

DIRECT TESTIMONY  
OF  
ELECTRIC FORECASTING PANEL

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

2 A. Glynis L. Bunt and Stacy E. Powers, Central Hudson Gas &  
3 Electric Corporation ("Central Hudson" or the  
4 "Company"), 284 South Avenue, Poughkeepsie, New York  
5 12601.

6

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

8 A. (Bunt) I am Director of Cost, Rates and Forecasts.

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

10

11 Q. Please summarize your education and business experience.

12 A. (Bunt) I received an Associate in Science Degree in  
13 Business Administration from Dutchess Community College  
14 in 1984. In 1986, I graduated from the State University  
15 of New York at New Paltz with a Bachelor of Science  
16 Degree in Business Administration. I received a Master  
17 of Business Administration Degree with a concentration  
18 in Finance from Marist College in January 1994.

19 Following about one year of employment as an internal  
20 auditor for a retail chain I was employed by Central  
21 Hudson in June 1987 as an Accounting Trainee in the  
22 Internal Audit Division. I was promoted to Assistant

ELECTRIC FORECASTING PANEL

1 Auditor in 1989 and subsequently transferred to the  
2 position of Assistant Financial Analyst in the Financial  
3 Planning Division later that year. I was promoted to  
4 Associate Financial Analyst in 1991, to Regulatory and  
5 Financial Analyst in 1993 and to Senior Regulatory and  
6 Financial Analyst in 1996. I was transferred to the  
7 position of Rates and Forecasts Analyst in the Cost and  
8 Rate Division in 1997 and promoted to my current  
9 position in September 2002.

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

16

17 Q. Have you previously testified before this Commission?

18 A. (Bunt) Yes. I have testified before this Commission in  
19 Cases 95-G-1034, 05-E-0934 and 05-G-0935, and have  
20 submitted an affidavit in 07-M-1139.

21 (Powers) No.

22

ELECTRIC FORECASTING PANEL

1 Q. What is the purpose of the Electric Forecasting Panel's  
2 testimony in this proceeding?

3 A. The Panel presents projected inflation rates as well as  
4 the following with respect to electric service: 1)  
5 historical sales and revenues; 2) the development of the  
6 forecast of electric customers, sales and base delivery  
7 revenues for all service classes for the period April 1,  
8 2008 through June 30, 2010; 3) the interclass revenue  
9 allocation of the Company's proposed delivery rate  
10 change; 4) the proposed changes in the Company's  
11 electric delivery rates and the revenue effect of those  
12 changes; 5) the Company's proposed method for collecting  
13 purchased power costs from customers; 6) the loss  
14 factor; and 7) a revenue decoupling mechanism ("RDM").

15  
16 Q. With respect to the subject of inflation, what are  
17 the projections of the inflation rate and how were they  
18 developed?

19 A. A Gross Domestic Product (GDP) implicit price deflator  
20 was developed using the consensus forecast of Blue Chip  
21 Economic Indicators included in the March 10, 2008

ELECTRIC FORECASTING PANEL

1 publication. The forecast for the Rate Year as shown  
2 below is an extrapolation of this forecast.

3 GDP Implicit Price Deflator

4		Index	Annual
5		2000 = 100	Percent
6	<u>Year</u>		<u>Change</u>
7			
8	2007	119.7	2.7
9	12 Months Ended		
10	March 2008	120.4	0.6 (a)
11	2008	122.5	2.4
12	2009	125.2	2.2
13	Rate Year	126.6	1.1 (b)

14  
15 (a) Change from 2007.

16 (b) Change from 2009.

17

18 Q. Should the Commission, when determining final Rate Year  
19 revenue requirements, adjust the GDP forecast to reflect  
20 actual data available at the time?

21 A. Yes, because of the uncertainty of this type of  
22 forecast, and the possibility of changes in the  
23 inflation rate, it would be advisable to take this  
24 approach as has been done in the Company's last several  
25 general rate proceedings.

26

ELECTRIC FORECASTING PANEL

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

5 A. Exhibit\_\_(EFP-1) sets forth, for the calendar years  
6 2005, 2006 and 2007, and the twelve months ending March  
7 31, 2008 the electric operating revenues of the Company  
8 by prime revenue account, as required by the  
9 Commission's rules. Also, this exhibit shows for each  
10 revenue account the kWh of electricity delivered  
11 (designated as sales), base delivery revenue and the  
12 average base delivery revenue per kWh sold.

13 Exhibit\_\_(EFP-2) consists of six schedules. Schedule A  
14 presents a summary by customer class of sales, base  
15 delivery revenues and customers for the twelve-month  
16 periods ended March 31, 2008, December 31, 2008,  
17 December 31, 2009 and June 30, 2010. Schedule B sets  
18 forth monthly sales, base delivery revenue and customer  
19 data by revenue account for the twelve-months ended  
20 March 31, 2008. Schedules C through F contain similar  
21 monthly information by service classification for the

ELECTRIC FORECASTING PANEL

1 twelve-month periods ended March 31, 2008, December 31,  
2 2008, December 31, 2009 and June 30, 2010, respectively.

3

4 Q. Were sales to full service customers, or those customers  
5 continuing to purchase their energy requirements from  
6 Central Hudson, addressed differently in the forecast  
7 than sales to retail access customers?

8 A. No. In a prior Central Hudson general rate proceeding,  
9 Case 00-E-1273, the Commission approved the elimination  
10 of separate service classifications for full service and  
11 retail access customers as the Company had unbundled  
12 commodity supply from delivery, resulting in the same  
13 base delivery rates for both full service and retail  
14 access customers. Therefore, the sales forecast reflects  
15 total full service and retail access deliveries.

16

17 Q. Please provide an overview of the process by which the  
18 forecast of own territory sales was developed.

19 A. Customer forecasts were developed for each customer  
20 class. For a number of these classes, sales volume  
21 forecasts were developed on a sales per customer basis,

ELECTRIC FORECASTING PANEL

1 with total sales specified as a function of sales per  
2 customer and customer count. Sales forecasts for the  
3 remaining classes were developed on a total class basis.

4

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

7 A. Generally, this approach was applied to the classes with  
8 relatively large numbers of customers. Separating total  
9 consumption into customer and sales per customer  
10 components recognizes that each component is influenced  
11 by different factors and provides the opportunity to  
12 incorporate more structure into the analysis of total  
13 consumption.

14

15 Q. What forecasting methodologies were used to project  
16 customer and sales levels?

17 A. Forecasts of customers and sales were developed  
18 utilizing various econometric or time series models, or  
19 trend projections. The models/forecasts were estimated  
20 using actual monthly billed customer and sales data  
21 covering the period January 1997 to March 2008.

ELECTRIC FORECASTING PANEL

1 Estimation periods vary somewhat for the different  
2 classes to recognize structural changes to the billing  
3 process and data quality issues that can sometimes limit  
4 data availability. For example, revisions to billing  
5 cycles, in terms of customer composition, and recording  
6 of customers' end-use category (residential, commercial,  
7 industrial, etc.) can cause dramatic shifts in data. A  
8 summary of the methods utilized for each forecast is  
9 provided below, with detail regarding model  
10 specifications and statistics presented on Exhibit\_\_\_\_  
11 (EFP-3).

12 List of Customer and Sales Forecast

13	14 <u>Class</u>	15 <u>Forecast Method</u>	
		16 <u>Customers</u>	17 <u>Sales</u>
18	Res. Heat	time series	econometric (per customer)
19	Res. Non-Heat	econometric	econometric (per customer)
20	Com. Demand	econometric	econometric
21	Com. Non-Dmd.	econometric	econometric (per customer)
22	OPA Demand	econometric	econometric
23	OPA Non-Dmd.	econometric	econometric
24	Ind. Demand	historic	econometric
25		constant	
26	Ind. Non-Dmd.	historic	econometric (per customer)
27		constant	
28	SC 13	individual	individual
29	Area Light	historic	fixture specific growth
30		constant	
	Street Light	historic	fixture specific growth
		constant	

ELECTRIC FORECASTING PANEL

1 Traffic Signal historic historic constant w. trend  
2 constant  
3 Interdepart. historic historic constant  
4 constant

5  
6 Q. Please explain the forecasting methods utilized to  
7 develop the customer forecasts.

8 A. Econometric models were constructed to forecast customer  
9 levels for the residential non-heat, commercial and  
10 other public authority (OPA) demand, and commercial and  
11 OPA non-demand classes. Two types of variables were  
12 employed in the specification of these models: economic  
13 and binary (or dummy). The model specifications for the  
14 residential and OPA customer classes utilize number of  
15 households, while the commercial demand and commercial  
16 non-demand class models utilize total employment and  
17 non-manufacturing employment data, respectively. The  
18 model specifications for the residential non-heat and  
19 OPA demand classes employ non-linear regression  
20 equations as they reflect the use of autoregressive  
21 ("AR") or moving average ("MA") terms. These terms  
22 capture the impact of all other variables that have not  
23 been included in the models due to the inability to

ELECTRIC FORECASTING PANEL

1 identify or quantify such variables or due to the lack  
2 of data for such variables.

3 The residential heat customer forecast was  
4 developed applying a linear regression equation to the  
5 rolling twelve-month average customer level. The  
6 resulting forecast customer level for each calendar year  
7 was then allocated to calendar month using the actual  
8 odd/even billing pattern for calendar year 2007 in order  
9 to reflect the recent increase in the pattern's  
10 amplitude.

11 Recent changes in categorization of customers' end  
12 use have produced significant shifts in the industrial  
13 demand and non-demand customer levels due to relatively  
14 small size of these classes. As a result, the forecast  
15 customer levels for these classes were maintained at the  
16 actual level experienced for the most recent twelve-  
17 month period.

18 As of March 31, 2008, Central Hudson provided  
19 transmission or substation service to seventeen  
20 customers under the provisions of Service Classification  
21 ("S.C.") No. 13. The Company expects to continue

ELECTRIC FORECASTING PANEL

1 providing service to fourteen of these customers, with  
2 the remaining three terminating operations or switching  
3 to another service class.

4 The Company has experienced little to no customer  
5 growth in both S.C. No. 5, area lighting, and S.C. No.  
6 8, street lighting, in recent years. As a result, the  
7 forecast customer level for area lighting was maintained  
8 at the actual level experienced for the most recent  
9 twelve-month period, while the street lighting customer  
10 level as of March 31, 2008 was maintained throughout the  
11 forecast period.

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

ELECTRIC FORECASTING PANEL

1

2 Q. What is the source for the economic data utilized in the  
3 forecast models?

4 A. Economic projections for the region served by the  
5 Company were based on the April 2008 forecast provided  
6 by Moody's Economy.com to the New York Independent  
7 System Operator for statewide forecasting. Composite  
8 forecast drivers for the Central Hudson region were  
9 constructed from four data regions included in the  
10 forecast: Albany, Catskills, Dutchess County and  
11 Newburgh. The composite economic forecast drivers were  
12 calculated as a weighted sum of the regional forecasts,  
13 where the weights reflect actual average residential and  
14 non-residential sales in the region for calendar years  
15 2005 through 2007.

16

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

19 A. Econometric models were constructed to forecast all  
20 classes excluding S.C. No. 13, area, street and traffic  
21 signal lighting and interdepartmental. Further, the

ELECTRIC FORECASTING PANEL

1 forecasts developed for the residential and commercial  
2 classes utilize Statistically Adjusted End-Use ("SAE")  
3 models.

4

5 Q. Please explain the SAE model approach.

6 A. Traditional sales forecasting methods tend to estimate  
7 sales as a function of a combination of variables such  
8 as weather, price and economic and seasonal factors.  
9 These types of models generally produce reasonable sales  
10 estimates for short-term purposes, but are less reliable  
11 for long-term purposes as they fail to capture the  
12 impact that structural changes in end-use saturation and  
13 efficiency have on energy consumption. Additionally,  
14 these models can misrepresent the impact of other  
15 independent variables on sales, such as the interaction  
16 of price and household income on energy consumption.  
17 The SAE approach integrates structural changes in end-  
18 use saturation and efficiency trends, as well as  
19 addressing the interaction of economic variables,  
20 through the construction of end-use variables: heating,  
21 cooling and other (base use). These end-use variables

ELECTRIC FORECASTING PANEL

1 include weather, price, economic drivers and end-use  
2 saturation and efficiency trends. Additionally, the  
3 end-use variables constructed for the residential  
4 classes reflect changes in housing square footage and  
5 thermal shell integrity.

6

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

9 A. Residential appliance and commercial end-use saturation  
10 and efficiency trends are based on Energy Information  
11 Administration estimates for the Middle Atlantic Census  
12 Region as compiled by Itron, Inc. Where possible, these  
13 estimates are calibrated to Central Hudson's service  
14 territory based on results from the Company's  
15 Residential Appliance Saturation Survey series.

16

17 Q. What is the basis for the price variable?

18 A. The historic price series for each class was determined  
19 as a function of the total bundled revenue (including  
20 delivery and supply) billed to full service customers  
21 divided by sales to full service customers in each

ELECTRIC FORECASTING PANEL

1 class. Monthly forecast prices for each class include  
2 all applicable base delivery charges, including the  
3 delivery rate increase effective July 1, 2008 as  
4 approved by the Commission in Case 05-E-0934 and a  
5 projected delivery rate increase of approximately ten  
6 percent effective July 1, 2009, as well as Merchant  
7 Function Charges ("MFC"), System Benefits Charge,  
8 Renewable Portfolio Standard Charge, an estimate for the  
9 Energy Efficiency Portfolio Standard ("EEPS") Charge in  
10 Case 07-M-0548, Purchased Power Adjustment,  
11 Miscellaneous Charges and Market Price Charge ("MPC").  
12 The MPC, or supply price, was forecasted using monthly  
13 regression equations to estimate MPC prices as a  
14 function of the on-peak price forecast for NYISO zone G  
15 as of May 7, 2008 as obtained from the Platts-ICE  
16 Forward Curve-Electricity. Commencing in January 2009,  
17 the MPC price forecast also includes a market price  
18 effect estimate of \$2/MWh related to the Regional  
19 Greenhouse Gas Initiative ("RGGI"). The price variable  
20 is expressed as the CPI-indexed twelve-month moving  
21 average on a one-month lag.

ELECTRIC FORECASTING PANEL

1

2 Q. What economic variables are utilized in the sales  
3 models?

4 A. The residential and OPA class models utilize household  
5 income and household size, while the commercial and  
6 demand models utilize GDP. As previously noted, this  
7 data is part of the forecast supplied by Moody's  
8 Economy.com and subsequently compiled by Central Hudson  
9 to more reasonably reflect the Company's service  
10 territory.

11

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

13 A. Weather is expressed in terms of degree days, with a  
14 heating degree day ("HDD") defined as the amount by  
15 which 65 degrees Fahrenheit exceeds the average of the  
16 high and low temperatures for a given day, and a cooling  
17 degree day ("CDD") defined as the amount by which the  
18 average of the high and low temperatures for a given day  
19 exceed 65 degrees Fahrenheit. Monthly actual HDDs and  
20 CDDs are transformed into billed HDDs and CDDs to more  
21 closely correspond to the sales billing period. The

ELECTRIC FORECASTING PANEL

1 sales forecasts are based on normal weather conditions,  
2 where the normal weather is determined from a linear  
3 trend of monthly HDDs and CDDs for the period 1975  
4 through 2007.

5

6 Q. Is this a change from the definition of normal weather  
7 that was utilized in the Company's filing in Case 05-E-  
8 0934?

9 A. Yes. In Case 05-E-0934 the Company defined normal  
10 weather as the average of actual HDDs and CDDs for the  
11 thirty-year period 1975 through 2004.

12

13 Q. Why has the Company changed its definition of normal  
14 weather?

15 A. Over the past several years there has been widespread  
16 scientific, regulatory, political and media attention  
17 focused on climate change, and more particularly, global  
18 warming. In fact, over the past two years the National  
19 Oceanic and Atmospheric Administration ("NOAA") has been  
20 working "closely with all segments of the energy/utility  
21 industry to strategize on ways to provide better climate

ELECTRIC FORECASTING PANEL

1 normals"<sup>1</sup> realizing that while the National Climatic Data  
2 Center's "climate normals are calculated retrospectively  
3 [for a thirty year period and only made available every  
4 ten years], [they are] utilized prospectively."<sup>2</sup> As a  
5 result, NOAA has indicated that "a current-day energy  
6 regulator... may be forced to make a decision for the  
7 future based on data from 1971-2000."<sup>3</sup> Thus ignoring the  
8 findings of the Fourth Assessment Report of the  
9 Intergovernmental Panel of Climate Change that "there is  
10 virtually universal consensus that the climate has  
11 warmed relatively rapidly over the last 30 years."<sup>4</sup> As a  
12 result, the Company believes that the revised definition  
13 of normal weather that is presented here is more  
14 indicative of recent weather patterns.

15  
16 Q. Please provide an example of the regulatory attention  
17 that has been focused on the issues of climate change

---

1 United States Department of Commerce, National Oceanic and  
Atmospheric Administration, National Environmental Satellite Data  
and Information Service, National Climatic Data Center, Asheville,  
NC, September 17, 2007 memo soliciting participation for Climate  
Normals Webcast on September 26, 2007.

2 Ibid.

3 Ibid.

4 Ibid.

ELECTRIC FORECASTING PANEL

1 and global warming.

2 A. While there has been widespread activity across the  
3 country, regionally ten Northeastern and Mid-Atlantic  
4 states have committed to reduce greenhouse gas emissions  
5 from power plants through the RGGI. In New York, three  
6 departments of government will be responsible for  
7 implementing RGGI: The Department of Public Service  
8 ("DPS"), the Department of Environmental Conservation  
9 ("DEC") and the Energy Research and Development  
10 Authority. Further, in 2007 a new office, the Office of  
11 Climate Change, was established within the DEC to "play  
12 a key role in carrying out the state's program to reduce  
13 climate-changing emissions, and to adapt where warming  
14 is unavoidable."<sup>5</sup>

15  
16 Q. Why was a linear trend model, utilizing data from 1975  
17 through 2007, selected to determine weather normals?

18 A. The linear trend model was developed based on recent  
19 research results indicating that "recent trends in the  
20 climate are approximately linear or have a substantial

---

5 New York State Department of Environmental Conservation, 2007 report to NYS Conservation Council from Office of Climate Change,

ELECTRIC FORECASTING PANEL

1 linear component."<sup>6</sup> The time period selected also  
2 reflects the results of this research which selects  
3 "1975 as the hinge point... based on numerous empirical  
4 studies and model simulations that all suggest the  
5 latest period of modern global warming began in the mid-  
6 1970's."<sup>7</sup>

7

8 Q. Why are you proposing a change in the definition of  
9 normal weather?

10 A. The Company believes that base rates should be based on  
11 the best forecast reflecting the most reasonably  
12 expected operating conditions. Further, the Company  
13 believes that continuing to utilize a thirty-year  
14 average will deliberately introduce an unreasonable  
15 amount of error into the forecast as "[a] time average  
16 will generally approximate a monotonically changing  
17 normal best near the mid-point of the averaging interval  
18 with error increasing towards the beginning and end of

---

DEC web site: <http://www.dec.ny.gov/about/37869.html>.

<sup>6</sup> Livezey, Robert E., Climate Services Division, Office of Climate, Water, and Weather Services/NWS/NOAA, et. al., Estimation and Extrapolation of Climate Normals and Climatic Trends, Second Revision, June 29, 2007, p. 2.

<sup>7</sup> Ibid, p. 17.

ELECTRIC FORECASTING PANEL

1 the interval."<sup>8</sup>

2

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

5 A. Yes. The residential and OPA sales models include  
6 price, income and household size elasticity estimates,  
7 while the remaining sales models include price and GDP  
8 elasticity estimates. With the exception of the  
9 residential heat price elasticity, the remaining  
10 estimates have been compiled by Itron. Utilization of  
11 binary, or "dummy", variables is quite common and is  
12 reflected in many of the customer and sales models  
13 presented here. In many instances, this type of  
14 variable was added as a switch to turn various  
15 parameters on and off, such as differences in odd/even  
16 month billing to reflect bimonthly billing for certain  
17 accounts, or to accommodate a specific data point to  
18 reduce model error, while maintaining a longer  
19 estimation period.

20

---

8 Ibid, p. 7.

ELECTRIC FORECASTING PANEL

1 Q. How do the models for the industrial and OPA classes  
2 differ from the SAE approach?

3 A. The sales forecasts developed for the industrial and OPA  
4 classes utilize more generalized econometric model  
5 specifications.

6

7 Q. How are the models evaluated for reasonableness?

8 A. The models perform well as measured by the Adjusted  $R^2$ ,  
9 Durbin Watson, and mean absolute percent error ("MAPE"),  
10 with statistically significant model coefficients.

11

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

13 A. The sales forecast for this class has been developed  
14 based on discussions with these customers. The  
15 forecasts were prepared with the understanding that they  
16 were derived using the best data available from each  
17 customer at the time.

18

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

ELECTRIC FORECASTING PANEL

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

8

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

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

16

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

18 A. Interdepartmental sales were projected by analyzing  
19 several years of actual sales data. Interdepartmental  
20 sales were held constant throughout the forecast period.

21

ELECTRIC FORECASTING PANEL

1 Q. Were any changes made to forecasted sales external to  
2 the models?

3 A. Yes. Three adjustments were made: (1) to move a  
4 customer currently taking service under S.C. No. 13 to  
5 S.C. No. 3 after completion of the historic year (2) to  
6 reflect targeted sales reductions included in the EEPS  
7 proceeding and (3) to reflect forecasted sales  
8 reductions resulting from increased penetration of  
9 residential net-metered photovoltaic ("PV") systems.

10

11 Q. How were the adjustments made for the customer switching  
12 from S.C. No. 13 to S.C. No. 3, and why were these  
13 adjustments made?

14 A. This customer recently took over the facilities of a  
15 customer who previously took substation service from the  
16 Company under S.C. No. 13. The new customer has decided  
17 to discontinue leasing the substation and will therefore  
18 be transferred to S.C. No. 3. Since the sales forecast  
19 for this customer was developed based on discussions  
20 with the customer, as part of the S.C. No. 13 forecast,  
21 the sales associated with this customer beginning April

ELECTRIC FORECASTING PANEL

1           2008 were added to the Commercial Demand sales forecast  
2           produced by the aforementioned econometric model.

3

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

6   A.   The Commission, in an Order issued October 19, 2007 in  
7           Case 07-E-0437, raised the residential PV net-metering  
8           ceiling for Central Hudson from 1.8 MW to 10 MW, with a  
9           provision for the deferral of delivery revenue losses  
10           attributable to PV penetration in excess of 0.8 MW, the  
11           level set pursuant to Public Service Law §66-j and the  
12           level assumed in the Company's current Rate Plan. The  
13           post-forecast adjustment set forth here reflects the  
14           termination of this deferral provision coincident with  
15           the end of the Rate Plan on June 30, 2009 pursuant to  
16           the aforementioned Order issued in Case 07-E-0437. As a  
17           result, it is necessary to build into the sales  
18           forecast, ultimately for inclusion in base rates, a  
19           forecast of sales reductions resulting from further  
20           anticipated PV penetration above the level as of March  
21           31, 2008, as included in the sales forecasts.

ELECTRIC FORECASTING PANEL

1

2 Q. Please explain how these adjustments were developed.

3 A. The sales reductions attributable to the EEPS were  
4 developed by allocating the annual reductions itemized  
5 in DPS Staff's Report on Recommendations for the EEPS  
6 Proceeding issued March 25, 2008 and the Straw Proposal  
7 issued by the Administrative Law Judges on February 13,  
8 2008 across applicable customer classes and months based  
9 on the pre-adjustment forecast.

10 The sales reductions attributable to PV penetration  
11 are based on a forecast of net-metered PV installations  
12 developed by applying a polynomial regression to  
13 cumulative kW installed since March 2004, reflecting  
14 this date as the date when installations accelerated.  
15 This model is presented on Exhibit\_\_\_\_(EFP-5). It should  
16 be noted that this estimate does not reflect expansion  
17 of net metering to additional customer classes or  
18 extension of the 10 kW PV system threshold contained in  
19 Public Service Law §66-j. The Company requests recovery  
20 of lost revenue associated with any expansion of net

ELECTRIC FORECASTING PANEL

1 metering provisions beyond the provisions reflected in  
2 the estimate included herein.

3

4 Q. What does the final sales forecast show?

5 A. While the Company continues to experience growth in the  
6 number of customers, use per customer has decreased  
7 significantly since the summer of 2005 due to increased  
8 prices. As a result of decreasing use per customer, as  
9 well as usage reductions due to the EEPS in Case 07-M-  
10 0548 and lost sales due to PV net metering, own  
11 territory sales (excluding unbilled) as shown on  
12 Schedule A of Exhibit\_\_\_(EFP-2) are forecast to decrease  
13 by 134,581 MWh, or 2.4 percent, based on the Rate Year  
14 estimate of 5,391,984 MWh as compared to the calendar  
15 year 2008 estimate of 5,526,565 MWh.

16

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

19 A. Yes. The models and methods that we have described  
20 incorporate a number of assumptions regarding economic  
21 activity, prices and consumption patterns. To the

ELECTRIC FORECASTING PANEL

1 extent that activity in our service territory, in terms  
2 of the level of customers, changes dramatically, or  
3 customers change their consumption habits in response to  
4 changes in economic/price conditions, these changes  
5 should be reflected in the final Rate Year forecasts  
6 utilized to determine the revenue requirement and rate  
7 design.

8

9 Q. How were the revenues associated with the sales forecast  
10 for 2008, 2009 and the Rate Year developed?

11 A. Monthly sales were based on an annual historical  
12 distribution to allocate revenue account sales to a  
13 service class or sub-class basis. Billing demands were  
14 projected based on historical load factor trends. The  
15 forecasted billing parameters derived were priced at  
16 rates, including delivery and Merchant Function Charges,  
17 effective July 1, 2007 and July 1, 2008 pursuant to the  
18 Commission's Order in Case 05-E-0934. Other operating  
19 revenues were estimated by extrapolating recent  
20 experience and adjusting for known changes.

21

ELECTRIC FORECASTING PANEL

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

2 A. No. Historical customers and sales for this service  
3 classification were included in the appropriate revenue  
4 group forecasts as previously detailed. Due to minimal  
5 activity under this service classification, forecasted  
6 customers and sales were allocated to the respective  
7 parent service classifications as previously detailed.

8

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

12 A. The Company has historically sought to bring the rates  
13 of return of the various service classifications to  
14 within 15 percent of the system average rate of return.  
15 In this filing, in order to mitigate impacts on those  
16 customer classes earning less than 85 percent of the  
17 system average rate of return, the maximum increase  
18 allocated is 1.25 times the overall increase while the  
19 minimum increase allocated to customer classes earning  
20 more than 115 percent of the system average rate of  
21 return is 0.75 times the overall increase.

ELECTRIC FORECASTING PANEL

1

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

4 A. No.

5

6 Q. Please explain Exhibit\_\_(EFP-6), entitled "Estimated  
7 Effect of Proposed Electric Revenue Increase."

8 A. Exhibit\_\_(EFP-6) consists of two schedules that present  
9 the details of the proposed interclass electric revenue  
10 allocation. Schedule A details the methodology used to  
11 allocate the electric revenue increase among the various  
12 service classifications. Schedule B combines the  
13 allocated revenue increases from Schedule A with  
14 revenues at present rates to determine total filed base  
15 rate revenue by service classification for the Rate  
16 Year.

17

18 Q. What revenue requirement was used in developing the  
19 proposed electric rate revisions?

20 A. Our own territory operating revenue must be increased by  
21 \$35,410,000 in the Rate Year in order to meet the

ELECTRIC FORECASTING PANEL

1 Company's costs of providing service. Of that amount,  
2 \$880,000 represents state and local revenue taxes that  
3 would be billed pursuant to the tax surcharge provision  
4 of the Company's tariff. The balance of \$34,530,000 is  
5 to be obtained from S.C. Nos. 1, 2, 3, 5, 6, 8, 9 and 13  
6 rates as explained below.

7

8 Q. Please describe your procedure for allocating the  
9 Company's proposed revenue increase among the various  
10 service classifications.

11 A. The Company has allocated the proposed increase with  
12 reference to the results of the Pro-Forma Rate Year  
13 Embedded Cost of Service Study ("ECOSS"), which is  
14 contained in Exhibit\_\_\_(LGA-2, Schedule C) and supported  
15 by the testimony of Mr. Arvidson. The revenue allocation  
16 methodology is a three-step process.

17 The first step is to use results from the ECOSS for the  
18 Rate Year ending June 30, 2010 to determine what revenue  
19 adjustment among service classifications is necessary to  
20 have all class rates of return fall within a plus or  
21 minus 15 percent tolerance band around the overall rate

ELECTRIC FORECASTING PANEL

1 of return as shown in columns 1-5 of Exhibit\_\_\_\_(EFP-6,  
2 Schedule A).

3 The second step is to allocate the proposed revenue  
4 increase based on total delivery service revenue. The  
5 results of Step 2 are shown in column 9 of Exhibit  
6 \_\_\_\_ (EFP-6, Schedule A). After adding the results of the  
7 first two steps together in column 10, the third step  
8 determines the resulting unconstrained percentage  
9 increases for each class as shown in column 11, which  
10 are then constrained as previously described.

11

12 Q. What were the results you obtained by applying the  
13 revenue allocation methodology?

14 A. Initially the methodology produced unconstrained rate  
15 changes for the service classifications ranging from -  
16 14.06 percent to 75.87 percent. The increases were then  
17 adjusted based on the percentage increases for the  
18 service classifications relative to the system average  
19 increase of 16.11 percent.

20 For S.C. Nos. 2 (Non Demand), 5, 13 (Substation and  
21 Transmission), for which the rate of return fell below

ELECTRIC FORECASTING PANEL

1 the lower tolerance level of 85 percent of the system  
2 average, the maximum permissible increase of 1.25 times  
3 the average overall increase, or 20.13 percent, was  
4 utilized.

5 For S.C. Nos. 2 (Secondary), 3, 6, 8 and 9, for which  
6 the rates of return exceeded the upper tolerance level  
7 of 115 percent of the system average, the minimum  
8 increase of 0.75 times the average overall increase, or  
9 12.08 percent, was utilized.

10 Application of these maximum and minimum increases  
11 produced a revenue deficiency as compared to the rate  
12 increase revenue. This revenue deficiency was then  
13 allocated pro-rata among the service classes. The  
14 resulting increases are shown in columns 21 and 22 of  
15 Exhibit\_\_\_\_(EFP-6, Schedule A).

16

17 Q. Were any adjustments made to the final base revenue  
18 increases?

19 A. Yes. The base revenue increase for each service class  
20 was reduced by the estimated increase in revenue to be  
21 collected through the redesigned Merchant Function

ELECTRIC FORECASTING PANEL

1 Charges for that class, as more thoroughly discussed  
2 below.

3

4 Q. Please explain Schedule B of Exhibit\_\_\_\_(EFP-6),  
5 regarding the effects of the proposed electric rates.

6 A. Schedule B of Exhibit\_\_\_\_(EFP-6) sets forth, by service  
7 classification, present base rate delivery revenues, the  
8 proposed revenue increase, total proposed delivery  
9 revenue and the net effect of the proposed increase.

10

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

12 A. No. The Company is proposing to continue to maintain  
13 the unbundled rate structure approved by the Commission  
14 in the Company's most recent general rate proceeding,  
15 Case 05-E-0934.

16

17 Q. Please describe the Company's unbundled rate structure.

18 A. As approved by the Commission in Case 05-E-0934,  
19 electric backout credits were eliminated effective July  
20 1, 2007 and replaced by service class specific Merchant  
21 Function Charges ("MFC") and lost revenue provisions.

ELECTRIC FORECASTING PANEL

1 MFCs were sub-divided into a MFC Administration Charge  
2 and a MFC Supply Charge.

3 The MFC Administration Charge includes an allocated  
4 portion of credit and collection function costs and  
5 procurement-related call center function costs, plus  
6 administrative and general rate base items associated  
7 with each of the aforementioned costs. This charge is  
8 not applied to the bills of customers that elect to  
9 purchase their commodity supply service from an energy  
10 service company ("ESCO") that maintains dual billing.

11 The delivery portion of forecast net lost revenues  
12 is recovered through the Transition Adjustment. Unlike  
13 the MFC Administration Charge, the Transition Adjustment  
14 is applicable to all deliveries regardless of a  
15 customer's source of commodity supply and bill service  
16 election under a dual bill approach.

17 The MFC Supply Charge includes commodity purchasing  
18 function costs, allocated portions of advertising and  
19 promotions function costs and procurement-related call  
20 center function costs, plus administrative and general  
21 rate base items associated with each of the

ELECTRIC FORECASTING PANEL

1       aforementioned costs, as well as the commodity supply  
2       portion of forecast net lost revenues. This charge is  
3       not applied to the bills of customers that elect to  
4       purchase their commodity supply service from an ESCO.

5

6 Q.    Is the Company proposing to update the rates for these  
7       charges?

8 A.    Yes. The Company is proposing to update the base rates  
9       for the MFC Administration Charge and the MFC Supply  
10      Charge as reflected on Exhibit\_\_\_(EFP-7, Schedule A).

11

12 Q.    How were these proposed rates developed?

13 A.    These rates are based on the results of the ECOSS which  
14      is contained in Exhibit\_\_\_(LGA-2, Schedule C) and  
15      supported by the testimony of Mr. Arvidson. More  
16      specifically, Mr. Arvidson has identified certain cost  
17      elements, as noted previously, that might be avoided if  
18      a customer were to procure their energy supply from a  
19      third party. These cost elements, detailed by service  
20      classification in the ECOSS, were grouped by MFC group  
21      and divided by estimated Rate Year sales to establish

ELECTRIC FORECASTING PANEL

1 base MFC rates. This procedure was followed for each  
2 MFC group to determine the base MFC Administration  
3 Charge rate and base MFC Supply Charge rate.

4

5 Q. Are there any other issues related to MFCs that you  
6 would like to discuss?

7 A. Yes. The Company is proposing that the net lost revenue  
8 provisions of the Joint Proposal (section VI.H.)  
9 approved by the Commission in Case 05-E-0934 continue to  
10 be applied, with the delivery portion of forecast net  
11 lost revenues recovered through the Transition  
12 Adjustment and the supply portion of forecast net lost  
13 revenues recovered through the MFC Supply Charge,  
14 subject to the deferral provisions previously approved  
15 by the Commission, updated as necessary to reflect  
16 outcomes approved in the instant proceeding.

17

18 Q. Are you proposing any other rate changes?

19 A. Yes. The Company currently provides a consolidated  
20 billing service to ESCOs participating in the Company's  
21 Retail Access Program. The accounts receivable balances

ELECTRIC FORECASTING PANEL

1 of ESCOs electing this consolidated billing service are  
2 purchased by the Company at a discount, with the  
3 discount rate reflecting the average of the Company's  
4 net write-offs for the most recent three calendar years  
5 and an allowance of 0.25 percent to reflect other costs  
6 of the program. This latter rate, which was initially  
7 effective November 1, 2004, was calculated as one-  
8 twelfth of the sum of the then effective customer  
9 deposit rate of 2.45 percent and 0.55 percent for other  
10 administrative costs. The Company is proposing to  
11 revise the determination of this rate such that it  
12 reflects the currently approved customer deposit rate in  
13 effect at the time of the annual update, which is  
14 effective with the Company's first billing batch of  
15 April, plus 0.55 percent for other administrative costs.

16 In relation to the consolidated billing service,  
17 the Company currently provides customers choosing to  
18 receive a consolidated bill with a \$0.68 credit per bill  
19 regardless of the customer's service classification. The  
20 consolidated bill credit provided to the customer is  
21 recovered from the customer's ESCO. The Company is

ELECTRIC FORECASTING PANEL

1 proposing to increase the Billing Services Credit to  
2 \$0.71 for S.C. No. 1 customers and \$1.42 for all other  
3 service classifications, based on the ECOSSE contained in  
4 Exhibit\_\_\_(LGA-2, Schedule C).

5

6 Q. Please describe how the charges to S.C. Nos. 1  
7 (Residential) and 6 (Residential Time-Of-Use) were  
8 developed.

9 A. For Service Classification No. 1 the monthly customer  
10 charge was increased from \$16.00 to \$25.00. The monthly  
11 customer charge for Service Classification No. 6 was  
12 increased by approximately the same percentage, from  
13 \$19.00 to \$30.00. These changes are intended to bring  
14 the customer charge closer to the embedded costs shown  
15 on Schedule C of Exhibit\_\_\_(LGA-2), and supported by the  
16 testimony of Mr. Arvidson. A flat delivery rate of  
17 \$0.03697 per kWh was developed to produce the remainder  
18 of the Service Classification No. 1 revenue requirement.  
19 On-peak and off-peak delivery rates of \$0.06638 per kWh  
20 and \$0.02212 per kWh, respectively, were developed to

ELECTRIC FORECASTING PANEL

1 produce the remainder of the Service Classification No.  
2 6 revenue requirement.

3

4 Q. Please describe how the charges to S.C. No. 2 - General  
5 Service were developed.

6 A. Customer charges for non-demand, secondary and primary  
7 service were all increased to bring them closer to the  
8 embedded costs of service, resulting in proposed monthly  
9 customer charges as follows: Non-Demand \$29.00,  
10 Secondary Demand \$50.00 and Primary Demand \$160.00. For  
11 the Non-demand class, a flat delivery rate of \$0.01141  
12 per kWh was developed to produce the remainder of the  
13 requirement.

14 Base delivery revenue from the secondary class is  
15 primarily driven by demand revenue which currently  
16 represents approximately 76 percent of secondary revenue  
17 while the volumetric rate contributes only 14 percent of  
18 the revenue. A flat demand charge of \$8.00 per kW was  
19 developed for the secondary class by increasing the  
20 current demand rate by approximately 6.2 percent. The  
21 increase to the demand rate was offset by a slight

ELECTRIC FORECASTING PANEL

1 decrease to the delivery rate resulting in a flat  
2 delivery rate of \$0.00424 per kWh.

3 Similarly, demand revenue for the primary class  
4 currently represents approximately 85 percent of base  
5 revenue while the volumetric rate contributes only about  
6 8.44 percent of the revenue. Therefore, the energy  
7 delivery charge for the primary class was maintained at  
8 the current rate of \$0.00135 per kWh with the remainder  
9 of the revenue increase allocated to the demand charge  
10 resulting in a rate of \$5.96 per kW.

11

12 Q. Are you proposing any rate design changes for S.C. No. 3  
13 - Primary Service and S.C. No. 13 - Substation and  
14 Transmission Service?

15 A. Yes. The Company is proposing to change the  
16 determination of reactive demand to increase the power  
17 factor level at which charges for reactive demand are  
18 applied. Currently, reactive demand is determined as  
19 the highest 15-minute integrated kilovoltampers of  
20 lagging reactive demand established during the month  
21 less one-half of the highest 15-minute integrated

ELECTRIC FORECASTING PANEL

1 kilowatt demand established during that month. The  
2 Company proposes to revise this determination to compute  
3 reactive demand as the highest 15-minute integrated  
4 kilovoltampers of lagging reactive demand established  
5 during the month less *one-quarter* of the highest 15-  
6 minute integrated kilowatt demand established during  
7 that month.

8

9 Q. Are you proposing any other changes related to reactive  
10 demand?

11 A. Yes. The Company is also proposing to increase the  
12 reactive demand charge per Rkva from \$0.44 to \$0.83  
13 based on the monthly estimated cost per kVAR that would  
14 be incurred if the Company were to install a 300 kVAR  
15 capacitor bank.

16

17 Q. Why does the Company feel that these changes to reactive  
18 demand are necessary?

19 A. The Company believes that these changes are required to  
20 properly assign costs of excessive current flow due to  
21 poor power factors, which reduces the capacity of the

ELECTRIC FORECASTING PANEL

1 Company's transmission and distribution equipment, to  
2 those customers who continue to draw excess current  
3 rather than install their own capacitors.

4

5 Q. Please describe how the remaining charges to S.C. Nos. 3  
6 and 13 were developed.

7 A. For both classes the monthly customer charge was  
8 increased; from \$400.00 to \$600.00 for Service  
9 Classification No. 3 and from \$500.00 to \$780.00 for  
10 Service Classification No. 13 (Substation and  
11 Transmission). These changes are intended to bring the  
12 customer charge closer to the embedded costs shown on  
13 Schedule C of Exhibit\_\_\_(LGA-2), and supported by the  
14 testimony of Mr. Arvidson. The customer charge for both  
15 classes was then increased by \$20.00 to recover costs  
16 associated with the monthly meter subscription fee for  
17 the Company's Energy Manager advanced metering software.  
18 Currently, Service Classification Nos. 3 and 13  
19 customers are provided access to this software free of  
20 charge as the costs are recovered from the competitive  
21 metering fund pursuant to the Commission's Order issued

ELECTRIC FORECASTING PANEL

1 and effective June 14, 2004 in Case 00-E-1273. Since the  
2 Company is proposing to eliminate utilization of the  
3 competitive metering fund for this purpose, the costs  
4 will be recorded as expense (although they have not been  
5 included in the revenue requirement determination in the  
6 instant proceeding) resulting in a required increase to  
7 the customer charge.

8 The overall increase in the customer charge does  
9 not produce a significant customer bill impact for  
10 either S.C. No. 3, because of the 500 kW minimum bill  
11 provision in this service classification, or S.C. No.  
12 13, due to the size of these customers.

13 A flat demand rate of \$8.25 per kW was developed to  
14 produce the remainder of the Service Classification No.  
15 3 revenue requirement. S.C. No. 13 Substation and  
16 Transmission flat demand rates of \$5.88 per kW and \$3.26  
17 per kW, respectively, were developed to produce the  
18 remainder of the revenue requirement for this class.

19

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

ELECTRIC FORECASTING PANEL

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

3

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

6 A. Yes. The Company currently offers standby service under  
7 S.C. No. 14. As there is minimal activity under this  
8 service classification with respect to the tariff rates,  
9 and these rates follow the parent service classification  
10 rates/cost of service, the Company believes that any  
11 rate design changes required to this service  
12 classification should be made at a later stage in this  
13 proceeding.

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

21

ELECTRIC FORECASTING PANEL

1 Q. How will the rate moderator proposed by Mr. Mosher in  
2 his direct testimony be applied to mitigate the rate  
3 year rate increase?

4 A. The Company is proposing that the moderator, or Electric  
5 Bill Credit ("EBC"), be applied for the twelve months  
6 ending June 30, 2010 on a service class or sub-class  
7 specific basis as a per customer month credit as  
8 presented on Schedule B of Exhibit \_\_\_(EFP-7).

9

10 Q. Please explain how these credits were determined.

11 A. The total amount of \$21,220,000 available for rate  
12 moderation was allocated to service class, or sub-class  
13 as appropriate, based on the cost of service treatment  
14 for each component. These amounts were then divided by  
15 the forecast of customer months for each service class,  
16 or sub-class, to arrive at the per customer month  
17 credit. This determination is summarized on Schedule B  
18 of Exhibit \_\_\_(EFP-7).

19

20 Q. Is the Company proposing any limitations on the  
21 application of the EBC to customer bills?

ELECTRIC FORECASTING PANEL

1 A. Yes. The Company is proposing to constrain the EBC for  
2 customers taking service under S.C. Nos. 3 and 13 such  
3 that (1) if the amount of the EBC in any given billing  
4 period exceeds the customer's billed delivery charges  
5 from Central Hudson for the billing period, resulting in  
6 a net bill less than zero, Central Hudson will issue the  
7 customer a delivery bill in the amount of zero dollars;  
8 or (2) if the customer's billed delivery charges for any  
9 given billing period prior to the application of the EBC  
10 are less than zero, no EBC will be applied in the  
11 billing period. Any ERC not received by the customer  
12 due to operation of this constraint will be reallocated  
13 to that customer in the subsequent billing period. In  
14 any such reallocation, the aforementioned constraints  
15 will continue to be applicable and may entail  
16 reallocation to subsequent billing periods. These EBC  
17 constraints will be applied prior to the existing  
18 constraints for the Purchased Power Adjustment, which is  
19 discussed below.

20

ELECTRIC FORECASTING PANEL

1 Q. Please explain Exhibit\_\_\_(EFP-7), entitled "Summary of  
2 Present and Proposed Electric Rates."

3 A. Exhibit\_\_\_(EFP-7) consists of ten schedules. Schedules  
4 A and B set forth the present and proposed MFC Charges  
5 and the proposed EBC, respectively, as previously  
6 discussed. Each of the remaining schedules set forth a  
7 comparison of the provisions of a present service  
8 classification and the proposed superseding service  
9 classification.

10

11 Q. Please explain Exhibit\_\_\_(EFP-8), regarding comparative  
12 bills.

13 A. Exhibit\_\_\_(EFP-8) provides comparisons of charges for  
14 typical usages under S.C. Nos. 1 and 2 at present and  
15 proposed rates. These comparisons were prepared using  
16 the monthly Energy Cost Adjustment Mechanism factors  
17 effective July 11, 2008 in order to develop estimates of  
18 full service bills to allow for a more accurate estimate  
19 of the utility bill impacts of the proposed rate  
20 changes.

21

ELECTRIC FORECASTING PANEL

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

3 A. From November 2001 to May 1, 2005 all energy costs  
4 incurred on behalf of full service customers were fully  
5 recovered through the Market Price Charge ("MPC") and  
6 Market Price Adjustment ("MPA") components of the  
7 Company's Energy Cost Adjustment Mechanism ("ECAM") or  
8 through the Hourly Pricing Provision ("HPP") for S.C.  
9 Nos. 2, 3 and 13 customers electing to take service  
10 under the terms of the HPP. Effective May 1, 2005, S.C.  
11 Nos. 3 and 13 customers continuing to purchase their  
12 energy supply requirements from Central Hudson were  
13 required to do so under the HPP. The HPP continues to  
14 be an optional pricing service for S.C. No. 2 customers.

15  
16 Q. Please describe the ECAM.

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

20 The MPC and MPA factors are applicable to all  
21 service classifications excluding S.C. Nos. 3 and 13 as

## ELECTRIC FORECASTING PANEL

1           previously noted. The MPC charge recovers the Company's  
2           cost of electricity supply related purchases, including  
3           firm energy, capacity, ancillary charges, risk  
4           management fees, and other charges imposed by the New  
5           York Independent System Operator ("NYISO"). The MPC  
6           also includes working capital carrying charges and an  
7           uncollectible allowance. In order to more closely align  
8           the MPC with wholesale market prices, energy and  
9           capacity purchased under the Purchased Power Agreement  
10          with Constellation, is marked to the market using NYISO  
11          day-ahead market prices. Energy and capacity purchased  
12          under mandatory IPP contracts and the Company's retained  
13          generation is priced at the monthly average of NYISO  
14          day-ahead market prices. The MPC charge is calculated  
15          on a monthly basis for each MPC group based on actual  
16          costs incurred during the previous month allocated over  
17          projected deliveries for the collection period. The MPA  
18          is the reconciliation mechanism for the MPC. It is also  
19          calculated on a monthly basis by MPC group and  
20          reconciles actual MPC recoveries with MPC costs.

21                 In addition to the MPC and MPA, there are two other

## ELECTRIC FORECASTING PANEL

1 factors that make up ECAM. The MISC factor recovers the  
2 cost or benefit of non-avoidable, variable energy related  
3 revenues or costs associated with the Company's retained  
4 generating facilities and from mandatory IPP purchases.  
5 The MISC also includes working capital carrying charges and  
6 an uncollectible allowance. The MISC charge or credit is  
7 calculated on a monthly basis on the previous month benefit  
8 or cost divided by estimated deliveries and is applicable  
9 to all energy deliveries as a uniform factor. The Company  
10 reconciles MISC recoveries with actual costs or benefits on  
11 a three-month lag.

12 The PPA factor is also applicable to all energy  
13 deliveries (excluding NYPA Power For Jobs allocations)  
14 as a uniform factor. This factor recovers the cost or  
15 benefit of the Company's PPA with Constellation for  
16 energy and capacity from NMP2. As previously indicated,  
17 the benefit or cost is calculated by measuring the  
18 difference between the contract price and the actual  
19 market price, as included in the MPC. The PPA factor  
20 also includes an allowance for uncollectibles. The PPA  
21 factor is calculated on a monthly basis based on the

ELECTRIC FORECASTING PANEL

1 cost incurred or benefit realized, as compared to actual  
2 market price, during the previous month divided by  
3 projected deliveries for the collection period, and is  
4 also subject to reconciliation similar to the MISC.

5

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

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

ELECTRIC FORECASTING PANEL

1

2 Q. Is the Company proposing any changes to the way it  
3 recovers purchased electricity costs?

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

13 Despite the sale of the Company's fossil and  
14 nuclear generating facilities, the unbundling of the  
15 supply and delivery function, the implementation of MFCs  
16 and the establishment of a mature wholesale electricity  
17 market, the Company continues to bear the obligation to  
18 forecast, procure, and manage the electricity supply  
19 obligation for the great majority of its customers. The  
20 Company continues to source and contract for cost  
21 effective supply on behalf of those customers that

ELECTRIC FORECASTING PANEL

1 choose to purchase their supply from the Company. Full  
2 recovery of these purchase costs is essential to the  
3 financial health and stability of the Company, absent  
4 the ability to control generation and wholesale market  
5 costs.

6

7 Q. Is the Company proposing any changes to these  
8 mechanisms?

9 A. Yes. The Company is proposing to update, on an annual  
10 basis, the uncollectible rate utilized in the  
11 calculation of the uncollectible allowance to reflect  
12 the most recent calendar year's charge-offs. Although  
13 the current uncollectible allowance component of ECAM  
14 fluctuates as commodity and commodity-related prices  
15 fluctuate, a static factor does not reflect changes in  
16 the overall rate of charge-offs as a percent of total  
17 revenue subject to bad-debt.

18

19 Q. Please explain how the factor of adjustment was  
20 determined.

ELECTRIC FORECASTING PANEL

1 A. The factor of adjustment of 1.042 approved by the  
2 Commission in Case 05-E-0934 was based on a three-year  
3 average ended June 30, 2006. Similarly, the Company  
4 proposes to continue to utilize a three-year average to  
5 strike the balance between reflecting current loss  
6 activity without producing a high degree of volatility.  
7 For the three years ended March 31, 2008 the average was  
8 1.045. The Company recommends that this factor be  
9 reviewed prior to the Commission's decision in this  
10 proceeding to reflect the most recent three years of  
11 data available at the time.

12  
13 Q. Is the Company proposing to make any other rate related  
14 changes?

15 A. Yes. Pursuant to the Commission's Order in Cases 03-E-  
16 0640 and 06-G-0746, issued and effective April 20, 2007  
17 ("RDM Order"), the Company is proposing implementation  
18 of a true-up based delivery service revenue decoupling  
19 mechanism ("RDM") coincident with the commencement of  
20 the Rate Plan resulting from the instant proceeding  
21 ("Rate Plan").

ELECTRIC FORECASTING PANEL

1

2 Q. Did the Commission address any RDM requirements in its  
3 RDM Order?

4 A. Yes. The Commission ordered that RDMs "should  
5 incorporate the following factors:

6 - The mechanism should be designed to true-up  
7 forecast and actual utility delivery service  
8 revenues for a given time period.

9 - The mechanism should be designed to prevent gaming  
10 by the utility (e.g., shifting customers to  
11 different classes).

12 - The recovery of any net lost revenue component of  
13 the mechanism should not, in and of itself, produce  
14 inter-class revenue re-allocations between customer  
15 classes (such re-allocations should only be made  
16 purposefully after considering a current fully-  
17 allocated cost of service study).

18 - All remaining design and implementation issues  
19 should be addressed in individual rate  
20 proceedings." (RDM Order, p. 16)

21

ELECTRIC FORECASTING PANEL

1 Q. Please provide an overview of the Company's proposed  
2 RDM.

3 A. The Company is proposing a RDM design based on a unit  
4 per customer ("UPC") model to refund/recover revenue  
5 increases/decreases resulting from the comparison of  
6 actual UPC to the levels that will be contained in the  
7 Rate Plan approved by the Commission in the instant  
8 proceeding.

9

10 Q. Will the RDM be applicable to all service  
11 classifications?

12 A. No. The RDM would be applicable to S.C. Nos. 1, 2, 3,  
13 6, 13 and 14, with S.C. Nos. 5, 8 and 9 exempt.

14

15 Q. Why is the Company proposing to exempt these service  
16 classifications from a RDM?

17 A. The rate structure for S.C. Nos. 5 and 8 is based on  
18 fixture type, with the rates for S.C. No. 5 including  
19 the lease of fixtures and rate for S.C. No. 8 dependent  
20 on the level of service provided: Company owned and  
21 maintained, customer owned and Company maintained, or

ELECTRIC FORECASTING PANEL

1 customer owned and maintained. Sales to these classes,  
2 as measured in kWh, are not metered, but are based on  
3 the fixture type and hours of operation. As a result,  
4 the rate structures for these classes generally preempt  
5 application of a RDM. Similarly, S.C. No. 9 would be  
6 exempt as the rate structure for this class is based on  
7 number of signal faces.

8

9 Q. How will the RDM be applied to S.C. No. 14 if there is  
10 no Rate Plan forecast for this class?

11 A. As previously indicated, due to the relatively minor  
12 activity in this service class, customer and sales  
13 levels for service provided under S.C. No. 14 have been  
14 included in the respective parent service  
15 classifications. The RDM would continue to apply this  
16 methodology.

17

18 Q. How will the RDM targets be determined?

19 A. For each month of the Rate Plan, total service class, or  
20 sub-class, billing determinant units, kWh and/or kW as  
21 applicable, will be divided by customer months to

ELECTRIC FORECASTING PANEL

1 determine the monthly UPC target. However, reactive  
2 demand ("Rkva") for S.C. Nos. 3 and 13 will not be  
3 subject to the RDM due to the relatively small amount of  
4 revenue collected through this charge.

5

6 Q. How will actual UPC be calculated and how frequently  
7 will actual UPC be compared to the target levels?

8 A. Actual UPC will be determined in the same manner as the  
9 target UPC on a monthly basis.

10

11 Q. Please explain how the revenue excess or shortfall  
12 corresponding to differences in UPC will be calculated.

13 A. The UPC difference for each target item will be  
14 multiplied by the actual number of customers to  
15 calculate the unit difference. The unit difference will  
16 then be multiplied by the applicable delivery rate to  
17 determine the excess or shortfall of allowed monthly  
18 base revenue. For S.C. Nos. 1, 2 and 6, the unit  
19 difference will also be multiplied by applicable  
20 Merchant Function Charge ("MFC") rates to determine the  
21 excess or shortfall of allowed MFC revenue, with the

ELECTRIC FORECASTING PANEL

1 total unit difference multiplied by the MFC  
2 Administration Charge and the proportion of the unit  
3 difference for which the Company provided commodity  
4 service multiplied by the MFC Supply Charge.

5

6 Q. How will any excess or shortfall of allowed revenue be  
7 treated?

8 A. Any excess or shortfall of allowed revenue will be  
9 deferred and will be subject to carrying charges  
10 calculated at the authorized pre-tax rate of return for  
11 refund/recovery.

12

13 Q. How will any refund/recovery be accomplished?

14 A. On a calendar-month basis, RDM refund/recovery factors  
15 will be determined by service class, or sub-class, on a  
16 unit, kWh or kW, specific basis by dividing any excess  
17 or shortfall of allowed revenue by an estimate of billed  
18 units. The factors so determined will be applied to the  
19 total measured quantities included in bills for which  
20 meters are read on and after the effective date of the

ELECTRIC FORECASTING PANEL

1 factors. The average of the current and prior month's  
2 RDM factors will be applied to bimonthly bills.

3

4 Q. Will refunds/recoveries through the RDM factors be  
5 reconciled?

6 A. Yes. Actual RDM refunds/recoveries will be reconciled  
7 similar to ECAM, on a three-month lag corresponding to  
8 completion of such refunds/recoveries, to the amounts  
9 utilized to set the factors. Any over or under  
10 recoveries will be refunded to or collected from  
11 customers on a monthly basis through the RDM factors.

12

13 Q. Will this RDM proposal include any thresholds to  
14 mitigate the potential bill impact associated with any  
15 calculated refunds/recoveries?

16 A. Yes. The Company proposes that for S.C. Nos. 1 and 6,  
17 RDM factors not exceed +/- 25 percent of the underlying  
18 unit delivery rate. Amounts in excess of this threshold  
19 will remain deferred for future disposition through  
20 subsequent factor determinations or as approved by the  
21 Commission.

ELECTRIC FORECASTING PANEL

1

2 Q. Does the Company's RDM proposal meet the Commission's  
3 requirements as included in the RDM Order?

4 A. Yes. The Company has proposed a true-up mechanism,  
5 which will utilize Rate Plan and actual data, preventing  
6 shifting of customers between classes, and is designed  
7 on a service class or sub-class basis, preventing inter-  
8 class revenue re-allocation between customer classes.

9

10 Q. Have RDMs been implemented at any other utilities in the  
11 State?

12 A. Yes. RDMs have been implemented at Consolidated Edison  
13 Company of New York, Inc.<sup>9</sup> ("ConEd"), Orange and Rockland  
14 Utilities, Inc.<sup>10</sup> ("O&R") and National Fuel Gas  
15 Distribution Corporation<sup>11</sup> ("NFG").

16

17 Q. Are all of these RDMs similar to the UPC model proposed  
18 here?

---

9 Order Establishing Rates for Electric Service, Case 07-E-0523, Issued and Effective March 25, 2008.

10 Order Concerning Proposed Revenue Decoupling Mechanism and Energy Efficiency Programs, Case 06-E-1433, Issued and Effective January 16, 2008.

11 Order Establishing Rates for Gas Service, Case 07-G-0141, Issued

ELECTRIC FORECASTING PANEL

1 A. No. ConEd's RDM is based on a total revenue model  
2 despite the Administrative Law Judge's recommendation,  
3 and support from the National Resource Defense  
4 Council/Pace Energy Project and Consumer Protection  
5 Board, for a revenue per customer model (similar to an  
6 UPC). O&R's RDM is also based on a total revenue model  
7 however, in a statement issued on April 30, 2008, O&R  
8 stated that it agreed to the total revenue model "in  
9 order to reach a settlement with Staff."<sup>12</sup>

10

11 Q. Why have the UPC or revenue per customer models been  
12 opposed?

13 A. In Case 07-E-0523 (ConEd) the DPS Staff RDM Panel  
14 opposed the Company's per-customer RDM model on the  
15 grounds that these types of models create "a strong  
16 potential for gaming the estimated number of  
17 customers."<sup>13</sup>

18

---

and Effective December 21, 2007.

12 Orange and Rockland Utilities, Inc., Statement in Support of  
Joint Proposal, Case 07-E-0949, April 30, 2008, p. 14.

13 Prepared Testimony of Andrew Harvey, et. al. (collectively "RDM  
Panel"), In the Matter of Consolidated Edison Company of New York,  
Inc., Case 07-E-0523, September 2007, p. 16.

ELECTRIC FORECASTING PANEL

1 Q. How did the DPS Staff RDM Panel indicate a utility would  
2 game the number of customers?

3 A. The RDM Panel indicated that a utility would  
4 intentionally underforecast the number of customers  
5 and/or encourage customers that had a number of  
6 facilities under one meter to treat each facility as a  
7 separate customer.

8

9 Q. Do you agree with these assertions?

10 A. No. First, as previously indicated, the Company  
11 believes that delivery rates should be based on the best  
12 forecast possible. Moreover, if the Company were to  
13 submit direct testimony supporting an intentional  
14 underforecast of customer levels other active parties in  
15 the proceeding would undoubtedly ensure that such  
16 forecasts were not adopted by the Commission in its  
17 final order. Finally, it is highly unlikely that  
18 customers with a number of facilities under one meter  
19 could be encouraged to agree to separate billing for  
20 each facility as such billing would entail increased  
21 cost to the customer as a result of separate monthly

ELECTRIC FORECASTING PANEL

1 basic service (customer) charges and might also entail  
2 increased delivery costs if the separate accounts failed  
3 to meet usage thresholds and were transferred to  
4 different service class rates.

5

6 Q. Do you agree with the assertions that the Company should  
7 not be allowed to retain increased revenues associated  
8 with growth in number of customers?

9 A. No. While the Company is not supporting a marginal cost  
10 of service study in this filing, common sense indicates  
11 that increased customer levels entail increased costs  
12 related to such items as system connection, maintenance  
13 and customer support. For example, additional customers  
14 require additional plant investment for connection to  
15 the system, resulting in increased depreciation expense.

16

17 Q. Has a similar RDM model been implemented at any other  
18 New York State utility?

19 A. Yes. In Case 07-G-0141, NFG proposed, DPS Staff  
20 supported and the Commission approved a revenue per  
21 customer based RDM. The DPS Staff Gas Rates Panel in

ELECTRIC FORECASTING PANEL

1 Case 07-M-0906 also recommended development of a revenue  
2 per customer RDM for both New York State Electric & Gas  
3 Corporation and Rochester Gas & Electric Corporation.

4

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

6 A. Yes, it does.