BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service — Case 14-E-___

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service — Case 14-G-___

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DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

July 25, 2014

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Please state the names of the members of the Forecasting and Rates ("Panel").

A. We are Glynis Bunt, Darlene Clay and Amy Dittmar.

Q. Ms. Bunt, please state your employer and business address.

A. I am employed by Central Hudson Gas & Electric Corporation ("Central Hudson" or the "Company") and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. Ms. Bunt, in what capacity are you employed by Central Hudson?

A. I am employed by Central Hudson as Senior Director of Cost, Rates, and Forecasts.

Q. Ms. Bunt, what is your educational background and professional business experience?

A. I hold an Associate in Science Degree in Business Administration from Dutchess County Community College, a Bachelor of Science Degree in Business Administration from the State University of New York at New Paltz, and a Master of Business Administration Degree with a concentration in Finance from Marist College. I have been continuously employed by Central Hudson since June 1987 in positions of increasing responsibility in the Internal Auditing, Financial Planning, and Cost and Rate Divisions. I was promoted to Director of Cost, Rates and Forecasts in September 2002 and to my current position in March 2011.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Ms. Bunt, have you previously testified before the New York State Public Service Commission ("Commission")?

A. Yes. I have testified before this Commission in Cases 95-G-1034, 05-E-0934, 05-G-0935, 08-E-0887, 08-G-0888, 09-E-0588, 09-G-0589, 12-M-0192 and have submitted an affidavit in 07-M-1139.

Q. Ms. Clay, please state your employer and business address.

A. I am employed by Central Hudson and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. Ms. Clay, in what capacity are you employed by Central Hudson?

A. I am employed by Central Hudson as an Associate Cost and Rate Analyst.

Q. Ms. Clay, what is your educational background and professional business experience?

A. I hold an Associate in Science Degree in Liberal Arts from Dutchess County Community College and a Bachelor of Science Degree in Business Administration with a concentration in Finance from Marist College. I have been employed by Central Hudson since 2006 in various positions within the Customer Accounting and Treasury divisions. I was promoted to the position of Customer Choice Coordinator in October 2011 and was subsequently transferred to my current position of Associate Cost and Rate Analyst in August 2013. Prior to my employment with Central Hudson, I was a Branch Manager for M&T Bank Corporation for 10 years.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Ms. Clay, have you previously testified before the Commission?

A. Yes. I have testified before the Commission in Case 12-M-0192.

Q. Ms. Dittmar, please state your employer and business address.

A. I am employed by Central Hudson and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. Ms. Dittmar, in what capacity are you employed by Central Hudson?

A. I am employed by Central Hudson as a Cost and Rate Analyst.

Q. Ms. Dittmar, what is your educational background and professional business experience?

A. I received a Bachelor of Science Degree in Financial Economics with a Business Management adjunct from Binghamton University in 2004 and a Masters in Business Administration from Marist College in 2013. I was employed by Central Hudson in February 2006 as an Accounting Clerk in the Plant Accounting Division. I was then promoted to the position of Assistant Financial Analyst in May 2006 and was subsequently transferred to the position of Assistant Cost and Rate Analyst in January 2008. I was promoted to Associate Cost and Rate Analyst in January 2009 and was promoted to my current position of Cost and Rate Analyst in March 2014.

Q. Ms. Dittmar, have you previously testified before this Commission?

A. Yes. I have testified before the Commission in Cases 08-G-0888 and 09-G-0589.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. What is the purpose of the Panel's testimony in this proceeding?

A. The Panel presents projected inflation rates as well as the following with respect to electric and gas service: 1) historical sales and revenues; 2) the development of the forecast of electric and gas customers, and sales and base delivery revenues for all service classes for the period April 1, 2014 through June 30, 2016; 3) the development of the projection of interruptible gas sales and revenues, and an overview of the current mechanism for interruptible profit calculation; 4) the interclass revenue allocation of the Company's proposed electric and gas delivery rate changes; 5) the proposed changes in the Company's electric and gas delivery rates and the revenue effect of those changes; 6) the Company's method for collecting purchased power costs from customers; 7) the Company's method for collecting natural gas supply costs from customers; and 8) the electric loss factor. The Panel also addresses the status of the Company's implementation of applicable management audit recommendation from Northstar Consulting Group's Final Audit Report, dated February 28, 2011 in Case 09-M-0764, related to Central Hudson's electric peak load model.

Q. Are you sponsoring any exhibits in support for your testimony?

A. Yes, we are sponsoring the following Exhibits:

Exhibit __ (FRP-1) contains a Statement of Electric and Gas Operating Revenues.

Exhibits __ (FRP-2) and __ (FRP-3) contain a summary of electric and gas sales, base delivery revenues and customers.

Exhibits __ (FRP-4) and __ (FRP-5) contain a summary of electric and gas model specifications and statistics.

Exhibits __ (FRP-6) and __ (FRP-7) contain a summary of the electric and gas forecast results by forecasting group.

Exhibit __ (FRP-8) summarizes cumulative photovoltaic (“PV”) net metered kW installed.

Exhibits __ (FRP-9) and __ (FRP-10) summarize the estimated effect of proposed electric and gas revenue increases.

Exhibit __ (FRP-11) reflects a comparison of gas bills under declining block rates and flat rates based on currently effective rates.

Exhibits __ (FRP-12) and __ (FRP-13) reflect a summary of present and proposed electric and gas rates.

Exhibits __ (FRP-14) and __ (FRP-15) reflect a comparison of present and proposed electric and gas rates.

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

A. A Gross Domestic Product (“GDP”) implicit price deflator was developed using the consensus forecast of Blue Chip Economic Indicators included in the March 10, 2014 publication. An extrapolation from this forecast was used to develop the forecast for the rate year ending June 30, 2016 ("Rate Year") shown below.

GDP Implicit Price Deflator		
Year	Index 2009=100	Annual Percent Change
2013	106.5	1.4 over 2012
12 Months Ended March 2014	106.9	0.4 over 2013
2014	108.3	1.3 over 12 ME March 2014
2015	110.3	3.2 over 12 ME March 2014
Rate Year	111.4	1.1 over 2015

Q. Turning to the subject of electric and gas service, please begin by describing your exhibits which summarize sales, revenue and customer data for recent historical periods and for 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 2011, 2012 and 2013, and the twelve months ended March 31, 2014, the operating revenues of the Company by prime revenue account, as required by the Commission's policy statements and rules. These exhibits also show for each revenue account, the kilowatt hour ("kWh") or thousand cubic feet ("Mcf") of electricity or gas delivered (designated as sales), base delivery revenue and the average base delivery revenue per kWh or Mcf sold.

Exhibit __ (FRP-2) consists of six schedules. Schedule A presents a summary by customer class of electric sales, base delivery revenues and customers for the twelve-month periods ended March 31, 2014, December 31, 2014, December 31, 2015, and June 30, 2016. Schedule B sets forth monthly electric sales, base delivery revenue and customer data by revenue account for the twelve months ended March 31, 2014. Schedules C through F contain similar monthly information by service classification ("S.C.") for the twelve-month periods ended March 31, 2014, December 31, 2014, December 31, 2015, and June 30, 2016, respectively.

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

Q. Were sales to full service customers (i.e., those customers continuing to purchase their energy and/or natural gas requirements from Central Hudson) addressed differently in your forecast than sales to retail access and/or transport customers?

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

Electric and Gas Sales Forecasts

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

A. Yes, they were.

Q. Can you please provide an overview of the process by which the forecast of electric own territory and firm gas sales were developed?

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

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

A. Generally, this approach was applied to the classes with relatively large numbers of customers. Separating total consumption into customer and sales per customer components recognizes that each component is influenced by different factors and provides the opportunity to incorporate more structure into the analysis of total consumption. For instance, total residential consumption can be influenced by such factors as customer count (e.g., total number of residential customers), weather, and the economy. In this example, weather will most likely not influence the number of customers, but could greatly influence use per customer. As a result, separating total consumption into components provides the opportunity to incorporate more structure into the forecast of each component.

Q. What forecasting methodologies were used to forecast or project customer and sales levels?

A. Forecasts of customers and sales were developed utilizing various econometric or time series models, or trend projections, as summarized in the table below. The models developed to produce the forecasts were estimated using actual monthly billed customer and sales data covering the period January 1997 to March 2014. Estimation periods vary somewhat for the different classes in order to recognize structural changes to the billing process and data quality issues that can sometimes limit data availability. For example, revisions to billing cycles, in terms of customer composition, and recording of customers' end-use category (residential, commercial, industrial, etc.) can cause shifts in data requiring different estimation periods.

A summary of the methods utilized to develop each forecast is provided below, with detail regarding model specifications and statistics presented on Exhibit __ (FRP-4) for electric forecasts and Exhibit __ (FRP-5) for gas forecasts. Electric forecast results for each class, and in total, are shown on Exhibit __ (FRP-6). Similarly, gas forecast results for each class, and in total, are shown on Exhibit __ (FRP-7).

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

List of Electric Customer and Sales Forecast Methods		
Class	Customers	Sales
Res. Heat	econometric	econometric (per customer)
Res. Non-Heat	econometric	econometric (per customer)
Com. Demand	time series	econometric (per customer)
Com. Non-Dmd.	time series	econometric (per customer)
OPA Demand	time series	econometric (per customer)
OPA Non-Dmd.	time series	econometric (per customer)
Ind. Demand	historic constant	econometric (per customer)
Ind. Non-Dmd.	historic constant	econometric (per customer)
SC 13	individual	individual
Area Light	historic trend	fixture specific growth
Street Light	historic constant	fixture specific growth
Traffic Signal	historic trend	historic trend
Interdepartmental	historic constant	historic constant

List of Gas Customer and Sales Forecast Methods		
Class	Customers	Sales
Res. Heat	econometric	econometric (per customer)
Res. Non-Heat	time series	econometric (per customer)
Com. Heat	time series	econometric (per customer)
Com. Non-Heat	time series	econometric (per customer)
OPA	historic constant	econometric (per customer)
Industrial	linear regression	econometric (per customer)
Interdepartmental	historic constant	historic constant

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

A. Econometric models were constructed to forecast customer levels for the residential classes. Two types of variables were employed in the specification of these models: economic and binary (or dummy), with the number of households utilized as the economic variable.

Q. Can you please explain what economic and binary variables are?

A. For the purposes of the forecast presented here, economic variables represent measurements of demographic or economic activity including, but not limited to, such items as population, GDP and household income. Utilization of binary or “dummy” variables is reflected in many of the customer and sales models presented here, consistent with standard modeling practices. In many instances, this type of variable was added as a switch to turn various parameters on and off, such as differences in odd/even month billing to reflect bimonthly billing for certain accounts, or to accommodate a specific data point to reduce model error, while maintaining a longer estimation period.

Q. Please continue with your discussion of the structures of the models used to develop the electric customer forecasts.

A. The customer levels for the commercial and Other Public Authority (“OPA”) classes were developed utilizing exponential smoothing models. The exponential smoothing technique was applied to the time series of monthly billed customers in each of the respective classes. This technique replicates the underlying trends, placing more emphasis on the most recent data.

The small industrial demand and non-demand customer forecasts were developed by maintaining the historic year levels.

As of March 31, 2014, Central Hudson provided transmission or substation service to fourteen customers under the provisions of S.C. No. 13. The Company expects to continue providing service to twelve of these customers with one expected to self-supply under the New York Independent System Operation's ("NYISO") station service tariff, and one terminating operations.

The Company has experienced diminishing customer growth in S.C. No. 5 (Area Lighting) and little to no customer growth in S.C. No. 8, (Street Lighting) in recent years. As a result, overall contraction in area lighting customers is anticipated for the forecast period, while the street lighting customer level as of March 31, 2014 was maintained throughout the forecast period.

As approved by the Commission in its Order in Case 00-E-1273, S.C. No. 9, which provides unmetered service, was closed to new customers effective November 1, 2001. Customers requiring service for new traffic signals are now required to take service under S.C. No. 2. Since the closing of this service class, the Company has experienced a minor contraction in the customer level for this class. As a result, continued contraction in customers is anticipated for the forecast period.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

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

A. Econometric models were constructed to forecast customer levels for the residential heating class. Two types of variables were employed in the specification of this model: economic and binary (or dummy). The model specification for the residential heating class utilizes population. The residential and commercial heating and non-heating class customer forecasts reflect utilization of exponential smoothing models.

Many schools, hospitals and government offices, which could be included in the OPA classification, are coded as commercial heating. As a result, the customer forecast assumes no growth in the forecast period, reflecting the most recent trend in historic data.

Q. Please explain how the industrial customer forecast was developed.

A. The industrial customer forecast was developed by applying a linear regression equation to the rolling twelve-month average customer level. The resulting forecast customer level for each calendar year was then allocated to calendar month using the average of the actual odd/even billing pattern for calendar years 2009 through 2013.

Q. Are there any other items you would like to note regarding customer forecasts?

A. As was reflected in the final customer forecasts in Case 09-G-0589, the Company has continued to include a post-forecast adjustment to account for the difference between the historic aggregate customer counts as reported by the billing system and the historic customer counts reflected in the forecasting models.

Q. What is the source for the economic data utilized in the Company's forecast models?

A. Economic projections for the region served by the Company were based on the April 2014 forecast provided by Moody's Economy.com to the NYISO for statewide forecasting. Composite forecast drivers for the Central Hudson region were constructed from four data regions included in the forecast: Albany, Catskills, Dutchess County and Newburgh. The composite economic forecast drivers were calculated as a weighted sum of the regional forecasts, where the weights reflect actual average residential and non-residential sales in the region for calendar years 2011 through 2013.

These data were the latest available to the Panel at the time of the preparation of our analyses. We recommend, later at an appropriate time, that the data employed by the Company and any party be fully updated, and models re-specified as appropriate to reflect changes to methodology, variables, and/or estimation period resulting from this updated data.

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

A. As discussed later in our testimony, post-forecast adjustments are made to reflect the Energy Efficiency Portfolio Standard ("EEPS") in conjunction with Case 07-M-0548. As a result, modifications were first made to adjust historic data to reflect the EEPS savings estimated to actually have been acquired in the historic period. Estimated actual savings reflect information filed on Company and the New York State Energy Research and Development Authority ("NYSERDA") scorecards in Case 07-M-0548 through December 31, 2013, as this was the most up to date information available at the time of preparation. Econometric models were then constructed to forecast all electric classes, excluding: 1) S.C. No. 13, 2) the three lighting classes, and 3) interdepartmental. Econometric models were also constructed for all firm gas classes, excluding interdepartmental and S.C. No. 11. Further, the forecasts developed for the electric residential and commercial classes and all firm gas classes utilize Statistically Adjusted End-Use ("SAE") models.

Q. What is the SAE model approach?

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

Q. What is the goal of this approach?

A. The goal of the SAE model approach is the construction of sound theoretical forecast models through the identification and utilization of variables that impact energy consumption, including incorporation of estimated long-term impacts in end-use saturation and appliance efficiency trends.

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

A. Residential appliance and commercial end-use saturation and efficiency trends are based on Energy Information Administration estimates for the Middle Atlantic Census Region as compiled by Itron, Inc. Where possible, electric estimates are calibrated to Central Hudson's service territory based on results from the Company's Residential Appliance Saturation and/or Energy Management surveys.

Q. Can you please describe these surveys?

A. For the period 1977 through 2006, the Company surveyed its residential customers eleven times to obtain information about housing stock, appliance saturation, usage patterns, preferences, and household characteristics in order to assist in the determination of growth in energy demand. In 2013, the Company commissioned an energy management survey of its residential customers to assist in efforts to develop and promote effective energy efficiency programs.

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

A. We used the latest information available to us at the time of the preparation of our analyses. The historic price series for each class was determined as a function of the total bundled revenue (including delivery and supply) billed to full service customers divided by sales to full service customers in each class. Monthly forecast prices for each class include applicable base delivery charges, projected delivery rate increases of approximately 12 percent effective July 1, 2015 and 3.5 percent annually thereafter, as well as Merchant Function Charges (“MFC”), the New York State Assessment (“NYSA”), System Benefits Charges (“SBC”), including the Renewable Portfolio Standard Charge and EEPS Charge, the Purchased Power Adjustment (“PPA”), Miscellaneous Charges and the Market Price Charge (“MPC”). The MPC, or supply price, was forecasted using monthly regression equations to estimate MPC prices as a function of the on-peak price forecast for NYISO Zone G as of April 29, 2014 as obtained from SNL.com. The price variable is expressed as the Consumer Price Index (“CPI”)-indexed twelve-month moving average on a one-month lag.

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

A. We used the latest information available to us at the time of the preparation of our analyses. The historic price series for each class was determined as a function of the total bundled revenue (including delivery and supply) billed to full service customers divided by sales to full service customers in each class. Monthly forecast prices for each class include applicable base delivery charges, and a projected delivery rate increase of approximately 16 percent effective July 1, 2015, as well as the MFC, the NYSA, the SBC, the Renewable Portfolio Standard Charge, an estimate for the EEPS Charge in Case 07-M-0548, and the Gas Supply Charge ("GSC"). The forecast of the GSC, or supply price, reflects utilization of assets currently under contract to Central Hudson, including pipeline transport, storage and commodity supplies, with commodity supply based on New York Mercantile Exchange ("NYMEX") natural gas futures prices as of April 29, 2014. The price variable is expressed as the CPI-indexed twelve-month moving average on a one-month lag.

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

A. The residential class models utilize household income and household size, while the OPA class models utilize household size. Commercial models utilize GDP while industrial models utilize manufacturing employment. As previously noted, these data are part of the forecast supplied by Moody's Economy.com and subsequently compiled by Central Hudson to correspond more precisely to the Company's service territory.

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

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

Q. How is weather incorporated into the sales models?

A. Monthly actual heating degree days ("HDD") and cooling degree days ("CDD") are transformed into billed HDDs to more closely correspond to the sales billing periods. The sales forecasts are based on normal weather conditions, where the normal weather is determined by a ten-year average of monthly HDD or CDD, as applicable and pursuant to the Commission's Order in Cases 08-E-0887 and 08-G-0888, based on hourly temperature readings obtained from the Dutchess County Airport for the calendar year ending 2013, which is the latest calendar year for which this information was available at the time the Company prepared its sales forecast. We recommend that the latest ten-year average ending December be reflected in the final Rate Year forecasts utilized to determine the revenue requirement and rate design.

Q. Please define a HDD.

A. Weather is expressed in terms of degree days measured over an electric day and a gas day consistent with industry standard definitions of these days. Electric HDDs are defined as the amount by which 65 degrees fahrenheit exceeds the average of the high and low temperatures for a given day as measured midnight to midnight. Gas HDDs are defined as the amount by which 65 degrees fahrenheit exceeds the twenty-four hour average of temperatures for a given gas day as measured 10 AM to 10 AM.

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Q. Please define a CDD.

A. CDDs are measured for electric only and are defined as the amount by which the average of the high and low temperatures for a given day, as measured midnight to midnight, exceed 65 degrees fahrenheit.

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

A. Yes. The electric and gas residential sales models include price, income and household size elasticity estimates. The electric and gas commercial and gas OPA and industrial include price and GDP elasticity estimates.

Q. Would you please define the electric S.C. No. 13?

A. S.C. No. 13 includes customers who require service at transmission voltage or who have provided all the necessary equipment to take service directly from a substation.

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

A. The sales forecast for this class has been developed based on discussions with these customers over the period April – May 2014. These customers provided the Company with either written or verbal general forecasts/indications of future electric consumption. The customers were asked to comment on potential changes in usage, demand, or operations affecting electric consumption for a period of several years, including the Rate Year.

In the absence of customer provided forecasts/indications, the Company considered historical customer-specific information including, but not limited to, usage, demand and load factor data in order to develop customer-specific forecasts.

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

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

Q. How were sales under S.C. No. 9 (Traffic Signals) forecast?

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

Q. Does the Company have interdepartmental sales and how were those sales forecasts developed?

A. Yes, the Company has such sales. Based on the extremely small volume of such sales, they were projected by analyzing several years of actual sales data. The electric forecast is based on the most recent three years of historic data, while the gas sales forecast was developed using the most recent two-year average of historic data. Both electric and gas interdepartmental sales held constant throughout the forecast period.

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

A. All forecasting methodologies are generally consistent with those presented by the Company in Cases 09-E-0588 and 09-G-0589, although different methodologies have been applied to different customer classes.

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

A. No. Historic sales to S.C. No. 14 have been fairly erratic and since this service class is included in the interruptible profit mechanism we discuss later, a forecast has not been developed for this class. The Company also did not prepare a forecast of Sales for Resale, which are commodity sales, since the Company's filing in this proceeding pertains to delivery service. Historic sales for resale are reflected, but associated historic revenues are not, as those revenues are addressed within the Gas Cost Adjustment.

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

A. Yes. The electric sales reductions attributable to the EEPS were developed by allocating certain annual reductions identified in various Orders issued by the Commission in Case 07-M-0548 across applicable customer classes and months based on the pre-adjustment forecast of sales.

The gas sales reductions attributable to the EEPS were developed by allocating the annual reductions itemized in various Orders issued by the Commission in Case 07-M-0548 across months based on historic actual acquired savings.

Although no specific targeted reduction values have been identified by the Commission beyond 2015, annual electric and gas reductions for EEPS programs were held at 2015 levels in 2016-2019 in anticipation of EEPS Phase III. The Panel believes this is reasonable because failing to recognize any additional reductions in out years would not be consistent with the Commission's longer term support of energy efficiency initiatives.

Q. Were any additional changes made by the Panel to forecasted sales that are external to the models?

A. Yes. Consistent with the approved forecasts in Cases 08-E-0887 and 09-E-0588, adjustments were made to the electric sales forecast to reflect forecasted sales reductions resulting from increased penetration of residential and non-residential net-metered PV systems.

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

A. Effective November 1, 2012, the Commission raised the overall net-metering ceiling for Central Hudson from 12 MW to 36 MW. This action, together with additional legislation enacted 2012 to expand the net-metering provisions of Public Service Law §66-j and §66-i (addressed by the Commission in Cases 10-E-0133, 10-E-0406, 10-E-0645, 11-E-0318, 12-E-0043, 12-E-0393 and 13-E-0421) and Central Hudson's continued active support of solar resources, are expected to produce further sales reductions as new solar installations are made. As a result, it is necessary to build into the sales forecast, and ultimately into base rates, a forecast of sales reductions resulting from the additional PV penetration above the level currently included in approved rates pursuant to Case 09-E-0588.

Q. Please explain how these sales reduction adjustments for PV penetration were developed.

A. In developing sales reductions attributable to increased penetration of net-metered PV systems, the Company employed the same methodology approved by the Commission in Case 09-E-0588. The sales reductions attributable to PV penetration are based on a forecast of net-metered PV installations developed by applying a polynomial regression to the monthly cumulative kilowatt (“kW”) installed for the period January 2012 through March 2014, reflecting the most recent response to legislative, regulatory and Company initiatives. This model is presented on Exhibit __ (FRP-8).

Q. Aside from PV, were any additional changes made by the Panel to forecasted sales that are external to the models?

A. Yes. Post forecast adjustments were made to the gas forecast to reflect the Company’s recent franchise territory expansion efforts in both the Athens area, pursuant to Case 13-G-0336, and the Town of Beekman.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. What do the Company's final electric and gas sales forecasts show?

A. While the Company continues to experience growth in the number of electric and gas customers, overall use per customer has decreased significantly since 2005. Use per customer is forecast to continue to decline, with usage reductions due to the EEPS in Case 07-M-0548 and lost electric sales due to PV net-metering contributing to this decline. As a result, electric and gas sales are forecast to decrease during the Rate Year. Electric own territory sales (excluding unbilled) as shown on Schedule A of Exhibit __ (FRP-2) are forecast to decrease by 73,314 MWh, or 1.5 percent, based on the Rate Year estimate of 4,919,680 MWh as compared to the calendar year 2014 estimate of 4,992,994 MWh.

Gas own territory sales (excluding unbilled, Sales for Resale and S.C. No. 14) as shown on Schedule A of Exhibit __ (FRP-3) are forecast to decrease by 687 MMcf, or 4.2 percent, based on the Rate Year estimate of 15,653 MMcf as compared to the calendar year 2014 estimate of 16,340 MMcf.

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

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

Q. How were the revenues associated with the sales forecast for 2014, 2015 and the Rate Year developed?

A. Monthly electric sales were based on an annual historical distribution to allocate revenue account sales to a service class or sub-class basis. Billing demands were projected based on historical load factor trends. The forecasted billing parameters derived were priced at present rates as filed by the Company in compliance with Cases 09-E-0588 and 09-G-0589.

Monthly gas sales, by forecasting group, were allocated between heating and non-heating sub-classes, for the purposes of billing block distribution. The resulting gas sales were spread between blocks based on an O-Give analysis of the actual bill distribution for calendar years 2012 and 2013. An O-Give analysis reflects a curve fitting process, which proportions actual billing blocks and billing block volumes to the forecast use per customer pursuant to the methodology proposed by New York State Department of Public Service Staff (“Staff”) in its testimony in Case 08-G-0888 and subsequently utilized in Case 09-G-0589. The monthly distributions were priced at present rates, effective July 1, 2012 as described above, with the exception of S.C. No. 11 which was priced at rates effective July 1, 2013, to obtain total base revenue.

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

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

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

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

A. Forecasts of sales/deliveries to these customers have been estimated based on historic usage patterns over the 24 months ended March 31, 2014. The forecasts were included on the assumption that these customers will continue to take service under the service classification for which they were billed as of March 31, 2014 through the forecast period.

Currently, both the Company's base delivery rates and Gas Cost Adjustment factor include credits derived from the net of fuel revenues received from interruptible sales (S.C. Nos. 8 and 9) and sales to generating facilities (S.C. No. 14). Pursuant to the Order in Case 09-G-0589 issued September 17, 2010, current base delivery rates include a profit imputation of $2.4 million estimated to be received from such sales. As a result, the Company is permitted to retain the first $2.4 million in net of fuel revenue in each rate year that it may receive from interruptible service and service to generating facilities. If the net of fuel revenue, or profit, is less than $2.4 million in any rate year, the Company is authorized to surcharge firm customers for 90 percent of the shortfall. If the margin exceeds $2.4 million in any rate year, the Company will credit to ratepayers 90 percent of the excess. Any such surcharges or credits are applied through the Gas Cost Adjustment factor as detailed below.

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

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

In step two, the imputation is applied by subtracting $2.4 million from the profit as determined in step one. Ninety percent of the resulting shortfall or excess is collected from or returned to customers.

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

A. No.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Revenue Allocation

Q. With respect to the subject of revenue allocation, please describe the criteria Central Hudson applied in allocating revenues and designing rates.

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

Q. What was the source of the constraints utilized for allocating the electric and gas revenue increases?

A. The constraints utilized for allocating the electric and gas revenue increases were based on the constraints most recently utilized and approved in Case 09-E-0588 and 09-G-0589. The Company is proposing to maintain these constraints for all electric and gas service classifications.

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

A. No.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Please explain Exhibits __ (FRP-9) and __ (FRP-10), relating to the estimated effect of the proposed revenue increases.

A. Exhibit __ (FRP-9) for electric and Exhibit __ (FRP-10) for gas each consist of two schedules that present the details of the proposed interclass revenue allocation. Schedule A details the methodology used to allocate the revenue increases among the various service classifications. Schedule B combines the allocated revenue increases from Schedule A with revenues at present rates to determine total filed base rate revenue by service classification for the Rate Year.

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

A. Electric own territory operating revenue must be increased by $40,121,000 in the Rate Year in order to meet the Company's costs of providing service. The rate increase is to be obtained from S.C. Nos. 1, 2, 3, 5, 6, 8, 9 and 13 rates as explained below.

Gas own territory operating revenue must be increased by $5,897,000 in the Rate Year in order to meet the Company's costs of providing service. The increase of $5,897,000, plus $2,400,000 that is offset through imputation to S.C. Nos. 1, 2, 6, 12 and 13 in the rate design process, or a total of $8,297,000, is to be obtained from S.C. Nos. 1, 2, 6, 12 and 13 rates as explained below.

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

A. The Company has allocated both the electric and gas proposed increases with reference to the results of the Historic 2012 and Pro-Forma Rate Year Embedded Cost of Service Studies ("ECOSS"), which are contained in Exhibits __ (COSP-1) and __ (COSP-2), Schedules A and B and supported by the testimony of the Cost of Service Panel ("COSP"). Pursuant to the methodology utilized in the Joint Proposal adopted in Cases 09-E-0588 and 09-G-0589, if the results of the ECOSS indicated varying results in the unitized rate of return for a service class, that class received an allocation of the incremental revenue requirement using the overall system average. If the results of the ECOSS did not indicate varying results in the unitized rate of return for a service class, those classes with a unitized rate of return less than 85 percent of the system average received 1.25 times the overall system average and those classes with a unitized rate of return more than 115 percent of the system average received 0.75 times the over system average. The revenue allocation methodology is a three-step process.

Q. Please elaborate on the three step process.

A. The first step is to use results from the ECOSS for the historic period and the Rate Year to determine what revenue adjustment is necessary for each class utilizing its unitized rate of return as shown in columns 1-6 of Exhibits __ (FRP-9), Schedule A and __ (FRP-10), Schedule A.

The second step is to allocate the proposed revenue increase based on total delivery service revenue, under the constraints as previously described. The results of step two are shown in columns 7 and 8 of Exhibits __ (FRP-9), Schedule A and __ (FRP-10), Schedule A. The third step then determines the resulting adjustment that must be allocated to each as a result of the previously described constraints, as shown in column 9 of these two exhibits.

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

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

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

For all other rate classes, which include S.C. Nos. 1, 9, and 13 (Substation), the unitized rate of return varied among the Historic and Pro Forma Rate Year ECOSS. As a result, these classes received an allocation of the incremental revenue requirement using the overall system average.

Application of these increases produced a revenue shortfall as compared to the rate increase revenue. This revenue shortfall was then allocated pro-rata among the service classes. The resulting increases are shown in columns 9 and 10 of Exhibit __ (FRP-9), Schedule A.

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

A. For S.C. Nos. 1 and 12, S.C. Nos. 2, 6 and 13 as well as S.C. No. 11 (Distribution), the rates of return in the ECOSS produced differing results. As such, the average overall system increase was utilized pursuant to the methodology described above.

For S.C. No. 11 (Transmission) and S.C. No. 11 (Distribution Large Mains ("DLM")), for which the rates of return exceeded the upper tolerance level of 115 percent of the system average, the minimum permissible increase of 0.75 times the average overall increase was utilized.

Application of this increase methodology produced a revenue shortfall as compared to the rate increase revenue. This revenue shortfall was then allocated pro-rata among the service classes. The resulting increases are shown in column 10 of Exhibit __ (FRP-10), Schedule A.

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

A. Yes. For each class, the base revenue increase was adjusted by the estimated difference in revenue to be collected through the redesigned MFCs for that class calculated as: 1) redesigned base MFC rates developed in the Pro Forma Rate Year ECOSS, multiplied by 2) class total deliveries. These adjustments are presented on Schedule A of Exhibits __ (FRP-9) and __ (FRP-10).

<u>Rate Design</u>

Q. Please explain Schedule B of Exhibits __ (FRP-9) and __ (FRP-10), regarding the effects of the proposed electric and gas rates.

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

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

A. Yes. The Company is proposing to eliminate the gas S.C. Nos. 1, 2, 6, 12 and 13 block rate differentials.

Q. Please explain the current and proposed rate structures for S.C. Nos. 1, 2, 6, 12 and 13.

A. Pursuant to the current rate structure provided in S.C. No. 12 (Gas), customers served under gas S.C. Nos. 1, 2, 6, 12 and 13 are subject to declining block gas base delivery rates. Under S.C. Nos. 1 and 12, separate declining rates are applied to Ccf usage based on three usage blocks: 1) the first 2 Ccf; 2) the next 48 Ccf; and 3) any additional Ccf. Under S.C. Nos. 6, 12 and 13, separate declining rates are applied to Ccf usage based on four usage blocks: 1) the first 2 Ccf; 2) the next 98 Ccf; 3) the next 4900 Ccf; and 4) any additional Ccf. The Company proposes to eliminate the declining block rate structure in favor of flat rates. The rate structure for S.C. Nos. 1, 2, 6, 12 and 13 would continue to include the first 2 Ccf in the customer charge, however all remaining Ccf billed would be at the same class-specific rates.

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

A. The proposal to eliminate declining block rates is consistent with the Commission's goal to promote energy efficiency. Declining block rates reward customers with a lower rate for greater usage, sending the wrong price signals. Customers are in a sense encouraged to increase rather than decrease consumption under the notion that the Company can provide additional power at lower costs. This is supported by a comparison of the marginal rate developed in Case 09-G-0589 to the approved tail blocks in that case, indicating the marginal rate as exceeding the tail block rates.

Q. Is there any Commission precedent or support for this proposed change?

A. In Con Edison's Case 09-E-0428, the Commission found that the elimination of Con Edison's existing electric declining block rates and a move toward a flat rate structure would promote the state's long-term energy efficiency policy by removing any incentive for customers to benefit from decreased rates for increased usage. Similarly, the Commission, in its Order issued and effective on June 17, 2011 in Case 10-E-0362, directed Orange and Rockland Utilities, Inc. ("O&R") to make a proposal in its next base rate case to replace the declining block rates charged to its electric customers receiving service under S.C. No. 2 and 3 with flat rates. O&R subsequently filed an analysis of the impacts of eliminating declining block usage rates in Case 11-E-0408. In its Order Adopting Terms of Joint Proposal, With Modification, And Establishing Electric Rate Plan issued and effective June 15, 2012 in Case 11-E-0408, the Commission approved the rate structure changes for S.C. No. 2 and S.C. No. 3.

Q. How will this change affect customers?

A. The Company understands that the elimination of declining block rates will result in some customers experiencing decreases while others experience increases in typical bills. To understand bill impacts, the Company redesigned Case 09-G-0589 Rate Year 3 rates to reflect a flat rate design. To achieve revenue neutrality, customer charges were kept at the levels agreed upon in Case 09-E-0589. The currently effective block rates and the re-designed flat rates were then used to analyze typical bill impacts. Exhibit __ (FRP-11) provides comparisons of charges for typical usages under S.C. Nos. 1/12 and 2/6/13 at Case 09-G-0589 Rate Year 3 declining block rates and at re-designed flat rates to demonstrate the impacts on bills to customers at various levels of consumption.

Q. Please describe some of the more important findings of the bill impact calculations.

A. As can be seen in Exhibit __ (FRP-11), Schedules A and B even at the actual sales per customer levels for the twelve months ending March 31, 2014 which were higher than normal given colder than average winter weather, an average residential and commercial heat customer would have experienced minor or favorable bill impacts at flat rates. Although the Company's largest numbers of customers are served under S.C. 1, the largest use per customer is attributed to S.C. 6 customers. Average use per customer for the S.C. 6 customer class as a whole for the twelve months ended March 31, 2014 was 9,175 Mcf. As shown on Exhibit __ (FRP-11), Schedule B the resulting bill impact would be an increase of approximately 3.22 percent. Customers taking service under S.C. 6 who have an annual consumption of 50,000 Ccf or greater are subject to pricing only at the tail block rate. For the twelve months ended March 31, 2014, there were approximately 85 high volume S.C. 6 customers who average use of 138,450 Ccf. The resulting bill impact on these customers would be an increase of approximately 4.30 percent, as shown on Exhibit __ (FRP-11), Schedule B. However, in order to retain these customers on firm service, the Company is proposing that a discount rate be developed for high volume S.C. 6 customers consistent with the magnitude of the current tail block discount.

Q. Are you proposing any changes to electric rate design?

A. Yes. The Company currently offers three different types of service under Service Classification No. 8 (Public Street and Highway Lighting): 1) Rate A wherein the Company owns and maintains the fixtures; 2) Rate B wherein the Company maintains customer-owned fixtures; and 3) Rate C wherein the Company provides delivery service to customer-owned and maintained fixtures. Central Hudson proposes to close Rate B to new installations while grandfathering existing installations.

Q. Why is the Company making this proposal?

A. Recently, the Company proposed to eliminate several underutilized lighting options from its tariff in order to create a more uniform asset profile resulting in a more streamlined maintenance process. These tariff changes, designated as Case 14-E-0059, were approved by the Commission at its session on May 8, 2014 to become effective June 1, 2014. The current proposal to close Rate B to new installations is another step in the process to create a more uniform asset profile. While this will limit the number of fixture types for which the Company provides maintenance service, Rate C continues to provide customers with the flexibility to choose any type of facility that will serve their needs.

Q. Are there any other electric rate design issues that you would like to address?

A. Yes. In 2011 the Company filed tariff amendments to modify the Commission's Order Establishing Rate Plan in Case 09-E-0588 by maintaining the S.C. No. 6 (Residential Time-of-Use ("TOU") Service) on-peak and off-peak delivery rates, adjusted for the rate increase effective July 1, 2012. The Company proposed this approach rather than implementing the single delivery rate that was scheduled to become effective July 1, 2012 as a result of the phase-out of the on-peak/off-peak delivery rate differential approved in Case 09-E-0588. At that time, the Company believed that the then current on-peak and off-peak delivery rates might be beneficial for residential customers acquiring plug-in hybrid vehicles and desiring to charge these vehicles during off-peak hours. In late 2013 Central Hudson agreed to be a utility partner in an analysis of electricity pricing strategies to facilitate electric vehicle adoption in New York led by M.J. Bradley & Associates LLC, the firm selected by NYSERDA to address two of the focus areas of Program Opportunity Notice 2755. The Company believes that the result of this analysis, which is not yet available, may provide viable alternative pricing structures to current TOU rates. As a result, the Company proposes to maintain the current TOU on-peak and off-peak delivery rate structure, reverting to the pre-phase out on-peak/off-peak delivery rate differential ratio of 3:1.

Q. Is the Company proposing any changes to its unbundled rate structure?

A. No. The Company is proposing to continue to maintain the unbundled rate structure approved by the Commission in the Company's most recent general rate proceeding, Cases 09-E-0588 and 09-G-0589, including recovery of net lost revenues related to MFCs. However, the Company proposes to update certain rate elements to reflect the results of the ECOSS. The update to base rates (excluding lost revenue) for the MFC Administration Charge and the MFC Supply Charge as reflected on Schedule A of Exhibits __ (FRP-12) and __ (FRP-13) as well as the update to the billing services credit are based on the results of the ECOSS, as contained in Exhibits __ (COSP-1) and __ (COSP-2), Schedule C. The proposed updates to the billing services credit are shown below.

Per Bill Billing Services Credit	**Current**	**Proposed**
Electric	$1.38	$1.37
Gas	$1.02	$0.95

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

A. For S.C. No. 1, the monthly customer charge was increased from $24.00 to $30.00. The monthly customer charge for S.C. No. 6 was increased by approximately the same percentage, from $27.00 to $34.00. These changes are intended to bring the customer charge closer to the embedded costs shown on Schedule C of Exhibit __ (COSP-1), and supported by the testimony of the COSP. A flat delivery rate of $0.05409 per kWh was developed to produce the remainder of the S.C. No. 1 revenue requirement.

The on-peak and off-peak delivery rate differential for S.C. No. 6 was reinstated with a rate differential ratio of 3:1, as previously discussed. This resulted in on-peak and off-peak delivery rates of $0.08964 and $0.02988 per kWh, respectively, to produce the remainder of the S.C. No. 6 revenue requirement.

Q. Please describe how the charges to S.C. No. 2 (General Service) were developed.

A. The monthly customer charge for non-demand service was increased from $35.00 to $42.00 to bring the customer charge closer to the embedded costs of service. The monthly customer charges for secondary and primary service were left unchanged, with Secondary Demand at $84.00

and Primary Demand at $310.00. For the Non-Demand class, a flat delivery rate of $0.00642 per kWh was developed to produce the remainder of the requirement.

Base delivery revenue from the secondary class is primarily driven by demand revenue, which currently represents approximately 64 percent of secondary revenue while the volumetric rate contributes only 14 percent of the revenue. A flat demand charge of $9.30 per kW and a flat delivery rate of $0.00622 per kWh were developed for the secondary class by increasing each by approximately 15 percent to produce the remainder of the revenue requirement.

Similarly, demand revenue for the primary class currently represents approximately 80 percent of base revenue while the volumetric rate contributes only about 7 percent of the revenue. Therefore, the energy delivery charge and the demand charge for the primary class were each increased by approximately 13 percent to produce the remainder of the revenue requirement. This resulted in a flat delivery rate of $0.00166 per kWh and a flat demand charge of $7.52 per kW/per month.

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

A. The monthly customer charge for S.C. No. 3 was left unchanged at $1,400.00, while the monthly customer charges for S.C. No. 13 (Substation and Transmission) were increased from $2,040.00 and $3,810.00 to $3,740.00 and $4,640.00, respectively. These latter changes are intended to bring the customer charge closer to the embedded costs shown on Schedule C of Exhibit __ (COSP-1), supported by the testimony of the COSP.

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

A flat demand rate of $9.88 per kW was developed to produce the remainder of the S.C. No. 3 revenue requirement while maintaining the reactive demand charge approved by the Commission in Case 08-E-0887 and continued in Case 09-E-0588. S.C. No. 13 (Substation and Transmission) flat demand rates of $7.32 per kW and $4.38 per kW, respectively, were developed to produce the remainder of the revenue requirement for this class while maintaining the reactive demand charge approved by the Commission in Case 08-E-0887 and continued in Case 09-E-0588.

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

A. Since the Company fully supports movement toward the costs reflected in ECOSS, the Company is proposing increases to those customer classes with the greatest number of customers. The table below shows, for customer classes with the greatest number of customers, the extent to which the current customer charges fall below the indicated costs of service and the movements towards costs proposed by the Company:

Electric Customer Charges					
S.C. No.	Current	Proposed	ECOSS	Current vs ECOSS	Proposed vs ECOSS
1 – Nht	$24.00	$30.00	$38.75	-38%	-23%
2 – ND	$35.00	$42.00	$42.83	-18%	-2%

Gas Customer Charges					
S.C. No.	Current	Proposed	ECOSS	Current vs ECOSS	Proposed vs ECOSS
1 & 12 Ht	$23.00	$29.00	$43.47	-47%	-33%
2, 6 & 13 Ht	$37.00	$46.00	$65.30	-43%	-30%

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 of service, the Company believes that any rate design changes required to this service classification should be made at a later stage in this proceeding consistent with the determination of the final revenue requirement.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Are there any other electric and gas rates for which the Company is proposing no change at this time?

A. Yes. Pursuant to Case 11-M-0542, the Company currently offers specific delivery rates for electric and gas Excelsior Jobs Program participants. The rates for these provisions are required to reflect the marginal cost of providing service. As explained by the Company's COSP, Central Hudson proposes to submit marginal cost of service studies on or before September 15, 2014 in this proceeding. As a result, the Company proposes that any rate design changes to these rates be made at a later stage in this proceeding.

We are also proposing to maintain the current level of the electric contract demand charges for S.C. No. 10 until such time as the marginal cost of service study is submitted. The underlying customer charges for this service classification, however, are being updated with the customer charges proposed for electric S.C. Nos. 2 (Primary), 3 and 13.

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

A. In designing rates for residential customers, the initial goal was to increase the customer charge to be more in line with the customer charge indicated by the ECOSS. To accomplish this, the minimum charge for the first 200 cubic feet or less was increased from $23.00 to $29.00 per month. The remaining increase was then allocated to the volumetric delivery charge.

Q. Please describe how the charges to S.C. Nos. 2, 6 and 13 were developed.

A. The primary goals in designing the rates for these classes were to increase the customer charge to be more in line with the customer charge indicated by the ECOSS and to maintain a similar increase in the customer charge in comparison to the residential customer classes.

The first step in the rate design was to increase the minimum charge from $37.00 to $46.00, moving this charge closer to the percentage increase allocated to S.C. Nos. 1 and 12. The next step was to allocate the remaining increase to the volumetric delivery charge.

Q. Please describe how the discount applicable to High Volume S.C. No. 6 customers was developed.

A. First, a composite rate was calculated to reflect high volume usage priced out at currently effective block rates. The usage was calculated as 18 percent of the S.C. Nos. 2, 6 and 13 sales forecasted for the Rate Year as the average 2009 to 2013 high volume sales accounted for approximately eighteen percent of actual total S.C. Nos. 2, 6 and 13 sales. The composite rate was then compared to the current tail block rate to determine the current percentage discount. This percentage discount, which is approximately 9.44 percent, was then applied to proposed rates.

While high volume tail block customers will experience larger rate increases than non-high volume customers as a result of the approved rate design in Case 09-G-0589 where rate increases were not allocated to the tail block, the aforementioned method continues to maintain a 9.44 percent discount from standard rates for these customers.

Q. Should this discount also be utilized for S.C. Nos. 2 and 13 gas air conditioning customers?

A. As of June 30, 2014, the Company did not serve any customers under this S.C. No. 2 or S.C. No. 13 Special Provision. However, as current tariff provisions provide the same tail block discount for gas air conditioning customers as is reflected for high volume S.C. No. 6 customers, the Company is proposing to maintain the same discounted rate for both.

Q. Please describe how the charges for S.C. No. 11 (Transmission, Distribution and DLM) were developed.

A. The monthly customer charge for each subclass was increased from $1,200 to $1,400. Due to the limited number of customers taking service under S.C. No. 11, this proposed increase does not generate a significant amount of revenue. The remaining increase was allocated to the Maximum Daily Quantity (“MDQ”) charge. The MDQ is the maximum volume of gas the Company is obligated to accept on behalf of a transportation customer during a 24 hour period beginning at 10 AM Eastern Standard Time each day.

DIRECT TESTIMONY OF THE FORECASTING AND RATES PANEL

Q. Is the Company proposing any changes to the MDQ structure currently in place for S.C. No. 11 customers?

A. No.

Q. Did the Commission direct the Company to explain its treatment of the MDQ structure in this rate case?

A. Yes. In an Order issued and effective February 24, 2014 in Case 13-G-0531, the Commission directed Central Hudson to submit testimony in its next gas rate filing to explain: 1) why S.C. No. 11 customers should continue to be billed using the MDQ (fixed volume) delivery rates with a tariff provision to raise and lower the MDQ; or 2) why delivery rates should be replaced with a volumetric rate design, where benefits from employed energy efficiency measures are immediately realized by the customers.

Q. What is the Company's position on changing the MDQ-based rates?

A. A change from MDQ-based rates is not warranted. MDQ-based rates were proposed in Case 92-G-1056 by Alan Rosenberg on behalf of Multiple Interveners who indicated that "because this is a firm transportation rate, it is reasonable to require these customers to nominate a MDQ, which forms the basis for not only their delivery entitlement but also the rate." Since the gas system is built to meet peak period demand, the Company's costs to serve these customers are essentially fixed. As a result, an MDQ-based rate better matches revenue recovery with cost causation. A volumetric rate could jeopardize the

Company's full recovery of costs to serve these customers due to volume fluctuations. Additionally, the aforementioned testimony filed by Mr. Rosenberg states "customers desire stable, predictable prices" which MDQ-based rates provide compared to volumetric rates. Finally, even with delivery rates on an MDQ basis, benefits from employed energy efficiency measures are immediately realized by customers through lower total commodity costs resulting from reduced volumes.

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

A. No. The Company does not currently serve any customers under S.C. Nos. 15 and 16 (Distributed Generation ("DG") – Commercial and Industrial and DG – Residential), respectively. Therefore the Company recommends that any rate design changes required to this service classification be made at a later stage in this proceeding consistent with the determination of the final revenue requirement.

Q. Is the Company proposing any new delivery rates?

A. Yes. The Company is proposing a new Electric Bill Credit and a new Gas Bill Credit. These bill credits would serve as rate moderators as discussed in the testimony of Company Witness Mosher, returning half of the proposed base rate increase, or approximately $20.1 and $2.95 million to electric and gas customers, respectively, over the Rate Year. The credits were allocated based on the adjusted base rate increase as a percentage of system, which is the same methodology utilized for the Electric Bill Credit approved in both Cases 08-E-0887 and 09-E-0588. The new Electric Bill Credit is reflected on Schedule B of Exhibit __ (FRP-12). The new Gas Bill Credit is reflected on Schedule C of Exhibit __ (FRP-13).

Q. Are there any other rate items for which the Company is proposing a change?

A. Yes. The Company is proposing to update the electric and gas reconnection charges. The Company last updated the re-connection charges in November 2001 in compliance with the Order Establishing Rates issued October 25, 2001 in Case 00-G-1274. As the re-connection charge reflects the labor, vehicle and materials costs related to performing the re-connections, the Company believes it is reasonable to update these rates to reflect more recent information in order to more accurately allocate costs to those customers for whom those costs are incurred.

Q. Please describe how the re-connection charge rates were developed.

A. The re-connection charge was designed to reflect hours of work required for re-connection at appropriate labor costs for collectors, commercial representatives, line crews and gas crews. The Company also included call center and dispatch labor costs. Finally, the re-connection charge rates reflect vehicle expense related to travel and material costs related to performing the re-connection.

Exhibits

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

A. Exhibit __ (FRP-12) consists of ten schedules. Schedule A and Schedule B set forth the present and proposed MFC Charges, and the proposed Electric Bill Credit, respectively, as previously discussed. Each of the remaining schedules sets forth a comparison of the provisions of a present service classification and the proposed superseding service classification.

Exhibit __ (FRP-13) consists of three schedules. As previously noted, Schedule A sets forth present and proposed base MFC charges. Schedule B sets forth a comparison of the provisions of present S.C. Nos. 1, 2, 6, 11, 12 and 13 and the proposed superseding service classifications. Schedule C sets forth proposed Gas Bill Credit rates.

Q. Please explain Exhibits __ (FRP-14) and __ (FRP-15) regarding comparative bills.

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

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

These comparisons were prepared using the monthly Energy Cost Adjustment Mechanism (“ECAM”) factors effective July 14, 2014 and the monthly GSC factors effective July 2, 2014, respectively, in order to develop estimates of full service bills to allow for a more accurate estimate of the utility bill impacts of the proposed rate changes.

Q. Has the Panel provided additional information for annual periods beyond June 30, 2016?

A. Yes, the Panel has included additional schedules similar to Schedule F of Exhibits __ (FRP-2) and __ (FRP-3) for the twelve month periods ending June 30, 2017 and 2018. These schedules have been provided as additional information to the letter transmitting the Company's filing.

Other Rate Provisions

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

A. From November 2001 to May 1, 2005, all energy costs incurred on behalf of full service customers were fully recovered through the MPC and MPA components of the Company's ECAM or through the Hourly Pricing Provision ("HPP") for S.C. Nos. 2, 3 and 13 customers electing to take service under the terms of the HPP. Effective May 1, 2005, S.C. Nos. 3 and 13 customers continuing to purchase their energy supply requirements from Central Hudson were required to do so under the HPP. Effective October 1, 2011, S.C. No. 2 customers with demand exceeding 500 kW in any two of the previous twelve months continuing to purchase their energy supply requirements from Central Hudson were also required to do so under the HPP. Effective October 1, 2012, HPP was further required for all full service S.C. No. 2 customers with demand exceeding 300 kW in any two of the previous twelve months.

Q. Please describe the ECAM.

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

Q. Please describe the MPC and MPA components of ECAM.

A. The MPC and MPA factors are applicable to all service classifications excluding S.C. Nos. 2, 3 and 13 HPP as previously noted. The MPC charge recovers the Company's cost of electricity supply related purchases, including firm energy, capacity, ancillary charges, risk management fees, and other charges imposed by the NYISO. The MPC also includes working capital carrying charges and an uncollectible allowance. Energy and capacity purchased under mandatory Independent Power Producer ("IPP") contracts and the Company's retained generation is priced at the monthly average of NYISO day-ahead market prices. The MPC charge is calculated on a monthly basis for each MPC group based on actual costs incurred during the previous month allocated over projected deliveries for the collection period. The MPA is the reconciliation mechanism for the MPC. It is also calculated on a monthly basis by MPC group and reconciles actual MPC recoveries with MPC costs.

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Q. Please describe the MISC component of the ECAM.

A. The MISC factor recovers the cost or benefit of non-avoidable, variable energy-related revenues or costs associated with the Company's retained generating facilities and from mandatory IPP purchases. The MISC also includes working capital carrying charges and an uncollectible allowance. The MISC charge or credit is calculated on a monthly basis by dividing the previous month's benefit or cost by estimated deliveries and is applicable to all energy deliveries as a uniform factor. The Company reconciles MISC recoveries with actual costs or benefits on a three-month lag.

Q. Please describe the PPA component of ECAM.

A. The PPA factor is also applicable to all energy deliveries as service class and sub-class specific PPA factors. Prior to December 1, 2011, these factors recovered the cost or benefit of the Company's PPA with Constellation Energy for energy and capacity from Nine Mile Point 2 ("NMP2"). Effective December 1, 2011, the PPA reflects the Revenue Sharing Agreement ("RSA") with Constellation. Under the RSA, Constellation is required to pay 80 percent of the net cumulative positive spread, if any, between the actual revenues per MWh earned by NMP2 and the floor price per MWh for the period as set forth in the RSA. The PPA factors also include an allowance for uncollectibles and are subject to reconciliation similar to the MISC.

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

A. Since May 1, 2005, the HPP has been the only commodity pricing option available to S.C. Nos. 3 and 13 customers that continue to elect to purchase their energy supply requirements from Central Hudson. In Case 08-E-0887, the Company was required to expand HPP to all S.C. No. 2 customers exceeding 500 kW in any two months in a twelve month period. Under the HPP, the Company recovers its costs by charging customers for their hourly supply requirements at the NYISO Zone G day-ahead market price, increased to reflect the applicable factor of adjustment. Customers under the HPP plan are also subject to the HPP charge which recovers costs for energy balancing ancillary services, allowances for working capital and uncollectibles, as well as the HPP unforced capacity ("UCAP") charge which recovers capacity charges.

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

A. No, the Company seeks to continue to fully recover the costs of electricity purchased for full service customers through the continued application of the provisions of the ECAM and HPP. Continued application of these mechanisms entails the continued use of deferral accounting, as necessary, to recognize the timing differences that occur between the actual purchases of energy requirements and the collection of costs from customers.

Despite the sale of the Company's fossil and nuclear generating facilities, the unbundling of the supply and delivery function, the implementation of MFCs and the establishment of a mature wholesale electricity market, the Company continues to bear the obligation to forecast, procure, and manage the electricity supply obligation for the great majority of its customers. The Company continues to source and contract for cost effective supply on behalf of those customers that choose to purchase their supply from the Company. Full recovery of these purchase costs is essential to the financial health and stability of the Company, given the absence of the ability to control generation and wholesale market costs.

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

A. Gas supply expense (demand and commodity) incurred by the Company to serve full service customers taking service under S.C. Nos. 1 and 2 is recovered through the GSC. The GSC is determined monthly and reconciled annually, for the twelve-month period ending August 31, in accordance with 16 NYCRR §720-6. The GSC is equal to the sum of the average demand cost of gas and the average commodity cost of gas, multiplied by the factor of adjustment and adjusted for the annual reconciliation of gas expense, gas supplier refunds, interruptible sales credits, capacity release credits, and all other adjustments as approved by the Commission.

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

A. Yes. Currently, the system factor of adjustment is 1.046 based on the 36 month average ending May 2010, and is allocated to service and/or sub-class based on the methodology initially approved in Case 08-E-0887. The Company proposes to utilize a system factor of adjustment of 1.0485 based on the 36 months ended March 2014 and the same allocation methodology updated to reflect the results of the loss study submitted to the Commission on January 21, 2010 pursuant to the Order in Case 08-E-0887. The resulting service class/sub-class factors of adjustment are provided in the table below.

	RY 1 Sales (MWh)	% Sales	Adjusted FOA	Weighted FOA
S.C. No. 1	2,005,320	40.761%	1.0586	0.431513
S.C. No. 2 - ND	157,996	3.212%	1.0586	0.033998
S.C. No. 2 - SD	1,343,012	27.299%	1.0586	0.288995
S.C. No. 2 - PD	207,744	4.223%	1.0356	0.043730
S.C. No. 3	265,684	5.400%	1.0356	0.055927
S.C. No. 6	20,000	0.407%	1.0586	0.004304
S.C. No. 13 - Sub	130,170	2.646%	1.0208	0.027009
S.C. No. 13 - Trans	752,830	15.302%	1.0134	0.155079
S.C. No. 9	2,540	0.052%	1.0586	0.000547
S.C. No. 5	12,560	0.255%	1.0586	0.002703
S.C. No. 8	21,820	0.444%	1.0586	0.004695
Total	**4,919,676**	**100.000%**		**1.048500**

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

A. Yes. The COSP will address this item.

Q. Have Revenue Decoupling Mechanisms ("RDMs") been implemented for the Company's electric and gas operations?

A. Yes. In its Order Adopting Recommended Decision with Modifications issued and effective June 22, 2009 in Case 08-E-0887 and Case 08-G-0888, the Commission adopted RDMs for both the electric and gas operations of the Company. The RDMs were subsequently continued, with minor revisions, in accordance with the Commission's Order Establishing Rate Plan issued and effective June 18, 2010 in Case 09-E-0588 and Case 09-G-0589.

Q. Please describe the electric RDM currently in place.

A. The electric RDM is a revenue per class model applicable to S.C. Nos. 1, 2ND, 2PD, 2SD, 6, and 14. Pursuant to the RDM, actual delivery revenue by service class or sub-class for RDM eligible classes is compared, on a monthly basis, to a delivery revenue target. If the monthly actual delivery revenue exceeds the delivery revenue target, the delivery revenue excess is accrued for refund to customers at the end of the annual RDM period (twelve months ending June). Likewise, if the monthly actual delivery revenue is less than the delivery revenue target, the delivery revenue shortfall is accrued for recovery from customers at the end of the annual RDM period.

At the end of an annual RDM period, total delivery revenue excess/shortfalls are refunded/surcharged to customers through service class or sub-class specific RDM adjustments applicable during a corresponding RDM adjustment period (twelve months beginning August 1 immediately following the annual RDM period).

Q. Does the electric RDM address interim adjustments?

A. If at any time during an annual RDM period the total of the cumulative delivery revenue excess/shortfalls for all service classes and sub-classes subject to the RDM exceeds $4 million, the Company is required to implement interim RDM adjustments. RDM adjustments are determined by dividing the amount to be refunded/surcharged to customers in each respective RDM eligible service class or sub-class by the estimated kWh deliveries to the customers in the respective service class or sub-class over the RDM adjustment period.

Q. Please describe the gas RDM currently in place.

A. The gas RDM is a unit per customer (“UPC”) model and is applicable to S.C. Nos. 1 and 12 combined and S.C. Nos. 2, 6 and 13 combined. The RDM provides for a monthly comparison, by billing block, of actual UPC as adjusted by the Weather Normalization Adjustment (“WNA”), to UPC targets, with any revenue excess/shortfall refunded to/recovered from customers over a twelve-month period commencing August 1. If, however, during the Rate Year, the cumulative delivery revenue excess/shortfall exceeds $2 million, the Company is authorized to begin refund/recovery of such excess/shortfall over a twelve-month period.

The UPC structure of the gas RDM is continued per the Commission's Order in Case 08-G-0888. However, revenues earned as a result of customer months in excess of those used to determine the UPC targets, but only up to the upper limit of customer months as approved by the Commission in Case 09-G-0589, are now also deferred monthly, with interest at the Commission's rate for other customer provided capital, for refund to customers. The Company retains revenues earned as a result of customer months in excess of the upper limit. These provisions currently only apply to residential customers.

Q. Are there any issues you would like to address with respect to the current RDM mechanisms?

A. Yes. Since inception the Company has effectuated six electric RDM statements and five gas RDM statements to recover various under/over collections and reconciliations. The tables below show when each statement went into effect as well as what each statement was intended to recover/refund.

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Electric Statement	Effective Date	Refund/Surcharge
RDM 1	10/1/2009	Trigger – 7/2009-8/2009
RDM 2	8/1/2010	Remaining RY – 09/2009-6/2010
RDM 3	8/1/2011	RY – 7/2010-6/2011 and RDM 1 Reconciliation
RDM 4	Not Effective	
RDM 5	Not Effective	
RDM 6	4/1/2012	Trigger – 7/2011-2/2012
RDM 7	10/1/2012	Remaining RY – 3/2012-6/2012 and RDM 2 Reconciliation
RDM 8	8/1/2013	RY – 7/2012-6/2013 and RDM 3 Reconciliation

Gas Statement	Effective Date	Refund / Surcharge
RDM 1	8/1/2010	RY – 7/2009-6/2010
RDM 2	6/1/2011	Trigger – 7/2010-4/2011
RDM 3	8/1/2012	RY – 7/2011-6/2012 and RDM 1 Reconciliation
RDM 4	5/1/2013	Trigger – 7/2012-3/2013
RDM 5	4/1/2014	Trigger 7/2013-2/2014 and Remaining RY 5/2011-6/2011 and Remaining RY 4/2013-6/2013 and RDM 2 Reconciliation

As can be seen above, the nature of the mechanisms has resulted in various effective dates and timing delays in regards to when over/under deferrals are refunded/surcharged. Additionally, the tracking of RDM over/under collection deferrals and RDM collections has become administratively burdensome.

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

A. Yes. The Company proposes that the RDMs be revised to replace the interim adjustment process with two routine semi-annual factor updates on February 1 and August 1 of each year in place of the current annual RDM adjustment period. The over/under deferrals recorded for July 1 through

December 31 would be collected/refunded over the six-month period commencing February 1 and the over/under deferrals recorded for January 1 through June 30 would be collected/refunded over the six-month period commencing August 1.

Q. Is this consistent with the operation of RDMs at other utilities?

A. Yes. In conjunction with Case 13-E-0030, Con Edison made a tariff filing to change the RDM adjustment in a similar manner.

Q. Is the Company proposing any other changes specific to the RDM?

A. Yes. The Company is proposing that the electric RDM be applicable to S.C. Nos. 3 and 13 and the gas RDM be applicable to S.C. No. 11 (Transmission), S.C. No. 11 (Distribution) and S.C. No. 11 (DLM). NYSERDA administers energy efficiency programs directed to large customers. Moreover, in Case 13-G-0531, the provision for downward revisions to S.C. 11 MDQs was expanded to apply to all S.C. 11 customers. As energy efficiency measures taken by S.C. 11 customers can now be reflected in downward revisions to MDQ, the Company believes it is appropriate to reflect this class of customers in the RDM, which is designed to offset conservation-related revenue losses.

The Company also proposes that the customer related calculation included in the gas RDM, which was implemented as a result of the approved Joint Proposal in Case 09-G-0589 and as detailed above, be eliminated.

Q. Is the Company's gas business subject to a WNA?

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

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

A. No. However, if the Company's proposal to eliminate the gas block rate structure is approved, a conforming change to the WNA will be required to revise the definition of "pure base rate" from the tail block delivery charge to the volumetric delivery charge.

<u>Management Audit</u>

Q. Please provide an update of the status on the implementation of the applicable management audit recommendation related to the Company's electric peak load model.

A. As provided in greater detail in the testimony of Company Witness Lewis, a management audit conducted during 2009 reviewed among other things the Company's electric peak load model and recommended that the Company re-evaluate the variables utilized in the annual peak demand model to determine if additional economic variables would provide a better statistical fit. In addition to reviewing model specification, including identification of economic forecast drivers and weather variables, the Company also re-evaluated its normalization process which is utilized to weather adjust the actual electric peak experienced to current design conditions for comparison to the forecast peak. As a result, the Company has implemented a modeling process that reflects the specification of two models based on two different economic drivers (GDP and residential non-heat customer level) as well as a revised normalization process that more closely follows the process utilized during the annual weather normalization incorporated in the installed capacity ("ICAP") forecast as coordinated and prepared by the NYISO. This implementation has been accepted by Staff.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.