjustment to expenses, labeled "Research and Development," reflects an increase in the level of research and development expenditures charged to Electric operations. The detail shows 1978 Research and Development expenditures of $2,393,100, less that portion of the PSC assessment attributable to Research

and Development and internal expenses, which have already been pro formed in the prior adjustment and on Schedule D. The net adjusted expenditures for Research and Development are $1,911,100. The difference between the pro forma and the test period expenditures for Research and Development is $169,548.

The next adjustment to Expenses labeled "Ginna security," also summarized on Schedule E, reflects the increased cost of security at Ginna Station. Under the Nuclear Regulatory Commission's regulations, 10 CFR 73.55, effective August 1, 1977, the Company has been required to modify its security operations at Ginna Station. The annual expenditures necessary to comply with these regulations will exceed test period expenditures by $529,994.

The next three adjustments to Expenses are summarized on Page 2 of Schedule E. The first, labeled "Insurance," reflects a $58,266 increase in the cost of excess public liability insurance. "Telephone charges" increase $32,075 to reflect repricing of test period telephone charges on the basis of current telephone rates. The third adjustment, "Non-recurring expenses" eliminates test period expenditures totalling $33,214 that will not be applicable to the rate year.

The next adjustment under expenses, labeled "Uncollectible Accounts," summarized on page 3 of Schedule E, reflects the pro forma adjustments made to customer revenues. Applying to pro formed customer revenues the current .710% ratio of uncollectible accounts to customer revenues results in a provision for uncollectable accounts of $1,360,701. This amount exceeds the test period provision for uncollectable accounts by $82,375.

In a similar manner, the adjustment to "Injuries and damages accrual" also reflects the Pro forma changes in customer revenues. This adjustment is also shown on page 3 of Schedule E.

The adjustment labeled "Interdepartmental charges," an increase of $26,758, is summarized on Schedule F. This adjustment reprices test period use of electricity by other departments and steam by the Electric Department at December, 1977 costs. It also reflects gas used by the Electric Department at January 2, 1978 costs.

The last adjustment to expenses, labeled "Allowance for Escalation" totals $4,369,255. This adjustment has been made to reflect the estimated increase in test period operating expenses for which a specific Pro forma adjustment has not been made. This adjustment seeks to account for general increases in expenses that will

result from inflation. The details of this adjustment are shown in Schedule E of Exhibit 10. A more detailed explanation of this adjustment will be given in my testimony relating to that Exhibit and Schedule.

Q: Will you return to the first page of this Exhibit and explain your adjustments under "Depreciation".

A: The first adjustment to Depreciation, labeled "Accruals effective December 1, 1977," in the amount of $199,674, reflects the changes in depreciation accruals, effective December 1, 1977, pursuant to the Commission Order in case 27108. The detail of these changes are shown on page 1 of Schedule H.

The second adjustment, labeled "Accruals effective May 1, 1979," increases depreciation expenses by $213,678. The changes in depreciation rates reflected in this adjustment are based on our most recent depreciation studies which included updated net salvage studies similar to the ones performed by staff in Case 27108. We are proposing to place in effect increased depreciation rates concurrently with the implementation of rates established in this proceeding. These changes are summarized on page 2 of Schedule H.

The third adjustment to depreciation is labeled "Ginna Normalization" and has been made to reflect the

annualization of depreciation expense on the new low pressure rotor that was installed at Ginna Station in the spring of 1978. The normalization of generation described in Schedule C includes the increased Ginna rating to 470 megawatts, an increase made possible by the installation of the rotor. The cost of the rotor is an appropriate addition to rate base. Correspondingly, an appropriate level of depreciation expense related to the rotor is reflected in this adjustment. The derivation of this adjustment, as well as the adjustment to rate base, are shown on Schedule M.

The last adjustment to depreciation, "Non revenue producing capital expenditures," is consistent with the Pro forma adjustment to rate base for non-revenue producing capital expenditures. I have reflected the increase of $571,800 of depreciation expense appliable to these additions. This adjustment is summarized at Schedule N.

Q: Returning to the first page of this exhibit, under the caption "Taxes Other Than Income", would you please explain the adjustment labeled "Real property & special franchise taxes and water pollution control charges," reflecting an increase in taxes of $1,420,508?

A: This adjustment is shown on page 1 of Schedule I and

updates these test period expenses to the levels anticipated for the year 1978. On the upper portion of that page, I have shown, by the various taxing jurisdictions, the 1977 total Company tax and the allocation of that tax to the Electric, Gas and Steam departments. The amounts for the City of Rochester, School and Water pollution are estimated 1978 taxes. All of the others are actual 1978 taxes. This is the same information filed with the Commission to support our supplemental rate filing which became effective in February, 1978. This filing was authorized pursuant to the Order in Cases 27108 and 27109, and was designed to recover wage and tax increases.

Q: Mr. Henderson, could you explain how the Company allocates its property taxes to departments.

A: Yes. The amount of taxes directly applicable to each department is determined by detailed analysis of departmental use of each of the Company's various individual property units. Common properties are allocated on the basis of common utility plant allocation percentages which I will explain later.

Q: Would you continue with your explanations of the adjustments to taxes other than income.

A: A reduction in "Water use charges" of $5,969 has been

made to reflect the current lower tax charged on water consumption, effective January 1, 1978. The details of this adjustment are shown on page 2 of Schedule I.

An increase of $459,658 in "Revenue Taxes," detailed at page 3 of Exhibit I, reflects revenue taxes applicable to the pro forma revenues shown in this exhibit.

The adjustment labeled "Payroll taxes", an increase of $673,793, is shown on page 4 of Schedule I, and reflects the payroll taxes applicable in the rate year. This schedule shows the taxable wage base for Social Security and Medicare in effect for the calendar year 1979 and 1980, as well as the current taxable wage base for federal and New York State unemployment insurance. From the taxable wage base and the pro forma wages applicable to each period, I have derived the pro forma taxable wages for each of the periods. Using the tax rates under current law, I have derived the pro forma taxes for the rate year. Of these company taxes, 83.02% are allocated to operating expense, of which 66.35%, or $2,110,780, is applicable to the electric department. The difference between pro forma and actual payroll taxes is $673,793.

The next Adjustment relates to "Sales and Use

Taxes." I have increased the allowance for "Sales and Use Taxes" to reflect the fact that as the Company's cost for materials and supplies escalate, the liability for sales and use tax will also increase. Applying our estimated escalation rate of 16.1545% for materials and supplies derived in Exhibit 10, I have estimated that the rate year sales and use taxes will increase to $2,401,674. Using the percentage applicable first to operating expense, in general, and then the percentage applicable to the Electric department, in particular, the pro forma figure of $798,919 is derived. Subtracting the test period charges of $719,236 from the pro forma taxes results in the increase of $79,683. This calculation is set forth at page 5, Schedule I.

The last adjustment under "Taxes - Other Than Income", labeled "Excess dividends tax," reflects the rate year level of excess dividends taxes applicable to the Electric department. The adjustment, as derived on page 6 of Schedule I, sets out the estimated equity balance as of April 30, 1980, which will be used to determine the excess dividends tax. The excess dividends tax is applied to dividends which exceed 4% of the equity balance. Thus, applying the 4% rate to our April 30, 1980 equity balance results in a base for

dividend comparison of $16,240,855. RG&E's anticipated dividends for the 12 months ended April 30, 1980 are $40,163,205, resulting in a taxable base of $23,922,350. Applying the current excess dividends tax rate of 4.5% results in a pro forma excess dividends tax of $1,076,505, $281,817 greater than the comparable test period expense. Of this tax increase, 87.78%, or $247,378, has then been allocated to the electric department.

Q: The next adjustment is a downward revision to Federal Income Tax in the amount of $5,487,000. Would you please explain this adjustment?

A: This adjustment is detailed on page 1 of Schedule J of Exhibit 8. This schedule is a computation of the federal income tax applicable to the Electric department. Page 1, Column 1, of Schedule J reflects the test period Electric Department per books computation of federal income tax. Column 2 reflects adjustments made to the books' figures which are required to translate federal income tax per books into an allowance for federal income tax related to pro forma Electric Department operations. Column 3 simply reflects the pro forma income tax resulting from the adjustments made in column 2.

Q: Would you please comment on the adjustments shown in Column 2?

A: These adjustments are primarily of three general types. The first adjusts for a change in tax deductions directly related to known changes made in the statement of income, such as the change in fuel cost resulting from the elimination of fuel cost deferrals. Other examples of this kind of an adjustment are the following: "pension costs capitalized;" and "taxes charged to construction" which are both related to changes in wages and salaries; and "additional deductible depreciation," which reflects changes in book depreciation accruals. The second type of adjustment reflects current departmental allocations. The third adjustment shown on Schedule J reflects a change in interest charges on the basis of the company's rate year capital structure.

Q: Mr. Henderson, are there any of the components of the tax computation which are shown for the first time in the year 1977?

A: Yes, there are two such items. The first is the item labeled "Nuclear Fuel Storage Costs," which increases taxable income by $6,971,000. The second is the item labeled "Fossil Plant Abandonment," which reduces

taxable income by $4,500,000. "Nuclear Fuel Storage Costs," reflect the amortization of nuclear fuel expense applicable to future storage cost for nuclear fuel which is non-deductible for tax purposes. In 1977, as a result of a change in federal policy which now proscribes nuclear fuel reprocessing, the Company revised its calculations to provide for the cost of estimated permanent storage for spent nuclear fuel. We are, however, unable to take a current tax deduction for these estimated future storage costs. We reflected this in the Company's 1977 results of operations and also adopted prepaid tax accounting for the timing difference that results from the different treatment of this expense for book and tax purposes. The Company currently has a petition pending before the Public Service Commission to approve this use of prepaid tax accounting.

The next item, labeled "Fossil Plant Abandonment," is also new in the year 1977 and again is the subject of a Petition for approval of accounting treatment pending before the Commission. In 1977, we have taken a tax deduction for costs attributable to the Sterling Fossil Plant. We have requested deferred tax accounting for this to allocate such tax benefit as an offset to the

ultimate expenses attributable to recapture of the loss. This is, of course, a non-recurring item and has been eliminated in the determination of pro forma Federal income tax.

Q: Returning to page 1 of the Exhibit, would you please continue by explaining the next adjustment under the heading "Provision for Deferred Income Taxes Net", a decrease of $2,959,528.

A: This adjustment has been made to eliminate the deferred taxes applicable to deferred fuel accounting followed for book accounting purposes. In addition, adjustments have been made to proform deferred income taxes related to non revenue producing capital expenditures as well as to eliminate the deferral applicable to the nonrecurring fossil plant abandonment tax deduction which I have just discussed.

Q: The next adjustment shown on Page 1 of Exhibit 8 is entitled Interperiod Tax Allocation." Would you please explain this adjustment?

A: The adjustment has been made to reflect, for rate purposes, the use of net of tax, AFUDC accounting for the investment in Oswego #6, Nine Mile Point #2, and Sterling. The Company, in Case 27108, was authorized to adopt net of tax, AFUDC accounting for Oswego #6 and

Nine Mile Point #2. In this proceeding, we are requesting permission to extend net of tax, AFUDC accounting to our investment in the Sterling Plant. On Page 3 of Schedule J, I have shown the test period AFUDC accruals for the three plants, adjusted in the case of Oswego #6 and Nine Mile Point #2 to exclude the impact of net of tax, AFUDC for December 1977. Applying 46.5%, the interest portion of our current AFUDC rate, to the test period accruals of $9,074,818 results in $4,219,790 as the interest portion of the test period accruals. Application of the 48% federal income tax rate to the interest portion of the accrual, results in the pro forma adjustment of $2,025,500.

Q: How was the adjustment for Investment Tax Credit derived?

A: The next adjustment, labeled "Investment Tax Credit Adjustment", an increase of $1,935,500, has been made to reflect an appropriate pro forma adjustment to the investment tax credit utilized in computing pro forma federal income tax expense. On page 4 of Schedule J, you will see that on the upper portion I have shown the investment tax credit generated in 1977 in the amount of $6,816,000. However, as shown in the Exhibit one line below, the Company was only able to utilize $4,615,000

of investment tax credits in 1977. The difference of $2,201,000 is shown as an adjustment to Federal income tax on Schedule J, Page 1.

In accordance with the Commission's statement of policy, 50% of the 4% credit, which is accounted for on a flow through basis, is shared between customers and shareholders. The Company elected under Section 46 of the Internal Revenue Code to have the additional 6% investment tax credit that became available under the 1975 Tax Reform act to be treated on a normalized basis. This adjustment is summarized on the lower portion of the page and is carried forward to page 1 of the Exhibit.

Q: Returning to the first page of Exhibit 8, will you explain the adjustment labeled "Adjustment of Allowance for Funds Used During Construction?"

A: This adjustment, reflects the fact that the Company has not taken into consideration all of the construction work in progress balances when computing the allowance for funds used during construction on its books. The adjustment recognizes the fact that the Company should be permitted to reflect in balance for return an allowance for the amount of interest on these non-interest bearing construction expenditures. This adjustment in

the amount of $704,105 is summarized on Schedule K of this exhibit.

Q: Would you please explain the adjustment entitled "Dividends Received from Canadea Power Corporation?"

A: This adjustment, in the amount of $120,000, represents dividends received from the Company's subsidiary, Canadea Power Corporation. In accordance with the Uniform Systems of Accounts, these dividends are not included in operating income. The Company leases a dam from this corporation and the lease payments are included as part of the Company's operating expenses. Accordingly, we are including, for rate purposes, the dividends received from this corporation as an adjustment to operating income.

The net effect of the known adjustments itemized in column 2 of page 1 of Exh. 8 is a decrease of $4,405,313 in "Balance for return."

Q: Directing your attention now to column 1 on the first page of Exhibit 8, please explain the development of the average rate base figure of $425,848,853.

A: The details of this computation are shown on Schedule L. Page 1 of Schedule L shows the monthly balances of the net Electric plant in service for the period December 1976 through December 1977. The average Electric plant

in service of $408,431,266 is computed using the average of the monthly averages. To this figure, $34,030,875 is added for electric department working capital, $7,176,778 is deducted for accumulated deferred income taxes, and $4,695,142 is deducted for accumulated deferred investment tax credits. This results in an average rate base before adjustment for excess capitalization of $430,590,221. I have then deducted $4,741,368, the amount of earnings base in excess of capitalization, to arrive at the net average rate base as shown on the first page of this exhibit. The derivation of the monthly balances of the net electric plant in service are detailed on page 2 of this schedule. The derivation of working capital is detailed on pages 5 through 9. Computation of the deferred income taxes and investment tax credits, are shown on page 10 and a summary of the earnings base in excess of capitalization is shown on page 11 of this exhibit.

Q: Would you explain the formulas used for allocating common utility plant in service to the electric department?

A: Common utility plant in service is divided into two categories: "Transportation Equipment" and "Other." The dollar value of transportation equipment in Account

392 is assigned to the Electric, Gas or Steam Departments based upon the use of vehicles by each of these departments. This figure is computed at the end of each calendar year and the resulting percentages are used for that December and for the ensuing 11 months. At December 31, 1976 the percentage of transportation equipment applicable to the electric department was 74.2% and at December 31, 1977, 75.3%.

The remaining amounts of common utility plant are allocated to the Electric, Gas and Steam Departments, giving consideration to space occupied, number of customers, number of employees, and departmental clearing of shop expenses. Again, these allocations are made at the end of each calendar year and the resulting percentages are used for that December and the ensuing 11 months. The composite percentage at December 31, 1976 applicable to the electric department was 66.5% and at December 31, 1977, 67.9%. These percentages are shown on the lower portions of pages 3 and 4, respectively, of Schedule L.

Q: Was the same method of allocating common utility plant in service to the electric department also used to allocate the common utility "Field completed construction work in progress?"

A: Yes, but the construction work in progress amounts, are analyzed and computed separately in arriving at composite percentages.

Q: Would you turn to page 5 of this schedule and continue with your explanation.

A: Page 5 is a summary of the computation of the Electric Department's "Allowance for working capital" which totals $34,030,875. The Company has computed the working capital allowance under the method traditionally used by the Commission. The first component of working capital, "Materials and Supplies", in the amount of $7,094,241, is shown on page 6. An average of the monthly average balances for the 12 months of 1977 is derived from the monthly balances of the various specific electric stock divisions. A similar computation is made for general materials and supplies accounts, which are then allocated to departments on the basis of net plant as of December 31, 1977.

The next component, oil stock, in the amount of $1,635,725 is shown on page 7. The average oil stock for the 12 months ending December 1977 for stations 3, 7 and 9 and the projected minimum reserve stock of number 6 and number 2 oil is shown. The percentage of oil stock applicable to the Electric Department is based on

usage during the test period. The December 31, 1977 cost of fuel has been used to determine the working capital allowance.

The next component of working capital, coal stock is detailed at page 8. The average coal stock for the 12 months ending December 31, 1977 was 166,313 tons. However, for computation of working capital on a prospective basis, I have used the projected average of 210,000 tons which the company intends to maintain. Again, using December 1977 cost of $30.37 per ton, I derived the coal stock working capital allowance of $6,378,120.

The allowance for "Coal is transit", is shown on the lower portion of page 8. Using the average test year amount of coal in transit of 35,979 tons at the December 1977 cost results in a $1,092,754 working capital allowance.

The computation of Prepayments is set forth on page 9. The average of thirteen monthly balances, December 1976 through December 1977, are used to arrive at the average balance of $5,760,130. Applying the ratio at December 31, 1977 of the electric department net plant to total company net plant (80.9%), yields a Prepayments balance of $4,659,945.

The last component of working capital, operation and maintenance expense, is shown on the lower portion of page 9 in the amount of $13,170,090. This represents 1/8 of the Electric Department's operation and maintenance expense, excluding the cost of purchased power.

The next two items in the development of average rate base are shown on page 10 of Schedule L, and are both reductions. The first represents the average balance of accumulated deferred income taxes of $7,176,778. The second is a reduction equal to the average balance of accumulated deferred investment tax credits of $4,695,142. These totals reflect the average of the monthly averages of the balances in each account.

The last item used to derive the average rate base is the adjustment for earnings base in excess of capitalization. This adjustment is shown on page 11 of Schedule L. I have shown the total company test period Earnings Base of $712,768,922, allocated by department. The allocation of capitalization was derived by utilizing the same percentages. Since Earnings Base exceeds Capitalization, a net reduction in rate base applicable to the Electric Department of $4,741,368 was necessary.

Q: Mr. Henderson, has the derivation of the capitalization

been computed in the manner adopted by this Commission?

A: Yes, it has. We have used daily balances in derivation of total company capitalization for the following items: long-term debt, short-term debt and temporary cash investments. All of the other components of capitalization are based on monthly average balances.

Q: Mr. Henderson, are you in agreement that the derivation of capitalization as shown on this page is the proper means of determining capitalization for this adjustment?

A: No, I am not. Although this issue was litigated in prior proceedings, I still believe that this method of mixing average daily and average monthly balances is both invalid and illogical. However, based on the Commission's policy requesting that parties in rate case proceedings not relitigate issues once decided, we shall not pursue the issue in this proceeding.

Q: Would you continue by explaining the known adjustments to average rate base.

A: The first adjustment, a reduction to average rate base, is labeled "Accruals Effective December 1, 1977." This adjustment, summarized on page 1 of Schedule H, reduces average rate base consistent with the pro forma adjustment for the increase in depreciation accruals effective December 1, 1977 which I have already discussed.

In a similar manner, the next adjustment, labeled "Accruals Effective May 1, 1979," a reduction of $106,839, has been made to reduce average rate base consistent with the pro forma adjustment for the increase in depreciation accruals, also discussed earlier. This adjustment is summarized on the lower portion of Page 2 of Schedule H.

The next adjustment labeled "Ginna Normalization", an increase of $4,088,059, reflects the investment for the new rotor necessary to allow the plant to return to its normal capacity. This adjustment is shown on the upper portion of Schedule M.

The next adjustment to average rate base, labeled "Non Revenue Producing Capital Expenditures," totals $28,797,100. The derivation of this adjustment is shown on Schedule N. In our last electric rate case, the Commission authorized us to include in rate base two non-revenue producing plant additions totalling $21,600,000. These two additions which went into service in 1977 are reflected in the average test period net plant in service in the amount of $6,296,000 and a reduction is therefore appropriate. A further reduction of $285,900 or one half of the increased depreciation expense is also shown. Reducing the gross figure by the amount

included in net plant in service results in a pro forma increase in average rate base of $15,018,100.

The next component of this adjustment in the amount of $4,378,000, represents a transfer to rate base, as "plant held for future use," of that portion of the Sterling plant site currently recorded in construction work in progress not certified in case 80005. In a prior rate proceeding, Case No. 26848, the Commission ordered that all land purchased for the Sterling nuclear plant be placed in interest-bearing construction work in progress. Accordingly, at the conclusion of that case we did transfer from "plant held for future use" to "construction work in progress," the land purchased for the Sterling nuclear plant. The Siting Board certified 1244 acres of the 2800 acre site as applicable to the Sterling plant. Therefore, consistent with this certification, we are proposing that the balance of this land investment be transferred to plant held for future use, when the rates established in this proceeding become effective. This procedure has two benefits. First, it will alleviate some of the tremendous cash flow problems the company is facing, which I will discuss later. Second, it will stop increasing the Company's investment in this property through the accrual

of additional AFUDC.

The next component of non-revenue producing capital expenditures is labeled "Sterling fossil unit" in the amount of $7,371,000. As previously mentioned, in 1977 the Company claimed this project as a loss for tax purposes. The Company has petitioned the Commission for deferred income tax accounting for the resulting reduction in Federal income taxes. This proposed tax deferral is included in the deferred taxes shown on page 10 of Schedule L; in turn, those deferred taxes are used to reduce rate base as shown on page 1 of Schedule L. Thus the ratepayer is to have the benefit, in this proceeding, of the tax loss attributable to this project. It would seem appropriate that the capital dollars which give rise to that tax loss likewise be included in rate base. Further, so long as these dollars remain in Construction Work In Progress, they will continue to accrue AFUDC. Putting the current balance for the project in rate base at this time will stop the build-up of the investment. This will benefit ratepayers in the long run since less will be added to rate base now than would be added later if the project remains in CWIP.

The last component of this adjustment, labeled the "Hojack Line right-of-way," reflects, for rate purposes,

the annualization and inclusion in rate base of this item. The Hojack Line right-of-way was purchased for $2,030,000 in January of 1978 and is currently recorded in Electric Plant in Service.

The next adjustment to average rate base shown on Schedule O, labeled Canadea Power Corporation, has been made to include in rate base the company's investment in its wholly-owned subsidiary, Canadea Power Corporation. On Schedule O, I have shown Canadea's average capitalization for the test period consisting of $684,000 of long term debt, a reduction of $33,843 for Canadea's investment in RG&E's preferred stock, $1,447,166 of retained earnings and a reduction of $585,000 for temporary cash investments, resulting in a total average capitalization of $1,512,323.

Q: Was the inclusion of RG&E's investment in Canadea Power Corporation in rate base a contested item in the Company's last rate proceeding?

A: Yes, it was. In that proceeding, the Company claimed that RG&E's investment in Canadea Power Corporation should be included in rate base. Staff and the Commission disagreed on the basis that an original cost study had not been performed for Canadea Power Corporation. We have subsequently supplied Staff with a copy

of the Canadea original cost documents.

The last adjustment, labeled "Working capital," represents the adjustment to the working capital allowance resulting from the known adjustments made to expenses, as shown on the Schedule P.

As a result of the adjustments to rate base, the average pro forma rate base is $461,171,084. The Pro forma rate of return is 6.95% as shown in Column 3 on the first page of this exhibit.

Q: Mr. Henderson, would you please describe the adjustments shown in column 4 under the heading "Proposed Revenue Increase"?

A: Column 4 shows the revenue increase which will result from the rates proposed in this proceeding, as shown on Exhibit 17, and the corresponding changes in expenses, taxes, and rate base. Page 2 of Exhibit 8 sets forth the details of the adjustments shown in column 4.

The adjustment labeled "Attrition", demonstrates the impact of growth in the rate year which is disproportionate to the historical proportion of revene growth to expense increases and rate base growth. The rates requested have taken this factor into account and, absent this, the proposed rates would not produce the requested rate of return in the rate year.

This adjustment is required to reflect the impact of overall costs increasing at a rate greater than the increase in revenues. In essence, absent this adjustment, not all of the rate year changes, as detailed in Exhibit 10 which I will subsequently discuss, will be reflected in this Exhibit 8 presentation. Many of the specific changes which underly this Attrition adjustment are readily discernable from a review of Exhibit 10. If rates were set in this proceeding without taking this adjustment into account, such rates could not produce the requested rate of return in the rate year.

Column 5, labeled "Adjusted Pro Forma" is the sum of the adjustments shown in columns 3 and 4. The adjusted Pro Forma Balance for return in column 5, of $46,351,211, applied to the adjusted Pro Forma Average rate base of $461,206,084, produces a rate of return of 10.05%.

Q: Will you please describe and explain Exhibit 9 and state what it purports to show?

A: This exhibit develops, for the Gas department, a rate of return per books and pro forma for the twelve months ended December 31, 1977. The format is the same as Exhibit 8. Column 1 of page 1 is a statement of Gas Department revenues, expenses, operating income and rate of return per books. Column 2 contains pro forma adjustments to these book figures. These adjustments are described along the left hand side of the page and cross-referenced to a schedule providing details of the adjustment. Column 3 is the pro forma result of applying the adjustments in Column 2 to the book figures in Column 1. Column 4 reflects the proposed gas rate increase sought in this proceeding and column 5 reflects the adjusted Pro Forma Income Statement and Rate of Return including the proposed increase.

Q: Will you now refer to column 1 and explain the information shown there?

A: Column 1 is a statement of the revenues and expenses per books for the 12 months ended December 31, 1977. The Balance for return of $8,184,939 applied to the average rate base of $127,832,611 produces a rate of return per books of 6.40%.

Q: Would you please explain column 2 of this exhibit, labeled "Pro Forma adjustments"?

A: Yes. However, before I explain the adjustments shown in column 2, I would like to point out that many of the adjustments in this exhibit were prepared in exactly the same manner and for the same reasons that corresponding adjustments were prepared for the Electric Department, as shown in Exhibit 8. Therefore, in most cases, unless the adjustment is unique to the Gas Department or the rationale for the adjustment differs from that applicable to the Electric Department, I will not discuss the particular adjustment.

The first adjustment to revenues, labeled annualization of rate increases, in the amount of $2,516,322, is summarized on the upper portion of Schedule A. This adjustment reflects annualization of the rate increases effective November 1977 and February, 1978.

The next adjustment, labeled "Unbilled revenues", a decrease in revenues in the amount of $1,437,063, is also summarized on Schedule A. Unbilled revenues are revenues attributable to sales during a calendar year (December) which are not recorded and billed until the following year (January). The adjustment for unbilled

revenues reflects the difference between such amounts as of January 1977 and January 1978.

The next adjustment, labeled "Weather Normalization", reflects the fact that the weather during the test period was warmer than normal. Consistent with Commission policy, we have adjusted revenues for rate case purposes to reflect normal (i.e. colder) weather. This adjustment is summarized on the upper portion of page 1 of Schedule B.

The next adjustment to revenues, an increase of $3,021,804, labeled GCA revenues at January 2, 1978 cost of gas, reflects the GCA revenues that would have been received by annualizing the January 2, 1978 cost of purchased gas. The details of this adjustment are summarized on the lower portion of page 1 of Schedule B.

The adjustment to revenues labeled "Purchased gas curtailment," shown on page 2 of Schedule B, reflects the fact that due to volumetric limitations and force majeure curtailment during the test period, gas sales were 1,218,678 thousand cubic feet lower than normal. These sales at rates effective February 1978 would have produced $2,954,169 of additional revenue.

The last adjustment to revenues, labeled "Space-heating refund," reflects the Company's $10 rebate to

all space heating customers. As shown on the lower portion of page 2 of Schedule B, the number of February 1977 spaceheating bills to which this $10 rebate applied was 153,637, resulting in a total revenue reduction, after applying Rule 4.7, of $1,600,437.

Q: Returning to the first page of this exhibit, would you explain your known adjustments to expenses?

A: The adjustment, "Weather normalization," shown on Schedule D, reflects increased gas purchases over those which occurred during the warmer than normal test period. The increased purchases, priced at the January 2, 1978 cost of purchased gas, result in the pro forma increase of $12,090.

Also summarized on Schedule D is an adjustment of $2,629,392, representing an increase in the cost of purchased gas. This adjustment reprices test period purchases at the January 2, 1978 cost of gas, consistent with the adjustment to revenues labeled "GCA revenues at January 2, 1978 cost of gas."

The next adjustment to expenses summarized on the lower portion of Schedule D, "Purchased gas curtailment", has been made to reflect additional purchased gas expense that would have been incurred but for the purchased gas curtailments.

The last unique adjustment is labeled "Leak detection, recording and repair," in the amount of $350,000. This reflects an estimate of the annual incremental costs to comply with revised Commission mandated procedures for the surveying for, recording of data in connection with, the repair of, and the post-repair surveying of, leaks in the gas distribution system. The estimate is the best available estimate which could be made at the time of the Company's filing. By the time of cross-examination I expect to be able to provide more detail in connection with this adjustment. This adjustment is shown on schedule E, page 2.

Q: Mr. Henderson, would you return to the first page of the Exhibit and explain the pro forma adjustment labeled "Amortization of Extraordinary Property Losses", an adjustment of $154,706?

A: Yes. During 1977 the Company completed the accounting for the retirement and abandonment of its manufacturing gas facilities. The net result of the retirement was a loss of $154,706. This was charged to account No. 407.10 in accordance with PSC Order dated April 12, 1977. Since the loss is a nonrecurring item, it is being adjusted out of the test period for ratemaking purposes.

Q. Would you please continue with your explanation of this

Exhibit?

A: An adjustment under depreciation, labeled "Amortization of Reserve Deficiency," increases depreciation by $210,833. This adjustment, which is summarized on the lower portion of Schedule H, has been made to reflect that in the last rate proceeding, Case 27109, the Company was authorized to amortize a depreciation reserve deficiency over a twenty year period at the rate of $230,000 per year. This amortization commenced in December 1977 and hence only one month's amortization is included in the test period. This adjustment simply reflects the additional eleven months of the amortization.

Q: Directing your attention now to column 1 on the first page of Exhibit 9, please explain the development of average rate base in the amount of $127,832,611?

A: Details of this computation are shown on Schedule L. Page 1 of Schedule L shows the monthly balance of the net gas plant in service for the period December 1976 through December 1977. The average gas plant in service of $125,510,333 is the average of the monthly averages. To this figure, $5,706,098 has been added for gas department working capital. $1,669,538 has been deducted to reflect the accumulated deferred income

taxes and $630,250 has been deducted to reflect accumulated deferred investment tax credits. Also deducted is $1,084,033 representing the so called earnings base in excess of capitalization. The result of these adjustments yields the net average rate base of $127,832,611. The derivation of the monthly balances of the net gas plant in service is detailed on page 2 of the schedule. The derivation of the working capital is detailed on pages 6 through 8 of this schedule. The computation of the accumulated deferred income taxes and accumulated deferred investment tax credits are shown on page 9 of this schedule, and the derivation of the so called earnings base in excess of capitalization is shown on page 10 of this schedule. Once again, these components were all derived in the same manner as the corresponding components used for the development of the average rate base for the electric department, as reflected in Exhibit 8.

Q: Turning back to the first page of this exhibit, would you please explain known adjustments to rate base?

A: The adjustment labeled "Accruals Effective May 1, 1979" reduces average rate base consistent with the pro forma adjustment in depreciation shown in this exhibit. This adjustment is summarized on the lower portion of Sched-

ule H. In a similar manner, the adjustment labeled "Amortization of Reserve Deficiency," a reduction in rate base of $105,417, has also been made to reduce average rate base consistent with the pro forma adjustment for this amortization. This adjustment is summarized in Schedule H.

The last adjustment to rate base, labeled "Working Capital," an increase of $536,147, represents an adjustment to the working capital accounts as a result of the known adjustments to expenses, as shown on the upper portion of Schedule F. Using the average pro forma rate base of $128,161,402, the pro forma rate of return is 6.13 percent, as shown in column 3 on the first page of the Exhibit.

Q. Mr. Henderson, you have now described the Company's rate of return calculations based on the historical test year, calendar year 1977. You have stated previously that you will sponsor exhibits which will set forth the Company's operations for a rate year covering the 12 month period ending April 30, 1980. Before proceeding to those exhibits, would you indicate in a general manner how the Company prepared its forecasts.

A. For normal internal forecasting purposes, during the last quarter of each calendar year the Company prepares

an operating budget which encompasses the forthcoming calendar year. In addition, the Company prepares a ten-year, long-range planning forecast based on its corporate model. With respect to the one-year operating budget, the Company's rate department prepares detailed monthly estimates of sales and revenues. It also prepares a fifteen-year long-range energy and capacity forecast which becomes part of the Section 149b filing with the Public Service Commission. In a similar manner, the Company also makes long-range forecasts of gas and steam sales.

In connection with the annual operating budget, each of the Company's sixty-two cost-responsibility departments prepares a detailed operating budget of its operating expenses for the ensuing twelve months. These budgets are prepared on the basis of general cost guidelines provided by a planning committee consisting of divisional vice-presidents and the accounting and treasury departments. In addition, as a recent procedure, each such department is also now required to furnish a listing of anticipated activity level changes, either upward, or downward for one additional year. This procedure was established to provide the Company with a longer range indication of future trends and also

to provide a check as to the reasonableness of the ten-year forecasts referred to earlier. In addition, the Company requires each department to provide a ten-year forecast of capital expenditures which is then utilized for both the short and long-term forecasts.

All components of the one-year forecast are reviewed by the appropriate divisional vice president and then by the Executive Vice President, the President and the Chairman of the Board. This review, among other things, includes a check for internal consistency, compliance with earlier cost guidelines and justification for major departures from trends established in prior periods. Where necessary, as a result of the reviewing process, revisions are made to the forecast before presentation of the operating budget and capital expenditures for approval to the Board of Directors.

Q. How have the forecasts which you have described been utilized in the preparation of Exhibits 10 and 11?

A. As the Commission's Policy Statement envisioned, it has been necessary to modify the Company's forecast data to meet the detailed requirements established under the Policy Statement. The total departmental expenses, for example, have been shown by cost components and by functional locations as opposed to the internal forecasts

which are developed on a cost-responsibility departmental basis. In addition, where more recent information has become available since the preparation of the original internal Company forecasts, that information has been used in preparation of Exhibits 10 and 11.

Q. Will you please describe and explain Exhibit 10 and state what it purports to show?

A. This Exhibit is a forecast of the Electric Department income statement and a rate of return for the "rate year," the twelve months ended April 30, 1980. This exhibit, and its counterpart for the Gas Department, Exhibit 11, have been prepared in response to the Commission "Statement of Policy on Test Periods in Major Rate Proceedings" issued November 23, 1977. If you will turn to the first page of Exhibit 10, in Column 1 I have shown the income statement and rate of return for the year 1977 for the Electric Department as recorded on the books of the Company. Column 2 reflects adjustments to normalize 1977 operations. Column 3, the sum of Columns 1 and 2, reflects 1977 "normalized" operations. Column 4, labeled "Rate year adjustments", shows the changes in Revenues, Expenses, Taxes and Rate Base that will occur between normalized 1977 and the rate year. Column 5 shows the forecasted rate year, including the revenue

increase requested in this proceeding.

Q. Will you please refer to Column 1 and explain the information shown there?

A. As I stated, Column 1 is our Electric Department, per-books Income Statement and Rate of Return for the year 1977. This column shows, in a slightly different format, the same information that was shown in Column 1 of page 1, Exhibit 8.

Q. Will you now refer to Column 2 and explain the Normalization Adjustments made there?

A. Yes. However before explaining the specific adjustments, I would like to explain the method used to develop the normalizing adjustments. All of the normalizing adjustments are included, partially or wholly, as a Pro Forma adjustment in column 2 of Exhibit 8, and to that extent the method of computation and the reasons for the adjustments are the same as I described in connection with that Exhibit. Therefore the schedules supporting the normalizing adjustments in Exhibit 10 will, for the most part, simply refer to the appropriate schedule and amount of the adjustment in Exhibit 8. The normalizing adjustments shown in Exhibit 10 differ from the pro forma adjustments in Exhibit 8 in that, generally, only increases known to occur which would

affect 1977 data are reflected as normalizing adjustments in Exhibit 10. The remainder of those adjustments which were factored into 1977 pro forma data (Exhibit 8) are shown in Exhibit 10 as "Rate Year Adjustments".

The adjustments to revenues, labeled "Customer," ($11,707,000), and "Sales to other utilities" (-$3,963,000), are summarized on Schedule A.

Q. Now, turning to the normalization adjustments under expenses, would you please explain the adjustments you have made there?

A. Yes, before getting to the detail of the adjustments to expenses, I would like to briefly describe the format and layout of Schedule B. If you will turn to page 1 of Schedule B, you will notice that the five columns are identical to those shown on the first page of Exhibit 10. Page 1 of Schedule B is the Electric Department summary of expenses, by various cost components as required in the Commission's Statement of Policy. These cost components are then shown in detail by functional locations on the following eleven pages of Schedule B. Page 2 details Steam Power Generation by cost components. Page 3 details Nuclear Power Generation by cost components, etc. Since page 1 is a summary, if you were to take any cost component shown on page 1 from any of

the columns you will find that it is simply a summation of the detail shown on the applicable, subsequent pages of the schedule. The normalization adjustments made to expenses, with but two exceptions, are identical to the similarly labeled Pro Forma adjustments made to expenses on Exhibit 8. The first exception is that the Pro Forma adjustment for wages and salaries shown in Exhibit 8 includes wage and fringe benefit increases through the end of the rate year. The normalization adjustments in Exhibit 10 for payroll and related fringe benefits reflect wage rates, complement, and benefits costs only as of February 1, 1978, thereby omitting, as a normalizing adjustment, the February 1979 and February 1980 wage increases. The other exception is that the Pro Forma adjustment for escalation shown on Exhibit 8 is not reflected as a normalizing adjustment in this Exhibit.

The detail of the other normalizing adjustments to Expenses, and the reconciliation of these adjustments to their counterparts in Exhibit 8, are shown on pages 1 and 3 of Schedule C of Exhibit 10.

The Normalization adjustment to Depreciation expense is an increase of $577,000. This adjustment is summarized on the upper portion of page 4 of Schedule C.

The normalization adjustments to "Taxes-Other Than Income," other than payroll taxes, are identical to Pro Forma adjustments made for the same items in Exhibit 8, and are summarized on the lower portion of page 4 of Schedule C. The normalization adjustment labeled "Payroll Taxes" is detailed on page 5 of Schedule C and has been made to reflect normalized payroll taxes in a manner consistent with the normalization adjustment to payroll expense.

The net of all of the normalization adjustments I have described so far to Revenues, Expenses, Depreciation and Taxes-Other Than Income result in an increase in Operating Income before Federal income tax of $489,000.

Q. Would you please turn to Schedule D and explain the computation of the normalization adjustment to Federal income tax, shown as a negative $445,000?

A. Yes, if you will turn to page 1 of Schedule D, you will notice that, except for rounding to the nearest $1,000, the 1977 per books computation is identical to that shown on page 1 of Schedule J in Exhibit 8. The normalization adjustments, shown in column 2 of Schedule D, are the same as the the Pro Forma adjustments in Exhibit 8 except for the following items: Interest on

long term debt has been adjusted for updated departmental allocations only; it also does not reflect an adjustment for our Pro Forma capital structure. Similarly, "Taxes charged to construction", "Pension costs capitalized" and "Additional deductible depreciation" reflect only the impact of the corresponding normalization adjustments to payroll, fringe benefits and depreciation.

Q. Returning to the first page of Exhibit 10, would you continue with your explanation of the normalization adjustments?

A. Yes, the next three adjustments, that is, the adjustment labeled "Provision for deferred income taxes - net", a credit of $2,960,000, the adjustment labeled "Interperiod tax allocation", an amount of $2,025,000, and the adjustment labeled "Investment tax credit adjustment", in the amount of $1,936,000, are the same as the Pro Forma adjustments made in Exhibit 8. In a similar manner, the adjustments labeled "Adjustment of allowance for funds used during construction" and "Dividends received from Canadea Power Corporation" are the same as the Pro Forma adjustments made in Exhibit 8. The net effect of all of the normalization adjustments is a decrease in Balance for return of $651,000.

Q. Would you please explain the normalization adjustments made to Average rate base?

A. The first adjustment labeled "Depreciation accruals", a reduction of average rate base in an amount of $288,000, has been made to reflect the impact on rate base of the normalization adjustments to depreciation expense. This adjustment is summarized on the upper portion of page 6 of Schedule C.

The next two adjustments, the first labeled "Canadea Power Corporation", an increase of $1,512,000, and the second labeled "Ginna normalization", an increase of $4,170,000, are the same as the corresponding Pro Forma adjustments shown in Exhibit 8 and are also summarized on page 6 of Schedule C. The last normalizing adjustment to average rate base, labeled "Working capital", is an increase of $116,000. This adjustment has been made to reflect the increase in working capital required as a result of the normalization adjustments made to expenses, and is summarized on page 6 of Schedule C. On the basis of normalized 1977 operations, as shown in column 3 on the first page of Exhibit 10, the resulting $35,792,000 operating income, when applied to the average rate base of $431,359,000, produces a rate of return of 8.30%.

Q. Mr. Henderson, that column does reflect the full annualized impact of the revenue increases granted by the Commission in November 1977 and February 1978, does it not?

A. Yes it does.

Q. Have you made any computation of the additional revenue which would be necessary on the basis of normalized operations to earn the return authorized by the Commission in Case 27108?

A. Yes, I have. The Electric department, on the basis of normalized 1977 operations, would need additional revenue of $8,800,000 to produce the 9.31% rate of return authorized by the Commission in our last proceeding, an amount almost identical to the difference in the revenue increase requested by the Company (adjusted to the allowed return on equity), and that authorized by the Commission.

Q. Returning now to the first page of Exhibit 10, would you explain the adjustments in the column labeled "Rate Year Adjustments"?

A. Yes, these adjustments, shown in column 4, have been made to bridge the gap from the normalized 1977 year to the rate year -- the twelve months ended April 30, 1980 -- shown in Column 5. The first adjustment is an

increase in customer revenues in the amount of $22,537,000. The derivation of rate year customer revenues is shown in Exhibit 14, which is sponsored by Mr. Laniak. The second adjustment to Revenues, labeled "Sales to Other Utilities," a decrease in revenues of $10,062,000, will also be explained by Mr. Laniak. The revenue adjustment, labeled "Proposed revenue increase" and in the amount of $37,946,000, is the additional rate year revenue that will be produced by the rate increase requested in this proceeding. The derivation of this adjustment is shown in Exhibit 19, sponsored by Mr. Hobday. The last revenue adjustment, in the amount of $985,000, relates to Oswego #6. For convenience, I will subsequently discuss all of the adjustments related to Oswego #6 together.

The adjustments to Expenses produce a total increase in expenses of $11,031,000. Again, the components making up this adjustment are shown in column 4 on page 1 of Schedule B, except for the Oswego #6 adjustment. All of the other component adjustments amounting to $10,805,780, are shown by functional locations on the subsequent pages in Schedule B. The computation of these expense adjustments is shown in Schedule E. If you will turn to page 1 of Schedule E, you will see that

all of the rate year adjustments shown on page 1 of Schedule B are listed, along with a reference to the page of Schedule E which describes in more detail the method of determining the adjustment. For cross-reference, page 2 of Schedule E shows each of the component rate year adjustments that were reflected in summary on Schedule G of Exhibit 8 as a Pro Forma adjustment labeled "Allowance for escalations" in the amount of $4,369,255. Page 2 of Schedule E also refers to the subsequent pages of Schedule E, which show the detail of each adjustment. Page 3 of Schedule E shows those of the normalized 1977 expenses that have been escalated to rate year levels by use of a general inflation rate.

On the upper portion of the page I have shown the inflation rates which were utilized to make these adjustments. The rates utilized for 1978 and 1979 are based on the arithmetic average of three separate sources which forecast prospective inflation in 1978 and two which forecast the rate of inflation in 1979. We also reviewed other sources to cross-check the reasonableness of these forecasts. From these inflation rates the inflation factor of .161545 was calculated. The normalized 1977 expenses to which this general inflation factor was applied, and the resulting rate year adjust-

ment to each of these expenses, are shown on the lower portion of the page.

Q. Mr. Henderson, would you propose to modify the inflation factor you have used during the course of this proceeding?

A. Yes I would. As the actual rate of inflation for 1978 and more current estimates of subsequent inflation become known, I would plan to update this adjustment for any changes, whether upward or downward, in the rate of inflation.

Q. Please continue with the explanation of the remaining adjustments shown in Schedule E.

A. On page 4 we have shown the adjustment to postage expense, first on the basis of the newly increased postal rates applied to test period mailings and then by adding the additional bills which, based on the sales forecasts in Exhibit 14, will be rendered in the rate year, also at the new postal rates. This produces an upward adjustment of $49,408 for postage expense.

On the lower portion of page 4 the prospective increases in the Company's PSC Assessment are calculated, with the portion applicable to research and development broken out. As indicated, the general assessment has been increased at the derived inflation

rates, whereas, the research and development portions is based upon Company forecasts. The result of these components is an upward adjustment of $169,689.

Three adjustments are shown on page 5 of Schedule E. The first, labeled "Water for Power", is derived by applying to the test period expense the average, annual rate of increase in this expense, as actually experienced over the period 1972 through 1977. The result is an adjustment of $19,642.

The next adjustment on this page, labeled "Workmen's Compensation", adjusts for the increase in the Company's workmen's compensation premiums that will result from the rate year wage and salary level. The adjustment factor used is based on the ratio of the rate year wages to the normalized 1977 wages, and produces the $13,686 adjustment shown.

The last adjustment on this page, labeled "New York State Power Pool Assessment", adjusts the Company's 1978 share of the Power Pool's estimated costs to the level anticipated in the rate year. The adjustment factor is based upon the historic trend of this expense. The resulting adjustment, to bring this expense to the rate year level, is $58,488.

On page 6, an adjustment in the amount of $226,142,

increases the Company's "Insurance" expense to that level expected in the rate year. The estimates for 1979 and 1980 were made by those persons in the Company who administer and oversee the Company's insurance program, after analysis of the available data.

The lower portion of this page contains the adjustment for the Company's research and development expenditures, exclusive of amounts included as part of the Company's PSC Assessment and Company payroll. This adjustment is based upon the forecasts of these expenditures by the Company's R&D Committee for 1979 and 1980, respectively. The forecasts are based upon project-by-project estimates. The rate year increase over the test period amounts to $636,734.

Page 7 of Schedule E contains the adjustment to increase "Contractor service" expense to the level expected in the rate year. As shown, the two major, identifiable components of this expense -- for fly ash hauling and for tree-trimming -- are shown separately, and the balance is shown under the heading "Other". The factor of increase which is applied to these expenses is based on a weighted average of the rates of increases for the labor component (75%), and for materials and supplies component (25%). The rate of increase used for

materials and supplies was the general inflation factor to which I have previously referred. The rate of increase used for labor was that actually experienced for 1977, 7.675%. By contrast, the rate of increase for contractor labor experienced in 1976 was 8.55%, and in 1975 was 8.45%.

On page 8 of Schedule E, three adjustments are shown. The first, labeled "Purchased electricity", adjusts only for the additional capacity and energy to be purchased during the rate year planned outage of Ginna station. Such increases are due solely to the increased sales to customers reflected in Exhibit 14. The pricing of these purchases is discussed by Mr. Laniak.

The next adjustment shown, labeled "Payroll, Pensions and Life Insurance", adjusts the normalized wage expense, which is shown on page 2 of Schedule C of this Exhibit, up to the rate year wage expense, as shown on Schedule D of Exhibit 8. The last adjustment on this page, "Payroll taxes", increases the applicable payroll taxes to the level which results from the higher rate year wages.

The final two adjustments shown in Schedule E, on page 9, adjust "Uncollectibles" and "Injuries and

Damages" to the proper rate year level. The accrual rates are those presently in effect. The adjustment is derived by applying those accrual rates to the higher revenues forecast and proposed in this proceeding.

Q. Returning to the first page of Exhibit 10, would you please explain the next rate year adjustment in column 4, labeled "Depreciation" in the amount of $2,995,000?

A. Since this adjustment, and the adjustment to "Taxes-Other Than Income", are directly related to increases in plant in service, I would like first to describe the rate year adjustment to average rate base labeled "Plant additions", an increase of $84,732,000.

Schedule G of this exhibit details by month our forecast of plant additions for the period January 1978 through April 1980. On this schedule I have shown, project-by-project, our forecasted plant additions. In the column labeled "Reason for Project" the reason for the project is shown by code in order to save space. The explanation of the code keys is shown on page 10 of Schedule G. In the next columns I have shown the estimated cash cost, expected AFDC accruals, forecast total cost, actual expenditures as of December 31, 1977, and the estimated in service date, for each project. The monthly additions are then shown, totaled by months and

by functional locations.

Pages 1 through 6 show the detail of 1978 plant additions and pages 7 through 9 show the detail of forecasted 1979 and January through April 1980 plant additions. The upper portion of page 10 gives the explanation of the coding for the reason for the plant additions, and the lower portion shows the slippage factors that have been applied to the forecast additions used in developing the rate year average rate base in Schedule H. The slippage factors shown are developed from our historical experiences and reflect the fact that the dollar amount of actual plant additions will generally be less than forecast. Such slippage results from several factors, such as non-expenditure of contingency amounts, deferrals, delays due to weather, and material deliveries, etc.

Turning now to Schedule H of this exhibit page 1 summarizes the net electric plant in service, by month, for the rate year, arriving at an average net electric plant in service. The rate year adjustment is the difference between the rate year average net electric plant in service and the 1977 normalized, average net electric plant in service. Page 2 of Schedule H shows, again in summary, the forecast depreciation accruals, by

month, for the rate year.

The workpapers showing the derivation of this data are a voluminous computer printout. We have furnished a copy of these workpapers to Staff and will do likewise to any party to the proceeding who requests a copy. In lieu of including all of these pages as an exhibit, we have included, as page 3 of Schedule H, one of the pages from the workpapers showing the manner in which we have calculated the forecast net electric plant in service.

The development of the net plant in service was done by month, by functional location. On page 3 of Schedule H, the calculation of "Fossil Generation Plant" is shown, for the months of January through June of 1978. The first line, labeled "Retirement Factor," is the historical relationship we use for forecasting purposes relating the percentage of retirements of existing plant in service to plant additions. The next ratio shown is the "Book Depreciation Rate." This is the monthly rate for depreciation based on the actual accruals adjusted to reflect the normalizing adjustments to depreciation. The next factor shown, labeled "Salvage Rate," is again based on our historical experience and is the ratio of net salvage to plant retirements. The next line, labeled "Plant In-Service-B.O.P." is the existing gross

plant in-service as of the beginning of each month. The next line, labeled "Plant Additions", sets forth the plant additions by month that were developed in Schedule G, after factoring for slippage. The next line, "Retirements", is computed by the application of the retirement factor to the plant additions. The "Plant In Service-E.O.P." is simply the sum of the plant at the beginning of the month, plus plant additions, less plant retirements to arrive at the end-of-month plant in service. The next line, labeled "Accumulated Provision For Depr. Of Plant In Service-B.O.P.", shows the accumulated provision for depreciation as of the beginning of the month. The "Provision For Depreciation" is determined by applying the depreciation rate to the plant in-service balance as of the beginning of the month. The "Retirements", or the adjustment to the reserve for retirements, is the same adjustment made to plant in service, and "Net Salvage" is determined by applying the salvage factor to the retirements. The net of these three items added to the depreciation reserve at the beginning of the month, results in the "Accumulated Provision For Depr. Of Plant In Service-E.O.P." which is the depreciation reserve as of the end of that month. Subtracting the reserve from the plant in

service gives us the "Net Plant For Rate Base." In this manner, utilizing the data in Schedule G, the net plant for rate base is developed on a monthly basis through April, 1980, by functional location.

Q. Returning to the first page of Exhibit 10, I understand that, as you have previously indicated, you will discuss the Oswego #6 depreciation subsequently. Would you please now explain the rate year adjustments to "Taxes - Other Than Income"?

A. The first adjustment labeled "Real property and special franchise taxes and water pollution control charges," is an increase of $5,430,000, and is developed on Schedule F. If you will turn to the first page of Schedule F, the upper portion contains a summary of forecasted rate year "Real property and special franchise taxes and water pollution control charges." The total estimate of these taxes, including sales and use taxes, is $28,358,000. The development of this amount is shown on page 2. Next the estimated sales and use taxes of $799,000, is already provided for in Schedule C, page 4. The normalized 1977 taxes, in the amount of $22,129,000, are then subtracted. This results in the rate year adjustment of $5,430,000. The detail of the derivation of the forecast level of taxes

is developed on page 2 of Schedule F. We have found that a regression analysis, relating taxes to plant in service, has been an extremely accurate method of forecasting these taxes. On pages 3 and 4 of Schedule F you will see that I have shown the historical amount, by year, of the taxes paid during each calendar year, the plant in service and the derived percentage of taxes as related to plant in service. While I have not included the results of our statistical program with which we actually do the computations, we do, in that program, test four to six various regression formulas and bands of data prior to selecting the "best fit curve" for forecasting purposes. After the historical data, I have shown the regression formula and the R value of the curve for each category.

On page 2 of Schedule F, I have shown, by functional location, the forecasted plant in service that was developed in Schedule H, and the forecasted rate year ratio of taxes that have been utilized, thereby deriving the rate year taxes totalling $28,358,000.

Turning now to the lower portion of page 1 of Schedule F, the rate year adjustment to "Revenue taxes" reflects the net increase in these taxes because of the

rate year adjustments to revenues.

Q. Please continue with your explanation of the rate year adjustments which are shown on the first page of Exhibit 10.

A. As I previously described, the increase for "Payroll taxes", an amount of $103,000, reflects the increase in payroll taxes attributable to the 1979 and 1980 wage increases insofar as they are applicable to the rate year. Again, I will subsequently discuss the taxes applicable to Oswego #6.

The rate year adjustment to federal income tax, is detailed on page 1 of Schedule D. The rate year adjustments to interest deductions for long and short term debt reflect both changes in the rate year capitalization and changes in departmental allocations on the basis of that capitalization. The computation of these changes in interest deductions is shown on page 2 of Schedule D. The adjustment for "Additional deductible depreciation," shown on page 1 of Schedule D has been made to conform this deduction to the rate year plant in service.

The rate year adjustments for the "Interperiod tax allocation", is summarized on page 3 of Schedule D.

Q. Would you please continue with your explanation by

describing your rate year adjustments to average rate base?

A. The first adjustment labeled "Working capital" reflects the working capital increase as a result of the rate year adjustments made to operating expenses, and is summarized on the upper portion of Schedule I. The next adjustment shown on the first page of Exhibit 10, labeled "Plant additions", has already been discussed.

The next two adjustments, "Sterling Land" and "Sterling Fossil", as shown on Schedule I are the same as the similarly labeled Pro Forma adjustments made in Exhibit 8.

The last two adjustments labeled "Accumulated deferred income taxes", an adjustment of $4,923,000 and the other labeled "Accumulated deferred investment tax credits," a credit adjustment of $2,356,000, have been made to reflect an appropriate rate year rate base. These adjustments are summarized on Schedule I.

Q. Would you now please explain the Oswego No. 6 adjustments shown in the Rate Year Adjustments column on the first page of Exhibit 10?

A. The Oswego No. 6 unit is scheduled to go into service on November 1, 1979. The five adjustments for Oswego No. 6 are shown on Schedule J.

The first adjustment is to Revenues. As indicated on page 1 of Schedule J, the additional revenue is attributable to the increased incidental sales which are estimated as the result of having the Company's share of the Oswego No. 6 capacity available during the last six months of the rate year. The data on mWh of sales and the revenue per mWh, net of fuel, were provided by Mr. Laniak.

The second adjustment is to expenses. The two components of this adjustment are shown on page 1 of Schedule J. One component consists of an estimate of the Company's share of the operation and maintenance expenses, excluding fuel, for the plant. This estimate was provided by the operator of the plant, Niagara Mohawk Power Corporation. Another component, a negative amount of $800,000, reflects the reduction in replacement capacity which the Company would otherwise be required to purchase during the rate year portion of the scheduled shutdown of the Ginna Nuclear Station. The planned outage is scheduled to commence March 16, 1980. This estimate is supported by data supplied in Mr. Laniak's testimony.

The next adjustment, also shown on page 1 of Schedule J, is for the increase in depreciation attributable

to the Company's portion of the Oswego No. 6 plant. The calculation of this depreciation adjustment is shown on the upper portion of page 2 of Schedule J.

The final adjustment, shown on page 1 of Schedule J, reflects the addition of Oswego No. 6 to average rate base for six months of the rate year. The calculation of Average Net Plant is shown on the bottom portion of page 2 of Schedule J.

I should also add that, although it is not separately shown, the deferred income taxes attributable to Oswego No. 6 are included in the rate year adjustment labeled "Provision for deferred income taxes - net" on the first page of Exhibit 10. Likewise, the impact of Oswego No. 6 is included in the Rate Year Adjustments to "Federal income tax" and "Interperiod tax allocation" shown on the first page of Exhibit 10. The calculation of the latter adjustments is somewhat complex and we have not, therefore, broken out the Oswego No. 6 portions separately.

Q. Would you please summarize the results of your Rate Year Adjustments on Exhibit 10?

A. The rate year balance for return of $57,017,000, based on the increased rates requested in this proceeding, when applied to the rate year average rate base of

$567,116,000 will produce a rate of return of 10.05%.

Q. Will you please describe Exhibit 11 and state what it purports to show?

A. This Exhibit develops a forecast Gas Department income statement and rate of return for the rate year, the twelve months ended April 30, 1980.

Exhibit 11 has been prepared in the same way, using the same format, as Exhibit 10 which I have just covered. Thus the only items which I will discuss relative to Exhibit 11 are those which differ from the Exhibit 10 adjustments.

The only adjustment in the "Normalization Adjustments" column of Exhibit 11, which is not covered by my explanation of Exhibit 10, is the adjustment labeled "Amortization of extraordinary property losses". As indicated on page 4 of Schedule C, this adjustment was covered in my testimony regarding page 1 of Exhibit 9.

In the Rate Year Adjustments column of Exhibit 11, the rate year increase in "Customer revenues," exclusive of the proposed revenue increase, was furnished to me by Mr. Lauterbach and is explained in his testimony and Exhibits 21 through 25.

As shown in the "Pro Forma Rate Year" column, the result of all of the Normalization Adjustments, the Rate

Year Adjustments, and the proposed Gas Department rate year revenue increase of $10,789,000 is a Balance for return of $14,266,000. When the Balance for return is applied to the average rate base of $140,520,000, it produces a rate of return of 10.15%.

Q. I note that, in the 1977 Normalized column of Exhibit 11, you show a rate of return of 7.22%. Have you, as you did for the Electric Department, made a computation of the additional revenue which would have been necessary to earn the return authorized by the Commission in Case 27109?

A. Yes, I have. The Gas Department, on the basis of normalized 1977 operations, would have required additional revenues of approximately $5,400,000 to produce the 9.31% rate of return authorized by the Commission in our last proceeding.

Q. Has the Company addressed the subject of executive compensation?

A. Yes, it has done so in Exhibit 12. This three page document is a summary of a Stone & Webster analysis of the compensation paid to the Company's top three officers. This analysis is an update of a similar study submitted in the Company's last rate case. The exhibit, which is self-explanatory, reflects Stone & Webster's

view that the Company's executive compensation is appropriate.

Q. Has the Company addressed the subject of labor productivity in its filing?

A. The subject of labor productivity is implicitly addressed in the forecast rate year presentation. While customer sales are increased in the rate year over those in the historical 1977 period, no increase in numbers of employees or overtime is made, other than the employees indirectly added through the Company's partial ownership of Oswego No. 6, a matter over which the Company has no direct control. We believe that, in so structuring the forecast presentations, to provide for the volume growth in customer sales revenues without any increase in labor complement is, if anything, a very optimistic posture with respect to productivity.

Q. You stated at the outset of your testimony that you would introduce an exhibit which contained projected data showing the source and distribution of funds, capitalization, and coverage ratios, and that you would indicate how these data bear on the Company's need for additional revenues. Will you please do so at this time?

A. Exhibit 13 is a three page exhibit, the cover page of

which is entitled "1978-1982 Projections, Capitalization, Financing and Financial Statistics". Page 1 of the exhibit develops the Company's projected capital structures and capitalization ratios starting with 1977 actual, and projecting the annual changes through to the year 1982. As can be seen at the lower portion of the page, the Company is attempting to move its common equity ratio to approximately 40% of total permanent capitalization, excluding short-term debt, while maintaining a preferred and preference stock ratio of approximately 13 to 14%, and a long-term debt ratio in the range of 46 to 47%. We feel that these capital ratios are appropriate for several reasons, among which are the following:

(1) It recognizes our view that the utility business in general is more of a risk today than it was just recently, thus calling for a higher portion of common stock equity in the capitalization structure;

(2) to attempt to maintain adequate coverage ratios and internal generation of funds, again by means of a higher portion of Common stock equity, a measure which is in part necessitated because of the lack of substan-

tial cash flow provisions, such as allowance in rate base of major amounts of construction work in progress; and

(3) in light of our perception of the likely trend in capital markets, with the potential upward direction in interest rates.

The appropriateness of these capital ratios is also addressed by Messrs. Monteau and Fraser.

Q. Please explain how the dollar figures have been developed on page 1 of Exhibit 13.

A. The lines of the Exhibit showing total capitalization including and excluding short-term debt are derived from the Company's forecast construction expenditures. The Company uses a forecasting model starting with construction expenditures and develops therefrom the additions to total capitalization based on the objective capitalization ratios which I mentioned. The model then develops the amounts of each type of financing that is required on an annual basis.

One of the variables in such a forecast is the amount of retained earnings. For these purposes, the calculations on page 1 of the Exhibit are based on the assumption of a continuation of the Company's current return on equity of approximately 10% through May 1,

1979, and of a 13.8% return thereafter through the year 1982. This is so, notwithstanding the fact that the rates established in this proceeding will not be adequate to produce the earnings as shown beyond the midpoint of 1980. The assumed maintenance of the 13.8% return on equity used in this exhibit is based on an assumption of additional rate relief in future years to sustain the same level of earnings. Of course, the retained earnings are also a function of the Company's dividend policy. As shown on page 3, for purposes of these calculations, we have assumed the continuation of the current dividend rate through the year 1979. Thereafter, we have assumed a 5% annual increase in that rate, provided that such an increase does not result in an increase in the dividend payout ratio above 50%, which is our approximate payout goal. The calculations also assume a continuation of the Company's stock dividend policy. The calculation is performed, as I have stated, by a computerized planning model. The details of this calculation is part of the supporting work papers to this exhibit and will be made available as needed.

Page 2 of Exhibit 13 is entitled "Projected Source and Disposition of Funds 1978 - 1982". This schedule

again reflects the Company's most current projections of planned capital expenditures and financing, based on the same assumptions as stated earlier in connection with page 1. However, any change in allowed return on equity will affect the course of outside financing and projected capitalization, as will any significant aberrations in the capital markets.

Turning to page 3 of Exhibit 13, the upper portion of the page shows the assumptions which I described earlier as factored into the development of the retained earnings figures used on page 1 of the exhibit. On the lower portion of page 3, I have calculated the interest coverage ratios developed on the different bases shown. Coverage calculations vary depending on the applicable standards, such as the Company's bond indenture, applicable SEC regulations, or those of rating agencies. Coverage calculations performed by rating agencies, as explained by Mr. Fraser, are simply based on the total income before income taxes divided by actual interest charges. As can be seen by looking at these coverage ratios, under the Company's indenture, in the years 1978 and 1979, we maintain a reasonable coverage when compared to the two times minimum test in that document; and, assuming the Company earns the equity returns

requested in this proceeding, we would have adequate indenture interest coverage through 1982.

I should note however, that, as shown in Mr. Fraser's exhibits, the Company has been consistently unable to earn its allowed return on equity. We are hopeful that, in this proceeding, the Commission will make adequate provision in rates to permit the achievement of the allowed return on equity. Of course, as I will discuss, if the return allowed is less than that requested, none of the coverages shown can be achieved.

Turning to the rating agency coverage test which is, of course, one of the criteria used in the determination of the Company's credit rating, the coverage for the years 1978 and 1979 are 1.84x and 1.80x, respectively. Such coverage ratios are completely inadequate. Even assuming that the Company is able to earn the returns requested in this proceeding, rating agency coverage is barely adequate in 1980 and 1981 and again falls to substandard levels in 1982, as is indicated by the coverage ratio of only 1.99x. The Company will need additional improvements in cash flow from subsequent rate filings to maintain a reasonable coverage.

Q. In view of the rating agency coverage ratios shown, together with Mr. Fraser's testimony on the need to

maintain adequate coverage in order to retain the Company's current A Bond credit rating, why has the Company not requested additional revenues to provide further cash flow improvements and thereby bolster coverage ratios?

A. The Company in this filing has attempted to satisfy its financial objective of maintaining a healthy financial structure. At the same time, we are acutely aware of the impact on customers of ever-increasing rates. Therefore, we have limited our request to the approximate 18% electric rate increase in an attempt to satisfy both criteria.

Q. In the event that the Commission determines that investor requirements with respect to return on equity are something less than what is requested in this proceeding, how would that impact upon the interest coverages shown on page 3 of Exhibit 13?

A. If the required return on equity is determined to be lower than the 13.8% requested, this reduction would, of course, reduce the coverage ratios shown. In fact, it is the Company's position that the requested return on equity is supported as reasonable because of the minimally acceptable coverage figures which it will produce. However, should there be any reduction in the

revenue requirement due to a reduced cost of equity capital deemed appropriate by the Commission, or due to other changes that may be proposed in this proceeding, it is still the Company's intention to seek the full amount of the revenue increase requested via an inclusion of certain amounts of construction work in progress in rate base in lieu of AFDC. In other words, the minimal coverage ratios must at least be maintained if not improved. Any reduction in the allowed return on equity would simply have to be made up by other cash flow measures that would at least sustain or improve the ratio figures which we have indicated. This, in effect, would require an appropriate allowance in rate base of sufficient amounts of construction work in progress to achieve the same result. Accordingly, it is the Company's proposal that the rate relief for which it has filed be allowed regardless of any issues that may develop in this case with respect to the fair return on equity.

As is also shown on the bottom of page 3, the ratio of AFDC earnings to total earnings for common stock is 45% in 1978, 54% in 1979, 42% in 1980, 51% in 1981 and 62% in 1982. These ratios, in themselves, would indicate that the Company should be asking for

additional rate relief at this time to reduce these abnormally high levels of AFDC. However, as I previously discussed, that would raise the requested percentage increase in this proceeding to levels which the Company feels should be avoided at this time.

Q. Does that conclude your direct testimony?

A. Yes it does.

Rochester Gas and Electric Corporation

Direct Testimony

of

DAVID K. LANIAK

Division Superintendent of Electric System
Planning and Operations

Testimony of

David K. Laniak

Q. Would you state your name and business address please?

A. My name is David K. Laniak and my business address is 89 East Avenue, Rochester, New York 14649.

Q. By whom and in what capacity are you regularly employed?

A. I am employed by Rochester Gas and Electric Corporation as Division Superintendent of Electric System Planning and Operations. I am responsible for directing the Company's activities in electric system planning and electric system operation. I have particular responsibility, among other things, for long-range electric system planning, including long range demand and energy forecasts, and for related regulatory and administrative matters.

Q. Please summarize your educational background and business experience.

A. I graduated from Rochester Institute of Technology in 1958 with a Bachelor of Science degree in Electrical Engineering. I joined RG&E as a Technical Engineer in 1958 and was assigned to the Electric Laboratory. My work involved testing, specifying, and standardizing products and methods related to the Transmission and Distribution Division of the Company. In 1967, I was designated Standards Engineer. I became Assistant Superintendent of the Electric Meter and Laboratory

Department in 1968, and became Superintendent of that department in 1971.

I am a member of the Rochester Engineering Society and the Institute of Electric and Electronics Engineers. I am the Company's member and chairman of the New York Power Pool Operating Committee, and the Company's alternate member of the New York Power Pool Planning Committee. From 1963 to 1966 I taught electric machinery theory and lab in the Evening College at RIT.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to describe the short term electric load forecast and supporting exhibit. In addition I will also discuss the forecast of incidental sales and the need for Beebee Station Old House capacity by the Electric Department.

Q. Turning first to the electric load forecast would you please describe the purpose and methodology of such a forecast?

A. This forecast simply attempts to predict, based upon available indicators, the level of sales in RG&E's franchise territory during the rate year ending April 30, 1980. The sales forecast for the years 1978 through 1980 described in this testimony has been developed for

the short run, a term I will define subsequently. Based upon information available this forecast predicts modest economic growth in the Rochester area resulting in moderate customer and load growth.

The forecast of electric sales is based on the aggregation of forecasts by class of business. These classes are: residential, commercial, municipal, industrial and street-lighting. The forecast has then been restated by rate classification for each month of the subject years.

Before discussing the actual forecast, it is necessary to distinguish between short term and long-term forecasts. Long term forecasts of electric energy demand tend to be based on relatively stable trends reflecting the dominant influence of such slowly changing factors as population growth, economic growth, and price and supply conditions in energy markets. In the short run, electric energy requirements fluctuate around the long run trend, reflecting the effects of seasonal or cyclical factors such as weather or business conditions. Short term forecasts are therefore based upon factors which have immediate short term effects, such as plant expansion, increased new home sales and the like. The information developed through 1980

reflects the use of the short term forecasting methodology.

Q. Would you please describe Exhibit 14?

A. Exhibit 14 consists of twelve pages, the first page of which summarizes, by years from 1970-1980, the number of residential customers, both regular and spaceheating and the respective mWh sales. Page 2 contains a summary of mWh sales to commercial customers including heating, nonheating and municipals. Page 3 contains the same information for Industrial customers broken down between the Company's 17 largest customers and all other customers. Page 4 contains a summary of the mWh sales for all of the foregoing classes as well as street lighting customers. Page 5 contains a summary of the customers, mWh sales and associated revenues for the years 1977, 1978, 1979 and the twelve months ending April 30, 1980, by months. The balance of the Exhibit pages 6-12, contains a breakdown of the data shown on page 5, by Service Classification.

Q. Would you now describe the development of the residential sales forecast.

A. In developing the forecast of short run residential class sales, the following parameters are used: living units to be added, the number of those to be heated

electrically, the nature of the electric heating system used and the average use value for the various types of residential customers. The number of customers of each type is estimated and the consumption for each group is then determined by applying the appropriate average use value. The results are summed to derive the total sales forecast for the residential class.

The number of new residential heating customers is estimated on the basis of the availability of competing fuels, their relative costs and builder preference. Page 1 of Exhibit 14 shows the historic and forecast sales for residential space heating customers. The average use value is determined from surveys of electric space heating customers. Total estimated use is determined by multiplying the average number of customers by the average per customer use value.

The balance of the new customers estimated to be added in the short run are categorized as regular customers. The average use for this type of customer is determined by using appliance saturation data along with specific appliance consumption data. This average use value for regular customers is then multiplied by the number of customers to obtain the total estimated consumption. Page 1 shows the historic and estimated sales

for both space heating and regular residential customers together with the aggregate forecast sales for the residential class.

Q. Would you please describe the forecast of sales attributable to the commercial class?

A. As shown on page 2, the forecast for the commercial class is composed of three basic sections, (1) commercial customers who heat electrically, (2) commercial regular (non-heating) customers, who compose the bulk of the class and (3) municipal customers.

Sales to commercial customers who heat with electricity rose significantly in the 1973-1977 period (5,000 mWh to 92,000 mWh), primarily because of the unavailability of, or limitations on gas supply. The forecast for the 1978-1980 period for this group of customers is based on local economic conditions and specific customer information.

All other commercial sales were forecast by adjusting the long run commercial growth estimate for improvements in utilization efficiency and local economic conditions.

The forecast of municipal sales was based on normal growth and known major new loads. Normal growth was estimated to be approximately 3 percent (3%) per year

based upon an analysis of historical data. Major new loads were compiled by the Marketing Department based on customer inquiries, surveys and reports.

Q. Would you please describe how you went about developing the industrial class forecast?

A. As shown on page 3, the industrial forecast for the 1978-1980 period was developed in two parts; data supplied by our 17 major customers, accounting for approximately 53 percent of the industrial load, and an adjusted historical growth trend for the 1000 plus smaller industrial customers.

A survey of the 17 major customers in August 1977 indicated growth of approximately 6.4 percent in 1978, 5.5 percent in 1979 and 3.5 percent in 1980. The 1978 and 1979 increases reflect a large increase by two of the largest of 17 customers. Based on our familiarity with and confidence in the estimates supplied by these customers, as well as our own knowledge of their operations, we felt their estimates to be realistic and saw no reason to adjust the data.

The forecast for the 1000 plus customers was based on the historical trend adjusted to reflect economic activity and utilization efficiencies. This group of industrials is expected to grow 3.5 percent in

1978, 3.6 percent in 1979 and 4.9 percent in 1980.

Total industrial sales shown in column three were obtained by summing the sales of the two groups.

Q. Would you please describe what is shown on page 4 of this Exhibit?

A. Page 4 contains a summary of the mWh sales shown on the preceding pages together with sales to street lighting customers. As shown in the right hand column, sales are expected to grow 4.6 percent in 1978, 4.5 percent in 1979 and 4.0 percent in 1980.

Q. Would you please describe what is shown on pages 5 and following of Exhibit 14?

A. Page 5 is a summary of the customers, mWh sales, and revenues, by months for the years 1977, 1978, 1979, 1980 and the twelve months ended April 30, 1980, at the February, 1978 rates. As indicated at the bottom of the page, borderline sales reflected in the figures have been separately shown and subtracted. Miscellaneous sales have been separately shown and added to arrive at the subtotal figures which correspond to figures used in Exhibit 10, sponsored by Mr. Henderson.

The balance of the exhibit, pages 6-12, merely contain a breakdown by year and month of the figures shown on page 5, separately stated for each service

classification.

Q. Mr. Laniak, Mr. Henderson, in his pro forma adjustments has indicated that incidental sales will decline during the rate year. Would you explain the basis for the decline in such sales?

A. Yes. Exhibit 15 shows the 1977 and the rate year normalized resources and load in megawatthours. From this exhibit it is seen that the energy available for incidental sales in the rate year is reduced from 1,122,000 megawatthours to 615,000 megawatthours, primarily as the result of load growth in the RG&E system.

Q. Mr. Henderson has indicated that RG&E expects Oswego 6 to be in service on November 1, 1979. What effect will this have on the amount of energy available for incidental sales?

A. Referring again to Exhibit 15, the total resources available would increase from 6,677,987 to 7,071,987 megawatthours, an increase of 554,000 megawatthours. Purchases would decrease by 160,000 megawatthours, and the net increase in incidental sales would be 394,000 megawatthours.

Q. Would you explain the basis for both the $12,378,000 revenue from incidental sales shown on the first page of

Exhibit 10, and the $985,000 revenue adjustment as a result of Oswego 6 being in service, as shown on Exhibit 10, Schedule J?

A. The $12,378,000 is derived from the incidental sale of the 615,000 megawatthours shown on Exhibit 15 without Oswego 6 being available. This total includes not only the $5 per megawatthour margin anticipated from the sale of that energy, but a $15 per megawatthour fuel cost as well.

The availability of Oswego 6 for the last 6 months of the rate year increases the energy available for incidental sale by 394,000 megawatthours. It is expected that the margin on the sale of this energy will be $2.50 per megawatthour resulting in $985,000 additional revenue.

Q. Why do you expect the margin on the sale of energy from Oswego 6 to be $2.50 per megawatthour?

A. The energy from Oswego 6 will displace higher priced oil generation for the portion of the energy sold as incidental sales. The energy cost from Oswego 6 at today's oil cost is $20.70 per megawatthour and the cost of generation that it will displace is $25.70 per megawatthour or a difference of $5.00 per megawatthour. Based on dividing the savings for such transactions equally

between the buyer and seller the margin would be $2.50 per megawatthour.

Q. Mr. Henderson, on page 8 of Schedule E in Exhibit 10, shows an increase of 88,000 megawatthours purchased during the Ginna outage. What is the reason for this increase?

A. The load in the rate year is greater than the load in the test period and because of this it is necessary to purchase more energy during the period Ginna is on maintenance. During the Ginna shutdown we do not make significant incidental sales. By including the higher rate year customer requirements in a computer program designed to simulate the dispatch of available generation resources, we derived the increased purchases required to meet the higher rate year load during the rate year portion of the Ginna shutdown. The total purchases required will be 244,000 megawatthours in that period. Deducting the normalized 1977 purchases of 156,000 megawatthours results in the rate year adjustment of 88,000 megawatthours.

Q. How was the cost of $25.00 per megawatthour, which is shown on page 8 of Schedule E in Exhibit 10, determined?

A. The $25.00 per megawatthour is based on an analysis of the costs incurred in purchasing energy and capacity

during the 1977 Ginna shutdown.

Q. On page 1 of Schedule J in Exhibit 10 Mr. Henderson shows an $800,000 reduction in purchased power expense during the rate year portion of the 1980 Ginna shutdown because of the availability of Oswego No. 6. Please explain the derivation of this savings.

A. There are two components to this reduction: the reduction in megawatthours required to be purchased and the savings per megawatthour.

The reduction in megawatthours was determined by the use of the same computer program for simulating the dispatch of available generation resources to meet the rate year load during the Ginna shutdown. However, in this run the Company's 204 megawatt share of Oswego No. 6 was included as an available generation resource. The result of this run showed the reduction of 160,000 megawatthours in purchases from outside resources.

The savings of $5.00 per megawatthour of purchased capacity represents only non-fuel-related costs. It is again based upon an analysis of the costs incurred in making purchases during the 1977 Ginna shutdown. As stated in Mr. Henderson's testimony, the Oswego No. 6 operation and maintenance costs, provided for on page 1 of Schedule J of Exhibit 10, do not include fuel

expense. Since, in substituting the Oswego No. 6 energy for purchased energy, the Company will obviously incur fuel costs, it would be necessary to include the latter if the fuel-related purchase energy costs were to be deducted. In lieu of doing so, it was assumed that the two costs would approximately cancel out. Hence only the capacity-related costs were utilized to price-out the purchase power savings.

Q. Mr. Laniak, in the Company's last electric rate proceeding, the Commission called upon the Company to indicate the impact, upon the Company's Steam Department, of transferring fixed costs of Beebee Station Old House from the Electric Department to the Steam Department. The Commission also instructed the Company to provide the current basis upon which Beebee Station Old House is needed by the Electric Department. Please address yourself to this issue.

A. With regard to the potential impact, upon the Company's steam customers, of transferring Old House fixed costs to the Steam Department, the Company, through Mr. Henderson, has previously provided data to Staff which shows that impact. My testimony goes solely to the Electric Department's need for, and benefit from, the Old House capacity.

The Beebee Old House capacity provides fuel source diversity, capacity that is used to meet installed reserve and spinning reserve criteria and operational flexibility in meeting electric system peak demands. It should be noted that, because the Beebee Old House turbines are connected to a common steam header that is also used to supply the district steam system, a ready supply of steam is available, facilitating the use of these units for spinning reserves and for meeting peak demands.

The use of Old House capacity for reserve and reliability is best demonstrated by actual generation and operating data. Exhibit 16 shows the RG&E required reserve based on the New York Power Pool agreement. It also shows Old House turbine generation, and turbine hours run by turbine number, for the years 1972 to 1977. It also shows the utilization of Old House for spinning reserve.

It is apparent that Beebee Old House continues to provide a meaningful contribution to the Electric system in helping to meet peak demand, and in complying with installed and spinning reserve requirements of the New York Power Pool.

The Old House units represent peaking capacity that

provides an economic advantage in New York Power Pool short term energy transactions. Exhibit 16 shows at the bottom, the contribution of the Old House in meeting peak demands for the years 1972 to 1977. Our simulations of RG&E units, using a version of General Electric's time sharing Production Costing Program, continue to show a need for Old House generation in the years 1978 to 1983. During this period from 100,000 to 250,000 megawatthours per year may be expected to be dispatched from the Old House.

Further, the Old House units are centrally located in the RG&E system, increasing reliability during periods of high load or transmission system contingencies.

From all of the foregoing reasons, I conclude that the Old House capacity continues to be needed by the Electric Department.

Q. Does that complete your direct testimony in this proceeding?

A. Yes it does.

Rochester Gas and Electric Corporation

DIRECT TESTIMONY

of

Robert J. Hobday

Supervisor-Rate Research

Q. Mr. Hobday, will you please state your full name and business address for the record?

A. Robert J. Hobday, 89 East Avenue, Rochester, New York 14649.

Q. Mr. Hobday, will you also please state by whom you are employed and in what capacity?

A. I am employed by Rochester Gas and Electric Corporation and hold the position of Supervisor-Rate Research in the Rate and Economic Research Department.

Q. Please describe briefly your education and business experience.

A. I am a graduate of Union College. In 1965, I was employed by the Company as a statistician in the Rate and Economic Research Department. I was promoted to Senior Statistician in 1971 and to my present position in 1972.

Q. Please describe the scope of your testimony in this proceeding.

A. My testimony covers the proposed revisions to P.S.C. No. 9 - Electricity, P.S.C. No. 10 - Gas, and P.S.C. No. 13 - Electricity, which have been filed with the Public Service Commission, and the information contained in Exhibits 17-20, which were prepared under my supervision and direction.

Q. Will you explain briefly what revisions have been made and explain what the changes have been designed to accomplish?

A. The primary objective was to effect revisions which would produce an overall revenue increase of approximately $34,999,000, or 18.2%, in the Electric Department and $9,997,000, or 9.1%, in the Gas Department based on sales for the 12-month period ended December 31, 1977.

Q. Would you please tell us why the Company has not proposed time-of-day rates for electricity in this filing?

A. Let me begin by outlining a brief history of the Rulings and Orders in Case 26806. In a Procedural Ruling dated December 2, 1975, Rochester Gas and Electric Corporation was directed to prepare and submit a marginal cost study by October 1, 1976, subsequently extended to November 15, 1976.

In an Order issued January 7, 1976, the Commission ordered the electric utilities to propose time-of-day rate designs, based on marginal or average cost, for customers whose meters are capable of measuring load according to time or who could reasonably be provided with such meters. Subsequently, in Opinion No. 76-15 issued August 10, 1976, the Commission concluded that marginal costs do provide a reasonable basis for electric rate structures, and directed each electric utility to develop marginal cost studies, load data studies and other pertinent studies

sufficient to translate marginal costs into rates. The combined effect of these two Orders appears to be that each electric utility must now present time-of-day rates based on marginal cost for some or all of its customers or show why it is inappropriate to do so.

The Company, in a letter dated October 7, 1977, advised the Commission that it was engaged in collecting the necessary billing determinants to properly evaluate a possible new rate design and to predict customer impact. Part of that data has been provided Staff. We are continuing to assemble the necessary data and will advise Staff when the analysis is complete. Accumulation of the data will be complete in July.

Q. Would you please discuss the general approach to rate revisions proposed in P.S.C. No. 9 - Electricity and P.S.C. No. 13 - Electricity in these proceedings?

A. I am proposing to distribute the increased revenue requirement among classes on an equal percentage basis. That is, I have increased each class' base rate revenues net of the base cost of fuel by 21.9%. This is the same revenue allocation method adopted by the Commission in Case 27108.

Q. Would you please discuss the revisions to P.S.C. No. 9 - Electricity starting specifically with the revisions to Service Classification No. 1, Residential Service?

A. The proposed minimum monthly charge for service under Service Classification No. 1 is increased from $2.40 to $3.50 per month, an increase of $1.10 or 45.8%. Although this is a high percentage increase, it is cost justified and means that the seasonal and/or convenience use customer will pay a more representative portion of the minimum cost to serve that type of customer.

The second block has been extended an additional 200 kilowatthours and the increase in the unit rate has been held to a minimum. This represents a first step toward elimination of the third block and a flattening of the rate design. This block cannot be eliminated at this time without excessive customer impact. The third and fourth blocks have been increased by more than the average increase. The effect of this rate proposal is that monthly bills from approximately 100 to 500 kilowatthours will receive less than average increases. Service under the "Off-Peak" provision has been increased on a per-unit basis.

Q. Would you please describe the revisions to Service Classification No. 2, General Service - Small-Use?

A. It is proposed that the minimum charge for Service Classification No. 2 be increased from $2.40 to $3.50, the same as proposed for Service Classification No. 1. The rationale

for this proposal is identical to that underlying the increase in minimum charge for Service Classification No. 1, since the cost of supplying 12 kWh to a small-use customer is the same regardless of service classification.

The second block has been extended an additional 300 kilowatthours with the same unit rate applicable in order to simplify the rate structure. The present tailblock has been eliminated. All consumption over 600 kilowatthours will be billed on the proposed tailblock. Thus, the number of blocks in the rate have been reduced from four to three. This rate design adjusts the historically high second block and low tailblock rate structure to a flatter rate design.

The "Applicable To Use of Service For" clause and the "Special Provisions" have been restated to clarify when service will be provided under Service Classification No. 2 versus Service Classification No. 7, General Service-5 kW Minimum.

Q. What revisions have been made to Service Classification No. 3, General Service - 100 kW Minimum?

A. The revenue increase has been distributed 70% to the demand charges and 30% to the energy charges reflecting continued increases in demand-related costs, consistent with the Order in Case 27108.

It is proposed that the demand charge be simplified by eliminating the present tailblock. The proposed tailblock will apply to all demands over 500 kilowatts. The proposed energy rates have been increased on a per-unit basis.

Q. What revisions have been made to Service Classification No. 6, Area Lighting?

A. The proposed service classification is unchanged in format with all charges increased on an equal percentage basis.

Q. Would you now please describe the revisions to Service Classification No. 7, General Service - 5 kW Minimum?

A. The revenue increase has been distributed 100% to the demand charge reflecting continued increases in demand-related costs. This increase brings the Service Classification No. 7 demand rate closer to the unit rate for the first 500 kilowatts on Service Classification No. 3 as a preliminary step toward combining the two service classifications.

The proposed monthly minimum charge has been set as 5 kilowatts at the proposed demand tailblock rate of Service Classification No. 3.

The energy charge for over 400 hours' use has been increased to the energy charge applicable to the same

block in Service Classification No. 3. An offsetting adjustment has been made by lowering the energy charge for the first 200 hours' use. No change in the second energy block is proposed.

The "Determination of Demand" clause has been restated to clarify when service will be provided under Service Classification No. 7 versus Service Classification No. 2.

Q. What changes to the General Information section of the Schedule are you proposing?

A. On Leaf No. 19, in Rule 3.6, Standby: Auxiliary or Breakdown Service, the annual service capacity charge is proposed to be increased from $18.00 to $50.88 per kilowatt. As costs have continued to rise over the years, this charge has not been increased. Therefore, the charge has been set equal to the proposed demand tailblock rate of Service Classification No. 3. Since there are no customers currently contracting for service under Rule 3.6, there is no revenue effect.

Q. Would you please discuss what revisions have been made to P.S.C. No. 13 - Electricity - Street Lighting?

A. Service Classification No. 1 has been allocated a portion of the increased revenue requirement on an equal percentage basis of all the electric class' base rate revenues net of base cost of fuel.

The present two-tier rate schedule for fixtures and facilities, which provides different unit rates dependent upon date of installation, has been eliminated. A single unit rate for each type of equipment is proposed based on a weighted average of the rates in service during the test period. This revision has been made because the old rate design, which was necessary when five-year contracts were used, is no longer appropriate.

In addition to the above changes, a new Rule 4.5, Increase in Rates Applicable in Municipality Where Service is Supplied, has been added to the General Information section. This rule provides for an increase in the rates and charges, including Fuel Cost Adjustment, for service supplied within a municipality, by a percentage equal to the total percentage rate of taxes now imposed on the Company's revenues by that municipality and the State of New York. The Company proposes to reflect further changes in such taxes by filing a revised Rule 4.5 whenever the tax laws are amended. These revisions will, of course, be filed on 30 days' notice in accordance with the Commission's rules and statutory requirements. This provision tracks uniform provisions currently in effect in P.S.C. No. 9 - Electricity and our gas and steam tariffs.

Q. Have you proposed any roll-in of Fuel Cost Adjustment

revenues at this time?

A. No, I have not. However, due to increasing cost of fuels it may be appropriate to do so. I suggest that an appropriate amount be rolled in at the conclusion of the case to insure that as much as the fuel cost as practicable will be included in the final rates.

Q. What is the total revenue effect of these proposed revisions?

A. The effect of these revisions, including increased Forfeited Discount (or late payment charge) revenues, will be to increase the Company's electric revenues by $34,999,000 or 18.2%, based on sales for the 12-month period ended December 31, 1977.

Q. Would you now describe the contents of Exhibit 17?

A. Exhibit 17 contains summaries of revenue effects of the proposed electric rates for 12 months ended December 31, 1977, the comparisons of present and proposed rates, and comparisons of typical bills for various amounts of monthly use.

Page 2 of this Exhibit is entitled "Estimated Revenue Effects of Proposed Electric Rates, 12 Months Ended December 31, 1977." For the period indicated, it shows the average number of customers served, the total kilowatthours sold, and, in column four, the actual revenue

adjusted to annualize the effects of increased base rates effective February 18, 1978 for P.S.C. No. 9 - Electricity and rates effective March 1, 1978 for P.S.C. No. 13 - Electricity. Column five shows the revenues which would have been received if the proposed rates had been in effect during the same period. The last two columns show, in amount and percent, the increases which result from application of the proposed rates and increased Forfeited Discount revenues.

A summary of bill effects is shown on the last three lines on page 2. All bills will be increased and no bills will be decreased or remain unchanged.

For comparative purposes, pages 3 through 7 set forth in tabular form, the blocks, unit charges and provisions of the present and proposed rates.

Pages 8 through 12 list and compare typical bills for service under present and proposed rates indicating the amount and percent increase over present rates.

Q. Please describe what the revisions to P.S.C. No. 10 - Gas have been designed to accomplish and how the increased revenue requirement has been distributed.

A. The primary objective was to effect revisions which would produce an overall revenue increase of $9,997,000, or 9.1%, based on sales for the 12-month period ended

December 31, 1977.

In accomplishing that objective, we have sought to bring about further rate simplification of Service Classification No. 1 through elimination of one block. The present fourth block, 1001 to 5000 Ccf, and the present fifth block, 5001 to 100,000 Ccf, have been combined.

The proposed minimum monthly charge for service under Service Classification No. 1 is increased from $2.56 to $3.50, or 36.7%. This is to bring the minimum charges more closely in line with the cost of serving a minimum-use customer.

The remaining increased revenue requirement then was distributed to the remaining proposed blocks of Service Classification No. 1 by an across-the-board increase on a per-unit basis.

Proposed Service Classification No. 2, Gas Lighting Service, has been modified by increasing the noncommodity portion included in the present rate by the overall percentage increase. The result of this component increase is an increase in the Service Classification No. 2 flat rate from $4.51 to $4.70 per month.

I have not proposed any roll-in of Gas Cost Adjustment revenues at this time. However, I suggest that an appropriate amount be rolled in at the conclusion of the

case based on the cost of gas at that time to insure that as much as is practicable will be included in final base rates. Similarly, I suggest that the Service Classification No. 2 rate be increased by the amount of all further increases in purchased gas cost which have occurred by the time new rates become effective.

Q. On April 11, 1978, the Commission issued an Order in Case 27325 - Bath Electric, Gas and Water Systems - Gas Rate Increase in which it adopted a rate design with an initial charge to recover customer costs and flat rates thereafter. Is it your understanding that a flat rate for the Gas Department would be cost justified?

A. Definitely not. A flat rate would not track the costs involved to serve customers of different sizes.

The costs necessarily incurred in supplying a customer can be divided into three basic functions: capacity cost - reflecting an allocation of the costs related to transmission and distribution mains and regulators and the demand cost of purchased gas; commodity cost - reflecting the commodity cost of purchased gas; and customer cost - reflecting meter reading, customer accounting and collecting, meters and services, etc. A general review of these three costs may be useful.

Capacity costs are those controlled by the size of

the delivery facilities and are a function of the hourly or daily use of gas. In the gas industry, economies of scale are inherent in the use of large pipe sizes. For example, the cost of six-inch pipe is 9 times the cost of a one-inch pipe yet capacity is increased more than 800 times. Thus, cost per Ccf of capacity decreases as pipe size is increased. Accordingly, total costs per Ccf of capacity decrease quite sharply as customer loads increase.

Commodity costs are specifically related to the commodity cost of purchased gas and are in direct correlation to the amount of gas used. This cost, on a per Ccf basis, does not vary with customer use.

Customer costs include the capital costs and expenses of meters and services, operating expenses connected with customer accounting and collecting, and other general costs that vary directly by the number of customers served. The expenses incurred by the Company to read the meter, bill the customer and collect the revenue do not vary significantly from a residential customer to an industrial customer. Thus, as customers' use increases, the customer costs involved, per Ccf, decline. The costs involved with meters and services do vary with the customer's size but as was the case with capacity costs, the expense,

on a Ccf basis, decreases as the volume of gas used by a customer increases.

Therefore, it can be seen from this discussion of the three cost components that the overall costs necessary to serve a customer decrease, on a per Ccf basis, as the customer's load increases. This reduction in cost, per Ccf, is reflected in the price differentials between the blocks in a declining block rate structure.

Q. If a flat rate were to be instituted for Rochester Gas and Electric, would the effect of weather on revenues be magnified?

A. Yes. Weather effects, already a disrupting factor in revenue received, would have an intensified effect on total revenue and on revenue stability. Assuming that the revenues used to set the flat rate were based on normal weather, moving from a normal year to a colder-than-normal or warmer-than-normal year would create wider swings in the amount of money received by the Company. The revenue fluctuation would be more pronounced with a flat rate than with the current rate design because with a flat rate the price for weather sensitive usage would include a larger portion of fixed costs. Therefore, weather pattern changes from year to year would have a more serious impact on revenue stability.

Q. Do you have any other comments you wish to make?

A. If a flat rate design was adopted, it would have the effect of reducing most residential and small commercial and industrial bills at the expense of commercial and industrial customers requiring larger volumes of gas who would receive very substantial increases. This is a customer impact which should be weighed very carefully, particularly since a flat rate has no cost justification as discussed earlier. In addition, commercial and industrial customers have already taken measures to conserve gas and it would be unfair to now impose a greatly increased rate on these customers because their needs require larger volumes of gas. Significant increases to these customers are completely unjustified, particularly when one considers that the Rochester Area, like the balance of New York State, is having difficulty in attracting new industry and retaining existing industry.

Q. Would you now describe the contents of Exhibit 18?

A. Exhibit 18 contains summaries of revenue effects of the proposed gas rates for 12 months ended December 31, 1977, comparisons of present and proposed rates and comparisons of typical bills for various amounts of monthly use.

Page 2 of this Exhibit is entitled "Estimated Revenue Effects of Proposed Gas Rates, 12 Months Ended December 31,

1977." For the period indicated, it shows the average number of customers served, the total Ccf sold, and the actual revenue adjusted to annualize the effects of increased base rates and revised gas cost adjustment provisions effective February 2, 1978. Column five shows the revenue which would have been received if the proposed rates had been in effect during the same period. The last two columns show, in amount and percent, the increases which result from application of the proposed rates.

The increase in Forfeited Discount revenues of $39,930, shown on page 2, is based on the Forfeited Discount (or late payment charge) revenues for 12 months ended December 31, 1977 increased by the average base rate percentage increase for Service Classification No. 1.

A summary of bill effects is shown on the last three lines of page 2. All bills will be increased. No bills will be decreased or remain unchanged.

For comparative purposes, page 3 sets forth, in tabular form, the blocks, unit charges and provisions of the present and proposed rates, with the exception of proposed changes in Service Classification No. 2, which has a single flat monthly charge.

Page 4 lists and compares typical bills for service under the present and proposed Service Classification

No. 1 indicating the amount and percent increase over present rates.

Q. Would you now describe Exhibit 19?

A. Exhibit 19 is a summary of the estimated revenue effect of the proposed electric rates during the 12 months ended April 30, 1980. For this period, it shows the forecast average number of customers served, forecast kWh sales, annualized revenues based on forecast sales and current rates, and the revenues to be derived if the proposed rates are in effect in the period. The last two columns show, in amount and percent, the increases which result from the application of the proposed rates. A summary of bill effects is shown on the last three lines.

Q. Would you please describe Exhibit 20?

A. Exhibit 20 is the summary of estimated revenue effects of the gas rates proposed in this proceeding during the 12 months ended April 30, 1980. The format is the same as that used in Exhibit 19.

Q. Does that complete your testimony in this proceeding?

A. Yes, it does.

Rochester Gas and Electric Corporation

DIRECT TESTIMONY

of

Robert B. Lauterbach

Senior Statistician

Q: Would you please state your name and address?

A: My name is Robert B. Lauterbach and my business address is 89 East Avenue, Rochester, New York.

Q: Mr. Lauterbach, will you also please state by whom you are employed, your position and duties?

A: I am employed by Rochester Gas and Electric Corporation as a Senior Statistician in the Rate and Economic Research Department. My primary responsibilities involve the preparation of the Company's annual gas sales and revenue forecasts and the continual review of our gas supplier's rates, charges, tariffs and forecasts as each affects the Company. I have also undertaken special studies regarding gas supply and have prepared periodic statistical reports for management.

Q: Please describe briefly your education and business experience.

A: I am a graduate of the Rochester Institute of Technology with a B.S. degree in Accounting. I was employed by the Company in June, 1967, as a co-op student working in the Customer Accounting Department. Upon graduation, I assumed full time responsibilities in the Rate and Economic Research Department.

Q: Would you please describe the purpose of your testimony in this proceeding?

A: I have prepared the Gas Sales and Revenue Forecast for 1978, 1979, 1980 and the rate year ending April 30, 1980. The purpose of my testimony is to explain this forecast.

Q: Could you explain for us the general purpose of such a forecast?

A: The forecast is designed to determine the volume of sales, expressed in Mcf for the year in which rates are being set. From the volume of sales, the current tariff rate is applied to derive forecasted revenue, assuming no increase in rates.

Q: Would you briefly describe for us the format which you have developed for this forecast?

A: Yes, the forecast is divided by classes into monthly bills, Ccf per bill, and Mcf sales for the calendar years 1978, 1979 and 1980. The forecast spans 16 months prior to the commencement of the rate year and continues some eight months after its conclusion. However, for purposes of consistency, and to establish a demonstrable link between the historical and forecast period, I felt it was best to give a complete calendar year picture. In addition, the use of the calendar year 1978 will permit us to compare actual data as and when it becomes available.

Q: Would you briefly describe these exhibits?

A: Yes. Exhibit 21 is a summary of actual 1977 and forecasted 1978, 1979 and 1980 customers, sales in MMcf, and revenues for SC-1 by month. It also shows annual figures for SC-2 and Code 15 sales. Exhibits 22, 23 and 24 are detailed monthly forecasts for SC-1 by class of service for 1978, 1979 and 1980, respectively. Exhibit 25 is a Summary of Non-Residential applications for new or additional load between November 1, 1977, and April 20, 1978.

Q: Before we discuss the specifics of your forecast, could you explain to us the general methodology of the forecast?

A: First, the number of monthly bills (or customers), for each customer class was forecast. The number of bills for each class was further broken down into subclasses, that is, existing customers, new customers, conversions and customer losses to reflect changes over the forecast period. The monthly consumption per bill for each subclass was also forecast. By multiplying the estimated number of bills by the consumption per bill I determined the sales for each class.

Q: Would you describe how you determine the number of bills?

A: If you look at page 2 of Exhibit 22 you will find the components to which I previously referred, shown in the left-hand column.

Lines 1560 through 1700 show the breakdown of the residential class. Lines 1560 and 1640 show the number of existing customers as of December 31, 1977. Lines 1590 and 1670 show the number of customers lost through attrition, that is demolitions, fires, and so forth. Since we were not permitted to attach new customers during 1976 and 1977 through November, it was possible to determine the actual number of losses experienced in that period. By comparing the number of bills for comparable months in 1976 and 1977 I was able to determine the annual number of losses which, for forecasting future periods, I spread ratably over the year. Conversions, lines 1600 and 1680, represent the "residential regular" customers who have converted from an alternate heating fuel to gas heating. The number of conversions was based on estimates supplied by our Residential Marketing Department. Conversions also were spread ratably over the 12 months. Finally, line 1650 reflects the number of new homes.

Q: Would you tell us how you determine the number of new homes which you have projected in the forecast.

A: The number of new living units is based upon a forecast made late in 1977. That forecast took into account all of the relevant data available to us, including actual contacts with area builders.

At the same time, based upon available data, including recent trends and an evaluation of the probable impact of renewed gas sales, an estimate was made of the portion of those units which would utilize gas for heating. I did not forecast any new residential regular customers primarily because, in accordance with the Company's Tariff for gas service, customers requesting gas for purposes not including space heating are required to pay for the service lateral, which discourages such installations.

In the existing (line 1640), and new home (line 1650), categories the monthly spread of the changes in the number of customers reflects historic, seasonal trends.

Q: How was the number of non-residential bills (or customers) developed?

A: The number of existing customers, lines 1720, 1780, 1840, 1930 and 2020, was based on the December 1977 bill count. Lines 1890, 1980 and 2070 reflect existing large customers as of December 31, 1977 not included in the

previously mentioned lines. The latter customers account for large volumes of gas and were therefore forecast separately.

The number of new cusotmers is based on a summary of applications received between November 1, 1977 and April 20, 1978 for new or additional service. Data from those applications is shown on Exhibit 25. The January increases shown reflect actual November and December 1977 applications. The increases estimated for subsequent months are based on the remaining applications received through April 20, 1978. The January increase is believed to reflect pent-up demand due to the Company not having been permitted to serve new or additional loads prior to November 1, 1977. Based on the perceived leveling off of these customer applications an estimate was made of what now appears to be the normal level of new monthly applications for each class of non-residential customers.

Q: Would you please go on to explain how you developed the factors affecting consumption per customer which was used to develop sales volumes.

A: First I developed monthly Ccf per bill factors to be used for the existing bills as shown on page 3 of Exhibits 22, 23, and 24. Please note that the Ccf per

bill is divided into two elements; Ccf per consumption day (CD) and Ccf per daily degree day (DDD).

Q: Would you please define these two elements?

A: Yes, the Ccf per bill per CD is the class average of non-temperature sensitive load consumed each day during a particular billing month. The Ccf per bill per DDD relates only to the heating classes and is the class average of the temperature sensitive load consumed for each daily degree day during a particular billing month. The number of daily degree days is the number of degrees difference between 65° and the mean temperature, determined on a daily basis.

Q: What are Normal Degree Days (line 2210) and Average Billing Days (line 2220)?

A: What is labeled as "Normal Degree Days" is a derived average number which reflects the normal degree days in each of the twenty billing cycles for the indicated month. It is derived by adding the normal degree days in each billing cycle and dividing the result by twenty to determine the indicated normal degree days for each billing month.

The number of Average Billing Days (line 2220) is the sum of the number of days in each of the twenty billing cycles divided by twenty.

To determine these numbers, the 1978 "read schedule" was used, not only for 1978 but also for 1979 because the actual 1979 schedule has not yet been prepared. Since 1980 will be a leap year, the 1976 schedule was used for that year.

Q: On a class basis, how did you calculate the Ccf/CD and Ccf/DDD factors?

A: In the Residential Regular class, I used monthly Ccf per bill and divided it by the average number of billing days for each month of 1974, 1975 and 1976 to calculate the Ccf per bill per CD. Then I averaged the respective month of January, February, etc. to derive the factors shown on line 2240. This procedure was also followed for the Commercial Regular class (line 2290).

In the Residential Heating class, I developed the CCF/CD by using the monthly Ccf per bill of our 30,400 water heating customers in the Residential Regular class for 1974, 1975 and 1976 and divided it by the average billing days for each month. I then derived an average GCF/CD for each month. To arrive at the Ccf/DDD, I subtracted from the total reported Residential Heating Class Ccf per bill, the reported water heating Ccf per bill and the average monthly furnace pilot light consumption. The temperature sensitive load that remains

is divided by the actual number of billing Degree Days for each month to arrive at monthly Ccf/DDD. Line 2270 was arrived at by averaging the respective months of the three years.

For the Commercial Heating class, the Ccf/CD (line 2310), was calculated by taking an average of the lowest month's Ccf/CD in each of the historical years and profiling it back over the other months based on the Ccf/CD in the Commercial Regular class. These factors were multiplied by the number of billing days to develop the Ccf/bill to be subtracted from the total reported Commercial Heating Ccf/bill. The remaining load was then divided by the Actual Monthly Degree Days to get temperature sensitive Ccf/DDD. An average of the respective months in the three years is found on line 2320.

The industrial Regular Class was divided into two parts, the largest 14 accounts (about 80% of the class sales) and the remaining accounts. For each part, the monthly 1974, 1975 and 1976 Ccf/bill was divided by the average billing days in each month and an average was determined for the respective months to determine the Ccf/CD (Lines 2360 and 2350 respectively).

The Industrial Heating class was also divided into

two parts, the largest 6 customers (about 55% of the Class sales) and the remaining accounts. For each part, the Ccf/CD was calculated by taking an average of the lowest month's Ccf/bill and dividing by the number of billing days for 1974 through 1976. Since I do not have any base for determining a monthly profile of this use, in contrast to the Residential and Commercial classes, which have homogeneous base usage, I left this factor constant throughout the year (lines 2380 and 2400). The Ccf/DDD (lines 2390 and 2410) was then calculated using the same methodology as in the Commercial Heating class.

The municipal class was also broken down into two parts. The total class less one large account was calculated using the same method as in the Industrial Heating class (lines 2430 and 2440). The one large account is essentially a base load account, also using gas for space conditioning in the summer months and was forecast separately (line 2450).

Q: Mr. Lauterbach, please explain how you arrived at the normalized Ccf/bill used in the forecast for the existing classes of customers?

A: To obtain the existing classes' monthly Ccf/bill based on the normal degree days and average billing days, I utilized the following computations.

1. Non-heating classes: Ccf/bill/CD x average billing days

2. Heating Classes: (Ccf/bill/CD x average billing days) + (Ccf/bill/DDD x normal billing degree days). In the residential heating class, the monthly pilot light Ccf was also added.

The products of these calculations are shown on lines 2890, 2960, 2500, 2580, 2720, 2780, 2840, 2910, 2980 and 3030 of page 4 of Exhibits 22, 23, and 24.

Q: Would you please explain how you developed the Ccf/bill factors for conservation, customer losses, conversions and new customers?

A: Let's turn first to conservation due to energy efficient water heaters in the residential classes, (lines 2515 and 2600). In recent years, water heaters which are more energy-efficient have become available. After July 1, 1978, only the more efficient units may be sold in this State. The new efficient unit uses approximately 18% (or 5.25 Ccf/mo.) less gas than a non-conservation model according to the estimates made by the RG&E's Energy Utilization Department. The average life of a water heater is approximately 10 years or 120 months. Therefore, if all customers had a new efficient water heater, the class average, would drop 5.25 Ccf per month by the middle of 1987. To achieve that figure in 1987, the incremental monthly savings for each month for

the class would be .04375 Ccf per month (5.25 Ccf ÷ 120 months), per bill after July 1, 1978. The Residential Regular class (line 2515), shows only 75% of this effect based on the level of gas water heater saturation within the class. In the Residential Heating class, all customers are assumed to have gas water heaters, so the full effect of the new efficient water heaters is used (line 2600).

The Ccf/bill used for customer losses and for conversions in the Residential Regular class is derived by taking the existing Ccf/bill less the impact of this water heater conservation.

In the Residential Heating class, in addition to the conservation due to new water heaters, I also estimated the conservation due to factors which I have not been able to quantify but which I believe to be of increasing significance in this area. First, there is the effect of reduced thermostat settings. This has most likely accounted for significant portions of past conservation. I believe that more of our customers will reduce thermostats as conservation continues to become a topic of increasing importance. Second, I note that there are increasing uses of alternate fuels. The use of wood burning stoves in our service territory is

becoming more common. Third, customers are continuing to upgrade their insulation. Fourth, our customers will be installing more efficient furnances. After June 1, 1980, all new furnaces sold in the State will not have a pilot light; in fact, these furnaces are available for sale now. I developed an estimate of the effect on consumption of these factors combined through March 1978 by comparing the existing usage, developed from 1974-1976 data (line 2580), with the normalized sales data for January 1977 through March 1978. On the basis of this review, I have estimated the cumulative conservation levels from the base period to the forecast period. The percentages range from 3% in January to 10% throughout the summer and taper back down to 3% in December. For 1979 and 1980, I increased the monthly conservation levels by one percentage point. These percentages relate only to line 2640. The sum of all conservation for the Residential Heating class, existing customers, is shown on line 2650.

The lower Ccf/bill (line 2660) for a new home is based on the fact that new homes will be significantly more energy efficient than the existing housing stock. Due to increased insulation requirements in our gas and electric tariffs and the new energy efficient

appliances, the average consumption for new homes will be approximately 30% less than the 1974-1976 base period consumption for existing dwelling units. Since conservation has been built in, at the outset, to the Ccf/bill for new homes, this factor is kept constant throughout the forecast years.

The Ccf/bill used for losses and conversions is equal to the existing Ccf/bill less the effect of conservation experienced through that month.

Q: Turning now to the non-residential classes, that is Commercial, Industrial and Municipal, could you describe the Ccf/bill factors in the forecasts for conservation and new customers?

A: I estimated the amount of conservation in the same way that conservation was calculated for the residential heating class. My analysis indicates no further allowance for conservation is necessary in the Commercial Regular and Industrial Regular-Small classes. On the other hand, I found that the Commercial Heating class has declined about 7%, the Industrial Heating-Small, 16%, and the Municipal-Small 13%. For purposes of being conservative, I used 5%, 10% and 10% for the three classes respectively. I also assumed that the level of conservation would not increase for the remain-

ing years of the forecast, even though it is conceivable that some customers will install more energy efficient equipment in the future.

The Ccf/bill in the non-residential classes for the new customers includes existing customers who have applied for additional gas.

By referring back to Exhibit 25, it can be seen that the Mcf per customer shown on the far right-hand column is an incremental value for both new and additional loads. This is necessary since it is only new customers which affect the bill count. The factors to determine this incremental usage were calculated by dividing the expected new and additional annual use per customer by the annual use per existing customer based on the historic 1974-1976 period. By using this technique, the total new load per customer is spread over the months based on the existing use per bill profile.

The forecasts do not include five pending applications for new loads that require PSC approval (over 25,000 Mcf per year). These applications have not yet been approved. If the PSC approves the applications, an adjustment to the forecast would be required.

Q: Now that you have described all the factors, how did you develop the sales volumes?

A: On pages 5 and 6 of Exhibits 22, 23, and 24, the sales volumes in Mcf are shown. These volumes are derived by taking the number of bills forecast and multiplying by the Ccf/bill in each month by each class and sub-class. New sales to Industrial Regular-Large (line 3530), Industrial Heating-Large (line 3750) and Municipal-Large (line 3940) are based on Exhibit 25 (New Applications). These volumes were added equally throughout the year.

The conservation in the Industrial-Large Classes was based on an annual estimate spread equally across each month. It was not done on a Ccf/bill basis, but on a volume basis as shown on lines 3500 and 3720.

On page 1 of each forecast a class summary is provided for the total monthly bills, Ccf/bill and Mcf Sales.

Q: Would you please describe how you developed the associated forecast revenues?

A: The Revenues (in thousands of dollars) are summarized by class on pages 7 and 8 of Exhibits 22, 23 and 24.

In calculating the revenues I used the April 20, 1976 rates because the necessary historical data was available. The average rate per Mcf was calculated by each class of customer by using a rate ratio technique.

This method develops, for each class in an actual

period, the ratio of actual average base rate revenue per unit of sales experienced to the theoretical base rate average revenue per unit of sales which would have been obtained from an average use customer by applying such average usage to the actual base rate schedule. Using the twelve months ended August 31, 1977 for each month the actual average revenue per unit of sales was derived by dividing the total class base rate revenue in that month by the total class sales in the same month. Using the same period, again month-by-month, the theoretical average base rate revenue per unit of sales was calculated by applying the average use per customer in the month for the class to the April 20, 1976 base rate schedule to derive the theoretical revenue per average customer; that theoretical base rate revenue was then divided by the same average use per customer to arrive at the theoretical average base rate revenue per unit of sales for the month. For the same month, the ratio of the actual unit revenue to the theoretical unit revenue is then developed.

In the forecast month the average use per customer is known. This average use is applied to the same April 20, 1976 base rate schedule to arrive at theoretical base rate revenues from an average customer

in the class; this theoretical revenue is then divided by the same average use to arrive at the theoretical average base rate revenue per unit of sales for the class in that month. The rate ratio for that month, previously derived as already explained, is then applied to this theoretical unit revenue to calculate what can be expected to be the actual unit base rate revenue in the forecast month. Of course, the total class base rate revenue is then easily derived by multiplying the expected actual unit revenue for the month by the total class sales for the same month.

The results of these calculated Base Rate Revenues are shown on pages 7 and 8 of Exhibits 22, 23 and 24.

The rate increases were then added to the Base Rate Revenue to adjust the rate levels to the February 2, 1978 rates (exclusive of rolled-in gas costs). This was done partially on a per bill basis (due to the minimum charge increase), and the remainder on a per Ccf basis (due to the unit increase in the balance of the rates). Also, I added five cents per Ccf for the roll-in of purchased gas consts that occurred in the November 11, 1978 rate increase. The subtotal is base rate dollars based on the February 2, 1978 rates.

The Gas Cost Adjustment revenue is based on the pro forma average cost of gas as of January 2, 1978.

Consistent with Exhibits 9 and 11, it is kept at a constant unit rate throughout the three years.

Revenue tax (4.17%) was then added based on the year-end 1977 Average Revenue tax percentage. The sum of these revenues is the total forecasted revenue RG&E would expect to receive from Service Classification No. 1 in the forecast period, at February 1978 base rates and January 1978 GCA.

Q: Mr. Laterbach, please explain how you forecasted S.C. No. 2 sales?

A: S.C. No. 2 is a gas lighting service limited to existing locations and existing units in service as of April 28, 1972. Since this service classification is very small with annual sales of approximately 2,000 Mcf and annual revenues of approximately $6,000, the forecast was done on an annual basis. Although there is some attrition in this class, because of the minor impact, I based the forecast on the Pro Forma 1977 sales volumes and the rates in effect on February 2, 1978, and held them constant throughout the three forecast years. This is reflected on Exhibit 21.

Q: On Exhibit 21, I also notice Code 15 Sales. Would you please explain this item?

A: Code 15 Sales are sales to 4 customers from whom the

Company leases gas wells on a contract basis. I included them so the total customer count would balance to other reported data. The annual Mcf sales are less than 1,000 Mcf and the annual revenues are less than $1,000.

Q: Finally, would you explain the item miscellaneous revenues, shown on Exhibit 21?

A: Miscellaneous revenues are revenues derived from forfeited discounts and rents. When miscellaneous revenues are added to the revenues from S.C. No. 1, S.C. No. 2, and Code 15 sales, the total revenue for the rate year ending April 30, 1980, is derived on the basis of present rates. This revenue figure corresponds to the figure used by Mr. Henderson in Exhibit 11.

Q: Does this conclude your testimony?

A: Yes, it does.

DIRECT TESTIMONY

of

WAYNE D. MONTEAU

for

ROCHESTER GAS AND ELECTRIC CORPORATION

Q. Please state your name and address.

A. My name is Wayne D. Monteau. I live in Oceanport, New Jersey.

Q. By whom are you employed and in what capacity?

A. I am an Assistant Vice President for Stone & Webster Management Consultants, Inc., 90 Broad Street, New York, New York.

Q. Please explain briefly the nature of the financial and advisory services provided by Stone & Webster Management Consultants, Inc.

A. Stone & Webster performs a wide array of services for corporate clients. These services include rate analysis and design; financial planning; consultation on management policies; computer-feasibility, systems design, and installation studies; acquisitions and mergers; economic feasibility studies; market studies; organization studies; executive training; personnel policies; labor relations; insurance and pension plans; public relations; tax services; and many more.

Our Accounting and Financial Division assists its clients in the formation of long-range financial planning, in merger and acquisition studies, in economic feasibility studies, in analysis of decision alternatives, in valuation studies, in the development of earnings, cash and financing estimates, and the performance of cost of capital and objective function studies.

The preparation of studies of this nature requires the compilation of vast amounts of statistical data for both the company being analyzed and for other companies in that industry. Recently, we have formalized this procedure by incorporating much of this data in a comprehensive Utility

Financial Data Base. This data, together with our general familiarity with the securities and money markets, and our long business experience, form the basis for all of the financial and advisory services performed by Stone & Webster Management Consultants, Inc.

Q. Would you outline your educational background?

A. I have a BS degree in Accounting (magna cum laude) from Pennsylvania State University. I have done graduate work toward a master's degree in business administration at the Graduate School of Business Administration at Pennsylvania State University. In addition, I have taken Liberal Arts courses at Colgate University and Mathematics at Utica College of Syracuse University. Furthermore, while a graduate student I was an instructor in an undergraduate course in Managerial Accounting and was a research assistant in Public Utility Accounting.

Q. What has been your business experience?

A. A significant part of my work is and has been in the development and preparation of studies relating to cost of capital and rate of return for presentation before various utility regulatory bodies. In my capacity as a senior financial and accounting consultant, I have worked on a number of special assignments for both utility and nonutility client companies which are located throughout the United States, in Canada, and Mexico. I have developed several dynamic mathematical models for use in the study of debt management and rate regulation of public utilities. I have spoken before the Institute of Electrical and Electronic Engineers on the combined subjects of Debt Management and Federal Price Regulation.

Over the past several years, I developed the Stone & Webster Utility Financial Data Base computer program which is designed to maintain a 20-year history of detailed financial information for all utility companies on which there is public information available. Finally, I am the instructor at the Stone & Webster Management Training Course in the cost of capital and fair rate of return for public utilities.

Q. Have you testified as an expert witness prior to this case?

A. Yes. I have presented testimony on the subject of cost of capital and rate of return before utility regulatory agencies in the states of Alabama, Connecticut, Massachusetts, Michigan, Mississippi, Montana, New Hampshire, New Mexico, New York, South Dakota, and Texas as well as the U. S. Federal Power Commission, and in Canada before the public utility boards of Alberta, Manitoba, Ontario, and Quebec as well as the Canadian National Energy Board.

Q. Have you made a study to determine the fair rate of return for Rochester Gas and Electric Corporation (Rochester)?

A. Yes, I have made such an analysis.

Q. What investigations have you made in formulating your opinion as to fair rate of return?

A. I have reviewed the financial statements of the Company for the years ended December 31, 1966 through 1977. Furthermore, I examined other financial data as far back as the early 1950's.

In addition to my analysis of Rochester, I reviewed the available financial and operating information of a number of utility and nonutility

companies in the United States and reviewed the money markets generally.

Q. Before discussion of your study in detail, will you outline your general approach to the problem?

A. One of the basic questions to be resolved in this hearing is the fair return for Rochester. This is the number of dollars remaining after expenses and taxes, which are required to enable the company to service its debt obligations, to operate successfully to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed. This is as stated by the United States Supreme Court in Federal Power Commission vs. Hope Natural Gas Company, 320 U.S. 591 (1944). Furthermore, the Court went on to say that from the investor or company point of view, it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

The Supreme Court had earlier stated in Bluefield Water Works & Improvement Co. vs. West Virginia Public Service Commission, 262 U.S. 679, (1923) the proposition that "A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks

and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."

It is upon these principles that I have based my studies of the cost of capital of Rochester. From these studies I have derived a recommended fair rate of return which will, in my opinion, provide the Company with earnings comparable to alternative investment opportunities of corresponding risks, allow the Company to attract capital in the future on reasonable terms, and maintain its financial integrity.

In attempting to measure the fair rate of return, I directed my attention to the right-hand side of the balance sheet; that is, to the capital supplied by the investors in the Company. After determining what the Company needs to pay each class of investor, it becomes a direct mathematical calculation to establish the overall return requirements on total capital supplied, and thus, the recommended fair rate of return to be applied to rate base. Finally, as the costs attached to the senior securities of a company are fairly well set by the cost historically contracted for and paid by the Company, the problem of fair rate of return becomes largely a problem of determining a fair residual return to the Company's common equity investors. Therefore, I approached this problem from the point of view of the capital employed by the Company. I have measured the cost of each element of capital and then combined the elements to derive an overall cost of capital to the enterprise.

Q. I show you an Exhibit marked for identification ___ which consists of

24 schedules, the title page of which reads "Study on Cost of Capital and Fair Rate of Return." Were these schedules prepared by you or under your direction?

A. Yes, they were. I might add that in making my analysis I studied many facts and figures. I have included only those which I considered particularly significant in illustrating the basis for my conclusions. The first three schedules cover the Preliminary Study of the Company; Schedules 4 through 12, the Comparable Earnings Study; Schedules 13 through 19, the Discounted Cash Flow Study; Schedules 20 through 22, the Market Appraisal Study; Schedules 23 and 24, the Cost of Capital Summary.

Q. Please comment on the Preliminary Study of Rochester which covers Schedules 1 through 3.

A. A summary balance sheet at each year ended December 31, 1967 through 1977 for Rochester is shown on Schedule 1. From 1967 to 1973, gross utility plant grew by 52% (a compound annual growth rate of 7.2%). In recent years, however, gross utility plant growth has accelerated. Over the 4 years since 1973, gross utility plant has grown by 48% (a compound annual growth rate of 10.3%).

The source of the funds which financed the existing plant is the capitalization of the Company and is shown beginning on line 12. The total permanent capital consists of long-term debt, preferred and preference stock, and common stock equity. In addition, the Company has had short-term debt outstanding at the end of all but one year during the studied period. During the 1967 to 1977 period, total permanent and short-term capital (line 22) grew 118%, an annual compound rate of 8.1%. Since 1973, however, this annual growth rate has increased to 10.3%. In contrast, common stock equity has grown 139% since 1967 year-end, an overall compound growth rate of 9.1% through 1977 year-end. During the 1973 to 1977 period, common stock equity has grown at an annual compound growth rate of 9.0%. Thus, common equity growth has continued at a rate near its historical pattern while senior capital, i.e., long-term debt and preferred stock capital, has accelerated since the end of 1973. This explains the slight decline in common equity participation since 1973, as indicated by the common

equity ratios (line 31). Over the entire period, nonetheless, the Company has significantly and prudently increased its common equity participation in total capital.

Q. Would you describe the permanent financing accomplished by Rochester Gas and Electric during the 1968 to 1977 period?

A. Yes. During the ten years the Company issued approximately $374,211,000 of additional permanent capital as follows: Mortgage Bonds, $220,000,000; Preferred Stock, $45,000,000; Preference Stock, $28,000,000; and Common Stock, $81,211,000. During 1977, $25,000,000 of 11.0% Series O Preferred Stock was refunded with the proceeds of the $28,000,000, 7.6% Series A Preference Stock issue. Of the $81,211,000 of Common Stock sold, $70,195,000 was sold to the public or existing shareholders through rights offerings, $1,609,000 was sold to employees and $9,407,000 resulted from the Automatic Dividend Reinvestment Program.

Each issue of bonds and preferred stock that was offered was offered at a coupon or stated rate which exceeded the Company's embedded cost. Thus, each issue throughout the period raised Rochester's embedded cost of senior capital.

Moreover, as older low coupon bonds continue to mature and new higher rate issues continue to be required the embedded costs will likewise continue to rise. This is not unusual in our present economy. As long as the investor continues to demand higher rates on senior capital than the average historical rates paid by utility companies their embedded

costs will continue to rise.

In addition, in continuation of their dividend policy which began in 1960, Rochester Gas and Electric paid 3% stock dividends in each year of the studied period. This resulted in the capitalization as common stock of an additional $53,068,000 of earnings during the 1968 to 1977 period. Since its inception the stock dividend policy has provided $83,037,000 of additional common stock. In fact, because of it, from 1960 until 1972, the Company was able to maintain appropriate levels of common equity participation without issuing common in the market. I should note that I have studied the effects of their stock dividend policy upon the Company's shareholders in the past. I will discuss the conclusions of my most recent study at a later point in this testimony.

Q. Will you please continue with your description of Schedule 1?

A. Yes. Returning to Schedule 1, on lines 25-32, I show the relationship of each element of permanent capital to the total permanent capital. As a group, these relationships are generally referred to as Capitalization Ratios. I have excluded notes payable from total capital in making this analysis because notes represent interim financing which, in the normal course, is funded into each form of permanent capital: debt, preferred and common equity. As can be observed on line 31, the common stock equity ratio of Rochester has ranged from an inadequate low of 31.32% at December 31, 1970 to a high point of 39.80% at December 31, 1973 and averaged 35.90% for the eleven periods shown. Since December 1973, the

Company has increased its common equity investment by $82,601,000 or 41% while it has increased its senior capital participation by $151,667,000 or 50%. While Rochester's common equity is near the 40% level I recommend and much improved over the 1967-1971 level, the Company still faces a construction program estimated to exceed $430 million through 1980. The Company plans to issue additional common stock offerings during 1978 and beyond as reflected on Schedule 24, where I determined the capitalization for the rate period adopted by the Company is this proceeding. In order to do so, it is essential that the Company establish a solid record of improved and adequate earnings, restore its bond rating to a strong A, if not an AA, gradually increase its cash dividend and increase the market-to-book ratio of its common stock to the point where common stock can be safely issued without dilution of either earnings or equity, before the Company returns to the market.

Q. Will you describe the data shown on Schedule 2?

A. Yes. On Schedule 2, I show a summary income statement and certain other financial data. Total operating revenues (line 1) increased from $115 million in 1967 to more than $331 million for the year ended December 31, 1977, or by 188%. Total operating expenses (line 7) however, similarly have increased: from $94 million in 1967 to $286 million for the year ended December 31, 1977, a 205% increase. Total interest charges (line 16) have increased 262% through year-end 1977 from $6.7 million in 1967 to $24.4 million in 1977. Moreover,

preferred stock dividends increased from $2,050,000 in 1967 to $6,512,000 in 1977, a 218% increase.

Q. Please describe the data shown below the income statement on Schedule 2?

A. Earnings per share (line 22) for Rochester have varied between $1.64 in 1974 and $2.29 in 1976 and declined to $2.06 in 1977. The cash dividend payout ratio (line 24) represents clear evidence of the changes in the financial conditions of Rochester. Only in four years, all of declining earnings, has the payout ratio exceeded 55% of common earnings - well below the industry average. In 1977, the 60.3% payout was the second highest of any year studied. This obviously reflects the conservatism inherent in the same management policy which generated, internally, sufficient common equity investment through retention of earnings and stock dividends through 1971. Faced with the largest construction program in its history, the Company for the first time since 1959 issued common stock in 1972 and on several occasions since. Obviously, the construction requirements of Rochester are such that it's inadequate retained earnings and the stock dividend cannot provide all the common equity investment needed to support it. Moreover, I recognize the emphasis placed by investors on current cash yields and the necessity of utilities to increase cash dividends in response to these demands.

The rate of return earned on average common equity has been wholly inadequate since 1969 and in 1977 was only 9.97%. The return on total capital also fell to 7.9% during 1977 from 8.2% in 1976, the Company's

highest during the studied period. Both returns, however, were well below the rates of return allowed by the Commission.

The interest and fixed charge coverage ratios shown on lines 28 and 29 declined continuously through 1971, improved during 1973 and 1976 but in 1977 again fell close to the 1971 levels. Since 1970 the return on common equity has ranged within the narrow range of 11.16% to 9.82% except for 1974 when it fell to 8.31%. Thus, the maintenance of coverage, even at their inadequate levels, has resulted from increased common equity participation, not earnings. Note that there are only two means available to financial managers to maintain or to increase coverage levels in times of rising senior capital costs. The manager can attempt to increase earnings while holding the capital structure constant, for it is the common equity earnings which provide the coverage. Or, he can increase the equity participation in total capital, which, over the long run (if earnings are maintained), will have the same effect. In the case of Rochester, a ten percent return on a common equity participation of 31% (as in 1970) would result in drastically low coverage. If I assume the same embedded cost as existed in 1977 and the same relative split between debt and preferred, a 9.97% return on equity (as earned in 1977), on a common equity participation of 31% would have provided an after-tax fixed charge coverage of only 1.65 times. Thus, the difference between that 1.65 and the 1.86 times shown on line 28 of Schedule 2 for 1977 resulted solely from increased common equity participation, not increased

earnings. The difference between the 1.91 in 1970 and the 1.65 resulted from all other factors including decreased earnings. Finally, line 35 shows a key relationship in regards to the common stock investors' appraisal of the Company as an investment opportunity. As can be observed, the Market-to-Book Ratio has declined from a high of 1.59 times book value in 1968 to a low of 0.67 times book value in 1975. The improvement to 0.92 times in 1977 is not really comforting when one considers that the average utility company's ratio has improved to a value greater than 1.0 during the same period. This ratio reflects currently and directly the common stock investors' evaluation of the Company as a potential investment. Since it is the investor himself who sets the price in reaction to each company's earnings, the market-to-book ratio also represents an intercompany index of the adequacy of returns from the viewpoint of the investor.

Q. Will you continue with your preliminary study of Rochester Gas and Electric?

A. Yes. Schedule 3 is a graphical representation of the relationship between the returns experienced by Rochester itself and those experienced by investors in the common stock of Rochester. Although a common shareholder legally owns the return on common equity generated by a company, he, in fact, does not get it. The common shareholder obtains his return in the combined form of dividends paid on, and market appreciation of his common shares over specific time periods. For example, assume a common shareholder bought a share of stock for

$10.00 in 1972, received a $1.00 cash dividend, and sold the share one year later, in 1973, for $10.50. He realized a $1.50 gain on this $10.00 investment or an annual realized return of 15%. Assume, on the other hand, this same investor held the share for two years, receiving the same $1.00 cash dividend each year, but sold it for only $9.00 at the end of the second year. He would have realized a net gain of only $1.00 ($2.00 dividends less $1.00 loss in market price) on his $10.00 initial investment. In this latter instance, his annual rate of return would be only 4.89%. Limiting the analysis to increments of annual holding periods, a similar study can be performed for all possible holding periods for any number of years and any publicly traded company.

In Schedule 3, which graphically depicts such a study, the line which is entitled "Return Realized by Common Shareholders" represents the average annual rates of return realized by investors in Rochester's common stock for the ten-year periods prior to each year shown. Thus, the average return on the 55 possible investments during the ten-year period ended 1968 was 11.2%; it was 8.7% during the ten-year period ended 1969; and it was 2.8% during the ten-year period ended 1977. The actual average returns realized by Rochester investors are shown on Schedule 12, which I will discuss later. The important fact to consider at this time, is the comparison between the three lines shown on Schedule 3. Both the return experienced by Rochester on average common equity and on average total capital, though totally inadequate since 1969, have remained relatively stable and even increased in several

years. The returns actually realized by the common stock investors, however, during the same period have fallen below zero and remain below what is available to them in most savings accounts. Even more discouraging is the fact that the average dividend yield itself in each year since 1972 has exceeded these average returns realized by many of Rochester's common stock investors. In other words, the erratic and often depressed market prices over the past decade have prevented such investors from realizing a return even equal to their dividend yield.

Q. Please summarize the results of your preliminary study of Rochester.

A. My preliminary study brought out the following points which I consider significant in relation to rate of return:

1. That gross plant investment has grown by 125% in the 1967 to 1977 period, requiring additional capital investment at borrowing rates substantially higher than the historical borrowing rates.
2. That gross plant investment growth has accelerated in recent years and has been matched by accelerated growth in the capital which supports the plant investment.
3. That common equity investment has increased as a portion of total capital averaging 38.8% for the most recent five years.
4. That Rochester has been forced to issue Common Stock four times in the past six years. The last two issues were at a price below book value.
5. That fixed charges have increased and coverage of fixed charges

decreased since the end of 1967 due both to the increased cost of senior capital financings as well as the inadequate earnings on Rochester's common equity base.

6. That a major reappraisal of Rochester by common stock investors has occurred throughout the period as reflected by its Market-to-Book ratio. In 1977, Rochester's market price stood at 92% of book value - a clearly unacceptable level.

7. That the average returns on book values of Rochester have remained at inadequate levels throughout the period. An improvement experienced in 1976 has not been maintained and the Company has failed to even achieve rates of return allowed by regulation.

8. That certain investors in the common stock of Rochester lost money on their investments on average during the ten years ended 1974 and 1975. That investors have not realized a total rate of return even equal to the dividends received during the past six years.

Q. What conclusion did you reach from your preliminary study?

A. I concluded that, despite almost continuous rate case activity, the Company is presently earning a return which is simply inadequate. The events of recent years have seriously undermined the Company's investment position in the eyes of both bond and common stock investors. Further, I concluded that in the last seven years, at least, the Company has not been able to earn its allowed returns, let alone reasonable returns. I therefore proceeded with my study toward a recommendation of a fair rate of return which would enable the Company to maintain its

financial integrity, to attract debt capital on reasonable terms, to obtain additional common equity capital without dilution of its earnings or equity positions, and to properly compensate its investors for the risks assumed.

Q. What method have you used in your study of Rochester Gas and Electric?

A. As previously mentioned, the basic problem in arriving at a fair rate of return is that of determining a fair residual return to the common equity investors. To determine the fair return to the common equity investor, I employed three basic methods in my determination of fair rate of return: the Comparative Earnings or Relative Risk Study, the Market Appraisal Study, and the Discounted Cash Flow Study.

In addition, I supplemented the Comparative Earnings Study with an investigation of returns experienced by a group of highly rated industrial companies.

Q. Before you describe your studies, what exactly is a market-to-book ratio?

A. The market-to-book ratio is computed by dividing the average market price per common share by the dollar common equity investment on a per share basis. It is a key indicator of the investor's appraisal of a company's past and future operating results. If the market price falls below book value per share, that is, the market-to-book ratio falls below 1.0, it is clear indication that the investor does not consider his return to be adequate.

One important aspect of the market-to-book ratio is that it is investor determined. In the open market, there is only one means available to

an investor (in the short run) for increasing this rate of return. He must decrease the market price of the stock. For example, the one dollar return which yields a five percent rate of return on a $20 investment, will yield a ten percent return only if the investment (price) is reduced to $10. Thus, when the investor is unwilling to pay, at least, the dollar investment already made in an enterprise (the book value) he is indicating dramatically that he is not expecting the monies already invested to produce a return sufficient to attract his capital.

Q. Please explain your Comparative Earnings Study.

A. The Comparative Earnings Study looks at rate of return from the point of view of the returns earned by investors in comparable companies. This classic approach to rate of return is also called the Relative Risk Study. It recognizes that risks vary between industries in the economy and between individual companies within each industry and that such variations affect the rate of return required to attract capital. This approach also recognizes that all enterprises, regulated and nonregulated, are in competition for the investor's dollar and that investors will not continue to be attracted to an enterprise unless the return is commensurate with the risks involved.

If competition, higher costs, or other forces reduce return for an industry in the nonregulated field to an inadequate or noncompensatory level, capital will be diverted from that industry to other industries where the return is considered compensatory. Similarly, in a regulated

industry, if regulation keeps the return at a level considered noncompensatory for the risks involved, capital will no longer be attracted to that industry. It is essential that the rates for Rochester, as a regulated utility, be set to produce a rate of return in line with the returns of other companies with due regard to relative risk. Under this approach, I analyzed the capitalization and earnings of two groups of large primarily electric utilities as well as a group of 22 large, highly rated, industrial companies. Further, I analyzed the returns actually being received by the common stock investors in these companies. All of these comparison companies represent in my opinion, viable investment opportunities alternative to Rochester.

Q. Please explain the Market Appraisal Study?

A. A Market Appraisal Study is a statistical study based upon the a priori identity (equation) that the earnings on book value (rate of return on common equity) is equal to the Earnings-Price Ratio times the Market-to-Book Ratio:

(1) $$\frac{\text{Earnings}}{\text{Book Value}} = \frac{\text{Earnings}}{\text{Market Price}} \times \frac{\text{Market Price}}{\text{Book Value}}$$

This equation is proved by simply cancelling like terms. But, if the equation is solved for the Market-to-Book Ratio, we obtain:

(2) $$\frac{\text{Market Price}}{\text{Book Value}} = \frac{\frac{\text{Earnings}}{\text{Book Value}}}{\frac{\text{Earnings}}{\text{Market Price}}}$$

Thus, there is theoretically a direct mathematical relationship between what an investor will pay for a share of common stock and what the investment earns. Furthermore, there should be an inverse (opposite direction) relationship between the Market-to-Book Ratio and the Earnings-Price Ratio.

This study is characterized as statistical because a statistical study is required to prove or disprove the existence of this relationship and to test its validity. This approach recognizes that the investors in the common stock of a growing utility expect to realize a return on their investments in the form of dividends and market appreciation. It agrees with the concept that the price an investor pays represents the present value of the anticipated cash flow of dividends and price appreciation at the investor's required rate of return. Both dividends and price appreciation, however, are regarded as flowing from earnings on book value and the investor's appraisal of those earnings at any given point in time is reflected in the market price he is willing to pay.

Q. You have characterized this study as statistical. Have you performed such a statistical study?

A. Yes. I performed a statistical study which was designed to establish the existence of this relationship and to test its validity.

Q. Please explain the Discounted Cash Flow Study.

A. This approach is also founded on the principle that the investors in the common stock of a growing utility expect to realize a return on their investments in the form of cash dividends and market price appreciation.

It is based on the concept that the price an investor pays at any point in time represents the present value of the total anticipated cash flow (stream) of dividends and price appreciation discounted at the investor's required rate of return. Therefore, if an assumption is made as to the future cash flow in dividends and price appreciation, it is possible, on the basis of the market price paid, to determine the investor's required rate of return. If it is assumed that there will be a constant dividend growth rate and that the price-earnings multiple remains unchanged, the return to (required by) the investor will be represented by the sum of the current yield and the growth rate. Under this approach, the current yield is usually adjusted to reflect selling costs and pressure involved in the marketing of common stock. The growth rate of dividends per share assumed is often (based) on the actual growth rate realized by the company in the past over an extended period of years. While it is the growth rate in dividends per share that is required in the formula, the growth rate to be applied may be based on past earnings per share as representing the source of dividends, or on past book value per share as representing the source of earnings. In my study, I determined the growth rates for Rochester and for each of the comparison utilities in earnings per share, dividends per share, and book value per share for several periods during the twelve-year period from 1966 to 1977. Since there is no guarantee that historical growth trends will continue, or the historical growth trends necessarily reflect future expectation, I checked and

adjusted each rate for each company by examining a number of factors which impact upon growth trends such as construction programs, both past and future, and financings planned and accomplished.

Q. For comparison purposes, have you selected a group of utility companies which represent alternative investment opportunities of corresponding risks?

A. Yes, Rochester Gas and Electric is a combination (primarily electric) utility company operating in the city of Rochester and eight western counties of New York State with annual revenues in 1977 of $304.7 million. It is a publicly owned company with its common stock listed on the New York Stock Exchange. My selection of 15 comparison companies is shown on Schedule 4. It includes companies with annual operating revenues in excess of $100 million that I consider comparable in risk to Rochester Gas and Electric Corporation. I generally refer to the New York State Companies as a group as the "New York State Companies" and the five most similar as to growth in revenues, as to common equity component of return and as to growth rate in earnings per share as the "Rochester Type Companies." I refer to the entire group combined as the "Comparison Companies."

Q. Have you included in your Exhibit a study of the capital structure of the comparison utility companies?

A. Yes. Schedule 4 shows the capitalization ratios of the group of comparison companies and Rochester Gas and Electric for the 1967-1977 period.

Q. In calculating the ratios shown on Schedule 4 did you include bank loans as part of the total capital?

A. No, bank loans are not included in developing the capitalization ratios

since they represent interim financing and are typically converted into all three classes of permanent capital (debt, preferred stock and common equity) over a period of time.

Q. Please discuss the capitalization ratios shown on the Schedule.

A. As shown on the schedule the comparison group companies as a whole have followed moderately conservative financing policies throughout the 1967-1977 period, with the Rochester - Type companies being the most and the New York companies the least conservative, in the sense of the companies with a higher equity ratio being the more conservative. Yet all, have shown significant changes. For the eleven-year period, the group of fifteen utilities averaged 53.2% long-term debt, 12.9% preferred stock equity, and 33.9% common stock equity. For the same period, the group of Rochester - Type utilities averaged 52.7% debt, 12.0% preferred and 35.3% common equity. Thus, the latter group used slightly less preferred and debt, and therefore on average was more conservative in its capital structure. The New York companies averaged 53.4% debt, 13.4% preferred, and 33.2% common equity. This latter structure verges on the unacceptable in today's money market. Two significant trends, however, did appear. All three groups have increased the preferred equity components of total capital over the eleven years. This stems from the utilities' inability during the period to maintain adequate interest coverage levels in the face of tremendous increases in embedded debt costs. As preferred dividends are included in total income but not counted as interest, the issuing

of preferred stock permits a level of senior capital leverage not otherwise attainable under the existing constraints on earnings. More important, comparing the first three years with the last three years, the group of fifteen utilities on average maintained its common equity ratio. Conversely, the group of Rochester - Type companies reduced those ratios from an average of 36.7% for the first three years to an average of 35.1% during the last three. The New York companies, on the other hand, increased from 32.5% during 1967-1969 to 34.6% during 1975-1977. During the period in question, utility companies were required to raise staggering amounts of new capital from investors demanding even higher returns to offset the effects of inflation. Unable to get from their regulatory commissions the rate increases required to produce the earnings demanded by common equity investors, many utility companies chose to decrease their common equity capitalizations and, it follows, to increase their leverage. In making that choice, these utilities accepted a higher financial risk in order to continue construction programs to meet the needs of their service territories.

Q. How do the capitalization ratios which you have just given compare with those of Rochester?

A. As can be seen on Page 1 of Schedule 4, the long-term debt ratios of Rochester have been consistently below each group of comparison utilities and have averaged 50.2% during the eleven years shown. On the other hand, the Company has historically utilized more preferred

stock financing than have the comparison companies but not enough for its senior capital ratio (debt plus preferred) to have averaged above the comparison companies. For the entire period, the senior capital ratio for Rochester averaged 64.1%. Conversely, the eleven-year average common equity ratio for Rochester at 35.9% has been above the average for the three groups of comparison utilities. The thinnest common equity ratio for Rochester occurred in 1970 and the thickest in 1973. During the final six years of the study, Rochester has averaged 38.3% common equity, significantly higher than the average of all three comparison groups. As previously noted, at December 31, 1977, the Company's common equity ratio was 38.36%. In my opinion, this broadening of the Company's common equity participation has made an important contribution to its financial integrity as well as forming the base upon which to maintain its investors' confidence during the immediate future.

Q. What did you conclude from this phase of the comparative earnings study?

A. I concluded that the capitalization ratios of the comparison companies are appropriate to use as a guide in measuring the cost of common equity capital for Rochester if due regard is given to Rochester's thicker common equity participation. This means that throughout the remainder of my study due allowance was made for the relative value of the thicker common equity base of Rochester Gas and Electric.

Q. Will you continue with the Comparative Earnings Study?

A. Yes. On Schedule 5, I show the returns earned on average common equity for the comparison utility companies and for Rochester. Observe on line 16 that, on average, the returns for comparison utilities have ranged between a high of 13.3% in 1967 and a low of 10.6% in 1974 and have averaged 11.9% for the 1967 to 1977 period. For the Rochester - Type utilities again the high (12.3%) occurred in 1967 but the low (9.1%) occurred in 1975. For the 1967 - 1977 period, the Rochester - Type companies averaged 11.2%, somewhat lower than the total group. For the New York companies the high (12.7%) occurred in 1967 and the low (10.1%) in 1974. For the entire period the New York companies averaged 11.4%. In all cases, the returns have declined generally throughout the period.

Q. How do these returns compare with those of Rochester?

A. The return earned on average common equity by Rochester is shown on line 19. During the 1967 to 1977 period, Rochester earned an average return on its common equity of 10.7%. This is lower than all three groups of comparison utilities. Rochester ranked well below the overall average for the comparison utilities throughout the study. In seven years, the Company's returns have been below all three comparison groups. For the year ended December 1977, Rochester fell, for the fourth time, below 10% return on book value.

Q. Have you examined the common dividend payout ratios of the comparison utilities and of Rochester Gas and Electric?

A. Yes. The dividend payout ratios are shown on Schedule 6. The fifteen

utilities have paid out in cash dividends an overall average of 70.9% of their Balance Available for Common Stock over the eleven year period; the Rochester - Type companies, 68.6%; and the New York companies, 72.0%. Two groups have exceeded their average during the most recent five years; 73.7% for the comparison companies as a whole and 75.4% for the Rochester - Type companies. The New York companies have been able to reduce their payout ratios to an average of 68.5% for the most recent 3 years. Rochester, on the other hand, averaged a payout of 53.7% during the eleven years. Although this has increased to an average of 56.9% since 1973, it remains well below the averages for the comparison companies. I should caution that high payout ratios are not indicative of financial health and low ratios are not indicative of financial illness. Often, as in this case, high payouts result from low earnings, as companies attempt to maintain dollar dividend levels in the face of declining earnings. Investors look past the dividend to the Company and the earnings which support it in making their decisions. For this very reason, there exists no statistical relationship between market-to-book ratios and dividend payout ratios.

Q. Can you explain why Rochester Gas and Electric's payout ratio is so low in comparison to the other utilities and how this has affected their shareholders?

A. Yes. In the case of Rochester Gas and Electric, the low payout is the result of the same management policy which has issued 2% or 3% stock

dividends every year since 1960. Stone & Webster was asked in 1973 and again in 1976 by Rochester Gas and Electric to make a study of this dividend policy and to give our conclusion as to whether or not the policy has benefited its stockholders. I performed these studies for Stone & Webster, concluding that the dividend policy adopted by Rochester Gas & Electric has contributed to a more stable market price with less extreme fluctuations in the price/earnings multiple. In my opinion, therefore, the policy has been a sound one under conditions that prevailed during most of the studied period. The low cash dividend payout ratios and concomitant low dividend yields fo Rochester have been more than offset by higher than average market appreciation of its common stock. This extra growth potential of the Company's common stock must be and is recognized in the Discounted Cash Flow Study which I will discuss later.

Q. Have you studied the investor's general market appraisal of the utilities selected for study?

A. Yes, I examined the relative standing of the companies as shown by their market-to-book ratios (Schedule 7).

Q. Would you please discuss the data shown on Schedule 7?

A. Yes. Market-to-Book ratios deteriorated seriously throughout the 1967 to 1975 period, on the average, for each comparison company, and for Rochester. In 1976 and 1977 this trend has moderated but the market prices for the majority of the companies, including Rochester Gas and Electric, still remain below book value. This market price deterioration represents a long-term reappraisal of utility stocks by investors. There are many reasons for this reappraisal. Included among them are: rampant inflation caused in part by a restricted money supply coupled

with an unprecedented demand for funds, a recession, a sky-rocketing increase in the cost of money, the failure of utilities to earn an adequate rate of return; and the energy crisis, in general, and the gas and oil supply situation, in particular.

Q. How does the market-to-book ratio for Rochester compare with the ratios of the comparison companies?

A. The market-to-book ratio for Rochester is and has been at or significantly below the average for all three groups of comparison companies in almost every year studied. In 1977, the Company's market-to-book ratio was 0.92 which was equal to the average experienced by the Rochester - Type utility group, and below the averages for both the overall group and the New York State group.

Q. Has this market reappraisal of utility common stocks had any effect upon the returns realized by investors in utility companies, in general, and in Rochester in particular?

A. Yes. This is shown numerically on Schedule 8. The averages for the overall group are compared graphically to Rochester on Schedule 12. The average returns realized for by all utility common stock investors have declined generally throughout the studied period. Again, by realized return, I mean yield plus appreciation or total return. The price improvements in 1976 and 1977 for utility stocks in general have resulted in improved returns being realized by the average investor in the market but these returns remain dismally inadequate. It is demonstrated graphically on Schedule 13 that the average returns realized

by utility common stock investors until 1966 on average equalled or exceeded the return experienced by utility companies on average common equity. More recently, the average returns actually realized by common shareholders have fallen to such an extent that, on average, investors in 12 of the 15 comparison companies shown on Schedule 8, actually lost money for the period 1965 to 1975. In fact, not a single average common stock investor has earned even 5.0% on his investment in any of the companies since the ten-year period ended 1972. Observe on Schedule 8 that the Rochester investor has received higher returns than the average of the fifteen utilities in each year studied. Only the five Rochester - Type companies have on average equalled or exceeded Rochester investor's realized returns, and that occurred in only five of the eleven periods studied. Since 1974, the realized returns for Rochester have exceeded by wide margins all groups of comparison companies. Again, this has occurred despite the lower earnings, the lower cash payouts and the lower market to book ratios of Rochester Gas and Electric.

Since common stock investors in the past have rightfully demanded and received realized returns equivalent to the percent earned on book value of common equity by utilities, there is certainly no reason to think that their expectations, which ultimately represent the cost of common stock equity to the utility, have diminished in today's money market. The decade of general decline in utility market prices reflected re-evaluations by investors to bring the prices in line with the returns

they were actually realizing. It was all part of the same vicious cycle. As investors reduced the prices they were willing to pay, the returns actually realized in the form of dividends and market appreciation by investors on utility common stocks fell below the companies's earnings on book value. This disenchanted investors further and triggered still further reduction in prices. Is it any wonder that investors shunned utility common stocks as viable investment opportunities? Certainly the key problems facing utilities and regulators alike are to restore and to maintain investor confidence. And equally certain, investors' confidence will not be restored or maintained unless utilities are afforded the opportunity to earn reasonable rates of return.

Q. Earlier in your testimony you indicated that you also examined a selected group of industrial companies. Will you describe these companies?

A. Yes. Several years ago, at Stone & Webster Management Consultants, Inc., a study of nonregulated industrial companies for use in utility rate cases was initiated. This was begun due to our belief that the common stocks of such companies constituted viable alternative investment opportunities, and that public utilities must compete with such companies, as well as with other utility companies, for the investor's dollar. Nothing that has occurred since in the money market has altered that belief.

Q. Will you explain your method of selecting the industrial common stocks?

A. Yes. The initial selection was made in 1970 and was based upon the ratings of common stocks developed by Standard & Poor's. Standard & Poor's, in addition to rating bonds, has developed a rating system to show the quality of common stocks as measured by their relative stability in growth of earnings and dividends. The ratings assigned are as follows:

A+	Highest
A	High
A-	Above Average
B+	Average
B	Below Average
B-	Low
C	Lowest

The stocks accorded the top rating of A+, having a record of stability and of consistent growth in earnings and dividends, are thus frequently deemed comparable to utility stocks, most of which also have a consistent record of stability and of growth in earnings and dividends. (Standard & Poor's also rates public utility stocks using different standards, including such factors as capitalization and the regulatory environment.) Of the some 2,000 industrial stocks rated by Standard & Poor's, only 47 were rated A+ in 1970. We confined our study of industrials to the 27 of the A+ group with total capital at 1969 year end in excess of $400 million. Of these 27, 22 were rated A+ in 1960, 1965, and 1970. The common stocks of these 22 companies,

along with utility common stocks, represent investment opportunities which are characterized by stability and consistent growth in earnings and dividends. The 22 companies (the S&W Industrials) are as follows:

American Home Products
Borden
Campbell Soup
CPC International
Eastman Kodak
Exxon
GATX
General Electric
General Foods
Honeywell
International Business Machines
Kimberly-Clark
Kraftco
Lilly (Eli)
Merck & Company
Minnesota Mining & Manufacturing
Pfizer
Proctor & Gamble
Scott Paper
Shell Oil
Standard Oil of California
Texaco

Q. How does the common equity ratio of Rochester and the comparison utility companies compare with the ratios exhibited by the comparison industrial companies?

A. As shown in Schedule 9, these industrial companies have obtained only a small proportion of their capital in the form of senior capital, most of their capital being in the form of common equity. Thus, at the end of 1976, common stock equity of the group made up an average of 81.3% of the total capital. The average common equity for the eleven years, 1966 to 1976, is 83.0%. The common stocks of these industrial companies, representing 83% of total capital are, as a group, regarded in the investment community as an investment risk comparable to the comparison utilities, with common equity representing about 35% of total capital.

Q. Have you examined the returns on average common equity experienced by the comparison industrial companies?

A. Yes. This is shown on Schedule 10. The industrial companies, on the average, have earned between 14.3% in 1971 and 17.2% in 1974 and have averaged 15.5% for the eleven-year period, 1966 to 1976.

Q. How do these returns compare with the returns on the average common equity experienced by the comparison utilities?

A. On the average, the industrials have earned more than all of the comparison utility companies as well as Rochester itself, and they have earned those returns on substantially larger common equity ratios.

Q. Have you examined the average returns realized by common stock investors in the form of dividends and market price appreciation in the comparison

industrial companies?

A. Yes, on Schedule 11. As can be observed, the industrial company investor has fared better on average than the utility investor. The effect of the general market decline through 1975 was on average a reduction of the industrial returns actually realized, but nothing near the losses experienced on average by the utility common stock investor. This comparison is shown in graphical form on Schedule 12. The average common stock investor in the 22 industrial company group realized an average return of 5.2% for the 55 possible annual holding periods during the ten years ended 1976. The average investor in the fifteen utilities realized only 34/100ths of a percent profit on his average investment during the same period, and, in Rochester, he earned 1.35% on his average investment.

Q. What, in your opinion, does the Comparative Earnings Study show as to the required return on common equity capital for Rochester Gas and Electric?

A. The study indicates in my opinion that the required return on common equity is presently in the range of 13.75-14.25%. The comparison utility companies have historically earned more than Rochester on thinner common equity participation, and the effect on the real returns received by their common stock investors has been devastating. The comparison industrial companies on average have earned substantially more on substantially thicker common equity than Rochester, and their common stock investors on average have fared far better, despite a decade of

general stock market decline. Furthermore, Rochester Gas and Electric is faced with a difficult task: the restoration of its market to book ratio to a level higher than 1.0 so that the Company can successfully market the securities it will need to finance its impending construction program.

My analysis of the three groups of comparison utility companies and of Rochester showed that the rising cost of senior capital primarily among many other pressures undermined their rate of return on common equity capital throughout the studied period. This has prompted all of them to initiate and to pursue repeated applications for rate relief. Through the entire period, Rochester's earnings record has made a sorry comparison for investors in relation to the record of the comparison electric and combination utilities. But even the improvement in earnings that occurred for Rochester in the 1975 to 1976 period has been inadequate. Investors have continued to recognize the relatively poor earnings performance of Rochester, as is evidenced by the market value of its stock. Although the returns on common of the comparison companies have been depressed since the late 60's, the return earned by Rochester has been even lower. Despite rate increases, the Company has not been able in any year studied to earn its allowed rate of return. I concluded under the Comparative Earnings study that Rochester obviously required a materially higher rate of return on its common equity than it has achieved in the past. Therefore, giving due consideration to the disparity of risks and returns among the four groups of comparison

companies, the failure of the Company to earn its allowed rate of return and the need to rebuild investor confidence, the Comparative Earnings Study leads me to conclude that Rochester Gas and Electric's current requirement on common equity is a minimum of 13.75%.

Q. Will you please describe the Discounted Cash Flow analysis you performed in this case?

A. Yes. My analysis under the Discounted Cash Flow method is developed on Schedules 13 through 18 and summarized on Schedule 19. As stated previously, the discounted cash flow, or stock valuation, model is grounded upon the a priori concept that the price or value of any financial instrument (although not limited thereto) is equal to the projected stream of income to be generated by such instrument over its life discounted at the purchaser's (investor's) opportunity cost of money. In other words, the investor knows what he wants in terms of a rate of return for the use of his money. He theoretically sets the price, for example, that he will pay for a share of common stock by discounting to its present value each expected annual dividend and the selling price he expects to receive when he sells it. Thus, his discount rate, that is, the investor capitalization rate, is implicit in the price he has paid. Incidentally, this type of internal rate of return calculation is precisely the kind I performed to determine the investor's realized returns in the Comparative Earnings section of my study. If it is assumed that the common stock investor looks to the distant future at the potential dividend stream and that the

dividends continue to grow at a constant compound rate, then, the market price at any time can be described by the formula:

(Eq. 1) $$P_t = \frac{D_t}{k-g}$$

where P_t = the price at time (t)

D_t = the dividends expected to be paid at time (t)

k = the investors capitalization rate

g = the compound growth rate of dividends

If Equation 1 is solved for k, the investor's capitalization rate, then k is described by the following relationship:

(Eq. 2) $$k = \frac{D_t}{P_t} + g$$

which is, of course, the familiar form of the stock valuation model used in utility regulation, when $_t$ is set equal to zero.

The point to remember in this exercise is that the DCF method is a prospectively oriented formulistic approach to the investor's capitalization rate. It looks at the current dividend, the current market price and the expected growth rate in dividends, none of which are explicitly defined except by the investor to himself at the moment of investment. Recently, the Federal Power Commission issued a proposed ruling, Docket No. RM77-1, in which it proposed to require submission of cost of capital evidence in the form of the DCF formula. More importantly, it required such submission in a specific formulation of the methodology. The one required is based upon an inventory

forecasting model which, simply stated, weights current data with a factor which decays as it is applied to data further in the past. The details of that particular method are not important at this point as I have produced similar results using unweighted current yields. On Schedule 13, I show the estimations of the cost of common equity produced by applying this FPC procedure on a consistent basis over a long period to each of the companies contained in Moody's 24 Utilities Index. Compared to the DCF results on Schedule 13 are the actual operating results of the Moody's 24 Companies during the same period. An examination of the graph reveals several trends of note.

First, the DCF determined cost of equity during the period 1960-1967 was significantly less than both the average of the historical returns earned on common equity and the actual returns realized in the market place by investors. Further, as the returns earned on common equity and realized in the market declined, the DCF cost of common rose. These opposing trends have persisted throughout the remainder of the period. By 1973, the DCF estimate crossed both return lines and as of 1975 (the last year studied by the FPC) would set the cost rate significantly higher than that being earned on equity by the average of the Moody's 24 Utilities.

Second, the return actually realized by common shareholders has tracked very closely the Market-to-Book Ratios of the 24 Utilities and moved almost directly opposite to the DCF capitalization rate trend.

Finally, the returns realized and the market-to-book ratios have

declined generally during the period of decline in the companies' returns on equity. I will discuss this relationship further in my market appraisal study.

Q. What have you concluded from this phase of your study?

A. I have concluded that a formulistic application on a consistent basis of the DCF method does not work. The discounted cash flow method as often applied appears disarmingly simple. It is not. Neither does it satisfy the constitutional criteria of relative risk and comparability of returns nor even test financial integrity. It is a market oriented method approaching only the problem of capital attraction. It does not even directly answer the problem of translating the market determined investor capitalization rates into the cost of common equity. Yet, the only time when the two are equal is when the market price of common stock exactly equals its underlying book value per share. It does not even come close to fully explaining investor behavior. If it did, we would be able to explain 100% of the variations in historical dividend yields by looking at historical growth rates. The difficulty is that historical growth rates do not necessarily match expected growth rates. It can never be used alone, no matter how elaborate, as the sole determinate of the cost of common equity because if fails even to investigate let alone answer two of the three criteria for a fair return.

Q. Have you investigated the historical growth patterns of public utilities?

A. Yes. On Schedules 14 and 15. I present my analysis of the growth rates

in earnings, dividends, and book value per share for Moody's 24 Utilities over the past twenty years. As can be observed on Schedule 14 which shows 10-year growth rates, and again on Schedule 15, which shows 5-year growth rates, the growth rates of book value constituted the most stable estimate of growth throughout the studied period. The growth in dividends lagged behind the growth in earnings but tracked it closely. Both growth rates, earnings and dividends, attained high points in the middle sixties but have since fallen to below 3%. The growth rates in book value remained at or near 5% over the entire period. Only in the most recent years, have the book value growth rates declined in any meaningful manner. This, of course, resulted from utilities being squeezed between depressed earnings for common equity and the absolute necessity of increasing dividend payout ratios just to maintain their existing dividend levels, as well as from the forced issuance of common shares at prices below their underlying book values. Such a scenario simply cannot be attractive to investors. Note that it matters a great deal which growth rate is used to project dividends in the DCF methodology. A basic assumption of the model is that investors expect dividends will grow at a constant rate. For this to be true all three growth rates, book value, earnings and dividends must grow at the same rate. The relationships among the three growth rates are determined by the enterprise not the investor. If the company, for example, pays higher dividends without equally increased earnings to support such payment, then book value growth is

diminished. Thus, the investors growth estimate must consider all three variables. A final point revealed by these two schedules is that the five-year growth rates have shown wider variations than the ten-year growth calculations. With this in mind, I investigated the effects of period length on growth rates.

Q. Have you presented a schedule which describes your analysis of growth rate periods?

A. Yes, Schedule 16. On this schedule I present a graph of growth rates for Moody's 24 Utilities over varying periods all ending 1975. The growth rates which are plotted at 1956 are thus 20 years in length, the ones plotted at 1957 are 19 years long and the ones plotted at 1974 are one year growth rates. As is apparent, the shorter period growth rates vary all over the lot. In contrast, the longer the period the more stable the rates become and the more closely the three rates approximate each other and 5%. I have studied other ending points as well and in each case a similar pattern appears.

Q. What have you concluded from your study of growth rate estimations?

A. I have concluded that neither a single variable nor a single historical growth period can be determined which will unerringly predict the proper growth rate for any utility company. I have further concluded that the DCF method, to have any meaning, must consider a capitalization rate determined by investors themselves in the market place which reflects and therefore offsets the currently depressed earnings of public utilities. For these reasons, I determined the growth rate

estimates in my DCF study by analyzing the growth of all three variables over a number of periods adjusted for a number of specific factors which will impact upon its continuance in the future.

Q. Could you describe the discounted cash flow study you conducted in this case?

A. Yes. On Schedule 17 I list the growth rates in earnings per share, dividends per share and book value per share for each of nine periods for Rochester Gas and Electric and for comparative purposes for each of the 15 utilities which I selected in my comparative earnings study. After analyzing the individual growth rates and their pattern for each company I determined an estimate of growth in each category. In making my estimates I examined for each company current earnings, dividends and book value levels, current market-to-book ratios and trends, dividend payout ratios and yields, beta factors, investment ratings, fuel mix, regulatory climates, realized return levels - past and present, historical and projected growth in plant together with the financings which have or will support such growth, capital requirements, recent dilutions of earnings, recent population changes in service territories and finally current common equity ratios.

My final growth estimates in each category for each company are shown in the first three columns of Schedule 19.

Q. Have you presented a schedule of the current dividend yields which you employed in your study?

A. Yes, on Schedule 18. For the current yield I used the indicated dividend rate and the weighted average high and low market prices for the three months: January, February and March 1978, as shown in Standard & Poor's Stock Guides. This analysis is detailed on the schedule. Observe that the Current Dividend Yield for Rochester is 7.36% (line 19). This is the lowest of all 16 comparison companies shown. Thus, the common stock investors themselves currently demand a much lower return in the form of cash dividends from Rochester than from the average of any group of comparison companies. This is true, as it is the common stock investors themselves in the short run, who by adjusting the current market price adjust the current dividend yield from investment in a company. In other words, investors in Rochester's common stock are fully aware of the benefits which accrue to them from the Company's stock dividend policy and obviously expect much higher growth (in the form of market appreciation) from their investment than from the average utility.

Q. Will you continue with the explanation of your Discounted Cash Flow analysis?

A. The summary of the results of my discounted cash flow analysis is shown on Schedule 19. As shown on Schedule 19 (line 18), the average expected growth rate in earnings per share for the 15 comparison utilities is 4.14%. The average growth rate in dividends per share is 4.14% and, in book value per share, 4.17%. For Rochester (line 19), the expected growth rate in earnings per share is 6.00%; 7.25% in dividends per

share; and 5.50% in book value per share.

The primary reasons that I believe investors expect the growth premiums I indicate for Rochester over the growth rates for the comparison utilities are as follows:

1. That since the institution of the stock dividend policy in 1960, Rochester's investors have actually received more than 200 basis points higher market appreciation (growth) than companies in Rochester's earnings category.
2. That the stock dividend policy constitutes an automatic annual 3% ratchet upward on growth rates.
3. That both the extra market appreciation and the stock dividend shares represent capital income rather than ordinary income for the tax purposes of investors.
4. That the Company simply must increase its cash dividends growth rate in the immediate future as it did in 1977 (9.4%) to respond to the demands for current earnings by common stock investors if it intends to finance successfully its construction requirements.
5. That, assuming as a result of this rate case the Company indeed does earn its allowed rate of return, let alone its current cost of common equity, it can not fail to achieve the rates of growth I indicate on Schedule 19.

Q. Will you please continue with your description of Schedule 19?

A. Yes. As shown on Schedule 19 (column 4, lines 16 and 19), the average current yield for the 15 comparison companies is 8.98% and for Rochester

it is 7.36%.

Implicit in the Discounted Cash Flow model is that in the long run, when a company earns its indicated cost of capital, the market price per share of its common will equal the book value per share. In other words, when necessary to issue common the model assumes that no investor will pay more than the amount already invested per share. This causes a problem when the company needs to raise common equity capital in the marketplace. If the company does require the external infusion of common equity capital, it is at a disadvantage. The additional costs of financing, plus the effects of market pressure on the market price, will force the company to sell its stock below book value. Since this, in turn, causes dilution of earnings and confiscation of existing shareholder's book value, it should be avoided. For this reason, I have adjusted the current dividend yield upward slightly. The costs of financing and pressure vary considerably for different companies under different conditions. But, after performing and observing a number of such studies, I have concluded that a 10% adjustment to the ratio presently suffices as a reasonable estimate of the effect of these costs. This adjustment was made by dividing the current dividend yields in column 4 of Schedule 19 by 90.0% and produces the adjusted dividend yields shown in column five. For the 15 utilities the average adjusted yield is 9.98% and for Rochester it is 8.18%.

The last three columns of Schedule 19 shows the indicated capitalization rate of common equity based on each growth rate. Thus, on line 16

for example, the average capitalization rate for the 15 utility comparison companies, based on the earnings per share growth rate, equals 14.12%: the growth rate in earnings per share of 4.14% plus the adjusted yield of 9.98%. The capitalization rate based on dividends per share growth rate equals 14.12%: the growth rate in dividends per share of 4.14% plus the adjusted yield of 9.98%. The capitalization rate based on book value per share equals 14.15%: the growth rate in book vale per share of 4.17% plus the adjusted yield of 9.98%. The average of all three capitalization rates is 14.13%. For Rochester, the average of all three capitalization rates is 14.43%.

Q. What is your calculation as to the current cost of common equity capital for Rochester as determined by the Discounted Cash Flow approach?

A. The current average capitalization rate of Rochester investors, as determined by the DCF method, is 14.43%, the average of all three capitalization rates.

Q. Would you please describe the Market Appraisal Study?

A. Yes. Schedule 20 shows the important statistical relationship between Market-to-Book Ratios and Returns on Common Equity for 181 utility companies taken from the 189 utility companies listed on the C.A. Turner Sheet "Public Utility Common Stocks" for which I could develop 1977 data. The relationship shown on Schedule 20 is for two variables in 1977, but similar computations have been performed for 113 electric and combination utilities for 1977 (Schedule 21), and 100 utilities for

each year from 1969 to 1976 (Schedule 22). Also performed but not presented were several multiple variable analyses for 60 electric utilities for the years 1972 to 1976. These latter studies were employed as basic research tools as well as tests to verify the results of my studies.

Two important statistics revealed by the market appraisal study but not shown directly on the graph were the average market-to-book ratio and the return on common equity for the entire sample of 181 public utility companies during 1977. The average market-to-book ratio was 1.06 and the average return on common equity was 13.43%. As can be observed on Schedule 21 the line labeled R is the regression line $y = .4044 + 4.8945x$ where y (the dependent variable) is the Market-to-Book Ratio and x (the independent variable) is the Return on Common Equity. The r value is the coefficient of correlation; for 1977 data, $r = .72383$. As a coefficient of correlation near zero indicates the lack of any valid relationship, one that approaches positive or negative unity indicates a valid relationship. The t value is a measure of the conclusiveness of the evidence derived from the sample, in other words, it enables the user to test the results against a preestablished standard value. For example, in a sample of 181 items, one would expect the calculated t value to exceed a value of 3.291 less than once in 1,000 trials. In other words, we may not know precisely how significant our derived relationship is, but we do know that we would obtain these results by accident substantially

less than one-tenth of one percent of the time because the calculated t value for this data equaled 14.0355.

Simply, the graph shows that there is a direct and valid relationship in 1977 between Market-to-Book Values and Returns on Common Equity. This means that statistics demonstrate what common sense tells us: the investor looks at earnings in making his investment decisions. As earnings (the return on common equity) increase, so does the Market-to-Book Ratio, and vice versa; as the first declines so does the latter. For example, at the minimum acceptable market-to-book ratio of 1.00, the apparent required return on common equity was 12.17%. At this 12.17% return on common equity, the holder of an average utility common stock in 1977 had a 50-50 chance of selling his stock for a price at least equal to its book value. I should point out that returns on common equity for 1977 and 1976 were calculated on beginning book values and estimated earnings as complete year data were unavailable when the studies were performed. Furthermore, market prices used were year-to-date market prices. Since this calculation tends to overstate the returns at specific market-to-book ratios, it understates, that is, represents a conservative estimate of, the cost of common equity required. All other studies were based upon complete year data.

Q. Why have you characterized a Market-to-Book Ratio of 1.00 as the minimum acceptable Market-to-Book Ratio?

A. Every time a company issues its stock below book value the present shareholders must surrender without compensation a portion of their

rightful earnings. Therefore, the absolute minimum Market-to-Book Ratio is 1.00 and the absolute minimum return on common equity is one which will generate at least that minimum market-to-book ratio.

Q. What does the line titled "Market-to-Book Ratio = 1.11" represent?

A. Since the minimum acceptable market price is one which equals the company's book value per share the company is at the same disadvantage in issuing its common stock as I described during my discussion of the discounted cash flow study. Thus, to adjust for the costs of financing and for market pressure, I adjusted the minimum acceptable Market-to-Book value ratio upward by the same 10% I used to adjust the current dividend yield. This adjustment is made by dividing the Market-to-Book Ratio of 1.00 by 90.0%, and results in a minimum acceptable ratio of 1.11.

Q. Will you continue with the description of your study?

A. Yes. On the graph, I have noted eight points of some importance. In order, they represent:

Point 1. The point at which the regression line crosses the line of the Market-to-Book Value equal to 1.00. This point represents the rate of return on common stock selling in the open market at a price equal to or above its book value in 1977. Notice that a return on equity of 12.17% is indicated as being required, and yet it is still insufficient. It is insufficient because it allows nothing for the costs associated with financing and because it gives the stock equally a 50%

chance of selling below book value.

Point 2. This represents the point at which the average company will have a 50-50 chance of issuing stock at or above book value. This, then, is the indicated cost of common equity for the average utility company during 1977. Note the required return is 14.44%, still giving the company only the flip-of-a-coin chance of selling stock at or above book value.

Point 3. This represents the point at which the company will have a 75% chance of issuing stock at or above book value. The required return on common equity is 17.50%.

Point 4. This represents the point at which the company will have a 90% chance of issuing stock at or above book value. The required return on common equity is 20.28%.

Point 5. This represents the point at which the company will have a 95% chance of issuing stock at or above book value. The required returns on common equity is 21.95%.

Point 6. This represents the point at which the company will have a 5% chance of issuing stock at or above book value, and conversely, will have a 95% chance of issuing it below book value. The required return on common equity is only 6.95%. The effect on the present shareholders is devastating; 19 out of 20 times, the company's common will sell below book value.

Point 7. This represents the point at which the company will have a one-

out-of-ten chance of issuing stock at or above book value, and a nine-out-of-ten chance of issuing its stock below book value. The required return on common equity is only 8.62%. Again, the effect on shareholders is disastrous.

Point 8. This represents the point at which the company will have a 25% chance of issuing its shares at or above book value, a 75% chance of issuing below book value. The required return on common equity is 11.39%.

Q. Will you describe Schedule 21?

A. Yes. Schedule 21 shows a study identical to the 181 company market appraisal study except that all primarily gas utility companies have been removed. The first item to note is that the confidence intervals (lines AA', BB', and CC') are much closer to the trend line itself. This indicates that the remaining data points cluster more closely about the trend line. Also, the correlation coefficient is minutely higher. This indicates that the new relationship is slightly stronger than the relationship for the larger group of utilities. The t statistic is 11.3573, still extremely significant. The fact that it is lower than the t value of the 181 company study results only from our use of a smaller sample. The indicated average cost of equity capital is represented at point 2 is 13.79% for this group of 113 electric and combination companies. The data values for Rochester itself place it almost exactly on the trend line. This can only mean that investors view the Company's earnings similar in risk to the average utility despite lower dividend payout.

Q. Will you please describe Schedule 22?

A. Yes, Schedule 22 presents the results of another market appraisal study. This earlier study investigated the changing annual relationships between Market-to-Book Ratios and Returns on Common Equity over an eight-year period. As can be observed, the slope of each curve in succession decreased from 1969 through 1975. This meant that as the period progressed, the utility common stock investor demanded a greater and greater rate of return in compensation for the same investment. During 1976 the situation improved and the cost of common recovered to a point near the returns demanded in 1973. Upon comparison of Schedules 20 and 21 with Schedule 22, it becomes apparent that the returns demanded by common equity investors in 1977 also remained close to the returns demanded in 1973.

The Market Appraisal Study indicates that the 1977 cost of common equity for an average utility company in the United States was at least 14.44% and that for an average electric or combination company at least 13.79%. The study also establishes that recent costs of common equity reflect a fundamental change in investor attitudes towards public utilities and perhaps a far reaching alteration of the basic historical risk return relationships for utility companies in the financial community.

Q. What, in your opinion, does the Market Appraisal Study show as to the cost of common equity capital for Rochester Gas and Electric?

A. My study indicates that the 1977 cost of common equity for an average utility company in the United States ranged between 13.79% and 14.44%.

If the risk for an individual company can be shown to be greater than the 1977 average, then, certainly the cost for that company would exceed the indicated range.

Rochester differs from the average electric utility company in that its present common equity ratio is thicker than average and its common dividend yield is significantly lower because of a long standing policy of annually issuing stock dividends. Rochester data falls so close to the trend line that it is indistinguishable therefrom, both in risk and investment rating. Therefore, in my opinion, the Market Appraisal Study demonstrates that the Cost of Common Equity for Rochester Gas and Electric falls with the range from 13.79% to 14.44%.

Q. Can you at this point concluded as to what the current cost of common equity capital is for Rochester Gas and Electric?

A. Yes. The Comparative Earnings approach demonstrated a cost of common equity based upon historical data of at least 13.75%. The Discounted Cash Flow approach substantiated an investor expected return of 14.43% based upon projected growth rates and current market data. The statistical Market Appraisal Study indicated a rate of return on common equity within a range from 13.79% to 14.44%. Thus, the three studies separately all produced estimated costs of common equity which fell within the range of from 13.75% to 14.50%. Therefore, it is my opinion that a return on common equity within a range of from 13.75% to 14.5% is required at this time.

Q. Have you calculated the current embedded cost of senior capital of

Rochester Gas and Electric?

A. Yes, it is shown on Schedule 23. I believe the schedule to be self explanatory as it sets forth the particulars with respect to each issue outstanding at December 31, 1977 as well as the pro forma issuances of long-term debt and preferred stock scheduled during 1978 and 1979. The weighted average cost of total long-term debt is shown (line 23) to be 7.65%. Further, the weighted average cost of Preferred Stock (including the 7.60% Series A Preference Stock) is shown (line 35) to be 7.12%.

Q. Have you summarized the current cost of capital of Rochester Gas and Electric?

A. Yes, a summary of the cost of capital for the company is shown on Schedule 24.

Q. Will you please describe Schedule 24?

A. Yes. The schedule is divided into two sections. The top portion details the derivation of the pro forma capitalization at December 31, 1979 for Rochester (line 1 through 6).

Beginning on line 7, I have shown the calculation of the indicated cost of capital using the common equity cost rates of 13.75% in the first section, and 14.5% in the second section. The effective cost of long-term debt at December 31, 1979 was shown to be 7.65%. By applying this cost to 47.34% of total capital which is comprised of long-term debt (line 11), a cost of capital component (a required return) of 3.62% is derived. Similarly, by applying the effective cost of the preferred stock

of 7.12% to its appropriate segment of total capitalization, the cost of capital component of 0.89% is calculated on line 12. Next, on line 14, at a cost rate for the common equity capital of 13.75%, a cost component of 5.53% is derived; and at a cost rate for common equity of 14.5%, a cost component of 5.83% is derived.

The cost components are summed on line 15. This represents the overall cost of capital. Thus, at a 13.75% Cost of Common Equity, the overall return required is 10.04%, and at a 14.5% Cost of Common Equity, the overall return required is 10.34%. I, therefore, concluded that the overall cost of capital is within the indicated range of 10.04 to 10.34%.

Q. Mr Monteau, could you summarize the results of your study?

A. In addition to analyzing the money markets generally, I studied the financial and earnings record of Rochester and three groups of comparable utility companies as well as a group of 22 highly rated industrial companies. I performed a study of the market determined empirical relationship between Market Prices and Returns on Common Equity and made a Discounted Cash Flow analysis to assist in the determination of the cost of capital and fair rate of return. Under present conditions of tight money and continuing inflation, I have concluded that a fair rate of return for Rochester is currently within a range of from 10.04% to 10.34%.

Q. Does this conclude your testimony?

A. Yes.

DIRECT TESTIMONY

OF

H. RUSSELL FRASER

FOR

ROCHESTER GAS AND ELECTRIC COMPANY

MAY 1978

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is H. Russell Fraser and my address is 6016 Cricket Road, Flourtown, Pennsylvania 19031.

Q. BY WHOM ARE YOU CURRENTLY EMPLOYED?

A. I am employed by Paine, Webber, Jackson & Curtis Incorporated, 140 Broadway, New York, New York 10005.

Q. WHAT IS THE NATURE OF YOUR DUTIES AND RESPONSIBILITIES AT PAINE, WEBBER, JACKSON & CURTIS?

A. I am a Senior Vice President and Director of Fixed Income Research for the Fixed Income Division. The primary responsibility of the Fixed Income Research Department, which I head, is to keep investors properly advised as to the trends in credit worthiness of the major issuers of senior securities in our capital markets. Among other things, we publish periodic studies of the quality of the bonds of issuers in corporate, municipal and international bond markets. In the course of my work, I am in frequent contact with the principal agencies engaged in rating the quality of corporate and governmental securities, i.e., Moody's and Standard & Poor's.

Q. PLEASE DESCRIBE YOUR FORMAL EDUCATION AND YOUR BUSINESS EXPERIENCE.

A. I graduated from the University of Arizona in 1963 with a B.S. in Finance and Economics. From the fall

of 1963 to January 1967, I was employed by Philadelphia Life Insurance Company as an Investment Analyst. In January 1967, I was employed by Standard & Poor's Corporation as an Analyst in their Bond Department. In June 1969, I became Manager of S&P's Corporate Bond Department. In April 1971, I became Vice President of the Corporate Finance Department of Standard & Poor's Corporation. On September 22, 1975, I joined Paine, Webber, Jackson & Curtis,Inc. I was also the first President of the Fixed Income Analysts Society in New York from September 1976 to August 1977.

Q. PLEASE DESCRIBE MORE FULLY YOUR DUTIES AND RESPONSIBILITIES WHILE YOU WERE AT STANDARD & POORS?

A As Vice President of the Corporate Finance Department, I was responsible for all corporate bond, preferred stock, and commercial paper ratings. I was in charge of four publications: first, The Fixed Income Investor, which is a weekly publication setting forth evaluations of new issues of international, municipal, and corporate bonds, preferred stock, and commercial paper; second, Commercial Paper Reports, which presents two and three page reports evaluating the credit standings of leading issuers in the commercial paper market; third, Opportunities in Convertible Bonds, which is a weekly publication presenting coverage of new offerings in this area; and fourth, Convertible Bond

Reports, which was an alphabetically arranged guide to information about all convertibles in which there was active interest.

Q. IN THE COURSE OF YOUR EMPLOYMENT WITH STANDARD & POOR'S, WERE YOU INVOLVED IN THE CREDIT RATING OF PUBLIC UTILITIES INCLUDING ROCHESTER GAS AND ELECTRIC COMPANY (RG&E)?

A. Yes. I was involved in the credit rating of public utilities, including RG&E, for just over eight years.

Q. IN HOW MANY SECURITY RATINGS DID YOU PARTICIPATE DURING YOUR TENURE WITH STANDARD & POOR'S?

A. From January 1968 to about the middle of 1973, I participated in every corporate bond, preferred stock, and commercial paper rating that was issued by Standard & Poor's Corporation. From the middle of 1973 to September of 1975, I personally participated in about 50% of the ratings issued by Standard & Poor's on corporate bonds, preferred stock, and commercial paper. In an average year, we would rate approximately 500 different issuers of securities, in addition to reviewing the ratings outstanding on more than 1,900 companies.

Q. HAVE YOU EVER PREVIOUSLY TESTIFIED IN ANY JURISDICTION BEFORE A COMMISSION, COURT OR LEGISLATIVE COMMITTEE?

A. During my nearly nine years of employment with

Standard & Poor's, company policy was that its officers and employees not testify at regulatory commission hearings unless subpoenaed. The reason for this policy is to maintain S&P's neutrality as an independent rating agency. However, since my department was responsible each year for rating the credit worthiness of anywhere from $8 - $12 billion worth of utility securities and a total of anywhere from $15 - $30 billion of corporate securities, including utility, industrial, and financial securities, we consulted with many regulatory commissions on an informal basis.

Also while at Standard & Poor's, I testified before a number of legislative committees with respect to the problems of the utility industry. At the state level, these committees included the California Senate Committee on Energy, the Ohio Select Committee on Utilities and Energy, a committee of the Illinois Legislature, and several others. During 1974, when the utility industry was in a period of crisis, I worked very closely with the United States Department of the Treasury and Secretary Simon's staff in presenting to the Department of Treasury the financial problems faced by the utility industry. In relation to non-utility matters, I have worked closely with the Securities and Exchange Commission, the Controller of the Currency, the Federal Deposit Insurance Corporation, and the

Federal Reserve. I have testified twice before the U. S. Senate Banking Committee, and once before the U. S. House Ways and Means Committee's Sub-Committee on Health.

Since commencing my employment with Paine, Webber, Jackson & Curtis, I have testified before the California Public Utilities Commission, the Connecticut Public Utility Control Authority, the Public Service Commission of Delaware, the Florida Public Service Commission, the Illinois Commerce Commission, the Indiana Pubic Service Commission, the Michigan Public Service Commission, the Minnesota Public Utility Commission, the New Mexico Public Utility Commission, the Pennsylvania Public Utilities Commission, the South Dakota Public Utilities Commission, the Public Utility Commission of Texas, the West Virginia Public Service Commission, the Florida State House of Representatives' Committee on Growth and Energy, and the Canadian National Energy Board.

Q. WOULD YOU PLEASE DESCRIBE THE ACTIVITIES OF PAINE, WEBBER, JACKSON & CURTIS?

A Paine, Webber, Jackson & Curtis is one of the five largest securities firms serving individual investors, ranks as one of the largest firms that serving institutional investors, and acts as an investment banker to corporations.

Paine Webber's network of 130 branch offices covers

all regions of the United States and includes five overseas offices. The firm employs approximately 2,200 registered representatives, including more than 130 full time institutional salesmen, and serves approximately 650,000 retail and institutional clients.

In its role as an investment banker, the firm has been particularly active in the telephone and electric utility industries for many years. We act as the primary investment banker for General Telephone and Electronics Corporation and Central Telephone and Utilities Corporation. In recent years, we have frequently served as a co-manager of Bell System debt issues.

We are one of Tampa Electric Company's primary investment bankers as we are for many other investor owned electric utilities. In addition to our role as an underwriter and a marketer of new issues, we actively trade debt and preferred issues of telephone companies, electric utilities, and other corporations in the over-the-counter market and on the stock exchange.

Paine, Webber maintains two research departments, one for equities and one for fixed income securities, both of which are among the largest of their type in the securities industry. Both of these departments are active in evaluating securities of RG&E, and in offering advice to clients with regard

to these securities.

Q. HAVE YOU WRITTEN ARTICLES OR DELIVERED SPEECHES RELATED TO YOUR WORK?

A. I have spoken at the seminars, annual conventions, and financial conventions of the Edison Electric Institute, the American Gas Association, the Independent Telephone Association, the National Association of Regulatory Utility Commissioners, the National Consumer Finance Association, the National Water Company Conference, the Pacific Coast Electrical Association, and various other associations. I have also spoken at seminars and conferences in London, England; Montreal, Canada; Tokyo, Japan; Hamilton, Bermuda; and San Juan, Puerto Rico. I have authored articles which have appeared in Public Utilities Fortnightly, and other trade publications, including one published by the American Gas Association.

Q. DOES PAINE, WEBBER, JACKSON & CURTIS HAVE ANY DIRECT RELATIONSHIP WITH RG&E?

A. No. The only relationship my firm has had with RG&E has been as a participant in the underwriting of its securities for offering to the public, and as an owner of its securities.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. RG&E has asked me to explain the nature and use of security ratings and to state my views with respect

to: RG&E's financial position, the appropriateness of the company's capital structure and fixed charge coverage, the importance to RG&E and its customers of maintaining at least an "A/A" bond rating, and the conditions required for RG&E to retain its present "A/A" bond rating. In addition, I will express my opinion concerning the appropriateness of the company's requested return on common equity and the effect that the requested rate increase will have on the company's overall financial health.

Q. WHAT IS THE PURPOSE OF BOND RATINGS?

A. Bond ratings are intended to be an indication of the relative degree of probability of payment of interest and principal on time. Please note an important requisite in the definition is the phrase "on time". The quality of a company's bond rating depends heavily on its ability to perform its obligations in full when required. Under the quality rating system used by Standard & Poor's, interest-paying bonds are given one of eight ratings, ranging from "AAA" through "CCC". Bonds on which interest is not being paid are given one of four ratings, ranging from "C" through "D". Ratings by Moody's Investors Service, Inc. are very similar to those given by Standard & Poor's. Exhibit HRF No. 1 which is entitled "Key to Moody's Bond Ratings," describes in a nutshell the characteristics of bonds with various ratings from Moody's.

Again, the guidelines used by Standard & Poor's are quite similar.

Q. WHAT UTILIZATION IS MADE OF SUCH RATINGS BY THE FINANCIAL COMMUNITY?

A. Ratings are a designation which immediately relates to the investor and to other members of the financial community the quality of the debt instrument being bought or sold and, therefore, the interest rate on the instrument.

Q. DO RATINGS SERVE AS THE LEGAL BASIS FOR INVESTMENTS BY INSTITUTIONS IN SOME STATES?

A. Yes, most fiduciary type institutions have specific legal requirements on the type of investments they may hold. Generally commmercial banks, when buying securities for their trust accounts, are not allowed to buy anything rated lower than "BBB". In addition, most institutions have their own guidelines for the quality of securities they are willing to own. Investors today are much more sophisticated than in the past. In today's credit conscious world, individuals and professionals are more and more raising the minimum levels of risk they are willing to accept. Hence, the lower the quality of the security, the smaller the potential market for that particular security. This becomes an especially acute problem for issuers needing substantial amounts of capital. The lower the quality, the smaller the potential market, and thus, the

higher the price that particular issuer (borrower) must pay to attract the quantity of money required. As the bond rating declines, the number of potential investors becomes limited. In adverse markets, a company with a low rating may be unable to raise money on any reasonable basis.

Q. ARE RATINGS MORE IMPORTANT TO UTILITIES THAN MOST NONREGULATED COMPANIES?

A. Yes, ratings are extremely important to companies who are capital intensive and require frequent visits to the capital markets. In addition, public utilities face an even larger problem. They have a responsibility to expand to meet the growing needs of the public whether or not it is in the company's best interests. On many occasions during the last decade, public utilties have been forced to go to the market to raise large sums of capital when it may have been advantageous to stop construction and avoid borrowing. They were not free to follow options available to nonutility companies. These situations tend to occur just at a time when our capital markets may be in complete disarray. Furthermore, these periods not only seem to come more frequently but also are lasting longer than they did in previous years.

Q. WHAT IS THE VALUE TO A UTILITY IN MAINTAINING A HIGH SECURITY RATING?

A. First of all, it affords the utility the opportunity of obtaining a lower cost of money. The financing cost differential between strong and weak credits has become greater in recent years than in the past and it appears that this situation will be with us for the foreseeable future.

Secondly, a high rating affords the utility greater availability of capital which in turn increases the company's financial flexibility. There is a great deal of competition for investment capital. The utilities in New York, for instance, must compete with the utilities in every other state and with any other potential users of the capital markets. This includes the Federal government, one of the largest competitors for capital in recent years. The stronger a company's credit, the more people are willing to purchase and own that company's securities. It is as simple as that. The companies with the strongest credit standings have the most channels of capital open to them when they need it. A third advantage of a high credit rating is the superior position of the company in negotiating the terms of an offering. The stronger the credit, the less onerous are the terms lenders usually require attached to such financings. I have seen low-rated companies forced into accepting short bond maturity periods because investors were unwilling to risk long-term funds on their securities. I have also

witnessed low-rated companies able to market preferred stock only with the most stringent sinking fund provisions.

Q. ARE THERE ANY REASONS WHY RG&E SHOULD STRIVE TO MAINTAIN AT LEAST AN "A/A" BOND RATING?

A. First of all, RG&E will face a difficult problem in the total volume of money it will have to raise externally to provide the quantity and the quality of services required by its customers. Secondly, RG&E also faces a complicated problem known as "market saturation." Most major bond portfolios in the country contain some of RG&E's securities. These investors have both legal and self-imposed requirements to diversify and maintain the quality of their portfolios. Any further lowering of the company's credit rating will lessen the likelihood that these institutions will purchase additional RG&E securities. Also, as I mentioned previously, there is a trend of increasing credit consciousness by all investors. Only a few years ago "BB" and "BBB" rated companies could easily borrow large amounts of money for long periods of time with relative ease and with very little differential in cost. More and more, these issuers, however, are being excluded from the marketplace. Today, to have adequate capital-attracting capability and the minimum financial flexibility which I consider necessary, a company must have a strong credit rating.

Q. WHAT FACTORS ARE TAKEN INTO CONSIDERATION BY AN AGENCY WHEN RATING A UTILITY?

A. Rating securities will never be a precise science. There are simply too many variables to be considered. The rating agencies are called upon to judge a tremendous variety and combination of businesses. If they were to attempt to derive a formula applicable to just one business, we know from experience that exceptions would destroy the rule.

There are, however, five important factors considered in establishing ratings. It is important to recognize which ones have an impact on regulation and which ones regulation impacts. These five important factors are:

1. Issuing documents
2. Earnings
3. Asset protection
4. Management
5. Financial resources

Q. PLEASE DESCRIBE THE IMPORTANCE OF ISSUING DOCUMENTS.

A. Of the various documents which accompany the issuance of bonds, the trust indenture is usually the basic legal document that spells out the contract between the issuer and the bondholder. As a contract, it is examined as to both the nature of the covenants agreed to and the remedies provided for lack of compliance. The standard provisions

looked for include provisions for and the protection against issuing additional bonds with the same security, the property liens which may be provided, and the flow of funds. Of particular interest, so far as liquidity is concerned, are the requirements imposed upon the issuer to deposit funds in the interest payment account and in the sinking fund or property fund accounts, and the penalties imposed if such payments are not met. Establishing the machinery which will become operative in the event of a default is the purpose of the indenture. In determining a rating, the indenture is far less important than the other four factors being considered . This is not to say, however, that the indenture does not have a great bearing on bond ratings.

Q. PLEASE DISCUSS THE SECOND IMPORTANT FACTOR, WHICH IS EARNINGS.

A. The past earnings record and foreseeable potential is, in most cases, the single most important factor in credit rating. High levels of earnings frequently preclude liquidity problems, because short-term cash needs can be more readily accommodated. Remember that a bond rating attempts to quantify the liklihood of timely payment of principal and interest. Strong cash flows generated by high and continuing earnings, combined with an adequate depreciation policy and tax normalization, contri-

bute a healthy positive factor to the determination of a bond rating.

In order to project earnings power, a rating agency examines all the factors that can affect the company's ability to generate earnings. These factors include the industry the company is in and its financial position. The cost of the product, research and development, its pricing policies, its tax practices and any of the myriad of influences on profits. Two very important factors considered for a utility company such as RG&E are the level of AFUDC included in earnings and the extent to which it normalizes tax deferrals.

It is obvious that for utilities regulation has a very important impact on this fundamental criterion of credit worthiness. One fact that is rarely brought out, however, is the importance of consistency and certainty of earnings. This is true not only for the individual company involved. It can impact the credit rating, investors' opinion and, in turn, the cost of capital for all of the utilities regulated by a particular commission or board. A negative impression of the regulatory climate, as it pertains to one company, as perceived by analysts and investors, whether correct or not, can have an adverse impact on the cost of capital of all of the utilties operating within the jurisdiction of that particular regulatory body. For

example, investors opinion of the Alabama regulatory environement is such that despite a recent 56% improvement in coverages between 1976 and 1977 (coverages rose from 1.25x to 1.95x) Alabama Power Co. in its March 1978 bond financing was required to pay 9.50% nearly 20-30 basis points more than the typical yield on "Baa/BBB" electric utility bonds during this period. Investors' perception of regulation and the regulatory body's willingness to grant timely and adequate rate relief have become extremely important in a company's earnings outlook.

Q. MR. FRASER, HOW IS ASSET PROTECTION IMPORTANT IN DETERMINING CREDIT RATINGS?

A. Asset protection generally is more important as a long-term consideration. The analysis is primarily statistical and, hence, highly objective. Of primary interest are: 1) the ratio of the company's current and proposed debt to net plant assets; 2) the ratio of working capital to debt; 3) the ratio of debt to total capitalization; and 4) the ratio of total net tangible assets to debt. The relative importance of these major ratios varies depending on the type of industry involved. They are relatively unimportant, for example, in a publishing company, but are quite important in a heavy industrial firm and, of course, a utility.

Q. HOW DOES MANAGEMENT AFFECT A COMPANY'S BOND RATING?

A. Businesses are run by people and certainly the

management of a company can have a great influence on its debt rating. Management's demonstrated ability, perception, planning, and the execution of its plans are all parts of the evaluation. Of particular relevance to the company's ability to maintain liquidity is management's awareness of its responsibility to meet its obligations on time. Equally important is management's ability to conduct the company's business so as to always be in a position of having the necessary reserves to call upon.

Evaluating management is one of the most difficult chores a rating agency faces, but it is also one of the most important facets of a successful operation.

Q. PLEASE DISCUSS THE FIFTH FACTOR, WHICH IS FINANCIAL RESOURCES.

A. Financial resources are, of course, the largest single determinant of liquidity and have a direct impact on long-term debt ratings. In looking at the financial resources of a company, one is concerned not only with a company's cash position but also its ability to obtain cash as well as its cash requirements. When a company has several options to obtain cash at its disposal, it is less likely to be forced into accepting unreasonable credit terms or paying unusually high costs of money.

Q. WOULD YOU RELATE THESE FIVE FACTORS SPECIFICALLY TO THE ELECTRIC UTILITY INDUSTRY?

A. For the sake of simplicity, I will use a wagon wheel for illustration. Like the hub of a wheel, the heart or focal point of any company is its management. It is important to realize that with the billions of dollars the electric utility industry has invested in plant, it is still a business conducted by people and without good management, this industry, or any given company, has no future. The spokes of the wheel include several factors:

(1) The type of company, its operations and quality of service. The mix of the company business between residential, commercial, and industrial classes is important. Also considered is the growth in demand for electricity by customers. Customer relations and public image are considerations. Any information indicating the quality of service is important - customer complaints, reliability of system, etc. Efficiency of operations as measued by statistical indices are also important. These indices include operating ratios; employees per 1,000 customers, etc. The company's maintenance standards are important considerations. Such questions as whether management is postponing maintenance to sustain profits must be resolved. Accounting practices are also considered - flow-through versus normalization, depreciation practices, etc. Finally, the adequacy of the company's facilities and any competitive features of its

business are examined.

(2) A second spoke of the wheel is the company's territory and its economy. What are the advantages and disadvantages of its geographic location? Customer density is a consideration and whether customers are largely rural or urban. Other factors include economic and population growth rates, political atmosphere, and economic mix.

(3) A third spoke is the company's construction program. Considerations here are the company's accuracy in forecasting expenditures, the quality of planning, and the timing and position of the program. Environmental considerations and planning by the company are very important too.

(4) Another spoke of the wheel is the company's capitalization and financing requirements. A company with a conservative capital structure, not heavily weighted with debt, is a plus. Future capital needs are considered along with a projection of the percentage of these needs that can be generated internally. Any contingent liabilities are considered, along with the extent of dependence on short-term debt.

(5) The fifth spoke would be a detailed analysis of the utility's fuel program. Is sufficient fuel available? How much will it cost?

(6) One of the more important areas is regulation. Is there an adequate degree of communi-

cation between companies, regulators and consumers? Do regulators understand the company's needs? Provisions in the regulatory process which reduce regulatory lag are favorable.

(7) Another spoke of the wheel is the indenture itself. As I have already discussed, the indenture contains the terms whereby investors are protected from default.

Of course there are other spokes, but these are the areas of primary concern.

The rim of the wheel represents the company's financial results. Therefore, a statistical approach rounds out the analysis. The quantity of statistical protection required, and by statistical protection we are referring to fixed charge coverages, debt ratio, internal cash generation as a percent of construction expenditures, etc., however, for each company to retain any given rating will vary depending on the strengths and/or weaknesses of the numerous spokes.

When looking at statistical protection, the rating agencies concern themselves with two types: earnings protection, which is basically fixed charge coverage, and asset protection. Naturally, it is appropriate to have a balance between the two. Strong asset protection allows analysts time to look beyond a temporary decline in earnings to when a company might recover. Which area of protection is more

important? A low debt ratio is good, but where assets are earning little or nothing, how secure is debt service? Therefore, earnings must be the primary key.

Q. WHY IS QUALITY OF SERVICE AT REASONABLE COST PART OF YOUR WAGON WHEEL ANALYSIS?

A. It is my opinion that a utility that provides good service at a reasonable cost to the consumer is more likely to obtain reasonable and adequate rate relief when required.

Q. WHAT IS THE WEIGHT GIVEN TO EARNINGS IN ASSESSING THE QUALITY OF A UTILITY SECURITY?

A. In my opinion, a utility's earnings record (not only growth but consistency and quality) is the most important measurement of the quality of a utility's securities, whether it be bonds, preferred stock or common stock. I emphasize "record" - not only historical record, but also the probable prospective record. It is not the spot earnings, even if adequate, that count in assessing the quality of a utility's securities. It must be demonstrated that a company can maintain or improve such earnings over a reasonable future period.

Q. WOULD YOU COMMENT ON THE SIGNIFICANCE ASSIGNED FIXED CHARGE COVERAGE BY A RATING AGENCY?

A. As I have stated, one of the most important factors in rating utility securities is the company's earnings record. Even more important, in my view,

is what could be described as earnings protection. The most frequently used measurement of earnings protection is fixed charge coverage or times interest earned. While other factors are also important, no other number or ratio has more impact on a utility's credit rating, or its ability to attract capital in the marketplace, than its record and future potential of fixed charge coverage.

Q. IS IT CONCEIVABLE RG&E COULD ISSUE DEBT DESPITE A DROP IN COVERAGES BELOW THE 2.00 MINIMUUM COVERAGES AND IF SO HOW WOULD THIS EFFECT RG&E?

A. It is possible for RG&E to issue debt with coverages in the 1.7x range. However, it should be made clear that with coverage protection at such low levels the cost of debt financing will be very high as investor perception of credit protection will be at a low level.

Q. HOW DO RATING AGENCIES AND OTHER CREDIT ANALYSTS VIEW INCLUSION OF CONSTRUCTION WORK IN PROGRESS IN THE RATE BASE?

A. Rating agencies and credit analysts consider the inclusion of construction work in progress in the rate base as a favorable indication that the regulators understand the problem of cash flow and how a difficiency in cash flow eats away at the company's financial strength, flexibility and its viability over the longer term. While the capitalization of interest on funds used during construction is a

perfectly legitimate accounting principle, it creates non-cash earnings which are largely ignored in terms of fixed charge coverage. In measuring financial safety for the prospective purchaser, we continue to emphasize earnings rather than asset protection. In fact, there are two ratios that both analysts and rating agencies and other sectors use to measure the adequacy of cash flow and cash earnings. These are the calculations of fixed charge coverage excluding AFUDC and the calculation of internally retained and generated funds as a percentage of capital expenditures.

Q. WOULD YOU DESCRIBE EXHIBITS HRF NO. 3A AND 3B?

A. This exhibit lists four key statistical measurements of credit worthiness. These ratios are considered prime tools utilized by credit analysts for measuring debt protection risks. The exhibit gives the year end rate of return on common equity, the percent of capital expenditures financed externally, the embedded cost of debt, and fixed charge coverage for each of the years.

Q. HOW DO THOSE FACTORS YOU JUST OUTLINED RELATE TO THE DOWNGRADINGS OF ELECTRIC UTILITY COMPANIES IN RECENT YEARS?

A. The downgrading of electric utility companies and many other types of utility companies has occurred as a result of the industry being faced with a host of adverse fundamental factors. These included

rapidly expanding construction expenditures due to rising power requirements of their customers, the historically high level of inflation and required environmental control equipment; increasing external financing requirements; the rising level of interest expense and the increasing embedded cost of debt; skyrocketing operating and maintenance costs; plus the inability to offset these rising expenses with adequate rate relief in a timely manner.

These factors adversely affected this industry to a point where the average rate of return on the capital employed fell below any reasonable level, and many companies were pushed into nonviable financial positions which seriously handicapped their ability to attract permanent capital. The financial results of the utility industry on a statistical basis appear on Exhibit HRF No. 3B. These are composite figures for the industry. As in the case of all averages, some companies earn below and some companies earn substantially above the particular figure given, but I believe this composite clearly shows the basic problem from 1970-1976.

Q. WOULD YOU DESCRIBE EXHIBIT HRF NO. 2?

A. Exhibit No. 2 lists a group of high grade electric utilities which have experienced consecutive downgradings over a relatively short period of time. In this study, we recorded the internal cash generation

as a percent of the total construction program just prior to and during the actual time of downgrading.

Q. HOW DOES RG&E COMPARE WITH THE INDUSTRY AVERAGES SHOWN IN EXHIBIT HRF NO. 3B?

A. During the 1970-76 period RG&E's coverages underperformed the industry in each year except 1973 and 1975 (in the latter year the differential was immaterial). The industry's return on equity during this seven year period averaged 10.8% while RG&E's realized return averaged only 9.84% (See Exhibit HRF # 3a & 3b). Comparison of Exhibits HRF # 3a and 3b also reveals the fact that while the industry's external financing needs have declined moderately, RG&E's external financing requirements have increased dramatically and are expected to remain at these higher levels for the foreseeable future. In order to achieve and maintain an acceptable level of financial integrity and reasonable financial flexibility, RG&E over the next few years must maintain an above average track record relative to the industry.

Q. HASN'T RG&E HISTORICALLY ALWAYS BEEN ABLE TO FINANCE ITS CONSTRUCTION PROGRAM?

A. Yes, however, during the 1978-82 period the company will be spending more than double the approximate $350 million spent in the 1973-77 period. Furthermore, RG&E's internal generation of cash as a percent of expenditures will decline from 44.2% to

30.2% during the two periods. The ability to finance its construction program is no guarantee that a utility's credit rating may not still be downgraded with the attendant higher financing costs. For instance, in 1972 Standard & Poor's reduced RG&E's rating on its outstanding first mortgage bonds from "AA" to "A". In their nationally distributed "Bond Outlook", Standard & Poor's stated at that time, the reason for RG&E's downgrading: "The territory served has many favorable aspects and the debt ratio is reasonable. But with external financing requirements remaining formidable, fixed charge coverage already below a respectable level, and the regulatory lag something less than encouraging (two requests for interim relief have been denied) we are left with no alternative but to reduce the rating on all of the company's first mortgage bonds from "AA" to "A"."

Q. YOU MENTIONED IN YOUR PREVIOUS ANSWER THAT THE DEBT RATIO IS REASONABLE, WOULD YOU EXPLAIN WHY?

A. The capital structure during the rate year is projected to be 47.2% long term debt well below the industry average, 12.7% preferred and preference stock and 40.1% common stock.

RG&E's management has consistently maintained a conservative capital structure. By conservative I mean that the debt ratio has been maintained at a level well below the industry average, while the

equity ratio is well above the average. Analysts and investors view this capital structure as favorable because it allows some flexibility in the event that market conditions deteriorate.

Q. HOW WOULD THE PROJECTED INCREASE IN EXTERNAL FINANCING DURING THE 1978-82 PERIOD AFFECT RG&E'S FINANCIAL FLEXIBILITY AND ITS "A/A" CREDIT RATING?

A. During the 1973-77 period RG&E depended on external financing for 55.8% of its capital requirements and according to its current projections this dependence is expected to increased to 69.8% for the 1978-82 period. At this projected level, RG&E will have little, if any, financial flexibility. In fact, it is questionable whether the construction program, assuming no improvement in financial parameters, can be financed. In other words, without immediate and adequate rate relief, RG&E's financial integrity is in serious question. With the required increased visits to the capital markets, the pressures of an even higher external financing program will not go unnoticed by either the market place or the rating agencies.

It should be noted here that even if future external financings were maintained at the 55.8% level, the absolute dollar amount of external financings would increase materially because of the higher base of funds required. Therefore, the increase to the

69.8% level in the 1978-82 period has a compounding negative impact.

Q. WOULD YOU DESCRIBE EXHIBIT HRF NO. 4.

A. Exhibit No. 4 simply compares both the authorized and regulatory return on equity against the actual realized return on equity.

Q. HAS THE COMPANY BEEN ABLE TO ACHIEVE ITS ALLOWED RETURN ON EQUITY?

A. No, it has not. If you would refer to Exhibit HRF No. 4, you will note that RG&E has been unable to achieve its authorized return on common equity, either on an actual or regulatory basis. This exhibit shows that during the period 1970-78 (estimated) the actual shortfall ranged between .8% and 3.7%. For the nine year period the actual annual shortfall averaged 2.3%. However, it can be seen that, despite repeated requests for rate relief, the actual shortfall has increased significantly in the last five years. The actual average annual shortfall during the period 1974-78 had risen to 3.0%. If this trend is permitted to continue into the future, RG&E will suffer severe financial consequences, particularly in view of the company's need today to have its allowable return on equity set at levels higher than what has been granted in the past by this commission. If RG&E is to compete effectively in attracting capital at reasonable cost, then its allowed rate of return must be higher,

enabling the company to earn more and provide stronger financial parameter from both an equity and credit analysis standpoint.

Q. IS IT IMPORTANT THAT COMPANIES, SUCH AS RG&E, MAINTAIN A HIGH LEVEL OF INTERNALLY GENERATED RETAINED EARNINGS?

A. Yes, no matter what quality credit rating a borrower carries, the more frequently this issuer visits the marketplace, the more expensive the borrower's funds become. Even the United States Government has to pay more for its money as the ownership of its securities proliferates in the marketplace. Hence, if there can be a reasonable balance between internally and externally generated funds, the funds required from externally financing will cost less. In fact, it is no coincidence that many high grade electric utility companies, which have experienced consecutive downgradings over recent years, all exhibited inadequate levels of cash flow at the time of downgrading. (See Exhibit HRF # 2).

Q. WERE YOU INVOLVED IN THE DOWNGRADINGS OF ELECTRIC UTILITIES IN RECENT YEARS BY STANDARD & POOR'S?

A. Yes. I was involved in downgrading from 1968 to the fall of 1975. All of those unfortunate but necessary downgradings of electric utilities were primarily my responsibility.

Q. HAVE YOU ANALYZED RG&E'S FINANCIAL POSITION AND EVALUATED ITS CREDIT WORTHINESS?

A. Yes, I have.

Q. WHAT DATA DID YOU EXAMINE AND WHAT FACTORS DID YOU CONSIDER?

A. In evaluating any electric utility company, we typically review the last five years' financials. If there is a serious question of deterioration, we discuss with the company its current and future financial position. In arriving at our conclusion concerning RG&E, we considered many factors, as I have discussed in describing the credit analysis process. These include capital and financing requirements, the need for rate relief, the level of earnings, the interest charge coverage, the capital structure, the embedded cost of debt, the financial flexibility of the company, the ability of the company to obtain capital, the percent of capital the company will be generating internally, the quality of service, the company's future objectives, and whether their objectives appeared realistic and attainable.

Q. WHAT CONCLUSIONS ABOUT RG&E'S CREDIT WORTHINESS HAVE YOU REACH AT THIS TIME?

A. Without substantial rate relief, RG&E's credit position will continue to deteriorate. Interest coverage for the 12 months ended December 31, 1977 has deteriorated to 2.00x (before taxes) and headed south. In view of the company's pending burdensome financial requirements and the fact the company's

credit position has been considerably weakened in recent years, in my opinion it is no more than a mediocre "Baa/BBB" at best. Furthermore, its present "A" bond rating is in peril of an almost immediate downgrading by both rating agencies. Also, I believe, without immediate and decisive action on the part of the New York Public Service Commission, affording RG&E substantial rate relief over the next few years, RG&E's credit position will continue to deteriorate to the point that our capital markets under less favorable conditions will undoubtedly close their doors.

Q. ONCE DOWNRATED, WHAT IS YOUR OPINION AS TO THE ACTION REQUIRED BY A COMPANY TO REGAIN ITS FORMER RATING AND THE PERIOD OF TIME INVOLVED?

A. It is my opinion that once a major utility company has been downrated, a very substantial period of time is required for that company to regain its rating. Furthermore, during that period of time the company's rate of return on invested capital and fixed charge coverage must improve to the point where they more than justify the rating category to be regained. The rating agencies need to be convinced that the improvement is not transitory in nature. Establishing such improvements necessitates massive rate relief.

Downrating is not only expensive as far as time is concerned, but expensive when it comes to rate of

return and to the consumer. Once lost, the rating agency usually wants to see coverage 0.25 times to 0.50 times in excess of the minimum, so that they will feel reassured that the company will not be facing a possible downgrading again in a relatively short period of time. One of the problems a rating agency faces is maintaining consistency. Therefore, just as they are very slow to react and downgrade a company, making sure the downgrading is justifiable, when raising the rating, they likewise want to make sure that the company will be able to maintain that rating in good standing for some time to come so as to avoid the embarrassment of again reducing it. Rapidly changing ratings do not benefit the consumer, issuer, investor, or the rating agency.

Q. HAVING EXPERIENCED A DOWNRATING, WHAT IS A COMPANY'S ABILITY TO FORESTALL A FURTHER DOWNRATING AND DETERIORATION OF CREDIT?

A. It is difficult to avoid a further deterioration in credit rating after an initial downgrading. In my opinion, based in part on more than nine years experience at Standard & Poor's, credit deterioration is much like a snowball gathering momentum as it goes downhill. Once set in motion, it is extremely difficult to halt and even more difficult and expensive to reverse. For example, for a company to maintain the same level of fixed charge coverage when it is continuously paying anywhere

from 50 to 100 basis points more for its fixed rate capital it must earn these increased charges by the same number of times as in the recent past to maintain even the new lower credit rating. Therefore, it has a multiplier effect on the increased cost to the company. If these increased costs are not reflected in the utility's rates in a timely fashion, which many times happens, then the credit continues to deteriorate and further downgrading is likely. For example, if RG&E or any other electric utility has embedded interest expense of $12 million annually, it would take pretax (pre-interest) income of $36 million annually to produce three times coverage on the outstanding $180 million of long-term debt. For this example, assume the last issue sold was $30 million at 9% for an annual interest expense of $2.7 million which is included in the $12 million of total interest expense. If, however, because of a downgrading of its credit rating, this issue was sold at a 10% interest rate, the total interest expense for the company would then be raised by approximately $300,000 each year. The impact on the required net income, however, before interest and taxes, to maintain three times coverage would be $900,000. Because this is on a pretax basis, it would likewise require an additional $900,000 of revenue each year. Please remember this is just one year and only one issue.

Assuming this issue at a 30-year rate, then the consumer would be required to pay $27 million more over the life of the $30 million bond issue. One can imagine how expensive this can become for the consumer if such a company continues to see additional issues. Naturally, this does not take into consideration the cost of improving coverage to 3.5 times or 4 times which would be the minimum required for the company to regain its previous credit rating. Furthermore, if the company does not receive the additional revenue required to maintain the 3 times coverage, then the company's coverage continues to deteriorate as does its overall credit worthiness.