

DIRECT TESTIMONY  
OF  
FORECASTING & RATES PANEL

1 Q. Please state your names and business address(es).

2 A. Stacy E. Powers and Amy S. Dittmar, Central Hudson Gas & Electric  
3 Corporation (“Central Hudson” or the “Company”), 284 South Avenue,  
4 Poughkeepsie, New York 12601.

5

6 Q. In what capacity are you employed by Central Hudson?

7 A. (Powers) I am an Associate Cost and Rate Analyst.

8 (Dittmar) I am an Associate Cost and Rate Analyst.

9

10 Q. Please summarize your education and business experience.

11 A. (Powers) I received a Bachelor of Science Degree in Business Administration  
12 and Accounting from Marist College in 2006. I was employed by Central  
13 Hudson in July 2006 as an Assistant Cost and Rate Analyst. I was promoted  
14 to my current position of Associate Cost and Rate Analyst in March 2008.

15 (Dittmar) I received a Bachelor of Science Degree in Financial Economics  
16 with a Business Management adjunct from Binghamton University in 2004. I  
17 was employed by Central Hudson in February 2006 as an Accounting Clerk  
18 in the Plant Accounting Division. I was promoted to the position of Assistant  
19 Financial Analyst in May 2006 and subsequently transferred to the position of  
20 Assistant Cost and Rate Analyst in January 2008. I was promoted to my  
21 current position of Associate Cost and Rate Analyst in January 2009.

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## FORECASTING & RATES PANEL

1 Q. Have you previously testified before this Commission?

2 A. (Powers) Yes. I have testified before this Commission in Case 08-E-0887.

3 (Dittmar) Yes. I have testified before this Commission in Case 08-G-0888.

4

5 Q. What is the purpose of the Forecasting and Rates Panel's testimony in this  
6 proceeding?

7 A. The Panel presents projected inflation rates as well as the following with  
8 respect to electric and gas service: 1) historical sales and revenues; 2) the  
9 development of the forecast of electric and gas customers, sales and base  
10 delivery revenues for all service classes for the period April 1, 2009 through  
11 June 30, 2011; 3) development of the projection of interruptible gas sales  
12 and revenues, and an overview of the current mechanism for interruptible  
13 profit calculation; 4) the interclass revenue allocation of the Company's  
14 proposed electric and gas delivery rate changes; 5) the proposed changes in  
15 the Company's electric and gas delivery rates and the revenue effect of  
16 those changes; 6) the Company's method for collecting purchased power  
17 costs from customers; 7) the Company's method for collecting natural gas  
18 supply costs from customers; and 8) the electric loss factor and gas factor of  
19 adjustment.

20

21 Q. With respect to the subject of inflation, what are

22 the projections of the inflation rate and how were they developed?

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1 A. A Gross Domestic Product (GDP) implicit price deflator was developed using  
2 the consensus forecast of Blue Chip Economic Indicators included in the  
3 April 10, 2009 publication, for 2009 and 2010 forecast figures, and March 10,  
4 2009 publication, for 2011 forecast figures. The forecast for the Rate Year  
5 as shown below is an extrapolation of this forecast.

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GDP Implicit Price Deflator

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<u>Year</u>	<u>Index</u> <u>2000 = 100</u>	<u>Annual</u> <u>Percent</u> <u>Change</u>
2008	122.4	2.2
12 Months Ended March 2009	122.8	0.3 over 2008
2009	124.1	1.4 over 2008
2010	125.7	1.3 over 2009
Rate Year Ending June 30, 2011	126.8	0.9 over 2010

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Q. Now, turning to the subject of electric and gas service, please begin by  
describing the exhibits which summarize sales, revenue and customer data  
for recent historical periods and the forecast period.

A. Exhibit\_\_(FRP-1) consists of Schedules A and B for electric and gas,  
respectively. These schedules present, for the calendar years 2006, 2007  
and 2008, and the twelve months ending March 31, 2009 the operating  
revenues of the Company by prime revenue account, as required by the

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1 Commission's rules. These exhibits also show for each revenue account the  
2 kWh or Mcf of electricity or gas delivered (designated as sales), base  
3 delivery revenue and the average base delivery revenue per kWh or Mcf  
4 sold.

5 Exhibit\_\_(FRP-2) consists of six schedules. Schedule A presents a  
6 summary by customer class of electric sales, base delivery revenues and  
7 customers for the twelve-month periods ended March 31, 2009, December  
8 31, 2009, December 31, 2010, and June 30, 2011. Schedule B sets forth  
9 monthly electric sales, base delivery revenue and customer data by revenue  
10 account for the twelve-months ended March 31, 2009. Schedules C through  
11 F contain similar monthly information by service classification for the twelve-  
12 month periods ended March 31, 2009, December 31, 2009, December 31,  
13 2010, and June 30, 2011, respectively.

14 Exhibit\_\_(FRP-3) sets forth six schedules similar to Exhibit\_\_(FRP-2),  
15 summarizing gas sales, base delivery revenues and customers for the same  
16 time periods.

17

18 Q. Were sales to full service customers, or those customers continuing to  
19 purchase their energy and/or natural gas requirements from Central Hudson,  
20 addressed differently in the forecast than sales to retail access and/or  
21 transport customers?

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1 A. No. In prior Central Hudson general rate proceedings, Cases 00-E-1273 and  
2 00-G-1274, the Commission approved the unbundling of commodity supply  
3 from delivery, resulting in the same base delivery rates for both full service  
4 sales and retail access/transportation customers. Therefore, the sales  
5 forecasts reflect total full service and retail access deliveries.

6

### 7 **Electric and Gas Sales Forecasts**

8 Q. Were the electric and gas forecasts for firm sales developed in a similar  
9 fashion?

10 A. Yes they were.

11

12 Q. Please provide an overview of the process by which the forecast of electric  
13 own territory and firm gas sales were developed.

14 A. Customer forecasts were developed for each electric and gas customer  
15 class. For a number of these classes, sales volume forecasts were  
16 developed on a sales per customer basis, with total sales specified as a  
17 function of sales per customer and customer count. Sales forecasts for the  
18 remaining classes were developed on a total class basis.

19

20 Q. Why were forecasted sales volumes for certain classes developed on a sales  
21 per customer basis?

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1 A. Generally, this approach was applied to the classes with relatively large  
2 numbers of customers. Separating total consumption into customer and  
3 sales per customer components recognizes that each component is  
4 influenced by different factors and provides the opportunity to incorporate  
5 more structure into the analysis of total consumption.

6  
7 Q. What forecasting methodologies were used to project customer and sales  
8 levels?

9 A. Forecasts of customers and sales were developed utilizing various  
10 econometric or time series models, or trend projections. The  
11 models/forecasts were estimated using actual monthly billed customer and  
12 sales data covering the period January 1997 to March 2009.

13 Estimation periods vary somewhat for the different classes to  
14 recognize structural changes to the billing process and data quality issues  
15 that can sometimes limit data availability. For example, revisions to billing  
16 cycles, in terms of customer composition, and recording of customers' end-  
17 use category (residential, commercial, industrial, etc.) can cause shifts in  
18 data requiring different estimation periods.

19 A summary of the methods utilized for each forecast is provided  
20 below, with detail regarding model specifications and statistics presented on  
21 Exhibit\_\_ (FRP-4) for electric forecasts and Exhibit\_\_(FRP-5) for gas  
22 forecasts. Electric forecast results for each class, and in total, are shown on

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1 Exhibit\_\_(FRP-6). Similarly, gas forecast results for each class, and in total,  
 2 are shown on Exhibit\_\_(FRP-7).

**List of Electric Customer and Sales Forecast Methods**

<u>Class</u>	<u>Customers</u>	<u>Sales</u>
Res. Heat	time series	econometric (per customer)
Res. Non-Heat	econometric	econometric (per customer)
Com. Demand	econometric	econometric
Com. Non-Dmd.	econometric	econometric (per customer)OPA
Demand	econometric	econometric
OPA Non-Dmd.	econometric	econometric
Ind. Demand	historic constant	econometric (per customer)
Ind. Non-Dmd.	historic constant	econometric (per customer)
SC 13	individual	individual
Area Light	historic constant	fixture specific growth
Street Light	historic constant	fixture specific growth
Traffic Signal	historic constant	historic constant w. trend
Interdepart.	historic constant	historic constant

**List of Gas Customer and Sales Forecast Methods**

<u>Class</u>	<u>Customers</u>	<u>Sales</u>
Res. Heat	econometric	econometric (per customer)
Res. Non-Heat	time series	econometric (per customer)
Com. Heat	econometric	econometric (per customer)
Com. Non-Heat	time series	econometric (per customer)
OPA	historic w/ additions	econometric (per customer)
Industrial	linear regression	econometric (per customer)
Interdepart.	historic constant	historic constant

33 Q. Please describe the structures of the models used to develop the electric  
 34 customer forecasts.

35 A. Econometric models were constructed to forecast customer levels for the  
 36 residential non-heat, commercial and other public authority (OPA) demand,

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1 and commercial and OPA non-demand classes. Two types of variables were  
2 employed in the specification of these models: economic and binary (or  
3 dummy). The model specifications for the residential and OPA customer  
4 classes utilize number of households, while the commercial demand and  
5 commercial non-demand class models utilize total employment and non-  
6 manufacturing employment data, respectively. The model specification for  
7 the OPA demand class employs a non-linear regression equation as it  
8 reflects the use of an autoregressive (“AR”) term. This term captures the  
9 impact of all other variables that have not been included in the model due to  
10 the inability to identify or quantify such variables or due to the lack of data for  
11 such variables.

12 The residential heat customer forecast was developed applying a  
13 linear regression equation to the rolling twelve-month average customer  
14 level. The resulting forecast customer level for each calendar year was then  
15 allocated to calendar month using the actual two-year average odd/even  
16 billing pattern in order to reflect the recent increase in the pattern’s  
17 amplitude.

18 Recent changes in categorization of customers’ end use have  
19 produced significant shifts in the industrial demand and non-demand  
20 customer levels due to the relatively small size of these classes. As a result,  
21 the forecast customer levels for these classes were maintained at the actual  
22 level experienced for the most recent twelve-month period.

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1           As of March 31, 2009, Central Hudson provided transmission or  
2           substation service to fifteen customers under the provisions of Service  
3           Classification (“S.C.”) No. 13. The Company expects to continue providing  
4           service to thirteen of these customers, with the remaining two terminating  
5           operations.

6           The Company has experienced little to no customer growth in both  
7           S.C. No. 5, area lighting, and S.C. No. 8, street lighting, in recent years. As a  
8           result, the forecast customer level for area lighting was maintained at the  
9           actual level experienced for the most recent twelve-month period, while the  
10          street lighting customer level as of March 31, 2009 was maintained  
11          throughout the forecast period.

12          As approved by the Commission in its Order in Case 00-E-1273, S.C.  
13          No. 9, which provides unmetered service, was closed to new customers  
14          effective November 1, 2001. Customers requiring service for new traffic  
15          signals are now required to take service under S.C. No. 2. Since the closing  
16          of this service class, the Company has experienced a minor contraction in  
17          the customer level for this class. As a result, the most recent level  
18          experienced has been maintained throughout the forecast period.

19

20    Q.    Please describe the structures of the models utilized to develop the gas  
21          customer forecasts.

22    A.    Econometric models were constructed to forecast customer levels for the

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1 residential and commercial heating classes. Two types of variables were  
2 employed in the specification of these models: economic and binary (or  
3 dummy). The model specification for the residential heating class utilizes  
4 number of households while the commercial heating class model utilizes  
5 non-manufacturing employment data. The model specification for the  
6 commercial heating class employs a non-linear regression equation as it  
7 reflects the use of an AR term.

8 The residential and commercial non-heating class customer forecasts  
9 reflect utilization of exponential smoothing models.

10 The customer forecast developed for the Other Public Authority  
11 (“OPA”) class assumes that minor growth will continue through the forecast  
12 period with the addition of approximately five customers each year. Many  
13 schools, hospitals and government offices, which could be included in the  
14 OPA classification are coded as commercial heating.

15 The industrial customer forecast was developed by applying a linear  
16 regression equation to the rolling twelve-month average customer level. The  
17 resulting forecast customer level for each calendar year was then allocated  
18 to calendar month using the average of the actual odd/even billing pattern for  
19 calendar years 2004 through 2008.

20  
21 Q. How do the model structures for electric and gas customer forecasts  
22 compare to those approved by the Commission in the Company’s last major

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1 rate filing?

2 A. The Commission's final forecasts in Cases 08-E-0887 and 08-G-0888 were  
3 based on the Company's forecast of customers which were developed using  
4 the same forecasting methodologies and model structures presented in this  
5 proceeding.

6  
7 Q. What is the source for the economic data utilized in the forecast models?

8 A. Economic projections for the region served by the Company were based on  
9 the April 2009 forecast provided by Moody's Economy.com to the New York  
10 Independent System Operator for statewide forecasting. Composite forecast  
11 drivers for the Central Hudson region were constructed from four data  
12 regions included in the forecast: Albany, Catskills, Dutchess County and  
13 Newburgh. The composite economic forecast drivers were calculated as a  
14 weighted sum of the regional forecasts, where the weights reflect actual  
15 average residential and non-residential sales in the region for calendar years  
16 2006 through 2008.

17 These data were the latest available to the Panel at the time of the  
18 preparation of our analyses. We recommend that the models employed by  
19 any party be fully updated, and re-specified if appropriate, to reflect the latest  
20 data available at the time of the Commission's decision.

21

22 Q. What forecasting methods were used to project sales volumes?

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1 A. Econometric models were constructed to forecast all electric classes  
2 excluding S.C. No. 13, area, street and traffic signal lighting and  
3 interdepartmental and all firm gas classes excluding interdepartmental and  
4 S.C. No. 11. Further, the forecasts developed for the electric residential and  
5 commercial classes and all firm gas classes utilize Statistically Adjusted End-  
6 Use (“SAE”) models.

7

8 Q. Please explain the SAE model approach.

9 A. The SAE approach integrates structural changes in end-use saturation and  
10 efficiency trends, as well as addressing the interaction of economic variables,  
11 through the construction of end-use variables: heating, cooling and other  
12 (base use). These end-use variables include weather, price, economic  
13 drivers and end-use saturation and efficiency trends. Additionally, the  
14 electric end-use variables constructed for the residential classes reflect  
15 changes in housing square footage and thermal shell integrity.

16

17 Q. What is the source for end-use saturation and efficiency data?

18 A. Residential appliance and commercial end-use saturation and efficiency  
19 trends are based on Energy Information Administration estimates for the  
20 Middle Atlantic Census Region as compiled by Itron, Inc. Where possible,  
21 electric estimates are calibrated to Central Hudson’s service territory based

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1 on results from the Company's Residential Appliance Saturation Survey  
2 series.

3

4 Q. What is the basis for the electric price variable?

5 A. We used the latest information available to us at the time of the preparation  
6 of our analyses, with the exception of the New York State Assessment  
7 ("NYSA"), which was not included. The historic price series for each class  
8 was determined as a function of the total bundled revenue (including delivery  
9 and supply) billed to full service customers divided by sales to full service  
10 customers in each class. Monthly forecast prices for each class include  
11 applicable base delivery charges, including delivery rate increase(s) as filed  
12 by the Company in compliance with Case 08-E-0887 effective July 1, 2009  
13 on a temporary basis, pending Commission approval, and a projected  
14 delivery rate increase of approximately five percent effective July 1, 2010, as  
15 well as Merchant Function Charges ("MFC"), System Benefits Charge  
16 ("SBC"), Renewable Portfolio Standard Charge, the Electric Bill Credit,  
17 Purchased Power Adjustment, Miscellaneous Charges and Market Price  
18 Charge ("MPC"). The MPC, or supply price, was forecasted using monthly  
19 regression equations to estimate MPC prices as a function of the on-peak  
20 price forecast for NYISO zone G as of July 1, 2009 as obtained from  
21 INO.com. The MPC price forecast also includes a market price effect  
22 estimate of \$2/MWh related to the Regional Greenhouse Gas Initiative

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1 (“RGGI”) similar to the price forecast utilized by the Company in its most  
2 recent general rate proceeding Case 08-E-0887. The price variable is  
3 expressed as the CPI-indexed twelve-month moving average on a one-  
4 month lag.

5

6 Q. What is the basis for the gas price variable?

7 A. We used the latest information available to us at the time of the preparation  
8 of our analyses, with the exception of the NYSA, which was not included.

9 The historic price series for each class was determined as a function of the

10 total bundled revenue (including delivery and supply) billed to full service

11 customers divided by sales to full service customers in each class. Monthly

12 forecast prices for each class include applicable base delivery charges,

13 delivery rate increase(s) as filed by the Company in compliance with Case

14 08-G-0888 effective July 1, 2009 on a temporary basis, pending Commission

15 approval, and a projected delivery rate increase of approximately four

16 percent effective July 1, 2010, as well as Merchant Function Charges

17 (“MFC”), System Benefits Charge, Renewable Portfolio Standard Charge, an

18 estimate for the Energy Efficiency Portfolio Standard (“EEPS”) Charge in

19 Case 07-M-0548, and Gas Supply Charge (“GSC”). The forecast of the

20 GSC, or supply price, reflects utilization of assets currently under contract to

21 Central Hudson, including pipeline transport, storage and commodity

22 supplies, with commodity supply based on New York Mercantile Exchange

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1 (“NYMEX”) natural gas futures prices as of July 1, 2009. The price variable  
2 is expressed as the CPI-indexed twelve-month moving average on a one-  
3 month lag.

4

5 Q. Why were applicable NYSA Charges not reflected in the forecast for prices?

6 A. The New York State Assessment Charges filed in compliance with Order in  
7 Case 09-M-0311 dated June 19, 2009 and effective July 1, 2009, were filed  
8 on a temporary basis. In addition, the Company is currently developing a  
9 revised filing which it will file to become effective September 1, 2009. The  
10 Company’s new NYSA statements will reflect service class specific factors,  
11 and for electric sub-class specific factors, as applicable, to reflect voltage  
12 level. The Panel determined that it was more efficient to exclude NYSA  
13 entirely at this juncture pending the Commission's approval of the revised  
14 filing as well as any additional changes regarding implementation of NYSA.  
15 Therefore, we recommend that the latest known information available at the  
16 time of the Commission's decision be reflected in the final Rate Year  
17 forecasts utilized to determine the revenue requirement and rate design.

18

19 Q. What economic variables are utilized in the electric sales models?

20 A. The residential and OPA class models utilize household income and  
21 household size, while the commercial and industrial models utilize GDP. As  
22 previously noted, these data are part of the forecast supplied by Moody’s

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1 Economy.com and subsequently compiled by Central Hudson to correspond  
2 more precisely to the Company's service territory.

3

4 Q. What economic variables are utilized in the gas sales models?

5 A. The residential models utilize household income and household size, while  
6 the commercial, industrial and OPA models utilize GDP.

7

8 Q. How is weather incorporated into the sales models?

9 A. Monthly actual heating degree days ("HDD") and cooling degree days  
10 ("CDD") are transformed into billed HDDs to more closely correspond to the  
11 sales billing periods. The sales forecasts are based on normal weather  
12 conditions, where the normal weather is determined by a ten-year average of  
13 monthly HDD or CDD, as applicable, based on hourly temperature readings  
14 obtained from Dutchess County Airport, for the calendar year ending 2008,  
15 the latest calendar year for which this information was available at the time of  
16 preparation of the Company's sales forecast. We recommend that the latest  
17 ten-year average ending December be reflected in the final Rate Year  
18 forecasts utilized to determine the revenue requirement and rate design.

19

20 Q. Please define a HDD.

21 A. Weather is expressed in terms of degree days. Electric HDDs are defined as  
22 the amount by which 65 degrees Fahrenheit exceeds the average of the high

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1 and low temperatures for a given day. Gas HDDs are defined as the amount  
2 by which 65 degrees Fahrenheit exceeds the twenty-four average of  
3 temperatures for a given gas day.

4

5 Q. Please define a CDD.

6 A. Electric CDDs are defined as the amount by which the average of the high  
7 and low temperatures for a given day exceed 65 degrees Fahrenheit.

8

9 Q. Do the sales models contain any other assumptions or variables?

10 A. Yes. The electric and gas residential and electric OPA sales models include  
11 price, income and household size elasticity estimates, while the remaining  
12 sales models include price and GDP elasticity estimates. With the exception  
13 of the electric and gas residential heat and gas commercial heat and  
14 industrial price elasticity parameters developed by the Company, the  
15 estimates for these variables have been compiled by Itron. Utilization of  
16 binary, or “dummy”, variables is reflected in many of the customer and sales  
17 models presented here, consistent with standard modeling practices. In  
18 many instances, this type of variable was added as a switch to turn various  
19 parameters on and off, such as differences in odd/even month billing to  
20 reflect bimonthly billing for certain accounts, or to accommodate a specific  
21 data point to reduce model error, while maintaining a longer estimation  
22 period.

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1

2 Q. Please discuss the sales forecast for electric S.C. No. 13.

3 A. The sales forecast for this class has been developed based on discussions  
4 with these customers over the period April – July 2009 in which 14 of the  
5 existing 15 customers provided the company with either written or verbal  
6 general forecasts/indications of future electric consumption. The customers  
7 were asked to comment on potential changes in usage, demand, or  
8 operations affecting electric consumption for a period of several years,  
9 including the rate years.

10 In addition to customer provided information, the Company also  
11 considered historical customer-specific information including, but not limited  
12 to, usage, demand and load factor data.

13

14 Q. Please describe how the forecast of sales for the street and area lighting  
15 classes were developed.

16 A. Street and area lighting sales were projected by extrapolating inventory  
17 trends for existing fixtures. Sales per existing fixture continue to decrease as  
18 more efficient sodium lamps are installed as replacements. As a result of the  
19 switch to more efficient lighting and no growth in customer level, overall  
20 contraction in sales is anticipated for the forecast period.

21

22 Q. How were sales under S.C. No. 9 - Traffic Signals forecast?

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1 A. As previously indicated, S.C. No. 9 was closed to new customers effective  
2 November 1, 2001. As a result, this service classification has experienced a  
3 slight contraction in sales, which has been continued through the forecast  
4 period.

5  
6 Q. How were the Company's interdepartmental sales forecast?

7 A. Interdepartmental sales were projected by analyzing several years of actual  
8 sales data. Both electric and gas interdepartmental sales were held constant  
9 throughout the forecast period.

10

11 Q. Are the forecasting methodologies utilized by the Company in the preparation  
12 of the sales forecasts consistent with those presented by the Company in its  
13 last major rate filings?

14 A. With the exception of the electric small industrial demand sales forecast,  
15 which was changed from a total sales to a use-per-customer model in order  
16 to better fit historic data, all forecasting methodologies are consistent with  
17 those presented by the Company in Cases 08-E-0887 and 08-G-0888.

18 The Commission's final forecasts in Cases 08-E-0887 and 08-G-0888  
19 were based on Staff's sales models which utilized the Company's indices  
20 reflecting Economy.com's forecast of economic data, end-use saturation and  
21 efficiency data supplied by Itron and gas and electricity price forecasts (Tr.  
22 1398). Generally, Staff found the Company's sales models acceptable (Tr.

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1 1396). Moreover, Staff portrayed the changes made to the Company's  
2 forecasting equations as minor adjustments (Tr. 1397).

3

4 Q. Were sales forecasts developed for gas S.C. No.14 or Sales for Resale?

5 A. No. Historic sales to S.C. No. 14 have been fairly erratic and since this  
6 service class is included in the interruptible profit mechanism discussed  
7 below a forecast has not been developed for this class. The Company did  
8 not prepare a forecast of sales-for-resale, which are commodity sales, since  
9 the Company's filing in this proceeding pertains to delivery service. Historic  
10 sales for resale are reflected, but associated historic revenues are not, as  
11 those revenues are addressed within the Gas Cost Adjustment.

12

13 Q. Were any changes made to the sales forecasts to incorporate reductions  
14 identified in the on-going EEPS proceeding in Case 07-M-0548?

15 A. Yes. The electric sales reductions attributable to the EEPS were developed  
16 by allocating certain annual reductions identified in the June 23, 2008 Order  
17 in Case 07-M-0548 across applicable customer classes and months based  
18 on the pre-adjustment forecast.

19 The gas sales reductions attributable to the EEPS were developed by  
20 allocating the annual residential reductions itemized in DPS Staff's Report on  
21 Recommendations for the EEPS Proceeding issued March 25, 2008 and the

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1 Straw Proposal issued by the Administrative Law Judges on February 13,  
2 2008 across months based on the pre-adjustment forecast.

3

4 Q. Were any additional changes made to forecasted sales external to the  
5 models?

6 A. Yes. Adjustments were made to the electric sales forecast to reflect  
7 forecasted sales reductions resulting from increased penetration of  
8 residential and non-residential net-metered photovoltaic ("PV") systems.

9

10 Q. Why does the forecast reflect sales reductions from increased penetration of  
11 net-metered PV systems?

12 A. Effective August 5, 2008 the Commission raised the overall net-metering  
13 ceiling for Central Hudson from 10 MW to 12 MW and enacted new net  
14 metering legislation applicable to residential and non-residential service.  
15 These governmental actions, together with Central Hudson's active support  
16 for solar resources, are expected to produce further sales reductions as new  
17 solar installations are made. As a result, it is necessary to build into the  
18 sales forecast, and ultimately into base rates, a forecast of sales reductions  
19 resulting from the additional PV penetration above the level experienced  
20 through March 31, 2009.

21

22 Q. Please explain how these adjustments were developed.

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1 A. In developing sales reductions attributable to increased penetration of net-  
2 metered PV systems, the Company employed the same methodology  
3 approved by the Commission in Case 08-E-0887. The sales reductions  
4 attributable to PV penetration are based on a forecast of net-metered PV  
5 installations developed by applying a polynomial regression to cumulative kW  
6 installed since March 2004, reflecting this date as the date when installations  
7 accelerated. This model is presented on Exhibit\_\_(FRP-9). The Company  
8 requests recovery of lost revenue associated with any expansion of net  
9 metering provisions beyond the provisions reflected in the estimate herein.

10

11 Q. What do the final electric and gas sales forecasts show?

12 A. While the Company continues to experience growth in the number of electric  
13 and gas customers, overall use per customer has decreased significantly  
14 since 2005 primarily in response to prices. As a result of decreasing use per  
15 customer, as well as usage reductions due to the EEPS in Case 07-M-0548  
16 and lost electric sales due to PV net metering, electric and gas sales are  
17 forecast to decrease during the Rate Year. Electric own territory sales  
18 (excluding unbilled) as shown on Schedule A of Exhibit\_\_(FRP-2) are  
19 forecast to decrease by 170,128 MWh, or 3.2 percent, based on the Rate  
20 Year ended June 30, 2011 estimate of 5,191,349 MWh as compared to the  
21 calendar year 2009 estimate of 5,361,477 MWh. Gas own territory sales  
22 (excluding unbilled, Sales for Resale and S.C. No. 14) as shown on

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1 Schedule A of Exhibit\_\_(FRP-3) are forecast to decrease by 388 MMcf, or  
2 2.5 percent, based on the Rate Year ended June 30, 2011 estimate of  
3 14,851 MMcf as compared to the calendar year 2009 estimate of 15,239  
4 MMcf.

5

6 Q. Do you have any additional comments to make regarding the topic of sales  
7 forecasts?

8 A. Yes. The models and methods that we have described incorporate a number  
9 of assumptions regarding economic activity, prices and consumption  
10 patterns, including load factor. To the extent that activity in our service  
11 territory, in terms of the level of customers, changes dramatically, or  
12 customers change their consumption habits in response to changes in  
13 economic/price conditions, these changes should be reflected in the final  
14 Rate Year forecasts utilized to determine the revenue requirement and rate  
15 design.

16

17 Q. How were the revenues associated with the sales forecast for 2009, 2010  
18 and the Rate Year developed?

19 A. Monthly electric sales were based on an annual historical distribution to  
20 allocate revenue account sales to a service class or sub-class basis. Billing  
21 demands were projected based on historical load factor trends. The  
22 forecasted billing parameters derived were priced at present rates, as filed by

## FORECASTING & RATES PANEL

1 the Company in compliance with Cases 08-E-0887 and 08-G-0888, effective  
2 July 1, 2009 on a temporary basis pending Commission approval.

3 Monthly gas sales, by forecasting group, were allocated between  
4 heating and non-heating sub-classes, for the purposes of billing block  
5 distribution. The resulting gas sales were spread between blocks based on  
6 an O-Give analysis of the actual bill distribution for calendar years 2007 and  
7 2008. The monthly distributions were priced at present rates, effective July  
8 1, 2009 as described above, to obtain total base revenue.

9 Electric and gas other operating revenues were estimated by extrapolating  
10 recent experience and adjusting for known changes.

11

12 Q. Were electric S.C. No. 14 revenues excluded from the forecast?

13 A. No. Historical customers and sales for this service classification were  
14 included in the appropriate revenue group forecasts as previously detailed.  
15 Due to minimal activity under this service classification, forecasted customers  
16 and sales were allocated to the respective parent service classifications as  
17 previously detailed.

18

19 Q. What assumptions were made with respect to interruptible gas sales and  
20 transport service (S.C. Nos. 8 and 9)?

21 A. Forecasts of sales/deliveries to these customers have been estimated based  
22 on historic usage patterns and included on the assumption that they will

## FORECASTING & RATES PANEL

1 continue to take service under the service classification for which they were  
2 billed as of March 31, 2009 through the forecast period.

3 Currently, both the Company's base delivery rates and gas cost  
4 adjustment factor include credits derived from the net of fuel revenues  
5 received from interruptible sales (S.C. Nos. 8 and 9) and sales to generating  
6 facilities (S.C. No. 14). Pursuant to the Order in C.08-G-0888 current base  
7 delivery rates include a profit imputation of \$1.95 million estimated to be  
8 received from such sales. As a result, the Company is permitted to retain the  
9 first \$1.95 million in net of fuel revenue in each rate year that it may receive  
10 from interruptible service and service to generating facilities. If the net of fuel  
11 revenue, or profit, is less than \$1.95 million in any rate year, the Company is  
12 authorized to surcharge firm customers for 90 percent of the shortfall. If the  
13 margin exceeds \$1.95 million in any rate year, the Company will credit to  
14 ratepayers 90 percent of the excess. Any such surcharges or credits are  
15 applied through the gas cost adjustment factor.

16  
17 Q. Please elaborate on the process used to determine interruptible profit and  
18 apply the interruptible ratemaking mechanism.

19 A. This is a two-step process. Step one involves determining the profit (or net of  
20 fuel revenue) derived from interruptible service and service to electric  
21 generators. The profit is calculated as revenue less revenue tax and fuel  
22 cost.

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1           In step two, the imputation is applied by subtracting \$1.95 million from  
2           the profit as determined in step one. Ninety percent of the resulting shortfall  
3           or excess is collected from or returned to customers. The actual monthly net  
4           of fuel revenue for the three years ended March 31, 2009 is shown on  
5           Exhibit\_\_(FRP-8).

6

7   Q.    Is the Company proposing any changes to this interruptible profit  
8           mechanism?

9   A.    No.

10

### 11           Revenue Allocation

12   Q.    With respect to the subject of revenue allocation, please describe the criteria  
13           you have applied in allocating revenues and designing rates.

14   A.    For both electric and gas the Company has historically sought to bring the  
15           rates of return of the various service classifications to within 15 percent of the  
16           system average rate of return. In this filing, in order to mitigate impacts on  
17           those customer classes earning less than 85 percent of the system average  
18           rate of return, the maximum increase allocated to all electric and gas service  
19           classifications is 1.25 times the overall applicable system increase. The  
20           minimum increase allocated to customer classes earning more than 115  
21           percent of the system average rate of return is 0.75 times the overall  
22           applicable system increase. The constraints utilized for allocating the electric

## FORECASTING & RATES PANEL

1 and gas revenue increases were based on the electric constraints approved  
2 in Case 08-E-0887. The Company is proposing to maintain these constraints  
3 for electric service classifications while also utilizing the same constraints for  
4 all gas service classifications for consistency purposes.

5

6 Q. Were any changes made to forecasted revenues for purposes of revenue  
7 allocation and rate design?

8 A. No.

9

10 Q. Please explain Exhibits\_\_\_\_(FRP-10) and (FRP-11), relating to the estimated  
11 effect of proposed revenue increases.

12 A. Exhibit\_\_\_\_(FRP-10) for electric and (FRP-11) for gas each consist of two  
13 schedules that present the details of the proposed interclass revenue  
14 allocation. Schedule A details the methodology used to allocate the revenue  
15 increases among the various service classifications. Schedule B combines  
16 the allocated revenue increases from Schedule A with revenues at present  
17 rates to determine total filed base rate revenue by service classification for  
18 the Rate Year.

19

20 Q. What revenue requirement was used in developing the proposed rate  
21 revisions?

22 A. Electric own territory operating revenue must be increased by \$15,207,000 in

## FORECASTING & RATES PANEL

1 the Rate Year in order to meet the Company's costs of providing service. Of  
2 that amount, \$366,000 (total taxes of \$373,000 less \$7,000 obtained from  
3 other operating revenue increase) represents state and local revenue taxes  
4 that would be billed pursuant to the tax surcharge provision of the Company's  
5 tariff. The balance of \$14,841,000 is to be obtained from S.C. Nos. 1, 2, 3, 5,  
6 6, 8, 9 and 13 rates as explained below.

7 Gas own territory operating revenue must be increased by \$3,997,000  
8 in the Rate Year, in order to meet the Company's costs of providing service.  
9 Of that amount \$117,000 (total taxes of \$120,000 less \$3,000 obtained from  
10 other operating revenue increase) represents state and local revenue taxes  
11 that would be billed pursuant to the tax surcharge provision of the Company's  
12 tariff. The balance of \$3,880,000, plus \$1,950,000 that is offset through  
13 imputation to S.C. Nos. 1, 2, 6, 12 and 13 in the rate design process, or a  
14 total of \$5,830,000 is to be obtained from Service Classification Nos. 1, 2, 6,  
15 12 and 13 rates as explained below.

16

17 Q. Please describe your procedure for allocating the Company's proposed  
18 revenue increase among the various service classifications.

19 A. The Company has allocated both the electric and gas proposed increases  
20 with reference to the results of the Pro-Forma Rate Year Embedded Cost of  
21 Service Studies ("ECOSS"), which are contained in Exhibits\_\_(COSP-1) and  
22 (COSP-2), Schedule B and supported by the testimony of the Cost of Service

## FORECASTING & RATES PANEL

1 (“COSP”) Panel. The revenue allocation methodology is a three-step  
2 process.

3 The first step is to use results from the ECOSS for the Rate Year  
4 ending June 30, 2011 to determine what revenue adjustment among service  
5 classifications is necessary to have all class rates of return fall within a plus  
6 or minus 15 percent tolerance band around the overall rate of return as  
7 shown in columns 1-5 of Exhibits\_\_(FRP-10, Schedule A) and (FRP-11,  
8 Schedule A).

9 The second step is to allocate the proposed revenue increase based  
10 on total delivery service revenue. The results of Step 2 are shown in column  
11 9 of Exhibits \_\_\_(FRP-10, Schedule A) and (FRP-11, Schedule A). After  
12 adding the results of the first two steps together in column 10, the third step  
13 determines the resulting unconstrained percentage increases for each class  
14 as shown in column 11, which are then constrained as previously described.

15

16 Q. What were the results you obtained by applying the revenue allocation  
17 methodology to the proposed electric revenue increase?

18 A. Initially the methodology produced unconstrained rate changes for the  
19 service classifications ranging from negative 23.27 percent to 53.13 percent.  
20 The increases were then adjusted based on the percentage increases for the  
21 service classifications relative to the system average increase of 5.93  
22 percent.

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1           For S.C. Nos. 2 (Non Demand), 5, 13 (Substation and Transmission),  
2           for which the rate of return fell below the lower tolerance level of 85 percent  
3           of the system average, the maximum permissible increase of 1.25 times the  
4           average overall increase, or 7.41 percent, was utilized.

5           For S.C. Nos. 2 (Secondary), 3, 6 and 9, for which the rates of return  
6           exceeded the upper tolerance level of 115 percent of the system average,  
7           the minimum increase of 0.75 times the average overall increase, or 4.45  
8           percent, was utilized.

9           Application of these maximum and minimum increases produced a  
10          revenue deficiency as compared to the rate increase revenue. This revenue  
11          deficiency was then allocated pro-rata among the service classes. The  
12          resulting increases are shown in columns 21 and 22 of Exhibit\_\_\_(FRP-10,  
13          Schedule A).

14

15   Q.    What were the results you obtained by applying the revenue allocation  
16          methodology to the proposed gas revenue increase?

17   A.    Initially the methodology produced unconstrained rate  
18          changes for the service classifications ranging from negative 13.00 percent  
19          to 32.37 percent. The increases were then adjusted based on the  
20          percentage increases for the service classifications relative to the system  
21          average increase of 8.99 percent.

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1           For S.C. No. 11 – Distribution and S.C. No. 11 - DLM, for which the  
2 rate of return fell below the lower tolerance level of 85 percent of the system  
3 average, the maximum permissible increase of 1.25 times the average  
4 overall increase, or 11.24 percent, was utilized.

5           For S.C. No. 11 – Transmission, for which the rate of return exceeded  
6 the upper tolerance level of 115 percent of the system average, the minimum  
7 increase of 0.75 times the average overall increase, or 6.74 percent, was  
8 utilized.

9           Application of the maximum/minimum increase methodology produced  
10 a revenue excess as compared to the rate increase revenue. This revenue  
11 excess was then allocated pro-rata among the service classes. The resulting  
12 increases are shown in columns 21 and 22 of Exhibit \_\_ (FRP-11, Schedule  
13 A).

14

15 Q.   Were any adjustments made to the final electric and gas base revenue  
16 increases?

17 A.   Yes. For each class, the base revenue increase was reduced by the  
18 estimated increase in revenue to be collected through the redesigned  
19 Merchant Function Charges for that class calculated as 1) redesigned base  
20 MFC rates multiplied by 2) class total deliveries. These adjustments are  
21 presented on Schedule A of Exhibits \_\_ (FRP-10) and (FRP-11).

22

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### 1        **Rate Design**

2        Q.     Please explain Schedule B of Exhibits\_\_(FRP-10) and (FRP-11), regarding  
3        the effects of the proposed electric and gas rates.

4        A.     Schedule B of both exhibits sets forth, by service classification, present base  
5        rate delivery revenues, the proposed revenue increase, total proposed  
6        delivery revenue and the net effect of the proposed revenue increase.

7

8        Q.     Are you proposing any structural changes to rate design?

9        A.     Yes. The Company is proposing to eliminate the electric Service  
10       Classification No. 6 rate differential between on- and off-peak volumetric  
11       rates.

12

13       Q.     Why has the Company proposed to eliminate this rate differential?

14       A.     Residential time-of-use was implemented while the Company's rates were  
15       bundled (commodity and delivery). At that time, the rate differential was  
16       established to reflect the differential in commodity. When rates were  
17       unbundled in February 2001, the differential was maintained for delivery, but  
18       not commodity. Effective July 1, 2007 the commodity rate applicable to S.C.  
19       No. 6 customers was separated into on- and off-peak rates in compliance  
20       with the Order in Case 05-E-0934 to reflect the differential of procuring  
21       commodity during on- and off-peak periods. The Company is proposing to  
22       eliminate the volumetric delivery rate differential as there is no cost of service

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1 basis for continuing the differential. The commodity rate continues to be split  
2 between on- and off- peak.

3

4 Q. Is the Company proposing any other changes to rate design?

5 A. The Company is proposing to continue to maintain the unbundled rate  
6 structure approved by the Commission in the Company's most recent  
7 general rate proceeding, Cases 08-E-0887 and 08-G-0888. The Company  
8 proposes to update certain rate elements to reflect the results of the ECOSS.

9 The update to base rates (excluding lost revenue) for the MFC  
10 Administration Charge and the MFC Supply Charge as reflected on Schedule  
11 A of Exhibits\_\_(FRP-12) and (FRP-13) as well as the update to the billing  
12 services credit are based on the results of the ECOSS, as contained in  
13 Exhibit \_\_(COSP-1) and (COSP-2), Schedule C. The proposed updates to  
14 the billing services credit are shown below.

	Per Bill		
	<u>Billing Services Credit</u>	<u>Current</u>	<u>Proposed</u>
18	Electric	\$1.42	\$1.42
19	Gas	\$0.98	\$1.04

20

21 Q. After allocating the proposed electric revenue increase between various  
22 service classifications, how did you proceed to design the proposed charges  
23 for S.C. Nos. 1 (Residential) and 6 (Residential Time-Of-Use)?

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1 A. For Service Classification No. 1 the monthly customer charge was increased  
2 from \$18.00 to \$22.00. The monthly customer charge for Service  
3 Classification No. 6 was increased by approximately the same percentage,  
4 from \$21.00 to \$26.00. These changes are intended to bring the customer  
5 charge closer to the embedded costs shown on Schedule C of  
6 Exhibit\_\_\_(COSP-2), and supported by the testimony of the COSP. A flat  
7 delivery rate of \$0.04494 per kWh was developed to produce the remainder  
8 of the Service Classification No. 1 revenue requirement. The on-peak and  
9 off-peak delivery rate differentials for Service Classification No. 6 were  
10 eliminated, as previously discussed, and a flat delivery rate of \$0.04304 per  
11 kWh was developed to produce the remainder of the S.C. No. 6 revenue  
12 requirement.

13  
14 Q. Please describe how the charges to S.C. No. 2 – General Service were  
15 developed.

16 A. Customer charges for non-demand, secondary and primary service were all  
17 increased to bring them closer to the embedded costs of service, resulting in  
18 proposed monthly customer charges as follows: Non-Demand \$32.00,  
19 Secondary Demand \$64.00 and Primary Demand \$210.00. For the Non-  
20 demand class, a flat delivery rate of \$0.00259 per kWh was developed to  
21 produce the remainder of the requirement.

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1           Base delivery revenue from the secondary class is primarily driven by  
2 demand revenue which currently represents approximately 70 percent of  
3 secondary revenue while the volumetric rate contributes only 15 percent of  
4 the revenue. A flat demand charge of \$8.03 per kW and a flat delivery rate of  
5 \$0.00524 per kWh were developed for the secondary class by increasing  
6 each by approximately 0.4 percent to produce the remainder of the revenue  
7 requirement.

8           Similarly, demand revenue for the primary class currently represents  
9 approximately 86 percent of base revenue while the volumetric rate  
10 contributes only about 7 percent of the revenue. Therefore, the energy  
11 delivery charge and the demand charge for the primary class were each  
12 increased by approximately 4.3 percent to produce the remainder of the  
13 revenue requirement. This resulted in a flat delivery rate of \$0.00141 per  
14 kWh and a flat demand charge of \$6.57 per kW.

15  
16 Q.   Please describe how the charges to S.C. Nos. 3 and 13 were developed.

17 A.   For both classes the monthly customer charge was increased; from \$620.00  
18 to \$800.00 for Service Classification No. 3 and from \$800.00 to \$1,000.00 for  
19 Service Classification No. 13 (Substation and Transmission). These changes  
20 are intended to bring the customer charge closer to the embedded costs  
21 shown on Schedule C of Exhibit\_\_\_\_(COSP-2), and supported by the  
22 testimony of the COSP.

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1           The overall increase in the customer charge does not produce a  
2 significant customer bill impact for either S.C. No. 3, because of the 500 kW  
3 minimum bill provision in this service classification, or S.C. No. 13, due to the  
4 size of these customers.

5           A flat demand rate of \$8.71 per kW was developed to produce the  
6 remainder of the Service Classification No. 3 revenue requirement while  
7 maintaining the reactive demand charge approved by the Commission in  
8 Case 08-E-0887. S.C. No. 13 Substation and Transmission flat demand rates  
9 of \$6.64 per kW and \$3.59 per kW, respectively, were developed to produce  
10 the remainder of the revenue requirement for this class while maintaining the  
11 reactive demand charge approved by the Commission in Case 08-E-0887.

12

13 Q.    To what extent do the proposed changes to customer charges move the  
14 Company closer to costs reflected in the ECOSS?

15 A.    The Company is proposing relatively minor movements. The table below  
16 shows, for customer classes with the greatest number of customers, the  
17 extent to which the current customer charges fall below the indicated costs of  
18 service and the movements towards cost that the Company is proposing:

19  
20  
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22

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**Electric Customer Charges**

<u>S.C. No.</u>	<u>Current</u>	<u>Proposed</u>	<u>ECOSS</u>	<u>Current vs ECOSS</u>	<u>Proposed vs ECOSS</u>
1 – NHt	\$ 18.00	\$ 22.00	\$ 29.21	-38%	-25%
2 – ND	\$ 30.00	\$ 32.00	\$ 33.14	- 9%	- 3%
2 – PD	\$160.00	\$210.00	\$398.71	-60%	-47%
2 – SD	\$ 50.00	\$ 64.00	\$ 95.40	-48%	-33%

**Gas Customer Charges**

<u>S.C. No.</u>	<u>Current</u>	<u>Proposed</u>	<u>ECOSS</u>	<u>Current vs ECOSS</u>	<u>Proposed vs ECOSS</u>
1 & 12 Ht	\$17.00	\$20.00	\$37.01	-54%	-46%
2, 6 & 13 Ht	\$30.00	\$35.00	\$61.06	-51%	-43%

Q. How were proposed charges to S.C. Nos. 5 (Area Lighting) and 8 (Street Lighting) developed?

A. These charges were developed by applying the class increase to each offering across the classes.

Q. Are there any electric service classifications for which the Company is proposing no change at this time?

A. Yes. The Company currently offers standby service under S.C. No. 14. As there is minimal activity under this service classification with respect to the tariff rates, and these rates follow the parent service classification rates/cost

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1 of service, the Company believes that any rate design changes required to  
2 this service classification should be made at a later stage in this proceeding.

3 We are also proposing to maintain the current level of the contract  
4 demand charges for S.C. No. 10 at this time as the Company is not  
5 supporting a marginal cost of service study in the instant proceeding. The  
6 underlying customer charges for this service classification, however, are  
7 being updated with the customer charges proposed for S.C. Nos. 2  
8 (Primary), 3 and 13.

9  
10 Q. After allocating the proposed gas revenue increase between various service  
11 classifications, how did you proceed to design the proposed residential rates  
12 (S.C. Nos. 1 and 12)?

13 A. In designing rates for residential customers the initial goal was the keep the  
14 increase in the customer charge in line with the customer charge increase  
15 approved in Case 08-G-0888. To accomplish this, the minimum charge for  
16 the first 200 cubic feet or less was increased from \$17.00 to \$20.00 per  
17 month. The remaining increase was then allocated between the penultimate  
18 and tail blocks to maintain similar block ratios as those approved in Case 08-  
19 G-0888 while also maintaining similar levels of increase for each block.

20

21 Q. Please describe how the charges to Service Classification Nos. 2, 6 and 13  
22 were developed.

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1 A. The primary goal in designing the rates for these classes was to maintain a  
2 similar increase in the customer charge in comparison to the residential  
3 customer classes.

4 The first step in the rate design was to increase the minimum charge  
5 from \$30.00 to \$35.00, moving this charge closer to the percentage increase  
6 allocated to S.C. Nos. 1 & 12. The next step was to increase the remaining  
7 blocks in order to produce block ratios consistent with those approved in  
8 Case 08-G-0888 while also maintaining similar rate reductions for each  
9 block.

10

11 Q. Please describe how the charges to S.C. No. 11 – Transmission, Distribution  
12 and DLM were developed.

13 A. The monthly customer charge for each subclass was increased to \$800.  
14 Due to the limited number of customers taking service under S.C. No. 11,  
15 this proposed increase does not generate a significant amount of revenue.  
16 The remaining increase was allocated to the Maximum Daily Quantity (MDQ)  
17 charge.

18

19 Q. Are there any other gas service classifications for which the Company is  
20 proposing revised rates?

21 A. No. The Company does not currently serve any customers under S.C. Nos.  
22 15 and 16 (Distributed Generation (“DG”) – Commercial and Industrial and

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1 DG – Residential, respectively), therefore the Company believes that any  
2 rate design changes required to this service classification should be made at  
3 a later stage in this proceeding.

4

5 Q. Is the Company proposing to update any other delivery rates?

6 A. Yes. Pursuant to the Commission's Order in Case 08-E-0887, an Electric Bill  
7 Credit was implemented July 1, 2009 to return the electric regulatory liability  
8 of \$36 million to customers over a three year period. For the twelve months  
9 ending June 30, 2010, \$20 million of that liability will be returned to  
10 customers through the Electric Bill Credit factors effective July 1, 2009. The  
11 Company is proposing to update the bill credit factors pursuant to the Order  
12 in Case 08-E-0887 to return \$10 million over the twelve months ending June  
13 30, 2011. These charges are reflected on Schedule B of Exhibit\_\_(FRP-12).

14

### 15 **Exhibits**

16 Q. Please explain Exhibits\_\_(FRP-12) and (FRP-13), which set forth a  
17 summary of present and proposed rates.

18 A. Exhibit\_\_(FRP-12) consists of ten schedules. Schedule A and Schedule B  
19 set forth the present and proposed MFC Charges, and the proposed EBC,  
20 respectively, as previously discussed. Each of the remaining schedules set  
21 forth a comparison of the provisions of a present service classification and  
22 the proposed superseding service classification.

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1           Exhibit\_\_\_ (FRP-13) consists of two schedules. As previously noted,  
2           Schedule A sets forth present and proposed base MFC charges. Schedule B  
3           sets forth a comparison of the provisions of present S.C. Nos. 1, 2, 6, 11, 12  
4           and 13 and the proposed superseding service classifications.

5

6   Q.    Please explain Exhibits\_\_\_(FRP-14) and (FRP-15), regarding comparative  
7           bills.

8   A.    Exhibit\_\_\_(FRP-14) provides comparisons of charges for typical usages  
9           under S.C. Nos. 1 and 2 at present and proposed rates.

10       Exhibit\_\_\_ (FRP-15) provides comparisons of charges for typical usages  
11       under S.C. Nos. 1/12 and 2/6/13 at present and proposed rates.

12                These comparisons were prepared using the monthly Energy Cost  
13                Adjustment Mechanism factors effective July 14, 2009 and monthly GSC  
14                factors effective July 2, 2009, respectively, in order to develop estimates of  
15                full service bills to allow for a more accurate estimate of the utility bill impacts  
16                of the proposed rate changes.

17

18   Q.    How are the Company's energy supply costs recovered from full service  
19           customers?

20   A.    From November 2001 to May 1, 2005 all energy costs incurred on behalf of  
21           full service customers were fully recovered through the Market Price Charge  
22           ("MPC") and Market Price Adjustment ("MPA") components of the

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1 Company's Energy Cost Adjustment Mechanism ("ECAM") or through the  
2 Hourly Pricing Provision ("HPP") for S.C. Nos. 2, 3 and 13 customers electing  
3 to take service under the terms of the HPP. Effective May 1, 2005, S.C. Nos.  
4 3 and 13 customers continuing to purchase their energy supply requirements  
5 from Central Hudson were required to do so under the HPP.

6 Pursuant to the Order in Case 08-E-0887, the Company will file a Plan  
7 for expansion of the HPP to all S.C. No. 2 customers exceeding 500 kW in  
8 two consecutive months by August 21, 2009.

9  
10 Q. Please describe the ECAM.

11 A. The ECAM consists of four components: the MPC, MPA, the Miscellaneous  
12 Charges ("MISC") and Purchased Power Adjustment ("PPA").

13 The MPC and MPA factors are applicable to all service classifications  
14 excluding S.C. Nos. 3 and 13 as previously noted. The MPC charge  
15 recovers the Company's cost of electricity supply related purchases,  
16 including firm energy, capacity, ancillary charges, risk management fees, and  
17 other charges imposed by the New York Independent System Operator  
18 ("NYISO"). The MPC also includes working capital carrying charges and an  
19 uncollectible allowance. In order to more closely align the MPC with  
20 wholesale market prices, energy and capacity purchased under the  
21 Purchased Power Agreement with Constellation, is marked to the market  
22 using NYISO day-ahead market prices. Energy and capacity purchased

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1 under mandatory IPP contracts and the Company's retained generation is  
2 priced at the monthly average of NYISO day-ahead market prices. The MPC  
3 charge is calculated on a monthly basis for each MPC group based on actual  
4 costs incurred during the previous month allocated over projected deliveries  
5 for the collection period. The MPA is the reconciliation mechanism for the  
6 MPC. It is also calculated on a monthly basis by MPC group and reconciles  
7 actual MPC recoveries with MPC costs.

8 In addition to the MPC and MPA, there are two other factors that make  
9 up ECAM. The MISC factor recovers the cost or benefit of non-avoidable,  
10 variable energy related revenues or costs associated with the Company's  
11 retained generating facilities and from mandatory IPP purchases. The MISC  
12 also includes working capital carrying charges and an uncollectible allowance.  
13 The MISC charge or credit is calculated on a monthly basis on the previous  
14 month benefit or cost divided by estimated deliveries and is applicable to all  
15 energy deliveries as a uniform factor. The Company reconciles MISC  
16 recoveries with actual costs or benefits on a three-month lag.

17 The PPA factor is also applicable to all energy deliveries (excluding  
18 NYPA Power For Jobs allocations) as a uniform factor. Effective July 1,  
19 2009, pursuant to the Commission's Order in Case 08-E-0887, service class  
20 and sub-class specific PPA factors were implemented. These factor recover  
21 the cost or benefit of the Company's PPA with Constellation for energy and  
22 capacity from NMP2. As previously indicated, the benefit or cost is

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1 calculated by measuring the difference between the contract price and the  
2 actual market price, as included in the MPC. The PPA factor also includes an  
3 allowance for uncollectibles. The PPA factor is calculated on a monthly basis  
4 based on the cost incurred or benefit realized, as compared to actual market  
5 price, during the previous month divided by projected deliveries for the  
6 collection period, and is also subject to reconciliation similar to the MISC.

7

8 Q. Please provide a brief explanation of the Company's other supply recovery  
9 mechanism, the HPP.

10 A. Since May 1, 2005, the HPP has been the only commodity pricing option  
11 available to S.C. Nos. 3 and 13 customers that continue to elect to purchase  
12 their energy supply requirements from Central Hudson. Under the HPP, the  
13 Company recovers its costs by charging customers for their hourly supply  
14 requirements at the NYISO Zone G day-ahead market price, increased to  
15 reflect the applicable factor of adjustment. Customers under the HPP plan  
16 are also subject to an additional charge, the HPP UCAP charge, to recover  
17 costs for energy balancing and other components of electricity supply costs  
18 not reflected in the day-ahead market price for energy, such as installed  
19 capacity and charges for ancillary services.

20 Pursuant to the Order in Case 08-E-0887, beginning May 1, 2011, the  
21 HPP UCAP Charge will be renamed the HPP Charge and will continue to  
22 recover charges for energy balancing, ancillary services, allowances for

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1 working capital and bad debts. This charge will be applied to customer bills  
2 on a per kWh basis. In addition, a separate charge, HPP UCAP, will be  
3 implemented to recover capacity charges. Each customer's capacity charge  
4 will be calculated as the product of the customer's demand during the  
5 previous summer's NYCA peak hour and the monthly NYISO Spot Auction  
6 price for the NYCA for the prior calendar month. This charge will be applied  
7 to customer bills on a per kW basis.

8

9 Q. Is the Company proposing any structural changes to the way it recovers  
10 purchased electricity costs?

11 A. No, the Company is seeking to continue to fully recover the costs of  
12 electricity purchased for full service customers through the continued  
13 application of the provisions of the ECAM and HPP. Continued application of  
14 these mechanisms entail the continued use of deferral accounting, as  
15 necessary, in recognizing the timing differences that occur between the  
16 actual purchases of energy requirements and the collection of costs from  
17 customers.

18 Despite the sale of the Company's fossil and nuclear generating  
19 facilities, the unbundling of the supply and delivery function, the  
20 implementation of MFCs and the establishment of a mature wholesale  
21 electricity market, the Company continues to bear the obligation to forecast,  
22 procure, and manage the electricity supply obligation for the great majority of

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1 its customers. The Company continues to source and contract for cost  
2 effective supply on behalf of those customers that choose to purchase their  
3 supply from the Company. Full recovery of these purchase costs is essential  
4 to the financial health and stability of the Company, absent the ability to  
5 control generation and wholesale market costs.

6

7 Q. How are the Company's natural gas supply costs recovered from full service  
8 customers?

9 A. Gas supply expense (demand and commodity) incurred by the Company to  
10 serve full service customers taking service under S.C. Nos. 1 and 2 is  
11 recovered through the Gas Supply Charge ("GSC"). The GSC is determined  
12 monthly and reconciled annually, for the twelve-month period ending August  
13 31, in accordance with 16 NYCRR §720-6.

14

15 Q. Is the Company proposing to revise the electric factor of adjustment?

16 A. Yes. Currently, the system factor of adjustment of 1.043 is based on the  
17 three years ending March 2008, however, pursuant to the Order in Case 08-  
18 E-0887, effective July 1, 2009, the Company implemented service-level  
19 specific factors of adjustment based on the factors utilized in the Company's  
20 ECOS study. As a result, the system factor of adjustment of 1.047 for the  
21 three years ending March 2009 has been allocated back to service and/or  
22 sub-classes, as shown below, in the same manner as was done in Case 08-

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1 E-0887. Additionally, the aforementioned Order required the Company to  
 2 submit to the Commission a new loss study by January 22, 2010. The  
 3 Company proposes to update service-level specific loss factors at a later  
 4 stage in this proceeding to reflect the loss allocation included in that study.

			Adjusted Weighted	
	RY 1 Sales (kWh)	% Sales	<u>FOA</u>	<u>FOA</u>
<b>S.C. No. 1</b>	2,018,392,000	38.887%	1.0575	0.411207
<b>S.C. No. 2 - ND</b>	153,255,000	2.953%	1.0575	0.031223
<b>S.C. No. 2 - SD</b>	1,446,391,000	27.866%	1.0575	0.294673
<b>S.C. No. 2 - PD</b>	245,144,000	4.723%	1.0390	0.049072
<b>S.C. No. 3</b>	275,997,000	5.317%	1.0390	0.055248
<b>S.C. No. 6</b>	29,000,000	0.559%	1.0575	0.005908
<b>S.C. No. 13 - Sub</b>	165,640,000	3.191%	1.0190	0.032520
<b>S.C. No. 13 - Trans</b>	817,460,000	15.749%	1.0106	0.159167
<b>S.C. No. 9</b>	3,330,000	0.064%	1.0575	0.000678
<b>S.C. No. 5</b>	13,020,000	0.251%	1.0575	0.002653
<b>S.C. No. 8</b>	22,830,000	0.440%	1.0575	0.004651
<b>Total</b>	<b>5,190,459,000</b>	<b>100%</b>		<b>1.0470</b>

5

6 Q. Is the Company proposing to revise the gas factor of adjustment?

7 A. The current factor of adjustment of 1.0117 approved by the Commission in  
 8 Case 08–G-0888 was based on a three-year average ended August 31,  
 9 2008. Similarly, the Company proposes to continue to utilize a three-year  
 10 average to strike the balance between reflecting current loss activity without  
 11 producing a high degree of volatility. The Company recommends that this  
 12 factor be reviewed prior to the Commission's decision in this proceeding to  
 13 reflect the most recent three years of data ending August 31, 2009, available  
 14 at the time of the update.

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1

2 Q. Have Revenue Decoupling Mechanisms (“RDM”) been implemented for the  
3 Company’s electric and gas operations?

4 A. Yes. Pursuant to the Commission’s Order in Cases 08-E-0887 and 08-G-  
5 0888, RDMs were implemented for certain electric and gas service  
6 classifications effective July 1, 2009.

7

8 Q. Is the Company proposing any changes to the electric and gas RDMs  
9 currently in place?

10 A. No. Since the RDMs were implemented July 1, 2009, at the time of this filing,  
11 the Company has not yet concluded one billing month under the new  
12 mechanisms. As a result, the Company feels it would be premature to  
13 propose a change at this time.

14

15 Q. Is the Company’s gas business subject to a Weather Normalization Clause  
16 (“WNC”)?

17 A. Yes. Pursuant to the Commission’s Order in Case 08-G-0888, a WNC was  
18 implemented for all heating customers taking service under S.C. Nos. 1, 2, 6,  
19 12 and 13.

20

21 Q. Is the Company proposing any changes to the WNC currently in place?

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1 A. No. Similar to other New York State utilities, the Company's WNC is effective  
2 for the period October 1 – May 31, inclusive. As a result, there has yet to be  
3 any activity under the WNC and the Company feels it would be premature to  
4 propose a change at this time.

5

6 Q. Has the Forecasting & Rates Panel provided additional information for  
7 annual periods beyond June 30, 2011?

8 A. Yes, the Panel has included additional schedules similar to Schedule F of  
9 Exhibits\_\_(FRP-2) and (FRP-3) for the twelve month periods ending June  
10 30, 2012 and 2013. These schedules have been provided as additional  
11 information to the accompanying filing letter.

12

13 Q. Does this conclude your pre-filed direct testimony?

14 A. Yes, it does.