STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 14-E-0318 - 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-G-0319 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.

ORDER APPROVING RATE PLAN

Issued and Effective: June 17, 2015

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on June 17, 2015

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Gregg C. Sayre
Diane X. Burman, concurring in part, dissenting in part, and abstaining in part

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BY THE COMMISSION:

INTRODUCTION

In this Order, we approve the implementation of a three-year electric and gas rate plan for Central Hudson Gas & Electric Corporation (Central Hudson or Company). Except as otherwise noted in this Order, this rate plan is based on the recommendations of an April 22, 2015 Joint Proposal (Final Joint Proposal or JP) signed by the Company, trial staff of the

Department of Public Service (Staff), and four other parties.[1] Other parties participated in the case, including an active group of intervenors from the Central Hudson service territory (Citizens for Local Power or CLP), but were not signators of the agreement[2]. No party has recommended that the Commission reject the Final Joint Proposal.[3]

Under the three-year rate plan which we adopt today, the anticipated delivery revenues will, over the term of the rate plan, increase for each customer for each service. A portion of these delivery revenue increases, however, would be offset by regulatory liabilities which the Company owes to its customers and which, under the rate plan, are taken as customer bill credits. The delivery revenue increases which are not offset by these bill credits are paid by customers through increased bills for electricity or for gas. Under the rate plan adopted in this Order, the bill impacts which will be

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[1] Besides the Company and Staff, the Final Joint Proposal was also signed by Multiple Intervenors (MI), Retail Energy Supply Association (RESA), Pace Energy and Climate Center (Pace), and Sabin Center for Climate Change Law (Sabin). Except for RESA, each of these parties provided a Statement in Support of the recommendations in the Final Joint Proposal.

[2] In addition to CLP, the Department of State's Utility Intervention Unit (UIU), NRG Energy Inc, (NRG), Consolidated Edison Solutions, Inc. (Con Ed Solutions) and SolarCity were parties and were active participants in the case but did not sign the Final Joint Proposal. Con Ed Solutions and SolarCity provided Statements in support of all or a portion of the recommendations in the Final Joint Proposal. CLP and NRG provided comments on some of the recommendations of the Final Joint Proposal rather than a Statement in support or in opposition to it.

[3] The Final Joint Proposal is attached to this Order as Attachment A.

experienced by the average electric[4] or gas[5] customer in the largest rate classes are estimated to be:

Electric Service Classes	Rate Year 1	Rate Year 2	Rate Year 3
Residential (No. 1 – non-heating)	0.34%	3.42%	4.78%
Residential(No. 1 - heating)	0.37%	3.70%	5.15%
General (No. 2 - non-demand)	0.35%	4.69%	6.17%

Gas Service Classes	Rate Year 1	Rate Year 2	Rate Year 3
Residential (No. 1 & 12)	(-0.28%)	1.02%	4.25%
Commercial & Industrial (No. 2,6 & 13)	(-2.53%)	0.76%	2.87%

These bill impact estimates were developed by calculating the ratio of the delivery bill increase for a customer with average usage to the <u>total bill</u> for that customer and expressing that ratio as a percent. The calculation assumes that the commodity charges to that customer remain the same over the term of the rate plan. If calculated as the ratio of the delivery bill increase to the <u>delivery bill</u> for that customer, the delivery bill impacts for the average customer in the largest rate classes are estimated to be:

Electric Service Classes	Rate Year 1	Rate Year 2	Rate Year 3

[4] For Central Hudson, the usages of the "average" electric customers in the largest service classes are:

Electric Service Classes	Usage (kWh)/month
Residential (No. 1 - non-heating)	610
Residential(No. 1 - heating)	950
General (No. 2 - non-demand)	460

[5] For Central Hudson, the usages of the "average" gas customers in the largest service classes are:

Gas Service Classes	Usage (ccf)/year
Residential (No. 1 & 12)	840
Commer. & Ind. (No. 2,6 & 13)	5860

Residential (No. 1 - non-heating)	0.48%	7.92%	9.38%
Residential(No. 1 - heating)	0.56%	8.19%	10.92%
General (No. 2 - non-demand)	0.68%	10.02%	12.49%

Gas Service Classes	Rate Year 1	Rate Year 2	Rate Year 3
Residential (No. 1 & 12)	(-0.46%)	1.66%	6.82%
Commercial & Industrial (No. 2,6 & 13)	(-6.07)	1.89%	7.11%

In addition to the delivery rate increases ordered here, the rate plan we approve creates new or modifies existing practices or programs at the Company in several ways. Most noteworthy, Central Hudson will, under the rate plan:

- Create a Major Storm Reserve.
- Convert customers to monthly billing.
- Create an incentive/expansion program to promote the conversion of customers to gas service.
- Expand its program for the replacement of leak prone pipe.
- Operate under an incentive to reduce residential service terminations.
- Initiate a Same Day Reconnection program.
- Participate in a Reforming the Energy Vision (REV) Working Group established to develop demonstration projects for consideration through Case 14-M-0101 and related cases.

The rate plan also explicitly recognizes that we are currently implementing our REV initiative and that this implementation may require the Company to take action before the three-year rate plan is concluded. As is recognized in the recommendations of the Final Joint Proposal, we reserve the right to move ahead with the implementation of REV in the Central Hudson service territory notwithstanding the pendency of the rate plan. At the same time, we will preserve the opportunity for the Company, through deferrals or some other mechanism, to recover its REV associated costs, if any, which may be incurred.

BACKGROUND OF THE PROCEEDING

The operations of the Company and its rates are, at this time, guided by three Commission Orders. First, in 2009, the Commission provided the Company with a general rate increase and set rates for a rate year beginning July 1, 2009.[6] Second, through a rate case filed on July 31, 2009, the Commission considered and approved the provisions of a joint proposal establishing a three-year rate plan with the first rate year beginning on July 1, 2010.[7] After the 2010 Rate Order became effective, the Commission considered a petition for Commission approval of the acquisition of Central Hudson by Fortis, Inc., a Canadian holding company. As part of a joint proposal to conclude the acquisition case, Central Hudson agreed to "freeze" rates for two years. The proposal was approved by the Commission on June 26, 2013.[8] Accordingly, the three-year rate plan established in the 2010 Rate Order, which otherwise would have expired on June 30, 2013, was extended for two additional

[6] Cases 08-E-0887 and 08-G-0888, Central Hudson Gas & Elec. Corp. - Rates, Order Adopting Recommended Decision With Modifications (issued June 22, 2009) (2009 Rate Order). While the rates established by the 2009 Rate Order have been superseded by subsequent orders, several provisions established through the 2009 Rate Order continue. 2009 Rate Order at 16-18.

[7] Cases 09-E-0588 and 09-G-0589, Central Hudson Gas & Elec. Corp., Order Establishing Rate Plan (issued June 18, 2010) (2010 Rate Order).

[8] Case 12-M-0192, Petition for Approval of Acquisition of CH Energy Group by Fortis, Inc., Order Authorizing Acquisition Subject to Conditions (June 26, 2013) (Acquisition Order or 2013 Acquisition Order).

years to June 30, 2015. The rate plan established in this Order will set Central Hudson electric and gas delivery rates for three rate years, the first of which will begin on July 1, 2015.

The Central Hudson rate filing that began this case was made on July 25, 2014. In this filing, the Company sought to raise rates such that the Company's annual electric delivery revenues would increase by $40.1 million and its annual gas delivery revenues would increase by $5.9 million. In its filing, the Company also reported that it expected to have net balance sheet items amounting to $46.0 million (electric) and $5.1 million (gas) which could be directed either to increase support for existing or new programs or to use as rate moderators.

Shortly after the Company's initial filing, a procedural conference was held to establish a litigation schedule for the case. The schedule adopted called for the filing of testimony in response to the Company's initial filing on or before November 21, 2014, and the filing of rebuttal testimony on December 19, 2014.[9] Under this schedule the case would have proceeded with the commencement of evidentiary hearings on January 12, 2015.

Notices of Proposed Rulemaking concerning the electric and gas rate requests made by Central Hudson and under

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[9] Testimony and exhibits in the Company's initial filing, in Staff and the parties' response to the Company's initial filing, and in the subsequent rebuttal testimony pursuant to this ruling represent the initial litigation position for each of the parties. To provide a clearer picture of the normally adversarial positions of the parties and of the range of potential outcomes if this case were litigated to conclusion, the ALJs obtained, through an information request, a summary from each party of that party's litigating positions. The responses to this information request are compiled and filed in the Department's Document and Matter Management (DMM) system under the case numbers for these cases.

consideration here were published in the State Register on December 3, 2014 (SAPA 14-E-0318SP1 and SAPA 14-G-0319SP1). Pursuant to the State Administrative Procedure Act, the minimum time period for the receipt of comments in response to these notices expired on January 19, 2015.

Shortly after the filing of rebuttal testimony, the parties reported their intention to explore the possibility of settlement. Accordingly, a Notice of Impending Settlement Negotiations was prepared and filed. This Notice stated the parties' intention to address all issues in the cases through the settlement process. In light of the pendency of these discussions, the parties sought and, through a December 23, 2014 Further Ruling on Schedule, were granted a postponement of the date for the commencement of evidentiary hearings from January 12 to February 10, 2015.

On February 6, 2014, the Company, Staff and four other parties in these cases filed a Joint Proposal (February JP).[10] The February JP sought to prescribe Central Hudson's rates for electric and gas service for three years, and, using available credits, to limit the impact of rate increases in this time

[10] After this initial filing, certain technical errors were found, and a corrected version of the agreement was prepared. This corrected version (the March JP) was marked for identification as Hearing Exhibit 801 at the March 31 evidentiary hearing described infra. Subsequent to the evidentiary hearing, one element of the March JP was further modified. As described more fully at 15-16, infra, this modification was made to reflect the parties' most current recommendations for the continued recovery of certain energy efficiency expenditures, and the modifications were discussed on the record at the March 31, 2015 evidentiary hearing. As modified, the document is identified as the "Final Joint Proposal" and is attached to this Order as Attachment A. It is dated April 22, 2015 and was filed on that date in DMM as part of Item No. 60. References in this Order to the agreement as filed on April 22, 2015 will be to the Final Joint Proposal or JP.

period. Following the filing of the February JP, a new schedule was devised which called for the filing of Statements in Support or in Opposition on or before February 24, 2015, the filing of Reply Statements on or before March 6, 2015, and the commencement of the evidentiary hearing to address the recommendations in the February JP on March 31, 2015.

As this case has progressed, several organizations and individuals have sought to participate as parties. Each of the requests for party status asserts that the requestor's inclusion as a party will enhance the record or is otherwise justified under our rules. No objection has been raised regarding any of the requests for party status. A number of the requests for party status were granted in earlier rulings by the Administrative Law Judges.[11] Since these rulings, additional requests for party status have been made. To the extent requests for party status have been made but have not yet been acted upon, by this Order we grant those requests.

After the February JP was filed, a Notice of Public Statement Hearings was issued on February 19, 2015. This Notice scheduled two public statement hearings; one in Poughkeepsie on March 10, 2015 and one in Kingston on March 12, 2015. These hearings were conducted as scheduled, and six and 18 individuals used this opportunity to provide their comments in Poughkeepsie and Kingston, respectively.

In addition, throughout this case, the Department has maintained the capability to receive written or oral comments. In this case, 32 comments were received, and the record of these comments has been maintained on the Department's website. In general, these comments reflected the concerns raised in the

[11] Ruling on Schedule and Granting Party Status (issued September 16, 2014) at 2; Transcript of September 30, 2014 Procedural Conference at 7.

Public Statement Hearing which described the proposed rate increases as too large, unjustified, and unneeded.

THE FINAL JOINT PROPOSAL[12]

A. Term

The original filing by Central Hudson sought to raise rates as of July 1, 2015. If the Company's proposal were adopted, the Company would be able to seek still higher rates through a new rate case that could be filed as early as August 1, 2015 which could set new rates as early as July 1, 2016. The Company's proposal contained no commitment by the Company to refrain from filing a new case on that or any other schedule. In the Final Joint Proposal, in contrast, the parties recommend a three-year rate plan. To implement this plan, the Company makes an explicit commitment to refrain from filing for new rates to take effect prior to July 1, 2018.

B. Delivery Revenues

1. Revenue Increases. As noted above, the Company's initial filing sought to raise rates such that the Company's electric delivery revenues would increase by $40.1 million in the rate year beginning July 1, 2015 (Rate Year 1 or RY1) and its gas delivery revenues would increase by $5.9 million in RY1. In its filing, the Company also reported that it expected to have net balance sheet items amounting to $46.0 million (electric) and $5.1 million (gas) which could be directed either

[12] The provisions of the Final Joint Proposal discussed in this or other sections of this Order are simply highlights of the JP itself. For a complete statement of the recommendations made in the JP, we refer to the Final Joint Proposal itself (including the Appendices A through R to the JP which are appended to and incorporated by reference into the Final Joint Proposal) which is Attachment A to and constitutes a part of this Order.

towards increased support for existing or new programs or to use as rate moderators.[13]

In its testimony, Staff recommended that the Rate Year 1 electric delivery revenue increase be $12.9 million, and that the Rate Year 1 gas delivery revenue should decrease by $1.79 million.[14] Staff further proposed that the available electric bill credits be used to offset one half of the $12.9 million electric delivery revenue increase.[15]

In the Final Joint Proposal, parties reached agreement on a recommendation for increased electric and gas delivery rates to produce incremental revenues for Rate Year 1 and, as part of the three-year rate plan, for Rate Years 2 and 3 as follows:

	RY 1 revenue increase	RY 2 revenue increase	RY 3 revenue increase
Electric	$15.346 million	$15.987 million	$14.100 million
Gas	$1.827 million	$4.633 million	$4.379 million

2. Bill Credits. Central Hudson had deferred credits on its books for the benefit of ratepayers. Under the rate plan recommended in the Final Joint Proposal, these deferred credits are applied as one-time bill credits to mitigate the revenue increases as follows:

	Bill credits in RY 1	Bill credits in RY 2	Bill credits in RY 3
Electric	$13.0 million	$12.0 million	$2.0 million
Gas	$2.548 million	$1.700 million	$0.0

13 July 25, 2014 Letter submitting Central Hudson Initial Filing at 1-3.

14 Evidentiary Hearing Exhibit 206, prefiled testimony of Debbie Evans at 7-8.

15 Id.

The credits can only be used once, while the underlying rate increases continue on a permanent basis. Thus, although the credits reduce the bill impacts which occur when the rate increases are initially introduced, the underlying rate increases remain and result in more significant bill impacts in later years, after the credits have expired. After the application of these credits, the total net delivery bill increases paid by customers through the anticipated delivery rate increases would be:

	RY 1 net increase	RY 2 net increase	RY 3 net increase
Electric	$2.346 million ($15.346 million rate increase minus $13.0 million bill credit)	$16.987 million (expiration of $13.0 million RY 1 credit plus $15.987 million RY 2 rate increase, minus $12.0 million bill credit)	$24.100 million (expiration of $12.0 million RY 2 credit plus $14.1 million RY 3 rate increase, minus $2.0 million bill credit)
Gas	$(-0.721) ($1.827 million rate increase minus $2.548 million bill credit)	$5.481 million (expiration of $2.548 million RY 1 credit plus $4.633 million RY 2 rate increase, minus $1.7 million bill credit)	$6.079 million (expiration of $1.7 million RY 2 credit plus $4.379 million RY 3 rate increase, with no bill credit)

3. Additional Gas Delivery Revenues. Danskammer is an electric generating station in the Central Hudson service territory. While electric generation operations were discontinued at the Danskammer station several years ago, new ownership has recently returned the plant to service and is now taking gas delivery service from Central Hudson. Because the continued operation of the Danskammer plant is, at this point,

uncertain, estimates of future revenue requirements have not assumed that the plant will contribute to Central Hudson's gas delivery revenues. However, the Final Joint Proposal recommends that, to the extent that gas delivery revenues from the Danskammer plant are collected by Central Hudson in Rate Year 1 or Rate Year 2, one half of these revenues should be used to provide a refund to Central Hudson gas customers in the Rate Year following their receipt by the Company. It is further recommended that the remaining one half these revenues plus any such gas delivery revenues received by Central Hudson in Rate Year 3 should be deferred for the future benefit of ratepayers.

C. Major Revenue Requirement Issues

1. Labor

In its initial filing, the Company sought funding for 966 full time positions (FTEs) for Rate Year 1. In the Final Joint Proposal, the parties recommend that funding be provided for 950 FTEs in Rate Year 1, rising to 961 FTEs in Rate Year 2 (a 1.16% increase over Rate Year 1), and to 965 in Rate Year 3 (a 0.42% increase over Rate Year 2.[16]

2. Distribution and Transmission ROW Tree Trimming

Generally, the purpose of funding for this activity is to maintain the Company's existing programs which, when implemented, should increase the reliability of the electric

[16] For purposes of ratemaking, our Order here does not restrict the Company from hiring or require it to hire any particular number of persons. Rather, our Order provides rates sufficient for the Company to hire the specified number of persons. In this case, the funds to support the parties' agreement on Labor are set forth in the Appendix A, Schedule 1 to the Final Joint Proposal. Combining the Labor expense for the gas and the electric businesses indicates that the parties contemplated a Labor expense of $74.170 million in Rate Year 1, $77.093 million in Rate Year 2, and $79.675 million in Rate Year 3.

delivery system. After considering the Company's proposal, which sought greater funding, and Staff's, which would have provided less funding, the parties to the Final Joint Proposal recommended Right-of-Way (ROW)/Tree Trimming funding of $14.808 million, $15.326 million, and $15.862 million for Rate Years 1, 2 and 3, respectively.[17]

3. Monthly Billing

The Company currently bills most residential customers and many small commercial customers for gas or electric service on a bi-monthly basis rendering, on average, six bills per customer per year. Staff's proposal was for the Company to convert these customers to monthly billing, i.e. on average, 12 bills per customer per year. In the Final Joint Proposal, Staff's recommendation is adopted and funding to implement monthly billing for all customers is provided in the forecast revenue requirement.[18]

4. Rate Case Expense

This issue addressed the Company's efforts to recover expenses that it incurred in bringing the above-captioned rate cases. In its initial filing, the Company sought to defer for recovery over three years the total amount of these expenses

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[17] The Company's proposal for Rate Year 1 was approximately $2 million greater than that which was recommended in the Final Joint Proposal, and Staff's proposal was approximately $500,000 less. Staff Statement in Support of Joint Proposal at 22-23.

[18] For the Company's electric and gas businesses, the increase in costs resulting from the implementation of monthly billing, as reflected in the forecast revenue requirement are:

	Rate Year 1	Rate Year 2	Rate Year 3
Electric	$247,000	$1.147 million	$1.114 million
Gas	$64,000	$292,000	$284,000

Final Joint Proposal at Appendix A, Schedules 1 and 2.

($1.25 million). Staff's counter-proposal was that the recovery of outside legal expenses should be limited to $700,000 and that there should be no recovery for the "return on equity" (ROE) consultant used in this case. In the Final Joint Proposal, the rate case expenses are recovered over the three years of the rate plan. The amounts which may be recovered for external legal costs or for a ROE consultant are capped at $850,000 and $60,000, respectively.[19]

5. Productivity

Our practice in recent rate cases has been to impute savings from unspecified gains in productivity when forecasting the revenue requirement. The amount of this imputation has usually been 1.0% of a defined "total base" of payroll, employee benefits, pension, OPEBs and payroll taxes.[20] The Final Joint Proposal includes a productivity adjustment such as this, but the parties to the Final Joint Proposal have agreed to recommend the use of 1.5%, instead of 1.0%, as the imputation factor.

6. Major Storm Reserve

Each of the major electric utilities in the State, other than Central Hudson, has a major storm reserve. While details may differ, for the utilities already using a major storm reserve, the rate allowance for the reserve is recovered in delivery rates and credited to the major storm reserve. In addition, the balance in the major storm reserve accrues

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[19] Staff statement in support at 25-26. Pursuant to Appendix A of the Final Joint Proposal, the rate case expense over the three years of the rate plan is $286,000 for electric and $72,000 for gas in each year of the rate plan for a total over the three years of the rate plan of $1.074 million. The difference between this $1.074 million and the $910,000 ($850,000 plus $60,000) is the interest paid in Rate Years 2 and 3 for the amortization plus internal or other miscellaneous rate case costs. Tr. at 59-60.

[20] Evidentiary Hearing transcript (Tr.) at 64.

interest at the utility's allowed pre-tax rate of return. When a major storm occurs, the utility charges the reserve for the storm recovery expenses that it incurs. Central Hudson proposed a mechanism of this type in its initial testimony. The Final Joint Proposal recommends the adoption of a major storm reserve and has reduced the essential guidelines under which the reserve would operate to a memorandum attached as Appendix Q to the Final Joint Proposal.

7. Security Costs

In its initial submission, the Company sought $1.632 million for the development of greater security for its facilities. This amount for this purpose was supported by Staff and is recommended in the Final Joint Proposal.

8. Common Cost Allocation

At the present time, costs incurred by the Company that are not directly assignable to electric or to gas operations but that are associated with both are allocated for purposes of forecasting the Company's revenue requirements with 85% of such costs allocated for collection through electric delivery rates and 15% collected through gas rates. Staff proposed that this allocation be shifted from 85-15 to 80-20. The Final Joint Proposal recommends that the allocation be modified as described by Staff.

9. Distribution Automation and Network Strategy

The Company's initial filing included a description of these two interrelated programs and their inclusion in the Company's five-year capital program. As described by Staff, the Company's Distribution Automation program "has two components: the Distribution Management System and the Infrastructure component. The Network Strategy program supports the 2-way communication needs of the Distribution Automation program and provides communications among Central Hudson’s fixed assets. The

Company’s filing projected $7.00 million for the Distribution Management System and an additional $39.30 million for the Infrastructure component over five years. A separate $18.50 million was projected for the Network Strategy program over five years."[21] Staff did not support the full implementation of the project as proposed by the Company, but sought implementation of a demonstration project first with checkpoints where an evaluation of functional capabilities and operational integration could be assessed. The Final Joint Proposal recognizes the conceptual design of the projects as proposed by the Company and then specifies a process, similar to that outlined by Staff's testimony, to define the scope of an initial demonstration project that will be undertaken by the Company and to set mutually agreed milestones at which the projects' continuation would be approved or, if necessary, modified.

10. Energy Efficiency Funds

Funding for the Energy Efficiency Portfolio Standard (EEPS) programs is currently provided through a surcharge on customer bills, and is not recovered in base rates. The Final Joint Proposal initially recommended that this surcharge be maintained for the first six months of Rate Year 1, and that, for the remainder of the that Rate Year and for Rate Years 2 and 3, energy efficiency funding be implemented through base delivery rates. After the February JP was finalized and filed on February 6, 2015, we issued our Regulatory Framework Order.[22] In light of the Regulatory Framework Order, the parties reconsidered the budgets and targets embedded in base rates reflected in the February JP. At the evidentiary hearing, the

[21] Staff Statement in Support at 30.

[22] Case 14-M-0101, Proceeding in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (Regulatory Framework Order)(February 26, 2015).

parties reported on their agreement that the terms of the February JP should be modified such that the recovery of energy efficiency funding should continue through a surcharge mechanism and not be integrated into base rates as part of this rate plan, and that the energy efficiency targets and budgets reflected in the February JP should be modified to match the currently approved 2015 targets and budgets to be consistent with the Regulatory Framework Order.[23] These modifications are reflected in the Final Joint Proposal filed on April 22, 2015. [24]

D. Rate Year Net Plant Additions

The signing parties have incorporated their recommendation as to the Net Plant Targets for the three rate years of the proposed rate plan in the Final Joint Proposal.[25] The recommendations in the Final Joint Proposal also include detailed procedures that will be used to identify and calculate the Net Plant Targets and to reconcile actual investment against these targets.

The revenue requirement associated with these targets is reflected in the total revenue requirement on which rates are set. However, if investment in utility plant is insufficient to result in a net plant amount that meets the targets, ratepayers

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[23] TR. 111-117.

[24] The February JP included 6 months of Energy Efficiency Program base rate funding ($5,054 million) for RY1, and full year base rate funding ($10.108 million) for each of Rate Years 2 and 3. The Final Joint Proposal dated April 22, 2015, included only base rate funding for the Company's internal labor expenses for the Company's Energy Efficiency Program ($0.224 million for RY1, and $0.504 million for each of Rate Years 2 and 3.) The Company's non-internal expense funding was left for recovery through the existing surcharge mechanism. In addition, the total funding for the Company's Energy Efficiency program was set at the total amount prescribed by our Regulatory Framework Order (under the 2016 Budget, $8.48 million).

[25] Final Joint Proposal, Appendices B and C.

would end up paying for investments that have not occurred. To protect ratepayers from this exposure, the Final Joint Proposal recommends the continuation of a one-way downward reconciliation for the benefit of ratepayers. Under this reconciliation, which was first implemented through the 2009 Rate Order, the revenue requirement associated with the investment shortfall, which was collected in rates, is deferred for the benefit of ratepayers and is unavailable as a benefit to the Company or its shareholders.

Staff proposed in its direct testimony a requirement that the Company acquire a gas unit cost tracker which is described as a tool to provide more detailed information on the costs incurred from different construction conditions. The Final Joint Proposal adopts this recommendation, and includes a further recommendation that the Company may recover up to $250,000 for the costs incurred to acquire this tool.

E. Accounting Matters - Deferrals

The Final Joint Proposal recommends the continuation of 25 Deferral Mechanisms which were applicable in the July 1, 2014 to June 30, 2015 Rate Year and nine Deferral Mechanisms which are currently in place and will be continued with certain modifications in the new rate plan. The Final Joint Proposal also recommends the implementation of thirteen new deferral mechanisms and lists six deferral mechanisms that will expire.[26]

F. Capital Structure and Rate of Return

Regarding the proposed capital structure, the Final Joint Proposal recommends that rates be set based on the

[26] Although the Final Joint Proposal advises that the lists of Commission approved deferrals in Appendix E of the JP "is intended to be comprehensive," the Company and Staff and the other parties to the agreement advise that other deferrals employed by the Company may have been "inadvertently" omitted.

assumption that the portion of the capital structure provided by common equity will be 48% in each of the three rate years under the rate plan and that the cost of common equity will be 9.00%. In other joint proposals for multi-year rate plans, the parties have identified a "stay out premium" as an adder to the rate of return permitted the Company. In three-year rate plans, the size of this "adder" is about 30 basis points.[27] In this case, however, there is no identifiable "stay out premium" and the risks to shareholders and to ratepayers associated with a three-year rate plan are assumed to be implicitly and fully reflected in the rate of return recommended in the Final Joint Proposal.

The Final Joint Proposal's recommendations also include the assumption that the weighted cost of long-term debt will be 4.45%, 4.45%, and 4.36% in Rate Years 1, 2, and 3, respectively. These recommendations further include a true-up mechanism by which the differences between the estimated costs of long-term debt reflected in the Final Joint Proposal's Appendix H are trued up with the Company's actual long-term interest costs. The difference between the forecasted weighted cost of long-term debt and the actual weighted cost of long-term debt is calculated, and this difference is multiplied by the forecasted rate base amount to determine the amounts that will be deferred for the benefit of the Company (where the actual cost of debt is higher than forecast) or ratepayers (where the actual cost of debt is lower than forecast).

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[27] As used in the Final Joint Proposal, "basis point" is a measurement of the change in the per cent value of the return on equity. Specifically, it is a 1/100th of 1% change in this percentage value. The dollar value of the basis point is the revenue requirement impact of a change in the equity return of 0.01%, or, specifically, the difference in dollars between the annual value of the revenue requirement associated with a 9.00% return on equity and a 9.01% return on equity.

The Rate Plan outlined in the Final Joint Proposal also includes an Earnings Sharing Mechanism (ESM) through which a portion of the Company's return on equity above the 9.0% level will be deferred for the benefit of ratepayers. More specifically, the Company's equity earnings greater than 9.5%, but less than 10.0%, will be shared equally between ratepayers and the Company, and the equity earnings associated with a return on equity between 10.0% and 10.5% will be shared with ratepayers receiving the benefit of 80% of the return above 10%. Finally, equity earnings above 10.5% will be shared with 90% of the earnings going to ratepayers.

G. Additional Reporting Requirements

The Final Joint Proposal recommends that the Company be required to make several reports. The specific reports would address or relate to:

- the Empower program;
- low-income customers;
- security upgrades and projects;
- the network strategy and distribution automation demonstration project;
- actual earnings;
- capital expenditures; and
- gas safety.

H. Forecasts of Sales and Customers

The Final Joint Proposal includes estimates of the numbers of customers and of sales for both electric and gas service. These estimates reflect the views of both Company and the Staff and were not contested.

I. Revenue Allocation and Rate Design

Revenue Allocation is the determination of the portion of the revenue requirement that will be paid by each class of customers. Within the Final Joint Proposal's Revenue Allocation, if one class of customers provides, as a class, less revenue, a different class of customers will provide more. Rate Design is the determination of what portion of the Revenue Allocation assigned to a class of customers will be collected through each of the various rates and charges paid by members of that class of customers. If one charge that some or all of the customers in the class pay is reduced, a different charge would be increased so that the total class revenue remains consistent with that allocated to the class through the underlying Revenue Allocation. The Final Joint Proposal reflects the agreement among the parties as to the electric and gas revenue allocation and rate design that should be implemented through the Final Joint Proposal's three-year rate plan. The result of this agreement is, inter alia, the Final Joint Proposal's recommendation to adjust the fixed customer charge (for electric customers) or the first block charges (for gas customers) in many of the service classes.

J. Provisions for Low-income Customers

The Final Joint Proposal's recommendations regarding low-income programs call for the continuation of the Company's two existing programs, i.e. its EPOP or Enhanced Powerful Opportunities Program (at a funding level increased to account for the impact of the rate increases recommended in the Final Joint Proposal) and its Low-income Bill Discount Program (with funding to provide continued discounts at the current levels). The first of these programs, the EPOP, reaches out to certain residential customers who are behind on their account and provides incentives for the customer to pay current bills on time and, with the Company's assistance, to become current on their account. This program serves at any given time approximately 1100 residential customers.

The second Central Hudson program provides a monthly discount to customers who have received a grant under the Home Energy Assistance Program (HEAP), a federally funded program providing heating assistance to qualifying low-income households. The recommendations made in the Final Joint Proposal do not suggest any change in the monthly benefit to be provided through the low-income discount program. The amount of this benefit was set in the Acquisition Order in July 2013, has not been modified since then, and would not be modified at any time in the currently proposed three-year rate plan.

The Final Joint Proposal's recommendations also provide for the continuation of the existing deferral mechanisms to recover actual costs that are higher or lower than the forecasts included in the Final Joint Proposal's proposed revenue requirement. The Recommendations also provide for a forum for interested parties to continue their discussions concerning the need for the existing weatherization programs in the Central Hudson service territory to address the waiting list for weatherization services. Finally, the Final Joint Proposal proposes a program to provide same-day reconnections. Under the program, the Company's objective will be, for households that have lost service but that become eligible for reconnected service, to complete the reconnection of service on the same day at least 80% of the time.

K. Tariff-related Matters

The Final Joint Proposal includes several recommendations that would be implemented through the Company's tariffs. As described in the Final Joint Proposal, these proposals are described below.

1. Reconnection Charges

While the Company suggested an upward adjustment in its reconnection charges, the Final Joint Proposal continues the charges at the existing levels.

2. Electric Serv. Class. No. 8

Under this tariff as currently written, customers have three options if they wish to participate in the Service Class No. 8 street lighting program. The proposed tariff change in the JP would end the option by which the Company maintains the customer-owned street lighting equipment. It retains the other options whereby the Company will own and maintain the street lighting equipment or, in the alternative, whereby the Customer both owns and maintains the equipment.

3. Economic Development Funding

The Company currently provides eight different economic development programs, and carries a balance of funds for use in these programs of approximately $6.27 million. The recommendation in the Final Joint Proposal is to maintain each of the eight existing programs in their current form and at the current funding level.

4. Gas Design Day Forecasting - The Final Joint Proposal recommends that the Company provide to Staff, beginning with the 2015-2016 winter preparedness review and in each rate case filing thereafter, documentation concerning its design day and winter season demand requirements.

5. Unauthorized Use of Gas

In the gas balancing process, a gas transportation customer or its ESCO may make unauthorized use of gas. When such unauthorized use of gas occurs, a penalty may be imposed for this violation of the tariff. The Final Joint Proposal recommends that the Company's tariff be revised to clearly reflect this charge as a penalty.

6. Gas SC 11 Electric Generation Subclass

The Final Joint Proposal recommends the creation of a new subclass of SC 11 customers. This subclass would be composed of gas customers with a minimum electric generating capacity of 50 megawatts and that take firm gas transportation service from the Company.

7. Gas Balancing

The Final Joint Proposal recommends that greater penalties be imposed for under-deliveries of gas. Further, it also recommends that the Company's tariffs describe daily balancing as the default option for new customers that are large gas-fired generators. These new customers would then have to make a persuasive showing to justify the use of monthly balancing. Finally, the Company would reserve the right to require daily balancing when monthly balancing would negatively impact reliability.

8. Remote Operated Valves for Electric Generators

Remote Operated Valves are currently not required and, as a result, a manual shutoff is used when the interruption of gas service is required. The Final Joint Proposal recommends that new electric generation gas customers be required to install Remote Operated Valves at their expense to qualify for service. Existing customers, however, would not have to install such equipment unless the generator has failed to comply with a Company issued interruption.

9. Continuation of ECAM, GSC and PPA Allocation

The Final Joint Proposal recommends that the existing Energy Cost Adjustment Mechanism (ECAM) and the Gas Supply Charge (GSC), including the Purchased Power Adjustment (PPA) costs/benefits, continue unchanged.

10. Gas Retail Access Operating Procedures

The Final Joint Proposal includes several recommendations with respect to the Company's Gas Retail Access Program. First, the Company agrees to revise its "cash out" process to address, in any given month, those accounts with valid meter readings in that month. Second, the Company agrees to revise its Winter Bundled Service (WBS) Price to reflect its weighted average cost of storage (WACOS) from the previous month. In addition, the parties agreed to initiate a collaborative to address issues that may be raised by three or more members of the "retail access community."

11. Gas Service Expansion Program

It is forecast that the Company will have approximately 255,000 electric customers over the term of the rate plan. In contrast, it is estimated that the Company will provide only about 69,000 customers with gas service in this period.[28] Central Hudson has pursued a system-wide program to promote the conversion of customers' heating units to gas-fueled units. To achieve its intended level of program expansion, the Company plans to convert 5,000 residential customers and 3,875 commercial customers to gas service over the next five years. In the Final Joint Proposal, it is recommended that this program be continued and supported by $63.7 million in capital expenditures over the next five years. In addition, the Final Joint Proposal recommends that the Company undertake to provide $1 million per year to provide direct assistance to customers who wish to convert to gas service.[29] This program would be jointly designed by Staff and the Company, and the funding would

[28] Final Joint Proposal, Appendix I, Sheets 3, 17.

[29] At the evidentiary hearing, the Company indicated that, if approved, this program would be available to assist customers for the coming heating season. Tr. at 105.

be provided from available rate moderators. Further, to provide a direct incentive to the Company, the Final Joint Proposal recommends that the Commission adopt an incentive in the form of an award equivalent in va1ue to one basis point for every 200 gas customers the Company serves above the forecasted total combined gas customer count in each year of the rate plan.[30] In this recommendation, the extent of the incentive is capped at 5 basis points.

12. Electric and Gas Revenue Decoupling Mechanisms (RDMs)

The parties' recommendation is to convert the existing gas RDM from one calculated in units per customer to one calculated in revenue per customer. The Final Joint Proposal recommends no other significant changes to either the gas or the electric RDMs.

L. Rate Unbundling and Retail Access Lost Revenue Recovery

The Final Joint Proposal recommends the continuation of the Merchant Function Charge (MFC) as it is currently implemented for electric service. The recommendation for gas service, however, is to replace the current MFC with a new mechanism to reconcile actual billed MFC revenue, by MFC group, with monthly MFC revenue targets. The Final Joint Proposal also recommends a target Factor of Adjustment (FOA) for the Company's recovery of the costs associated with Lost and Unaccounted For ("LAUF") gas and an annual updating of the FOA by averaging the Company's most recent five-year's FOA experience. The Final

[30] The parties to the Final Joint Proposal have stated in the Final Joint Proposal that the pre-tax value of each basis point for the gas system would be $21,300, $24,000 and $27,000 for Rate Years 1, 2 and 3, respectively. If the incentive is awarded, the Company would take the incentive amount as a deferral for later collection from ratepayers.

Joint Proposal also recommends the specification of a dead band above and below the FOA value used in each year.

M. Reforming the Energy Vision

The Final Joint Proposal defined a plan of work for a REV Working Group, which started during the pendency of this case to consider the REV conceptual programs proposed by the Company along with any other REV demonstration projects identified by the Working Group. The plan of work called for the filing of a report by May 1, 2015 on the Working Group's review of these demonstration projects and for the filing of comments on this report by May 15, 2015.[31] These filings have occurred, and the review of these proposals will proceed in our Case 14-M-0101.

With the issuance of our Regulatory Framework Order, the ALJs recognized that some requirements imposed on the parties in this case through the Final Joint Proposal were similar to requirements imposed through that Order, and a further information request was issued by the ALJs seeking clarification. The response to this interrogatory was provided on the record by the parties at the March 31 evidentiary hearing. In that discussion, the parties agreed that the recommendations in the Final Joint Proposal and the provisions of the Regulatory Framework Order were not in conflict so that the requirements of the Regulatory Framework Order could be met by the participants in these cases without compromising the agreements reflected in the Final Joint Proposal and that the parties' responsibilities described in the Final Joint Proposal were unmodified by the terms of the Regulatory Framework Order.[32]

[31] The May 15 filing date was extended by the signatories to May 22, 2015.

[32] Tr. 117-122.

The parties also recognized in the Final Joint Proposal that Case 14-M-0101 may impose costs on the Company not contemplated at the time of the Final Joint Proposal or of our decision in these rate cases. In that event, the parties recommend that Central Hudson be permitted to petition for a deferral of such costs and that such petition be exempt from the application of the Commission's three-part test for entitlement to deferral accounting.

N. Performance Mechanisms

The Final Joint Proposal addresses the continuation, modification or development of a number of performance mechanisms as follows:

1. Customer Service

The Final Joint Proposal recommends the continuation, using the same penalty levels, of the PSC Annual Complaint Rate and the Customer Satisfaction Survey metrics as they currently exist today. It also recommends the continuation of the Company's practice to provide a $20 credit to the customer's account when the Company fails to keep a service appointment.

2. Service Termination Reductions

The Final Joint Proposal describes the desire of its signers to reduce service terminations to residential customers. To implement this objective, the Final Joint Proposal includes a recommendation to create an annual incentive of five basis points for each rate year in which the number of service terminations imposed on residential customers is less than 11,000.[33]

[33] This metric is measured in terms of terminations of service for residential customers for non-payment. It does not include terminations at locations where there is no customer of record for natural gas service.

3. Electric Reliability

The Final Joint Proposal also recommends the continuation of electric reliability assessments through the Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Frequency Index (SAIFI) metrics. It proposes to leave the CAIDI metric unchanged, but to modify the SAIFI target by lowering it from 1.45 to 1.30. It also proposes to increase the negative revenue adjustment for failing to meet the SAIFI or the CAIDI metric from 15 basis points for each metric to 30 basis points for each metric.

4. Gas Safety

The Final Joint Proposal recommends the continuation of the gas safety metrics and negative revenue adjustments with the following exceptions:

- A new metric is established to impose a negative revenue adjustment when the Company fails to respond to a gas emergency call within 60 minutes at least 95% of the time. The negative adjustment associated with this metric is one basis point.
- The metric that measures the Company's gas leak backlog is reduced from 260 (with no more than 20 repairable leaks at year end) to 200 (with no more than 16 repairable leaks at year end).
- The metrics for damage prevention are lowered from 2.4 to 2.2 incidents of Total Damage per 1000 tickets, and from 0.50 to 0.45 Mismarks per 1000 tickets. There is no change in the Company/Company Contractor Damages (CCCD) metric proposed for the first year of the rate plan. All three metrics

are further reduced in the second and third years of the rate plan.

Under the performance incentives in place today, the Company is exposed to adjustments at 1.5 or two times the base level for repeated failures to meet the performance metrics. Under the Final Joint Proposal, the exposure under such circumstances is limited to 1.5 times the revenue adjustment.

5. Gas Safety Violations

The current performance incentives include a potential negative revenue adjustment based on the number and severity of Central Hudson violations of our gas safety code. This adjustment was created in the Acquisition Order and is continued here without modification. The Final Joint Proposal recommends a clarification of the applicability of the Gas Safety Violations metric, however, so that, if an occurrence is the subject of a penalty proceeding under PSL § 25 or 25-a, the occurrence will not be counted in the Gas Safety Violations metric.[34]

6. Infrastructure Enhancement for Leak Prone Pipe

The Final Joint Proposal recommends that the Company's program to replace or eliminate leak-prone pipe will be measured against goals of 13 miles, 14 miles, and 15 miles of pipe replaced or eliminated in 2016, 2017 and 2018, respectively. Currently, the Company is required to make a certain expenditure ($7.7 million), and, if the expenditure goal is not met, to return half of the revenue requirement associated with the unspent amount to ratepayers. Under the Final Joint Proposal,

[34] Final Joint Proposal at 51. The cited portion of the Final Joint Proposal implies and we infer that the converse is also intended, i.e. if an occurrence is not the subject of a penalty proceeding under § 25 or § 25-a, it may still be counted in the Gas Safety Violations metric.

if the Company fails to make the mileage goals, it would be assessed an eight basis point negative revenue adjustment.

Currently, there is no positive incentive to exceed the $7.7 million per year expenditure goal. As noted, under the Final Joint Proposal, the performance goal would be shifted from an expenditure goal to a "miles of pipe replaced or eliminated" goal, and the Company would be incented by a positive revenue adjustment to exceed these mileage targets. Specifically, the Company would be provided an incentive of 2 basis points per additional mile (capped at 5 miles or 10 basis points) per calendar year.[35]

O. Outreach & Education

The Final Joint Proposal makes no new recommendations for the Company's Outreach & Education program. Instead, it merely proposes the filing of an annual Outreach and Education Plan similar in scope to the plans that are currently filed.

STATEMENTS IN SUPPORT OF OR COMMENTS ON THE FINAL JOINT PROPOSAL

After the February JP was filed, the parties in the case were afforded the opportunity to file statements in support or in opposition to its recommendations. Six parties filed

[35] A separate proceeding has begun to examine mechanisms available to accelerate the replacement of leak-prone pipe. Case 15-G-0151, Recovery Mechanisms to Support Accelerated Replacement of Natural Gas Infrastructure, Order Instituting Proceeding for a Recovery Mechanism to Accelerate the Replacement of Leak Prone Pipe (April 17, 2015). We expect that the mechanisms examined in that case, if implemented, would address cost recovery for leak prone pipe expenditures that are incremental to those specified in the recommendations of the Final Joint Proposal.

Statements in Support,[36] no parties filed Statements in Opposition, and three parties did not identify their filings as in support or in opposition, but characterized the filings as comments.[37]

A. Statements in Support

Comprehensive Statements in Support were provided by Central Hudson and by Staff. The Company's Statement acknowledges each of the provisions of the Final Joint Proposal and describes generally how each relates to the Commission's standards for approval. It concludes by stating:

> The Joint Proposal represents a comprehensive, integrated multi-year rate plan. It reflects not only recommendations and concessions from the Signatories, but also represents a substantial effort to address the concerns voiced by all Parties. The Joint Proposal represents a good-faith effort to address all interests to the greatest extent possible. Should one or more Parties criticize individual elements of the Joint Proposal and/or urge its rejection, such arguments must be measured against the numerous compromises that were negotiated in order to reach an agreement and the many benefits of the Joint Proposal taken as a whole.[38]

Staff's Statement provides a comprehensive, section-by-section discussion of the provisions of the Final Joint Proposal as well as a useful analysis of the consistency of each section with the factors that the Commission would use to evaluate whether the recommendations of the Final Joint Proposal

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[36] The parties filing Statements in Support were the Company, Staff, Multiple Intervenors, Pace, Sabin, and SolarCity Corporation.

[37] The parties filing comments were Consolidated Edison Solutions, Inc., NRG Energy, Inc., and Citizens for Local Power.

[38] Statement of Central Hudson in Support of Joint Proposal (February 24, 2015) at 37.

were in the public interest. Staff's Statement concludes by stating that the:

> rate increases identified in the JP's three-year rate plan allows customers to engage in long-term planning both for energy use and conservation measures. The other provisions of the JP ensure compliance with existing Commission [o]rders and policies, and limit the risk of a difficult, litigated rate proceeding, the outcome of which may not benefit ratepayers as fully as the mutually agreed upon outcome created through the JP. As a result, the JP satisfies the Commission's standard to approve negotiated settlements and is in the public interest.[39]

The Statement in Support provided by Multiple Intervenors provides a more focused analysis of certain of the provisions of the Final Joint Proposal such as the overall rate increase, the revised common cost allocator, the authorization for and limitation on deferrals for REV demonstration project costs, and the electric and gas revenue allocations for large industrial and commercial customers. The Statement states in summary that:

> In this proceeding, the Joint Proposal truly represents a series of interrelated compromises and concessions on the outstanding issues. Multiple Intervenors certainly feels like it compromised on certain issues in exchange for compromises by other Signatories on different issues. Multiple Intervenors' decision to execute and support the Joint Proposal was not made lightly, and, similar to the other Signatories, it likely would have elected to litigate certain issues but for the favorable resolution of other issues such that, on balance, the Joint Proposal was deemed an acceptable resolution of this proceeding and preferable to the uncertain outcomes associated with the potential litigation of all or most issues.[40]

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[39] Staff Statement in Support of Joint Proposal, February 24, 2015 at 12.

[40] Statement of Multiple Intervenors in Support of Joint Proposal, February 24, 2015, at 40.

The Statement in Support from the Sabin Center focuses completely on the recommended process by which the Company will review certain climate change studies and, if necessary, meet with the parties to review the incremental capital investments, if any, that these studies may suggest are needed.

The Pace Energy and Climate Center statement also urges the climate study provisions in the Final Joint Proposal as a basis for the approval of its recommendations. Pace also emphasizes the importance of the provisions in the Final Joint Proposal that structure a continuing collaborative to address REV demonstration projects that may be forthcoming, and that Pace considers to be a significant step towards the likely implementation of our REV initiative.[41]

The final Statement in Support was supplied by SolarCity. This party focuses its support on the provisions by which a deferral is established for the recovery of the Company's REV demonstration project incremental costs. In addition, the SolarCity comments urge the Commission to provide increased returns to those companies that, like Central Hudson in Solar City's view, are "willing partners" in the implementation of the REV program.

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[41] There are several provisions in the Final Joint Proposal outlining commitments made by the Company concerning REV demonstration projects, including the filing of a report by May 1, and the provision of an opportunity to comment on this report by May 15. Inasmuch as this report was filed and the opportunity for comments occurred and inasmuch as the parties have made clear that the fulfillment of these commitments does not limit, amend, or otherwise alter the responsibilities set forth in our Regulatory Framework Order (Tr. 119-122), these actions are not within the scope of our review in this case at this time.

B. Statements Providing Comments

In its comments, Con Edison Solutions describes positively its participation, through this case, in the establishment of the "REV Working Group" in which it was and is a participant and on other REV-related issues.

The comments by NRG also focus on the REV provisions of the Final Joint Proposal, and they enumerate several specific concerns. First, NRG urges that the decision to review and, if appropriate, implement the Company's Network Strategy and Distribution Automation project must be carefully executed in light of the potential, depending on the outcome of the REV case, for stranded costs. In addition, NRG emphasizes that the project is not now defined as to scope, timing or cost and, therefore, there is no basis on which to evaluate the project.

Second, the NRG comments focus on the estimates provided in the JP of the Company's net plant additions over the term of the rate plan. NRG is concerned that these estimates of net plant additions do not properly reflect the environment that will follow from implementation of our REV program. In this future environment, there will be, it asserts, a diminished need for utility investment as the use of distributed energy resources (DERs) grows. NRG speculates that, if the pace of utility investments declines, the ability of the utility to generate revenue through its normal program of capital investment would also decline. In anticipation of this, the utility may, in NRG's view, be incented to slow or otherwise discourage the REV program's intended expansion of the use of DERs.

Third, the NRG comments focus on the proposed deferral of incremental revenue requirements associated with the REV demonstration projects as described in the JP. In NRG's view, these projects should be strictly reviewed, in the deferral process, to assure that, wherever possible, they include "competitive, non-utility partners" or "establish the foundation for further distributed energy resource projects that do not require utility involvement or utility ownership."[42]

NRG's final comment focuses on language that appears to obligate the parties that participated in the REV collaborative to support cost recovery for REV demonstration projects, even if the party does not agree that the specific demonstration project should go forward. NRG urges that, whatever the effect of this language on parties that signed the JP, any Commission action approving the recommendations in the JP should not purport to limit the ability of those, such as NRG, that participated in the REV working group, but do not support particular projects, from objecting to cost recovery for such projects.

The third party providing comments, Citizens for Local Power, focuses on several specific provisions in the Final Joint Proposal. First, the CLP comments voice concerns that the increases in revenue requirements, as expressed in rates and, in particular, in the fixed delivery charge in the proposed rates, are too high. Second, the CLP comments urge more caution in the transition to monthly billing due to the labor costs that appear to be associated with this initiative and the uncertain relationship between this initiative, as described in the JP, and the development of the REV reforms. Third, the CLP comments suggest that the establishment of a major storm reserve may become unnecessary as more distributed forms of generation or electricity supply become more common. Fourth, the CLP comments focus on the Network Strategy and Distribution Automation Project and argue that this Project is essentially undefined in the record thus far. In the absence of a clear definition, it

[42] Letter from NRG to Sec. Burgess, February 24, 2015 at 2.

may be possible, according to CLP, that the Company's implementation may fail to maximize the potential for the project to render the grid more hospitable to customer and third-party engagement.

Fifth, CLP urges that a stronger commitment should have been forthcoming from the Company to accelerate the street lighting upgrades during the rate plan. Sixth, CLP urges that the Economic Development programs and funding described in the rate plan should be re-targeted, at least in part, to REV or REV-related Distributed Energy Resource projects. Seventh, CLP urges that the program to accelerate the pace of conversions to natural gas for heat should have included, for each low-income and middle-income customer participating in the program, assistance or incentives for contemporaneous weatherization or insulation improvements and that these improvements should have been funded from revenues received from the operation of Danskammer, if it occurs. Eighth, CLP, like NRG, objects to the JP provisions which purport to limit the objections that may be filed when the Company seeks funding through a Commission order for REV demonstration projects. Ninth, as materials are produced or distributed to implement the Climate Change provisions of the JP and discussions ensue regarding actions by the Company, CLP urges that it, and any interested non-parties, will have full opportunity to receive these materials and to participate in any discussions.

DISCUSSION

A. Procedural Soundness

At the outset and as set forth in our Settlement Guidelines Order,[43] our examination of the recommendations made

[43] Cases 90-M-0255 and 92-M-0138, Opinion No. 92-2, Opinion, Order and Resolution Adopting Settlement Procedures and Guidelines (March 24, 1992)(Settlement Guidelines Order).

in the Final Joint Proposal begins with the settlement process by which the recommendations were developed and the record created in the public process to evaluate these recommendations. As we stated in that Order, "[t]he threshold requirement for any such decision [to accept the recommendations in a Joint Proposal] is that it be reached in accordance with applicable procedures."[44] As described more fully above, the procedures used to develop the Final Joint Proposal's recommendations and to solicit comments or statements in support or opposition were an appropriate reflection of the public's interest in having a broad opportunity for participation by parties and non-parties in a transparent process to develop a comprehensive record regarding the Final Joint Proposal's recommendations.

Specifically and as noted above, before developing the Final Joint Proposal, the parties conducted extensive discovery and exploited their opportunity to file testimony in opposition to the Company's request for a rate increase, and, thereafter, to file rebuttal testimony. The settlement process then began with the filing by the Company of a November 25 Notice of Impending Settlement Negotiations, which invited the participation of any interested party in the negotiations.

At the conclusion of settlement negotiations, the parties subscribing to the agreement filed their Final Joint Proposal, and a process to evaluate it was initiated. This process included the continuing opportunity to seek discovery and the opportunity to submit statements in support or opposition to the adoption of Final Joint Proposal's recommendations. After the submission of these statements, an evidentiary hearing was held at which any party wishing to do so could challenge any of the assertions made in support of the Joint Proposal recommendations. Finally and in addition, the

[44] Settlement Guidelines Order at 30.

Department conducted two public statement hearings after the February JP had been filed -- one in Poughkeepsie and one in Kingston, New York -- to provide an opportunity to comment to those not formally a party to this case.[45]

The process followed in this case was open, transparent, and inclusive and clearly meets the procedural requirements associated with the development and review of the recommendations of a joint proposal.

B. Substantive Factors in Review

In our Settlement Guidelines Order, six factors are identified which would be examined to assess whether the proposals in a joint proposal should be adopted through a Commission Order. Specifically, the Settlement Guidelines Order states:

> Procedural soundness, of course, is necessary but not sufficient, and the factors to be considered in the ensuing substantive review do not lend themselves to codification. As the comments suggest, they include (1) the settlement's consistency with law and with the regulatory, economic, social, and environmental policies of the Commission and the State; (2) whether the result compares favorably with the likely result of full litigation and is within the range of reasonable outcomes; 3) whether the settlement strikes a fair balance among the interests of ratepayers and investors and the long-term soundness of the utility; (4) the existence of a rational basis for decision; (5) the completeness of the record; and (6) whether the settlement is contested.[46]

[45] Although certain technical differences resulted in some differences between the February JP and the joint proposal presented for our review, the comments provided at the public statement hearings address aspects of the joint proposal which were unchanged by the April JP or by the Final Joint Proposal.

[46] Settlement Guidelines Order at 30.

In the Settlement Guidelines Order, the first four of these factors are identified as "elements of the public interest standard", while the fifth and sixth factors are described as guidance in making the public interest analysis.[47]

C. Completeness of the Record (Factor 5) and Extent of Opposition (Factor 6)

In this case, the negotiation of the recommendations made in the Final Joint Proposal occurred after the parties had served and filed their direct and rebuttal testimony. In addition, after agreement on the recommendations in the Final Joint Proposal was reached, the parties had another opportunity to prepare and submit statements in support of the recommendations, and an evidentiary hearing was held to examine those recommendations and the parties' statements. As a result, the record available to us is more than well developed. It is full and complete and contributes significantly to meeting the burden borne by the parties sponsoring the Final Joint Proposal to establish that adoption of the recommendations in the Final Joint Proposal is in the public interest.

Similarly, as stated earlier, no party urges the Commission to reject the Final Joint Proposal, and some of the parties in support of the Final Joint Proposal are normally adversarial parties. Consequently, this too helps the parties in support to meet their burden.

D. Public Interest Standard (Factors 1 through 4)

Notwithstanding the well-developed record with which we are provided, and the apparent agreement through the Final Joint Proposal of normally adverse parties, we must nevertheless evaluate the recommendations of the Final Joint

[47] Settlement Guidelines Order at 30.

Proposal by reference to their contribution to the public interest. We do so below in our discussion of the major recommendations made in the Final Joint Proposal.

1. Term of the Rate Plan

Pursuant to the recommendations of the Final Joint Proposal, we consider here a three-year rate plan as the recommended alternative to the one year rate plan outlined in the Company's initial filing. A significant advantage of a three-year rate plan is the certainty it can provide to the Company and its lenders, to other market participants, and to consumers as to the rates and other aspects of service for the greater-than-one year period covered by the plan. From the consumers' point of view and especially from the non-residential customer's perspective, this certainty provides a significantly enhanced opportunity to know as much as three years in advance what electric rates should be expected. This up-to-three year look ahead supports the customer's planning initiatives to optimize its energy supply alternatives. It also helps to animate the energy marketplace since the pricing certainty associated with a three-year rate plan is useful as market participants seek to provide or to acquire new or enhanced products and services.

For the Company, the three-year rate plan precludes the Company from seeking further rate increases while the plan is in place. However, the three-year term of the proposed rate plan also enhances the utility's ability to plan, to execute, and to benefit from most instances, initiatives undertaken by the utility in response to a rate order which cannot be completed in only one year. The additional time provided in a multiyear rate plan may greatly enhance the efficiency with which new programs or initiatives can be introduced, and the value that may be realized by the Company upon the successful introduction of such programs or initiatives.

While it is true that the development of a multi-year rate plan requires us to estimate or forecast expenses and revenues as much as three years in advance, there is a growing availability of ratemaking mechanisms, such as revenue decoupling mechanisms (RDMs), revenue sharing mechanisms, and true-ups of major expense items, that greatly increases our confidence in the ability to implement rates through multi-year rate plans without imposing unreasonable risks on consumers or on the utility.

Finally, the three-year plan means that the Company will forgo as many as two additional rate cases before bringing its next request to adjust rates. For practical purposes, with a three-year rate plan, the drain on regulatory resources for the Company, for Staff and for intervenors is as little as one third of that which would be needed to litigate the annual rate cases that could otherwise ensue.

We are pursuing on a statewide basis, a comprehensive reform of our systems to supply and deliver electricity and energy efficiency services to New York consumers. Over the three-year term of the proposed rate plan, and in the context of our Reforming the Energy Vision initiative, we expect each utility in the State to undertake or participate in several transformational projects, and this expectation will extend to Central Hudson notwithstanding any action we may take here to approve one or more of the recommendations in the Final Joint Proposal. As discussed more fully below, the parties have recognized the possibility that implementation of our REV program may impose new obligations on Central Hudson which are not accounted for in the current rate plan. With this recognition, we conclude that our adoption of the recommended multi-year rate plan poses no barrier to the full implementation of our REV initiative by Central Hudson, and that the establishment of a three-year rate plan is well within the public interest.

2. Size of the revenue increase

As described above, for Rate Year 1, the Final Joint Proposal's recommended electric revenue increase is well below that initially sought by the Company and closely approximates that recommended by Staff. For gas, the Rate Year 1 proposal is for no increase at all. For Rate Years 2 and 3, the Final Joint Proposal's recommendations would provide revenue increases in both electric and gas. The need for revenue requirement increases is, in large part, the result of several factors. In particular and as Staff observes, the electric revenue requirement increases are "driven by increased capital spending and related depreciation expense, a reduction in sales volume due to energy conservation measures, [and] a substantial increase in property taxes."[48] Similar factors are identified by Staff as drivers of the increased revenue requirement for gas.[49] In large part, these increases are a response to factors outside the Company's control (most notably, property taxes), or increases in the revenue requirement associated with increased rate base resulting from capital expenditures made during the two-year rate freeze required by our Acquisition Order, or to items of expense to which agreement has been reached in other portions of the Final Joint Proposal. No party suggests that the Commission

[48] Staff Statement in Support of Joint Proposal (February 24, 2015) at p. 19.

[49] Id. at p. 20.

should reject the revenue requirement recommendations of the Final Joint Proposal.[50]

We find, therefore, that the electric and gas revenue requirement increases recommended in the Final Joint Proposal are needed to provide the Company with the necessary resources to earn a fair return for its shareholders, and to continue to provide the safe and adequate service from which all customers benefit. Therefore, the proposed revenue requirement, as described in the Final Joint Proposal, is in the public interest and should, subject to our discussion of specific items of expense below, be adopted.

3. Monthly Billing

Currently, the meters for most Central Hudson customers are read once every two months, i.e., bimonthly, and bills are also provided to customers on a bimonthly basis. Central Hudson's initial filing did not include a proposal to read meters on a monthly basis or to convert its customers to monthly billing. Staff, on the other hand, sought both. In its rebuttal testimony, the Company agreed with Staff's proposal to transition to monthly billing for all its customers, but disagreed with Staff's recommendation to implement monthly meter reading. Under the Company's design for monthly billing without monthly meter reading, the Company

[50] Only one party, Citizens for Local Power (CLP), commented to challenge the size of the revenue requirement increase. Even CLP, however, recognized that the Company faced substantial cost increases from rising property taxes and inflation. Among those who provided public comments, but did not participate as parties, opposition to the electric and gas rate increases was voiced through a local advocacy group, identified as Nobody Leaves Mid-Hudson. This group or speakers aligned with it provided the six speakers who appeared at the Poughkeepsie public statement hearing. They described high rates as a "displacement" issue for low-income and fixed income customers.

would estimate the bills for each month not supported by an actual meter reading. These estimates would be derived using algorithms provided by the Company that reflect the likelihood that circumstances and usage may well change between the first and the second month of a two-month metering reading interval.

The recommendations in the Final Joint Proposal reflect the Company's testimonial position. If adopted, the recommendations would not alter the schedule for Central Hudson meter reading, but would require Central Hudson to convert all customers to monthly billing. This conversion would be completed by the end of Rate Year 1.

Other than Central Hudson, all other major gas or electric utilities in the State now utilize monthly billing. Accordingly, a conversion by Central Hudson to monthly billing must be recognized as consistent with our current billing policies. It is possible that, through our REV program, these policies may be reconsidered and changed or extended so that usage information is collected and bills are transmitted to customers more frequently or with more detail than is currently provided by these other utilities or than is proposed here for Central Hudson. In this event and as noted above, the recommendations adopted by this Order, including the recommendations for monthly billing, would be superseded by the requirements imposed by or through the REV program and this Order would, therefore, remain consistent with Commission policy.[51]

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[51] At Section XIII of the Joint Proposal, the signatory parties "acknowledge that the Commission has initiated Case 14-M-0101, the determinations from which will take precedence and may require the implementation of certain REV opportunities, procedures, or requirements impacting or effecting Central Hudson and its customers while the terms of this JP are operative." Final Joint Proposal at page 45.

Most Central Hudson customers are paid or receive Social Security or pension benefits and make major payments for rent, the home mortgage, and car or other consumer loans on a monthly basis.[52] Consequently, for many, household financial planning is done on monthly basis, and the conversion of their utility bills to a system of monthly billing brings those bills into that familiar framework. As urged by Staff, the introduction of monthly billing should strengthen the ability of many residential households to plan for and remain current on their utility accounts. Because of this assistance for customers, the proposal to convert Central Hudson to monthly billing is in the public interest and should be approved.[53]

4. Recovery of rate case expenses

Each rate case brought by a utility company is supported by the expenditure of significant internal resources and may also be supported by expenditures for outside counsel and experts. Historically, these costs have been recovered by the utility as an undifferentiated element of the company's operational costs. It is recommended in the Final Joint

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[52] Tr. 142.

[53] Citizens for Local Power urges delay in the implementation of the monthly billing program pending the further development of the REV policies. In effect, CLP asks us to assume that the only benefit to customers from monthly billing is through the elements of the REV program that monthly billing will support, and, until that program is more clearly defined, the transition to monthly billing would be premature. Because we find a modest benefit to customers, and particularly to customers whose household budget is funded and disbursed on a monthly basis, from monthly billing, we conclude that the monthly billing program is in the public interest now. As CLP suggests, further benefits of monthly billing may be realized from monthly billing in conjunction with the REV program. The possibility of greater benefits in the future, however, does not mean that customers must forgo the modest benefits that would be currently available.

Proposal, however, that the costs incurred by Central Hudson for this case should be more explicitly called out. In the Final Joint Proposal, the revenue requirement allowance for rate case expenses is determined to be as set forth in Appendix A to the Final Joint Proposal, and Appendix A calls for the recovery of these expenses in roughly equal amounts in each of the three years of the rate plan. In making this recovery, the amortization is calculated so that the Company will collect its costs plus interest. The recommendations for recovery of rate case expenses include a further recommendation to cap the amount that would be recoverable for external legal costs to $850,000 and for an ROE consultant to $60,000. While the recovery of rate case expenses is normally part of a utility's revenue requirement, either explicitly, as is recommended here, or implicitly, as a cost that is "rolled in" with a number of other miscellaneous costs, caps on such recoveries have not previously been used.

At the outset, we must review carefully a proposal that requires ratepayers to reimburse the Company the costs of legal and other outside assistance the Company receives so that the Company will be better able to resist arguments made in a rate case for the benefit of customers. However, in reviewing this recommendation, we are greatly impressed by the agreement among the Final Joint Proposal signatories to attach caps to the most significant elements of the rate case expense. Staff asserts that this recommendation in the Final Joint Proposal would, when implemented, effectively limit the recovery available to the Company for these expenses to $850,000 for outside legal services and $60,000 for outside consultants. According to the Company, these caps are, at least in the case of outside legal services, "a low number" in comparison to historic expenditures.[54]

Under the Final Joint Proposal, it is recommended that the provisions applicable in Rate Year 3 "will, unless otherwise specified herein, remain in effect until superseding rates or terms become effective."[55] The recovery of the rate case expense allowance is not one of the provisions which is expiring at the end of Rate Year 3. Both Staff and the Company agree, however, that the recovery provided in the proposed rate plan is for rate case expenses in this rate case, and that the three years of recovery under this rate plan will repay the Company over its three-year term all of the expenses for which the parties have intended a repayment to be made. Therefore, in the event that a new rate plan is not in place to follow the rate plan provided in this order, the revenues collected through this provision of the rate plan will be deferred for the benefit of customers.

5. Productivity

As noted by Staff, the Commission's usual adjustment for productivity savings in multi-year rate plans is 1%.[56] It is further asserted that the Company will find additional productivity savings through the implementation of recommendations from the Company's recent management audit. The recommended productivity adjustment in the Final Joint Proposal is 1.5%. We will approve the adjustment in this amount because of the potential for management audit-based savings.

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[54] Tr. at 63-64.

[55] Final Joint Proposal at Section III at page 6.

[56] Staff Statement in Support at 27.

6. Major Storm Reserve

We have previously approved the creation of a major storm reserve for each of the major electric utilities in the State. Clearly, the recommendation to establish one for Central Hudson is fully consistent with Commission policy in this regard.[57]

Major storms are, almost by definition, both predictable and unpredictable. We know that they occur and that, when they do, the utility has no choice but to pay the reasonable costs of cleanup and recovery. Because of this predictability, the utility correctly urges that these costs should be recovered as part of base rates. At the same time, we cannot predict when major storm costs will occur since there may be several years when no major storm occurs, or, in the alternative, there could be more than one major storm in a particular year. Because of this unpredictability, the inclusion in the revenue requirement for any particular rate year of any particular amount for major storm expense is problematic.

The major storm reserve is created to bridge the gap between the unpredictability of major storm expense in a given rate year and the predictability that significant storm

[57] One party, CLP, asserts that the size of the major storm reserve is greater than needed. It argues that the introduction of DERs in the distribution system will leave the system more resilient and that, as a result, the expense of storm recovery would be lessened. We fully expect that the introduction of DERs will bring changes to many aspects of utility operations, including, as may be relevant here, to the resources needed for major storm recovery. However, DER penetration to the point that these effects will be measurable may be several years away. When, in the Company's subsequent rate plans, the impacts from implementation of the REV program, including the impacts from DER penetration, are assessed, we could and would modify the major storm reserve, as needed.

expenses will occur at some time in the future. In performing this function, the reserve is helpful to the utility. It provides the utility with a reasonable assurance that these storm costs will be recovered. At a time when utility performance in the field is essential and likely to be under close examination, the availability of the major storm reserve encourages the Company focus on storm recovery, rather than cost recovery.

The process for recovering costs from the major storm reserve is set forth in Appendix Q of the Final Joint Proposal, and this process includes several provisions to assure that the reserve is used as intended. Specifically, Appendix Q establishes clear time periods within which the claim from the reserve must be pursued and justified. It also establishes a $500,000 hard threshold to protect the reserve from claims associated with smaller storms that are addressed elsewhere in base rates. Finally, the Appendix Q process includes a 3% "deductible" to account for the base rate resources that would be available and used to address storm damages notwithstanding the storm's qualification as a "major storm".

The establishment of a major storm reserve will permit the utility to plan for the financial impacts of major storm recovery notwithstanding the unpredictability of the occurrence of any particular storm. This is a significant advantage to the utility and one which is available to all other major utilities in the State. At the same time, as noted above, the major storm reserve recommended in the Final Joint Proposal includes several provisions which provide customers with the assurance that the reserve will be used as intended. Therefore, the major storm reserve, as proposed, fully reflects a useful balancing of the ratepayer, shareholder and utility interests as our settlement guidelines prescribe, and is in the public interest.

7. Network Strategy and Distribution Automation

The Company's initial case included the above-named projects in its Five Year Capital Plan. Pursuant to the recommendations in the Final Joint Proposal, the first year funding for these projects is provided. Future funding, however, is dependent on a "successful demonstration of the functional capability and operation/integration of these investments."[58] The recommendations include a commitment by the Company to file an Initial Report within 30 days of our issuance of this Order. This report will define scope and major performance milestones for the projects, and will describe a process for Staff and the Company to reach agreement on the definition of these milestones, and for the modification of such milestones if and when necessary.

While no party recommended that the Company's pursuit of these projects should be rejected, three intervenors expressed concerns that the projects may proceed along lines that ultimately prove to be inconsistent with our REV program.[59] If so, these parties are anxious that some expenditures, if not properly monitored, could result in stranded costs. They note that these projects are not now well defined, and the parameters of our REV programs are simultaneously in development.

The response in the Final Joint Proposal to these circumstances is a recommendation to include full funding for these projects in each year of the rate plan but to impose a rigorous program of interaction between the Company and Staff.

[58] Final Joint Proposal at 10.

[59] CLP Statement on the Joint Proposal at 8-9; Pace Statement in Support at 4-6; NRG Comments at 2-3.

In specifying the development of detailed milestones for these projects, the Final Joint Proposal emphasizes and engages Staff's ability to maintain alignment of these projects with the larger and more comprehensive goals of our REV program. At the same time, the process set forth in the Final Joint Proposal affords Staff with the opportunity to slow or stop the projects, if the Company cannot demonstrate that the desired functional capabilities and operation/integration will be achieved. As important in the present context, Staff (or the Company) may also slow or discontinue the projects whenever it concludes that the likelihood of stranded costs has undermined the projects' justification. With these safeguards in place, we conclude that the Final Joint Proposal's recommendations for these projects are in the public interest and should be adopted.

8. Energy efficiency funds

As noted above, the February JP reflected the signatory parties' intent to raise the funds needed to support the Company's energy efficiency programs through the Company's base rates. At that time, the proposed rate plan provided an increase in funding for the Company's energy efficiency programs over what is provided in the current rate year (Rate Year 1 budgets of $10.11 million for electric and $1.46 million for gas). Subsequently, we issued our Regulatory Framework Order, and thereafter, the parties, based on an analysis of that Order, indicated that the continued use of a surcharge to provide the funding for the Company's energy efficiency programs was preferable. Inasmuch as our Regulatory Framework Order provides clear direction as to the resources which we would commit for near term funding of these programs[60], and this direction favors the use of a surcharge rather than funding through base rates, the parties' recommendation as reflected in the Final Joint Proposal filed on April 22, 2015 has become more closely aligned with State policy and would be judged even more favorably under the criteria set forth in the settlement guidelines.

9. Net plant additions

The proposed rate plan underlying the Final Joint Proposal specifies, for each of the rate years an electric and a gas "net plant target." Under the proposed rate plan, the Company is expected to make capital investments that result in net plant levels equal to the amount of the "target" and, to recover an appropriate depreciation expense and a return on rate base in its revenue requirement. The Final Joint Proposal does not specify which capital projects will be pursued during the term of the rate plan, and it expressly states that the Final Joint Proposal is "not intended to alter the Company's flexibility during the term [of the Rate Plan] to substitute, change, or modify its capital projects."[61] The recommendation, however, does provide for annual reporting to Staff on the Company's capital expenditures and for an annual filing of the Company's five-year capital investment plan.

One party, NRG, objected to the provisions of the Final Joint Proposal that specified the Company's net plant targets over the three-year term of the proposed rate plan unless such expenditures were "strictly necessary".[62] NRG speculated that the opportunity to incur net plant additions would tempt the utility to disfavor the development of

[60] The Final Joint Proposal recommends $8.48 million in funding for the Company's electric energy efficiency programs.

[61] Final Joint Proposal at 17.

[62] NRG letter at 3.

distributed energy resources because the development of such resources could limit the Company's capacity to make an appropriate return. We agree with the NRG comment that such expenditures must be strictly reviewed, but we anticipate that this review has been done historically and will be continued in the future.

In general, we believe that appropriate capital spending programs are a necessary component of an efficient electric or gas utility. In our review of capital spending we seek to discourage utility overspending that could be wasteful or in support of unneeded initiatives, as well as utility underspending that might fail to provide the investment needed for the utility to meet its obligations to its customers safely and reliably.

In this regard, we note, with approval, the one-way reconciliation mechanism described in the recommendations of the Final Joint Proposal. Under this mechanism, if the utility overspends relative to the net plant targets, it cannot recover more than is available from spending at the target level. Conversely, if or to the extent the utility underspends relative to the targets provided in the proposed rate plan, the revenue requirement associated with this underspending is returned to customers at the end of the rate plan. Due to the one-way deferral, the utility's incentive to overspend is severely curtailed or eliminated and, at the same time, any incentive to underspend is also addressed.

No party, including NRG, has identified and we have not found any "not strictly necessary" element of the net plant additions proposed for the Rate Plan. Nor has NRG or any other party suggested why the net plant investment cap and the one-way deferral for the benefit of ratepayers are not effective disincentives to the "not strictly necessary" spending that NRG describes.

We approve the recommendations for net plant additions as set forth in the Final Joint Proposal.

10. Capital structure and rate of return

Central Hudson's initial filing sought a rate of return for a one-year rate plan based on a 9.0% equity return. In comparison, the Staff one-year rate plan filing recommended a rate of return reflecting an 8.7% equity return. Both the Company and Staff recommended a capital structure based on a 48% equity ration. As set forth above, the recommendations of the Final Joint Proposal project a revenue requirement for the Company based on a capital structure having an equity ratio of 48%, with an equity return of 9%. Although the JP's 9% equity return is greater than Staff's litigated position, the 30 basis point increase is appropriate as a multi-year stay out premium for the added business and financial risk to which the Company will be exposed under the JP.

The Final Joint Proposal projects a revenue requirement for the Company based on a capital structure having an equity share of 48%, with an equity return of 9.0%. It also recommends an earnings sharing formula by which equity earnings above 9.5% would be shared 50-50 between ratepayers and the Company, earnings above 10% would be shared 80% to ratepayers, 20% to the Company, and earnings above 10.5% would be shared 90% to ratepayers and 10% to the Company.

The Final Joint Proposal's ROE and equity ratio is comparable to allowances we have granted in the recent Con Edison rate cases that are supportive of an S&P A rating.[63] Also, the agreed upon ROE is clearly within the range of a

[63] Cases 13-E-0030 et al., Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal (issued February 20, 2014).

litigated result in this proceeding. As such, they are a good reflection of our policies, and we find that they strike a fair balance between ratepayers, who will pay at rates based on these parameters, and the Company, which should be provided the funds necessary to provide a fair return to its investors.

11. Rate Design

As noted above, the increases to electric revenue requirements and to gas revenue requirements recommended by the Final Joint Proposal are implemented in large part by significant increases in the fixed customer charges for residential and small commercial customers. Specifically, the fixed customer charges for residential customers will rise by $5 per month, which is a 20.8% increase, over the term of the rate plan. The rise for small commercial customers is $9 per month or 25.7% over this period.[64] At the evidentiary hearing, the Company and Staff agreed that the rationale for these increases was the embedded cost of service (ECOS) study provided during the course of this case and the cost causation principles that that study reflects. Staff conceded that other policy rationales could be used and that different rationales might produce different fixed charges.

One party, Citizens for Local Power, focused on this issue in its comments and asserted that electric rate designs with less or no reliance on the fixed charge could better incent customers toward energy conservation and efficiency, on-site renewables and other DERs. CLP asserted that the currently proposed fixed charge increases were the Company's "traditional rate design" and that this design missed "an

[64] The increase in charges for the first billing block for residential gas customers is from $23 to $26 over the three-year term of the rate plan - a rise of 13.0%.

important opportunity to advance the goals of the REV proceeding."[65]

We agree with CLP that the electric rate design recommended in the Final Joint Proposal and relying on significant increases in already significant fixed charges is a "traditional rate design." While it is appropriate for the rate design in this case to rely on the ECOS study and familiar cost of service principles as a guide for the apportionment of the electric revenue requirement increase between fixed and volumetric charges, we reject the proposal at this time. Throughout the Final Joint Proposal, the signatories have recognized that REV policy implementation for Central Hudson may well be required before the conclusion of the proposed three-year rate plan. Further, Track Two of the REV proceeding is expected to include a full examination of the current electric rate structures and designs, with specific emphasis on the mass market classes, to see how they might be changed to better achieve New York energy policy goals. Therefore, to avoid making changes now in the Company's electric rate tariff that could potentially be changed again in the near future, we reject the proposed increases to the customer charges for the electric residential and small non-demand metered commercial customer classes and direct the Company to maintain those charges at current levels.[66] Consequently, the revenues that would have been

[65] CLP Comment at 6. Similar arguments were made in unsworn comments submitted by the Public Utility Law Project through the Department's mechanisms in DMM to record citizen comments regarding specific cases.

[66] This decision does not preclude the Company from filing class revenue neutral rate structure and/or rate design changes subsequent to our issuance of an Order on Track Two where such structure or design changes would bring the Company's rate design into a better alignment with our Track Two decision.

recovered through the increased customer charges shall instead be recovered through the volumetric delivery charges.

12. Provisions for low-income customers

Central Hudson conducts two programs to assist low-income customers, the EPOP program and the low income discount program. Both of these programs have been in place for several years, and there are no significant changes to the programs recommended in the Final Joint Proposal. At the public statement hearings, criticism was leveled at these existing low income programs. Advocates there argued that the EPOP program served too few customers and that efforts to serve additional customers through the program should be greatly expanded. They also urged that the benefit provided through the low income discount program should be increased.

Pursuant to the Final Joint Proposal, two new initiatives largely intended to assist low-income customers are recommended. First, the Company undertakes to improve its performance in providing service reconnections. Specifically, if this recommendation is adopted, the Company would strive to provide a same-day reconnection in not less than 80% of the instances when a reconnection of service is to be implemented.

The second new initiative which would affect low-income customers and which is recommended in the Final Joint Proposal is a new performance metric addressing the frequency with which the Company elects to terminate electric or gas service to residential customers. If implemented, the Company would receive a Positive Revenue Adjustment equal to five basis points for each rate year in which the number of residential service terminations for non-payment is less than 11,000. According to Staff, if the 11,000 termination threshold is reached, it would mean that the Company sought a termination of service approximately 12.7% less frequently than it has, on average, in the four years from 2010 through 2013.[67]

We welcome the two new initiatives described by the Final Joint Proposal. Each of these initiatives focuses the Company's efforts on specific areas where customers may directly benefit from a successful implementation of the initiative. In the case of same day reconnects, the customer has met the utility's requirements for the reestablishment of service, but, in the absence of a same day reconnect, would not have service in his or her household until the next or a following day. The nighttime, when the customer without electric service may elect to use a candle or other non-traditional energy source for light or for heat, is a period of enhanced risk for that residential customer. If the customer qualifies for service, the Company's efforts to restore service on a same-day basis, which enables the customer to avoid this incremental risk, is fully justified. We also note that the ability of the utility to provide a same-day reconnection may actually provide an additional incentive to the customer to take the steps necessary for the reconnection to be ordered.

The use of a positive revenue adjustment to incent the implementation of the program to reduce terminations for nonpayment is also a welcome initiative. This incentive should encourage the utility to experiment with and to develop new strategies to lessen the Company's reliance on service terminations. In this way, we would also expect the Company to begin to collect more and better information on the circumstances when termination of service is the only

[67] Tr. at 158.

alternative and on when the customers' arrearage can be managed in other ways.[68]

We see significant steps forward in the introduction of the two new programs described above. In addition, we have an active case already moving forward which will be examining, on a statewide basis, existing low-income programs and the best practices that are in use in these programs.[69] The results from that case should soon be available, and the Final Joint Proposal recognizes that these results may be applied to Central Hudson and its low-income programs notwithstanding the pendency of a multi-year rate plan. With these considerations in mind, we can conclude that the recommendations of the Final Joint Proposal with respect to the Company's low-income programs are consistent with State policy, fair to ratepayers and to the Company, and should be approved.

13. Gas Service Expansion

As noted above, the Final Joint Proposal includes an agreement by the Company to vigorously expand gas service within its service territory. The initiative to expand gas service includes an aggressive goal to increase significantly the number of residential and commercial customers over the next five years and to support this effort with over $63.7 million in capital investment. The Final Joint Proposal also recommends that the rate plan include $1 million per year to assist customers with expenses incurred on the customer side

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[68] We expect the Company to work with Staff to design this data acquisition program. The program should include a report on a quarterly or semi-annual basis as to the number, date and location of shut off requests, and the date of associated shut off tickets. It should also track customer bills/locations that have no usage for four consecutive monthly billing cycles.

[69] Case 14-M-0565, Proceeding to Examine Programs to Address Energy Affordability for Low Income Utility Customers, Order Instituting Proceeding (issued January 9, 2015).

of the meter that would otherwise prevent the customer participating in the conversion program.

The Final Joint Proposal also includes a recommendation to create an incentive for the Company to provide service to additional new customers. Under this recommendation, the Company would receive a 1 basis point Positive Revenue Adjustment for each 200 customers that it adds above the total customer count forecast for residential and commercial customers in each rate year.

The commitment to aggressively promote expanded gas service and the establishment of the performance incentive for exceeding the service expansion goals are clearly supportive of our current policies, which favor the expansion of gas service to currently unserved customers in the State. As such, they are in the public interest and are approved.

14. Participation in REV Collaborative

As this case progressed, the parties participated in a "REV Working Group" as a collaborative effort to guide the development of REV demonstration projects in both the short and long-term. No party has voiced an objection to this process or the specific results. However, the Final Joint Proposal's discussion of the REV demonstration projects (or, as denominated in the Final Joint Proposal, the REV conceptual programs) concludes by asserting that participants in the REV working group will be precluded from objecting to the cost recovery, if any, sought by the Company in connection with the implementation of one or more of these projects.[70] None of the Final Joint Proposal signatories object to this provision. However, both NRG and CLP, which were participants in the REV collaborative referenced in the Final Joint Proposal, but not Final Joint Proposal signers, do object.

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[70] Final Joint Proposal at 45.

The provisions which NRG and CLP find objectionable are among those noted below which, if anything, purport merely to reflect agreements between parties and do not fall within the scope of this Order. Accordingly, the adoption of the Final Joint Proposal's recommendations by this Order would have no effect on the restraints, if any, which are purportedly imposed by this Final Joint Proposal language on signers of the Final Joint Proposal or on non-signers like NRG and CLP.

15. REV Demonstration Projects

Each version of the Joint Proposal, including the Final Joint Proposal, has included the parties' agreement as to the procedures they would follow in the development of REV Demonstration Projects. These procedures included the filing on May 1, 2015 of a Report to describe the results up to that date in identifying REV demonstration projects for the Central Hudson service territory. This Report was filed on May 1 as required, as were comments on the report, also as provided in the Final Joint Proposal. The Company has indicated by letter dated May 15, 2015 that the May 1 Report was used to provide a "status report" rather than a final submittal, as required by the Commission’s Regulatory Framework Order to be filed no later than July 1, 2015, seeking approval of the proposed Demonstration Projects[71] described therein, to afford the Interagency REV Demonstration Team, Central Hudson, and other

[71] The six projects identified in the May 1 Report are:

(1) Central Hudson Owned Community Solar Project ; (2) SolarCity Owned Community Solar Project; (3) Central Hudson's Microgrid Project; (4) Central Hudson Demand Response Demonstration Project (Central Hudson Non-Wires Alternative (NWA) Project); (5) Central Hudson Behind the Meter Services Project; and (6) Ulster County Community Choice Aggregation Project.

appropriate stakeholders the opportunity to work together to further discuss and develop the proposed Demonstration Projects. The Commission commends Central Hudson and the active participants of the REV collaborative for the efforts put forth in the development of potential REV demonstration projects. Such efforts have been, and will be, useful as the Company continues the development of its REV demonstration compliance filings.

The Company also confirmed by its May 1 letter to the Secretary that its Demand Response Demonstration Project (Central Hudson Non-Wires Alternative (NWA) Project), satisfies the Commission's Regulatory Framework Order, which directed the utilities, including Central Hudson, to file a non-wires alternative project by May 1, 2015.[72] In its May 21, 2015 comments on the May 1 Report filed in this case, Staff agrees with the Company that this NWA project would meet the requirement imposed by our Regulatory Framework Order for each utility to design, propose and implement a NWA project. Additionally, Staff recommends that the Commission authorize and allow Central Hudson to defer the costs associated with the Central Hudson NWA Project to expedite its implementation. Staff asserts that implementation of the NWA project, however, should not proceed unless, on a portfolio basis, there is a net benefit to customers in implementing the project and forgoing the capital investment associated with a traditional T&D solution. Staff recommends that the Company be directed to file with the Secretary a benefit cost analysis once final contractual agreements have been reached. Finally and regarding the Company's proposed cost recovery and incentive, Staff asserts that additional process is required to better inform the Commission.

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[72] Regulatory Framework Order at 130.

In comments filed on May 22, 2015, Pace and Solar City support the Central Hudson NWA project, and MI neither supports nor opposes it. MI requests, with respect to all projects described in the Company's May 1 report, that customer rate impacts be considered, that projects be cost-effective, and that, for the Central Hudson NWA project and for the other listed projects, information necessary for other parties to evaluate the project be made available, prior to the project being approved. MI further states that parties negotiated a cap on the cost of REV demonstration projects to customers and that such cap should apply to the Central Hudson NWA project. If, its position is rejected, then MI requests that the costs of this project be paid for by customer credits still on the Company's books. Under no circumstances, MI argues, should the Commission increase the delivery rates negotiated in the Final Joint Proposal or implement a surcharge mechanism having the same effect.[73]

The Central Hudson NWA project satisfies the requirement we set in the Regulatory Framework Order for each utility to propose a NWA project. As described in the May 1 report, the Central Hudson NWA project will allow the Company to avoid costs associated with transmission and distribution infrastructure investment in three designated locations. The distribution circuits, substations, and transmission regions identified in the May 1 report anticipate infrastructure investment needs related to expected load growth over the next four to ten years. With successful demand reduction programs, these investments may be deferred or eliminated.

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[73] Lastly, MI commented on the proposed incentive mechanism. However, because we allow for additional process to decide the appropriate incentive mechanism, we will not address MI's related comments here.

The Request for Proposal associated with the Central Hudson NWA project specifies the need for 2 MW of load reduction in 2016, and incremental load reductions of 4 MW, 5 MW, and 11 MW in 2017, 2018, and 2019 respectively. The planning to achieve load reductions such as these take time, just as the multi-year planning of T&D infrastructure projects would. With this timeline in mind, we should not delay our approval for the Central Hudson NWA project's financial support, and we will expect Central Hudson to move forward with its NWA project as it is described in the May 1 Report.

As Central Hudson proceeds with its NWA project, we authorize Central Hudson to defer its incremental revenue requirement effect.[74] The net of tax deferral balance will accrue carrying charges at the company’s pre-tax rate of return. We also note here that such amounts should not reduce the cap on demonstration project costs set forth in the Final Joint Proposal since the project is a component of the Company’s capital planning process and necessary to address expected load growth. However, as Staff urges, implementation of the project should not proceed unless, on a portfolio basis, there is a net benefit to customers. We expect an appropriate net benefit analysis to be provided by the Company in a filing with the Secretary to the Commission. This filing will be reviewed by Staff.

Regarding the Company’s proposed cost recovery and incentive mechanism, as it would be applied to its NWA project and as Staff posits, additional process is required to better inform our decision on these matters. Therefore, the Company is directed to file additional detail, including a description

[74] The incremental revenue requirement effect shall be net of tax benefits, other benefits (such as incremental revenues or operational benefits) and grants, revenues, or third party contributions.

of the surcharge mechanism to be used and of the manner in which costs will be recovered (i.e., as incurred versus over a period of time). The Company is also directed to include in this filing its analysis of the potential benefits and disadvantages of alternative incentive mechanisms, including incentive mechanisms similar to those approved in Case 14-E-0302.[75] After receiving comments on this filing, we expect to determine the appropriate cost recovery method and incentive mechanism for use by Central Hudson in connection with its NWA Project.

In its cover letter to the May 1 REV Collaborative Report, the Company requests that we clarify the Regulatory Framework Order and grant Central Hudson deferral and cost recovery accounting treatment for each of the other Demonstration Projects listed in the report with such treatment to begin when Staff provides written authorization to proceed. The Company further requests that it be authorized to continue to exercise this deferral and cost recovery authority until it is addressed in the Company's next rate case.

In the Commission’s Regulatory Framework Order (at p. 116), utilities were ordered to file initial demonstration projects consistent with the adopted guidelines, no later than July 1, 2015. Such compliance filings will be reviewed by Staff for consistency with the Commission’s guidelines, and for a reasonable relationship between costs and estimated benefits. This Order also permitted electric utilities to defer, until their next rate case, the revenue requirement

[75] Case 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program, Order Establishing Brooklyn/Queens Demand Management Program (issued December 12, 2014).

impacts of the incremental costs of demonstration projects that are compliant with the Regulatory Framework Order.

We note that electric utilities may want project specific written documentation of a project's compliance with the Regulatory Framework Order as Central Hudson has requested. Therefore, Staff is directed to provide such documentation to each utility as it proceeds to implement each compliant Demonstration Project. Alternatively, if Staff determines that the proposed demonstration project does not comply with the Commission’s Regulatory Framework Order Staff will provide the utility with written notification of its determination and the reasons for such determination. In either event, Staff is to file its determination with the Secretary who shall inform the Commissioners and post the filing to the document and matter management system.[76] In addition to providing written documentation to the Secretary of Staff determinations of noncompliance, commencing on October 1, 2015, Staff shall provide on a quarterly basis an information report to the Commission on the status of each demonstration project proposed by the electric utilities.

16. Performance Mechanisms

In addition to the performance metric to incent the utility to limit service terminations to 11,000 per year and the metric to encourage the expansion of gas service, which are discussed above, the Final Joint Proposal recommends the continuation, with minor adjustments, of several performance incentive plans which are already in place. These incentive plans address customer satisfaction (through the customer complaint rate, the customer satisfaction survey, and appointments kept), electric reliability (through SAIFI and CAIDI), gas safety (by assessing the Company's emergency

[76] Regulatory Framework Order at 116.

response, gas leak backlog, and damage prevention efforts) and gas safety violations (by associating a variable negative revenue adjustment with the Company's gas safety code violations). Each of these performance incentive plans are in use for other New York utilities. Their continuation here for Central Hudson is well aligned with our policies and fully consistent with the public interest.

17. Additional Provisions

In adopting the Final Joint Proposal recommendations, we neither reject nor adopt any terms contained therein that are concerned solely with one or more parties' commitment or obligation to take a specified action, and which are imposed on the party or parties at the time the Final Joint Proposal was signed, and the performance of which is not a matter of compliance with this Order. Accordingly and more specifically, the obligations described at Section XVIII, paragraphs A. through D. of the Final Joint Proposal are neither adopted nor rejected by this Order.[77]

CONCLUSION

As indicated in the forgoing discussion of the major issues in these cases, we find that the recommendations made in the Final Joint Proposal are fully consistent with Commission and State policy. In addition, the recommendations, if adopted, are well within the range of likely outcomes and compare favorably with the likely result were the matters resolved through fully litigated rate cases.

[77] Further and notwithstanding the provisions of § XVIII, ¶ C. of the Final Joint Proposal, nothing in the Final Joint Proposal would preclude reliance on our order adopting the Final Joint Proposal’s terms as precedent in other cases. See Cases 06-G-1185 and 06-G-1186, KeySpan Energy Delivery – Rates, Order Adopting Gas Rate Plans (issued December 21, 2007), pp. 58-60.

Finally, our decision to adopt the recommendations made in the Final Joint Proposal rests on a rational basis and strikes a fair balance between the interests of ratepayers, of shareholders and of the utility. In summary and for these reasons, we adopt the recommendations made in the Final Joint Proposal, as described or clarified in this Order and find them to be, in all respects, consistent with the public interest.

The Commission orders:

1. In accordance with the forgoing discussion, the recommendations made in the Final Joint Proposal dated April 22, 2015, are approved and adopted in their entirety, and are incorporated as part of this Order.

2. Central Hudson Gas & Electric Corporation is directed to file cancellation supplements, effective on not less than one day's notice, on or before June 19, 2015, canceling the tariff amendments and supplements listed in Attachment B to this Order.

3. Central Hudson Gas & Electric Corporation is authorized to file on not less than one day's notice, to take effect on or after July 1, 2015 on a temporary basis, such tariff changes as are necessary to effectuate the provisions adopted in this Order regarding Rate Year 1.

4. Central Hudson Gas & Electric Corporation is directed to file such further tariff changes as are necessary to effectuate the Rate Year 2 and Rate Year 3 rates provided for in this Order. Such changes shall be filed on not less than 30 days' notice to be effective on a temporary basis on the July 1 commencement of each Rate Year.

5. Central Hudson Gas & Electric Corporation shall serve copies of its compliance filings upon all parties to these proceedings. Any comments on the compliance filings

must be filed within ten days of service of the Company’s proposed amendments. The amendments specified in each compliance filing shall not become effective on a permanent basis until approved by the Commission and will be subject to refund if any showing is made that the revisions are not in compliance with this Order.

6. The requirement of §66(12)(b) of the Public Service Law that newspaper publication be completed prior to the effective date of the proposed amendments is waived with respect to the tariff changes for Rate Year 1, provided that the company shall file with the Commission, not later than August 12, 2015, proof that a notice to the public of the changes proposed by the amendments and their effective date has been published once a week for four successive weeks in newspapers having general circulation in the areas affected by the amendments. The requirements of Public Service Law §66(12)(b) are not waived with respect to the Rate Year 2 or Rate Year 3 filings or with respect to tariff filings in compliance with this Order made in subsequent years.

7. Within thirty days of the date of this Order, Central Hudson Gas & Electric Corporation shall file additional details regarding its proposed cost recovery and incentive mechanisms for its NWA project (also identified herein as the CH DR Demonstration Project), including its analysis of alternative incentive mechanisms, as described in this Order.

8. Within thirty days of reaching final contractual agreements for the implementation of the NWA project (also identified herein as the CH DR Demonstration Project) as described in this Order, Central Hudson Gas & Electric Corporation shall file with the Secretary to the Commission for Staff review a benefit cost analysis of such NWA project

to demonstrate that there is a net benefit to customers to implement the project, as described in this Order.

9. Central Hudson Gas & Electric Corporation is authorized, as set forth in this Order, to defer the incremental revenue requirement effect associated with its NWA project.

10. Central Hudson Gas & Electric Corporation is authorized to apply deferral accounting treatment for each Demonstration Project for which Staff provides written authorization to proceed as described in Section V.A.4.e of the Final Joint Proposal.

11. The Secretary at her sole discretion may extend the deadlines set forth in this Order. Any request for an extension must be in writing, must include a justification for the extension and must be filed at least one day prior to the affected deadline.

12. These proceedings are continued.

By the Commission,

(SIGNED) KATHLEEN H. BURGESS
Secretary

Commissioner Diane X. Burman, concurring in part, dissenting in part, and abstaining in part:

As reflected in my comments made at the public session on June 17, 2015, I concur in part on the overall adoption of the rate plan, dissent in part on the aspects on the REV demonstration projects’ delegation of authority, and abstain in part on issues dealing with funding streams for energy efficiency budgets for REV.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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-0318
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-0319

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April 22, 2015

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STATE OF NEW YORK
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FINAL JOINT PROPOSAL

I. INTRODUCTION

This Final Joint Proposal for the resolution of all issues in the above-captioned cases is made mutually by Central Hudson Gas & Electric Corporation ("Central Hudson" or "Company"), the Staff of the Department of Public Service ("Staff"), Multiple Intervenors ("MI"),[1] Pace Energy and Climate Center ("Pace"), Sabin Center for Climate Change Law at Columbia Law School ("Sabin"), the Retail Energy Supply Association ("RESA"), and the other entities whose signatures appear below (collectively, the "Signatories").

[1] Multiple Intervenors is an association of approximately 60 industrial, commercial and institutional energy consumers with manufacturing and other facilities located throughout New York State, including Central Hudson's service territory.

A. Background

On June 18, 2010, the New York State Public Service Commission ("Commission" or "PSC") issued an Order Establishing Rate Plan[2] establishing a three-year rate plan for the Company for the period from July 1, 2010 through June 30, 2013 ("2010 Rate Order").

The Commission issued an Order Authorizing Acquisition Subject to Conditions ("Acquisition Order") on June 26, 2013, approving the indirect acquisition of Central Hudson by Fortis, Inc., a Canadian holding company.[3] Under the Acquisition Order, Central Hudson was subject to a two-year rate freeze. As such, the Company did not seek to adjust delivery rates effective July 1, 2013 at the conclusion of the rate plan authorized under the 2010 Rate Order until the filing of the present rate cases.

B. Filing of the Present Cases

Central Hudson filed with the PSC on July 25, 2014, proposed tariff leaves and its direct testimony in support of proposed increases to its electric and gas delivery revenues based on a rate year comprised of the 12 months ending June 30, 2016 ("Rate Year"). Central Hudson also included select financial information for two additional rate years as Attachment B to its filing letter.[4] Central Hudson's proposed delivery rates were designed to produce an electric delivery base revenue increase of

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[2] Case 09-E-0588 et. al. - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, Order Establishing Rate Plan (June 18, 2010).

[3] Case 12-M-0192 - Joint Petition of Fortis Inc. et al. and CH Energy Group, Inc. et al. for Approval of the Acquisition of CH Energy Group, Inc. by Fortis Inc. and Related Transactions, Order Authorizing Acquisition Subject to Conditions (June 26, 2013).

[4] Case 14-E-0318 et al. - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, Cover Letter Attachment B (July 25, 2014).

approximately $40.1 million and a gas delivery base revenue increase of approximately $5.9 million, resulting in delivery revenue increases of 14.8% and 7.4%, respectively, or total bill increases of 8.4% and 2.7%, respectively, for an average residential customer.

On August 1, 2014, the Commission suspended the Company's proposed tariff leaves through December 21, 2014.[5] Discovery was commenced by Staff and other parties. To date, Staff has tendered a total of 846 multi-part information requests to the Company; the Utility Intervention Unit of the Department of State, Division of Consumer Protection ("UIU") tendered 151; MI tendered 154; Pace tendered 108; the County of Dutchess tendered 33; Citizens for Local Power ("CLP") tendered 21; and Sabin tendered 106. Various other parties also tendered more limited volumes of discovery to the Company.

On September 8, 2014, a Procedural and Technical Conference was held by Administrative Law Judge ("ALJ") Ben Wiles[6] during which, among other things, a litigation schedule was proposed and adopted in a subsequent ruling.[7] On September 30, 2014, an additional procedural conference was held to discuss the status of discovery. At the procedural conference, ALJ Wiles directed the Company to file redacted versions of the Confidential Information the Company had filed on August 5, 2014. The Company had requested exemption from public disclosure of the Confidential Information pursuant to the New York State Freedom of Informational Law

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[5] Case 14-E-0318 et. al., Notice of Suspension of Effective Dates of the Major Rate Changes and Initiation of Proceedings (Aug. 1, 2014). By notice issued Nov. 26, 2014 the Commission further suspended those tariffs through June 21, 2015.

[6] ALJ David Prestemon was subsequently assigned along with ALJ Wiles to these proceedings.

[7] Case 14-E-0318 et. al., Ruling on Schedule and Granting Party Status (Sept. 16, 2014).

("FOIL") (Public Officers Law § § 84, *et seq.*)[8], and the Company subsequently filed a supplemental response further describing Central Hudson's basis for protecting the Confidential Information. The Company provided the information in a letter to ALJ Wiles dated October 23, 2014.

Staff, MI, UIU, Solar City Corporation ("Solar City"), the County of Dutchess, NRG Energy, Inc. ("NRG"), Pace and Sabin filed direct testimony on November 21, 2014. Central Hudson, Staff, Pace and CLP subsequently filed rebuttal testimony on December 19, 2014.

Consistent with the Commission's Settlement Guidelines[9] and Title 16 of the New York Codes, Rules and Regulations ("NYCRR"), Section 3.9, the Company filed with the Commission and served on all parties a Notice of Impending Settlement Negotiations on November 25, 2014.[10] Settlement negotiations began on December 2, 2014 and continued on December 4, 9, 10, 11, 15, 17, and 18, 2014 and on January 7, 12, 16, 21, 29, and 30, 2015 and February 3, 4, 5, and 6, 2015. Participants included representatives of the Company, Staff, UIU, MI, Solar City, CLP, NRG, Pace, and numerous other interested parties. Negotiations were held either in person or via teleconference. All settlement negotiations were subject to the Commission's

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8 Case 14-E-0318 et. al., Request for Exemption from Disclosure (Aug. 5, 2014). Specifically, the Company sought protection for an exhibit to the Direct Testimony of the Finance Panel which contained confidential/trade secret reports of various credit rating agencies ("Confidential Information").

9 32 NYPSC 71; Case 90-M-0255 et al. - Proceeding on Motion of the Commission Concerning its Procedures for Settlement and Stipulation Agreements, filed in C11175, Opinion, Order and Resolution Adopting Settlement Procedures and Guidelines, Opinion 92-2 (Mar. 24, 1991) ("Settlement Guidelines").

10 Case 14-E-0318 et. al., Notice of Impending Settlement Negotiations (Nov. 25, 2014).

Settlement Rules, 16 NYCRR Section 3.9, and the Commission's Settlement Guidelines.

On December 23, 2014, a Further Ruling on Schedule was issued revising the date on which evidentiary hearings in these cases would begin to February 10, 2015 and requiring the parties to file a joint proposal by February 6, 2015 in the event that a settlement was negotiated.[11] A joint proposal executed by six signatories was filed on February 6, 2015. The joint proposal was subsequently updated on February 13th and again on March 27, 2015.

Given the filing of the joint proposal, the date of the evidentiary hearing was postponed until March 31, 2015.[12] In recognition of the Commission's February 26th Order Adopting Regulatory Policy Framework and Implementation Plan issued by the New York State Public Service Commission in Case 14-M-0101 ("REV Order"), the signatories to the joint proposal in Cases 14-E-0318 and 14-G-0319, met prior to the evidentiary hearing to discuss a potential amendment to the JP regarding energy efficiency costs. In light of the REV Order's treatment of energy efficiency funds, the signatories agreed to two modifications to the joint proposal with respect to energy efficiency costs. First, the signatories agreed to modify the joint proposal to substantially remove energy efficiency funds (both electric and gas) from base delivery rates and instead allow utility-run energy efficiency budgets to be recovered via a surcharge mechanism – similar to the method in which such costs are currently collected under EEPS. Removing the electric and gas energy efficiency funds out of the

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11 Case 14-E-0318 et. al., Further Ruling on Schedule (Dec. 23, 2014); Case 14-E-0318 et. al., Ruling Errata (Dec. 30, 2014).

12 Case 14-E-0318 et. al., Notice of Evidentiary Hearing (Mar. 20, 2015).

joint proposal's revenue requirement and creating an "Energy Efficiency Tracker" surcharge component allows for tracking of individual customer contributions to energy efficiency such that Self-Directed funds, and thus credits for those who opt in to a Self-Direct Program, can be determined more easily and transparently. Second, the Parties, agreed to facilitate integrating the administrative function of energy efficiency into base rates by allowing for the internal labor component associated with energy efficiency portfolio budgets to be included in base rates. With these final changes, the Parties' settlement negotiations have been successful and ultimately have resulted in this Final Joint Proposal ("Final JP" or "JP"), which is presented to the Commission for its consideration. The Signatories have developed a comprehensive set of terms and conditions for a three-year rate plan for the Company's electric and gas service. Pursuant to the Parties' settlement discussions, the Signatories recommend that the rates and surcharges of the Company be determined in accordance with the understandings, principles, qualifications, terms and conditions set forth in this JP and in the attached Appendices.

II. TERM

A. Agreement Term

The term of this JP is three years, commencing July 1, 2015 and continuing until June 30, 2018. The three successive twelve-month periods, or Rate Years, ending on June 30th shall be referred to as "Rate Year 1," "Rate Year 2," and "Rate Year 3." The JP sets out the terms for Rate Year 1 (July 1, 2015 through June 30, 2016). Rate Year 2 (July 1, 2016 through June 30, 2017) and Rate Year 3 (July 1, 2017 through June 30, 2018) will follow the same structure as Rate Year 1 at revenue and expense amounts as agreed to by the Signatories as set out in the JP. The provisions of Rate Year 3 will, unless otherwise specified herein, remain in effect until superseding rates or terms become effective.

Nothing herein precludes Central Hudson from filing a new general electric or gas rate case prior to June 30, 2018, for rates to be effective on or after June 30, 2018. Except for minor rate changes and Commission-required rate changes permitted by Section XVIII of this JP, the Company will not initiate rate changes to become effective prior to June 30, 2018.

III. REVENUE REQUIREMENTS

A. Revenue Requirements

The revenue requirements for Rate Year 1, Rate Year 2, and Rate Year 3 are shown in the Electric and Gas Income Statements set forth in Appendix A.

B. Delivery Revenue Increases

The base delivery revenue increases for electric and gas service are shown in the table below:

	Rate Year 1 ($000,000)	Rate Year 2 ($000,000)	Rate Year 3 ($000,000)
Electric	$15.346	$15.987	$14.100
Gas	$1.827	$4.633	$4.379

C. Electric Bill Credits

To achieve rate moderation, electric bill credits of $13.0 million in Rate Year 1; $12.0 million in Rate Year 2; and $2.0 million in Rate Year 3 will be applied utilizing available regulatory liabilities.

The bill credit will be allocated to each service class in proportion to class responsibility for the overall delivery rate increase. The allocated credits will be refunded to customers on a kilowatt-hour or kilowatt basis, consistent with the manner in which each class is billed.

D. Gas Bill Credits

To achieve rate moderation, in a manner similar to the electric bill credits, gas bill credits of $2.548 million in Rate Year 1 and $1.7 million in Rate Year 2 will be applied using available regulatory liabilities.

The bill credit will be allocated to each service class in proportion to class responsibility for the overall delivery rate increase. The allocated credits will be refunded to customers on a Ccf basis, consistent with the manner in which each class is billed.

To the extent that the Company receives gas delivery revenues from the Danskammer Generating Station ("Danskammer") in Rate Year 1, 50% of those revenues will be refunded via a bill credit to the Company's gas customers in Rate Year 2. Similarly, 50% of the gas delivery revenues received from Danskammer in Rate Year 2 will be refunded via a bill credit to the Company's gas customers in Rate Year 3. All gas delivery revenues received from Danskammer in Rate Year 3 will be deferred for the future benefit of the Company's gas customers. The 50% gas delivery revenues remaining from Rate Years 1 and 2 will be deferred for the future benefit of the Company's gas customers. Notwithstanding the general gas bill credit applicable to non-Danskammer actual delivery revenues set forth above, all Danskammer gas delivery revenue related bill credits will be allocated to each service class in proportion to its contribution to overall gas delivery revenue. The allocated credits will be refunded to the Company's gas customers on a Ccf basis, consistent with the manner in which each class is billed.

E. <u>Major Provisions Incorporated into Development of Revenue Requirements</u>

1. Labor Headcount

The Labor expense line item reflected in the Income Statements set forth in Appendix A reflects a headcount of 950 full-time employees ("FTEs") in Rate Year 1; 961 FTEs in Rate Year 2; and 965 FTEs in Rate Year 3. Labor expense also reflects 27 temporary employees throughout the Rate Plan. In addition, 11 additional employees needed for monthly billing are reflected in the Transition to Monthly Billing line item.

2. Distribution and Transmission Right-of-Way ("ROW") Tree Trimming

The electric income statements incorporate funding for transmission and distribution ROW maintenance as set forth in Appendix A.

3. Transition to Monthly Billing

The Transition to Monthly Billing line item reflected in the Income Statements set forth in Appendix A incorporates the costs and expenses the Company will incur to transition from its current bi-monthly billing of certain classes of customers to monthly billing for all customers.

4. Rate Case Expense

The Company's electric and gas Rate Case Expense shown in the Income Statements set forth in Appendix A incorporate legal and consulting expenses and other miscellaneous expenses associated with filing a rate case. The Signatories agree to a three-year amortization of rate case expense.

5. Productivity Adjustment

The Income Statements set forth in Appendix A incorporate a 1.5% productivity adjustment to the Company's gas and electric expenses in each Rate Year. The productivity adjustment is calculated on a total base including labor, pensions, OPEBs, fringes, and payroll tax expenses.

6. Major Storm Reserve

The electric Income Statements set forth in Appendix A incorporate $700,000 in funding for a Major Storm Reserve for each Rate Year. The Major Storm Reserve procedures and operation are set forth in Appendix Q.

7. Security Costs

The Signatories recognize that the Company requires adequate resources to provide security for its facilities and a safe environment for its customers, employees, contractors and guests. Accordingly, the Income Statements set forth in Appendix A incorporate funding for Security of Infrastructure.

8. Common Cost Allocation

The Signatories agree that the common cost allocation should be modified from the 85% electric and 15% gas allocation authorized in the 2010 Rate Order. Accordingly, the common cost allocation of 80% electric and 20% gas will be utilized and applied to O&M expense, plant and related property taxes and depreciation.

9. Network Strategy and Distribution Automation

The electric Income Statements set forth in Appendix A reflect revenue requirements related to plant in service in each of the three Rate Years, including Network Strategy and Distribution Automation capital expenditures. However, full implementation of the Network Strategy and Distribution Automation project beyond Rate Year 1 is dependent upon Staff's agreement that the Company remain on track for the successful demonstration of the functional capability and operation/integration of these investments.

The Company will file an initial report ("Initial Report") with the Secretary of the Commission ("Secretary") within 30 days of Commission approval of this JP containing the proposed Network Strategy and Distribution Automation projects' scope and major performance milestones. The milestones will establish a specific time for meeting clear, readily measured indicators showing functional capability and operation/integration. To recognize potential future costs in the event that the Network Strategy and Distribution Automation capital projects are not fully pursued, the Initial Report will also set forth the Company's expected capital expenditures and incremental operating expenses ("Business as Usual Case"). The Business as Usual Case, or expenditures incurred related to it, are not being advanced, addressed, or otherwise supported in this JP given that the Network Strategy and Distribution Automation Capital Projects have been included. Staff and the Company agree to meet to reach mutual agreement on the major performance milestones within 60 days of filing the Initial Report. If mutual agreement cannot be reached, either party may seek a ruling from the Commission regarding appropriate milestones.

The Company will file with the Secretary a major milestone performance report, no more than twice annually, within 15 business days of a milestone completion date ("Milestone Report") which describes the Network Strategy and Distribution Automation project's compliance with the applicable milestone or milestones. In addition to identifying compliance with the specified milestone's indicators, the Company will identify and describe in the Milestone Report its view of the project's direct customer and electric grid impacts. If necessary, a Milestone Report will also indicate potential and appropriate remedial action for a specific project that has not fully met a particular milestone. The Company and Staff recognize that milestones may need to be adjusted as the deployment of technology and the Commission's Reforming the Energy Vision proceeding evolve. If mutual agreement cannot be reached on revisions, either party may seek a ruling from the Commission.

Staff will present its review of the Milestone Reports to the Managing Director of Utility Rates and Services ("Director") for approval. The Director's approval of the continuation of the project shall be documented in a letter from the Director to the Company with a copy filed with the Secretary.

While the Director's approval letter is pending or until such time as the Company is notified in writing by the Director that it must alter or cease deployment of the project, the Company is authorized to continue project implementation, including continuation of recovery for all prudently incurred and committed expenditures (for example material purchases and internal and external labor). In the event that the Director or the Commission delays or cancels deployment and implementation of the Network Strategy and/or Distribution Automation Project, a deferral mechanism will be established to recover the incremental revenue requirement effect of the capital and operating expenses that the Company incurs as a result of the delay or cancellation of the deployment and implementation of the Network Strategy and/or Distribution Automation Project.

It is recognized and acknowledged by the Signatories that the full realization and measurement of many of the benefits associated with the Network Strategy and Distribution Automation project may not be realized in the short term or would continue to appreciate in value over time. This fact will be recognized in the selection of milestones. For example, proper assessment of the value of volt-var optimization requires that measurements be taken over a full year such that seasonable load profiles are considered. The Signatories also recognize that benefits of projects, such as the volt-var project discussed above, will also improve once they can be applied centrally through the Distribution Management System ("DMS"). DMS is not anticipated to be fully functional during Rate Year 1. Other grid functions/capabilities from the projects such as Fault Location, Isolation, and Service Restoration and real time load transfers also require full DMS implementation to maximize available benefits.

10. Energy Efficiency Programs

a) <u>Internal Labor</u>

The electric and gas Income Statements set forth in Appendix A reflect a rate allowance for internal labor for the Company's current suite of Energy Efficiency programs. Rate Year 1 internal labor funding for Energy Efficiency program expenditures reflects a half year of the continuing Energy Efficiency surcharge and a half year of base delivery rate funding. Internal labor for Energy Efficiency in Rate Year 2 and Rate Year 3 reflects inclusion of a full year of all Central Hudson Energy Efficiency internal labor program expenditures in base rates.

b) Surcharge and Targets

The 2016 Energy Efficiency electric surcharge amount will be as established in Appendix C to the REV Order ($8.5 million). The 2016 Energy Efficiency gas surcharge will be established and addressed in a forthcoming Order. Savings targets for both gas and electric are maintained at current EEPS2 targets for 2016. In addition, in recognition of the fact that while Central Hudson's electric energy efficiency budget authorized in Appendix C to the REV Order is less than the rate allowance for electric energy efficiency funds reflected in the joint proposal filed on February 6, 2015, Central Hudson will maintain current efficiency targets for 2016, the Signatories to the Joint Proposal agree that the Company is confronting unique circumstances that could impact performance in 2016. Therefore, the Signatories to the Joint Proposal agree that, in light of these mitigating factors, the Company will not be subject to any potential penalties or receive any incentives for meeting the Energy Efficiency targets for the 2016 period. Nothing in this JP precludes any party from raising positions in the other Commission proceedings regarding the optimal budget, design and/or implementation of Central Hudson's Energy Efficiency programs.

11. Depreciation

a) Depreciation Expense

The average service lives, net salvage factors and life tables used in calculating the theoretical depreciation reserve and in establishing depreciation expense are set forth on Appendix R. The Company is authorized to use these factors until new factors are approved by the Commission.

b) Gas Propane Accounts

The Company is authorized to eliminate the gas propane negative gas reserve balance of approximately $1.8 million by charging half of the amount to Account 376.00 and the remaining half to Account 380.00.

c) Gas Excess Cost of Removal

The Signatories agree that all gas costs of removal, including salvage, will be charged to the depreciation reserve.

IV. RATE YEAR NET PLANT ADDITIONS

A. Net Plant and Net Plant Targets

1. Components of Net Plant

Actual Net Plant and the Net Plant Targets have four components: 1) the Average Electric or Gas Net Plant; 2) the Average Electric or Gas Non-Interest Bearing Construction Work in Progress; 3) the Average Common Net Plant allocated to Electric or to Gas; and 4) the Average Common Non-Interest Bearing Construction Work in Progress allocated to Electric or to Gas.

2. Electric and Gas Net Plant Targets

The electric and gas revenue requirements for Rate Year 1, Rate Year 2, and Rate Year 3 are based on the net plant targets set forth in Appendix B. These net plant targets are applicable only to the time periods specified and not any subsequent period, notwithstanding any other provision of this JP. The actual average electric and gas net plant balances at the end of each Rate Year will be calculated using the calculation methods described in Appendix C.

3. Reconciliations

The actual electric and gas net plant will be reconciled to the electric and gas net plant targets for Rate Year 1, Rate Year 2, and Rate Year 3 on an annual Rate Year basis. The revenue requirement impact (i.e., return and depreciation as described in Appendix C) resulting from the difference (whether positive or negative) in actual average net plant balances and the target levels will carry forward for each of the Rate Years and will be summed algebraically at the end of Rate Year 3. The Company is authorized to defer for future recovery any incremental costs it incurs with respect to implementing a gas unit cost tracker, which requires the Company to collect and maintain information at a higher degree of granularity. The cost is estimated to be $250,000 and recovery will be capped at that amount. The Company and Staff will work together to develop the gas unit cost tracker information which will be reported annually to coincide with the annual Leak Prone Pipe Replacement Report.

4. Deferral For the Benefit of Ratepayers

If at the end of Rate Year 3 the cumulative incremental revenue requirement impact from net plant additions is negative, the Company will defer the revenue requirement impact for the benefit of customers. If at the end of Rate Year 3 the cumulative revenue requirement impact is positive, no deferral will be made. Carrying charges at the pre-tax rate of return ("PTROR") will be applied by the Company to the amount deferred from the end of Rate Year 3 until the effective date of the succeeding Commission rate order.

5. Related Reporting

The Company will provide Staff by March 1, 2016, 2017, and 2018 a report on its capital expenditures during the prior calendar year using a format similar to the format set forth in Appendix D of the 2010 Rate Order. This format also is presented in Appendix D to this JP. In addition, the Company will file its five year capital investment plan with the Secretary annually starting on July 1, 2016.

Unless expressly stated in this JP, nothing in this JP is intended to alter the Company's flexibility during the term hereof to substitute, change, or modify its capital projects.

V. ACCOUNTING MATTERS

A. Deferral Accounting

1. Continuing Deferrals

Except as expressly modified within this JP, the Company is authorized to continue its use of all continuing accounting deferrals for expenses and costs as specified in the 2010 Rate Order applicable in Rate Year 3 of that rate plan or for which Commission authorization for deferral accounting is currently effective whether by reason of a Commission Order or policy of general applicability or by reason of a Commission determination with specific reference to the Company.

Without limiting the foregoing, the accounting deferrals applicable in Rate Year 3 from the 2010 Rate Order include the following expenses and costs that will continue without modification:

a) Pension Expense under Accounting Standards Codification Topic 715 (formerly Statement of Financial Accounting Standards No. 87);

b) Post Employment Benefits Other than Pensions ("OPEBs") under Accounting Standards Codification Topic 715 (formerly Statement of Financial Accounting Standards No. 106);

c) Interest Costs on Variable Rate Debt;

d) Interest Costs on the cost rate of New Debt Issuances in Rate Year 2 and Rate Year 3;

e) Incremental costs of litigation regarding claims of exposure to asbestos at Company facilities;

f) Research and Development costs under Commission Technical Release No. 16;

g) Enhanced Powerful Opportunities Program ("EPOP") and Low Income Bill Discount Programs;

h) New York State Assessment and Commission General Assessment;

i) Net Lost Revenues associated with the Merchant Function Charge;

j) Revenue Decoupling Mechanisms (Electric and Gas);

k) Deferred Temporary Metro Transit Bus Tax Surcharge;

l) Deferred Unbilled Gas Revenues;

m) Renewable Portfolio Standards ("RPS"), EEPS and System Benefits Charge ("SBC");

n) Economic Development Plan Implementation;

o) Competition Education Campaign Program;

p) Commodity-Related Deferrals;

q) NMP2 Costs; and

r) Revenue Requirement of Net-Plant Shortfall.

The Company is authorized to continue its current deferral practices incident to commodity/delivery mechanisms such as ECAM, GCA, etc., which recognize the timing differences that occur between the actual purchases of energy requirements and the collection of costs from customers.

2. Modified Deferrals

The following deferrals from the 2010 Rate Order are modified:

a) All Environmental Site Investigation and Remediation Costs

The Company is authorized to continue to defer all environmental Site Investigation and Remediation ("SIR") Costs as authorized by the Acquisition Order.

b) Deferral of Actual Costs of Debt as Compared to Forecast

In all three Rate Years the actual interest rate of variable rate debt, consisting of the 1999 NYSERDA Series B issuance or its successor and the 2014 Series E or its successor, will be reconciled to the interest rates shown in Appendix H, Schedule 2 and the difference will be reflected in the updated average cost of long term debt and the updated weighted cost of debt for the respective rate year. In the event the 1999 NYSERDA Series B issuance or its successor and the 2014 Series E or its successor are refinanced, the Company is permitted to defer and amortize the costs associated with its new debt, subject to conditions in any Financing Order. In addition, for Rate Years 2 and 3 only, the actual interest rate incurred for new fixed rate debt will be reconciled to the interest rates shown in Appendix H, Schedule 2 and the differences will be reflected in the updated average cost of long term debt and the updated weighted cost of debt for the respective Rate Year. At the end of each Rate Year, the total difference between the forecasted weighted cost of long term debt and the actual weighted cost of long term debt for that Rate Year as determined above, will be multiplied by the forecasted rate base amounts as indicated in Appendix A to determine the electric and gas amounts to be deferred for future recovery, or returned to customers, with carrying charges at the PTROR.

c) Property Tax True-Ups and Deferrals

For each Rate Year, the difference between the rate allowance for property tax expense (including school, county, city, town, and village) and actual property tax expense on a Rate Year basis will be deferred for future recovery, or return to customers, with carrying charges at the PTROR. Differences will be shared 90/10 between customers and the Company (respectively); provided, however, that the Company's pre-tax loss or gain will be limited to 10 basis points per (electric and gas) department for Rate Year 1 and 5 basis points per (electric and gas) department for Rate Year 2 and Rate Year 3.

d) Governmental Actions

The Company is authorized to defer the revenue requirement effect of new legislative, governmental, Commission or other regulatory actions subsequent to the execution hereof that individually have material consequences (10 basis points or more of return on common equity for either the gas department or the electric department) for any elements of cost, with carrying charges at the PTROR.

e) International Financial Reporting Standards ("IFRS")

The Company is authorized to defer its actual non-labor costs of planning for and implementing IFRS incurred during the term of the Rate Plan.

f) Management and Operation Audit Costs

The Company is authorized to defer its actual outside professional or consultant-related costs incurred, in responding to any Commission initiated or required Management or Operations Audit cost, including in Cases 13-M-0314 and 13-M-0449, with carrying charges at the PTROR, for future recovery from customers.

g) Distribution and Transmission ROW Tree Trimming Costs

Actual distribution ROW tree trimming expenditures will be compared to the sum of the Rate Year expense allowances over the three year term. Any cumulative under-spending at the end of Rate Year 3 will be deferred for future return to customers with carrying charges at the PTROR.

Actual transmission ROW tree trimming expenditures will be compared to the sum of the Rate Year expense allowances over the three year term. Any cumulative under-spending at the end of Rate Year 3 will be deferred for future return to customers with carrying charges at the PTROR.

h) Stray Voltage

Actual Stray Voltage testing and mitigation expenditures will be compared to the Rate Year expense allowance. The difference between the rate allowance and actual Stray Voltage testing and mitigation expenditures will be deferred on a two-way basis for either future recovery by the Company, or return to customers, with carrying charges at the PTROR.

3. Expiring Deferrals

The accounting deferrals from the 2010 Rate Order for the following expenses and costs will expire:[13]

a) SBC Gas Low Income Program;

b) Information Technology Expense;

c) Transmission Sag Mitigation Costs-Capital Projects;

d) Gas Main Replacement Program;

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[13] The deferral of $1.85 million of synergy savings from the Acquisition Order will also expire.

e) SC 11 Levelized Rate; and

f) FAS 112 Long Term Disability.

4. New Deferrals

The following new deferrals are added:

a) Security Costs

Actual security costs will be compared to the Rate Year allowances on a Rate Year basis. Any under-spending as of the end of a Rate Year will be deferred for future return to customers with carrying charges at the PTROR.

b) Rate Case Expense

Actual Rate Case expense will be recorded against the Rate Case expense allowance as specified in the Appendix A income statements. Any under-spending will be deferred for future return to customers with carrying charges at the PTROR. The Company is authorized to defer the Rate Case expenses related to these cases, subject to the following limits: External Legal Costs at $850,000; Return on Equity Consultant Costs at $60,000.

c) Clean Energy Fund/NYSERDA Surcharge

The Signatories to the JP recognize the uncertainty surrounding the Clean Energy Fund, which as potentially structured may encompass existing items such as RPS, SBC, EEPS and 18-a or other items for which deferral is currently provided. To the extent not otherwise addressed or superseded by the Commission Order in the Clean Energy Fund proceeding,[14] the Company is authorized to defer the difference in

[14] Case 14-M-0094 - Proceeding on Motion of the Commission to Consider a Clean Energy Fund, Order Commencing Proceeding (May 8, 2014).

actual expenses incurred in connection with the Clean Energy Fund to the costs collected from customers on a Rate Year basis. The differences between the actual expense and the costs collected from customers will be deferred on a two-way basis for future recovery by the Company, or return to customers, with carrying charges at the PTROR.

Similarly, the Signatories to the JP recognize the uncertainty surrounding Part P of the Governor's proposed budget that includes an additional NYSERDA and Department of Environmental Conservation's climate change program surcharge on gas and electric utilities. To the extent not otherwise addressed or superseded by Commission Order, the Company is authorized to defer the difference in actual expenses incurred in connection with this surcharge to the costs collected from customers on a Rate Year basis. The difference between the actual expense and the costs collected from customers will be deferred on a two-way basis for future recovery by the Company or return to customers, with carrying charges at the PTROR.

d) Major Storms (Electric Service Only)

Actual Major Storm Costs will be compared to the Major Storm Reserve rate allowance on a Rate Year basis, subject to the provisions in Appendix Q. The differences between the rate allowance ($700,000 per Rate Year) and actual Major Storm Costs will be deferred for future recovery by the Company or will remain in the Major Storm Reserve with carrying charges at the PTROR.

e) REV Demonstration Projects

To the extent not otherwise addressed or superseded by subsequent Commission Orders, the Company is authorized to defer for future recovery the incremental revenue requirement effect, net of revenues of the Company's share of Reforming the Energy Vision ("REV") Demonstration Project capital expenditures up to $10 million including recovery of related operations and maintenance costs associated with any REV Demonstration Project not paid by the project participants or a third party that is authorized by the Commission in these proceedings, with carrying charges at the PTROR. If, upon further development, REV Demonstration Project capital expenditures appear likely to exceed $10 million, and are not paid by the project participants or a third party, the Company may petition the Commission for authorization to defer additional funds. The Company shall file quarterly reports with the Secretary that include all relevant details including: revenue requirement amounts, project details such as descriptions and in-service dates, incremental costs incurred, operational savings, tax benefits, grants, and all Company-identified benefits.

f) Non-Net Income Based Calculation of State Income Taxes

The Company is authorized to defer the incremental state income tax expense for any non-net income based calculation of state income taxes during the term of the Rate Plan. If the Company is required to file state income tax based on a non-net income based calculation, it will file a notice with the Secretary including the calculation of the incremental state income tax and the change that caused the Company to fall into a non-net income based tax calculation. This notice will be in lieu of the filing of a deferral petition and would not be subject to the Commission's traditional three-part deferral test. The method of the recovery of any deferred amounts will be addressed in Central Hudson's next rate case.

g) Bonus Depreciation

If bonus depreciation is extended, the Company is required to defer the revenue requirement impact of the bonus depreciation reduction to rate base during the term of the Rate Plan or until such time as superseding rates are set by the Commission.

h) Unbilled Electric Revenues

The Company will be authorized to defer the difference between total unbilled electric revenue and the amount recovered in revenue.

i) Danskammer Gas Revenues

Actual delivery revenues associated with providing gas service to Danskammer will be deferred for the benefit of customers, with carrying charges at the PTROR.

j) Energy Efficiency Incentives

The Company is authorized to accrue carrying charges on the net of tax deferred Energy Efficiency incentives (EEPS1 and EEPS2) at the PTROR effective July 1, 2015 until the Commission acts upon the deferred incentives earned.

k) Additional Leak Prone Pipe Replacement Deferral

In the event the Company replaces or eliminates Leak Prone Pipe in excess of its mileage target in any calendar year, for each mile in excess of the applicable target, the Company shall receive a positive revenue adjustment of 2 basis points per additional mile, capped at a maximum of 5 miles (10 basis points) per calendar year, which the Company will defer for future recovery. This deferral would allow for up to $1.4 million for every mile over 13 miles in 2016, up to $1.5 million for every mile over 14 miles in 2017, and up to $1.6 million for every mile above 15 miles in 2018. For the avoidance of doubt, the Company is expressly authorized to include Leak Prone Pipe eliminations (abandonment, disuse or any other method that terminates use of the Leak Prone Pipe while still serving the customer) in this deferral mechanism.

l) Asset Retirement Obligation Depreciation and Accretion Expense

The Company is authorized to defer asset retirement obligation depreciation and accretion expense consistent with the Uniform System of Accounts.

B. Listing of Deferrals

A listing of deferrals is set forth in Appendix E, together with the specific deferral method and associated carrying charge for each. While this listing is intended to be comprehensive, the Signatories recognize that other deferral accounting employed by the Company may have inadvertently not been included. Accordingly, the list is without prejudice with respect to any error or omission and each Signatory reserves the right to revise this listing pursuant to the procedures set forth in Section XVIII of this JP.

C. Deferral Extension/Continuation

For the avoidance of doubt, the deferrals authorized or permitted consistent with this JP will not terminate by reason of the end of Rate Year 3 but shall continue until such time as they are superseded or expressly revoked.

D. Right to Petition

The Company may petition the Commission for authorization to defer extraordinary expenditures or revenue loss not otherwise addressed by this JP, potentially including items discussed above. Other Signatories reserve the right to respond to any such petition as such Signatory may see fit. To the extent that new mandatory regulatory, legislative or accounting changes, tax law changes, other regulatory policy changes, or other events materially affecting the Company's cost of providing service not specifically addressed herein become effective or occur during the Rate Plan, any Signatory hereto may petition the Commission to adjust the Company's rates accordingly.

E. Projected Net Deferred Regulatory Credits

Actual July 1, 2015 balances for the items shown on Appendix F will be offset against each other as of July 1, 2015, with the net deferred credit balance available for rate moderation. Any unused balance shall remain deferred, with carrying charges at the PTROR.

F. Revenue Matched Rate Allowances

Rate allowances for revenue matched items are set forth in Appendix G.

VI. CAPITAL STRUCTURE AND RATE OF RETURN

A. Capital Structure

The capital structures and cost rates for debt and other customer capital are shown by Rate Year in Appendix H.

B. Allowed Rate of Return on Common Equity

The allowed return on common equity ("ROE") is 9.0% for all three Rate Years.

C. Earnings Sharing

The allowed ROE established for the term of the JP is 9.0%. Actual regulatory earnings in excess of 9.0% are authorized and those in excess of 9.5% ROE and up to 10.0% ROE will be shared equally between customers and shareholders. Actual regulatory earnings in excess of 10.0% ROE and up to 10.5% ROE will be shared 80/20 (customer/shareholder). Actual regulatory earnings in excess of 10.5% ROE will be shared 90/10 (customer/shareholder). These earnings sharing percentages shall be maintained until the effective date of the succeeding Commission rate order.

VII. ADDITIONAL REPORTING REQUIREMENTS

A. Empower

Empower is a program currently run by NYSERDA that provides no-cost energy efficiency solutions for income-eligible New Yorkers. The Company agrees to contact via e-mail its existing energy efficiency vendors and a list of specific Energy Service Company e-mail contacts provided by Staff regarding vendor interest in providing an alternative service to Empower. To the extent a vendor responds back to the Company expressing interest and capability, the Company will provide Consumer Services Staff with the vendor response and contact information. Staff, UIU, and the Company will meet to discuss the viability of an alternative program to Empower.

B. Low Income Customers

The Company will query via telephone in Rate Year 1 all potentially eligible customers for EPOP that it has identified that have not enrolled in EPOP to determine why such customers have not sought to participate in the program. The Company further agrees to provide information shared by customers on an aggregated basis (to protect customer privacy) to Staff, UIU and other interested parties. The Company will also continue to file quarterly and annual reports and evaluations of its low income programs with the Secretary.

C. Security

The Company will provide an annual report to the Director of Utility Security regarding major security upgrades and projects. In addition, within 60 days of the date of this JP, Central Hudson shall provide the Director of Utility Security with an initial security report. The initial security report shall include a detailed description of the electronic security measures presently in place and functioning at Company-owned 345 kV substations, and the extent to which such security measures are now providing real time imaging and alert information to a Company security monitoring facility. For any 345 kV substation not presently equipped, or not yet fully equipped, with electronic security measures, the Company shall include in the initial report a detailed plan for the deployment of such measures with specific timelines for the targeted completion and activation of them at each substation. The present and anticipated future capabilities of electronic security at the 345 kV substations shall be fully described, to include identification of intrusion detection technology solutions, video surveillance capability and area coverage, and the connectivity/monitoring technology required to ensure these security measures work as a full-time integrated system.

D. Network Strategy and Distribution Automation Project

The Company will file with the Secretary quarterly status reports regarding the Network Strategy and Distribution Automation project expenditures including a brief description of progress toward the next milestone.

E. Reporting of Actual Earnings

The Company will report within 90 days following the end of each Rate Year to the Secretary showing a computation of its achieved regulatory rate of return on common equity for the preceding Rate Year period. The achieved regulatory return on common equity computation will be measured by (electric and gas) department and will reflect the lesser of an equity ratio equal to 48% or Central Hudson's actual average common equity ratio. The financial consequences of any regulatory incentives positive or negative, and other exclusions consistent with existing practices, will be excluded in the computations of the regulatory rate of return on common equity.

F. Gas Safety

The Company will submit a report to the Deputy Director of the Office of Gas and Water in the Office of Electric, Gas and Water on its performance in the areas of the recommended targets set forth in Sections XIV.E within 60 days following the end of each calendar year.

VIII. FORECASTS OF SALES AND CUSTOMERS

The Signatories agreed-upon electric and gas forecasts for sales volumes and numbers of customers are set forth in Appendix I. Billing determinants corresponding to these forecasts are also set forth in Appendix K.

IX. REVENUE ALLOCATION AND RATE DESIGN

A. Revenue Allocation

1. Electric Revenue Allocation

The Signatories agree on the electric revenue allocation set forth in Appendix J.

2. Gas Revenue Allocation

The Signatories agree to the gas revenue allocation set forth in Appendix J.

B. Rate Design

1. Electric Rate Design

The Signatories agree to the electric rate design as set forth in Appendix K.

2. Gas Rate Design

The Signatories agree to the gas rate design set forth in Appendix K.

In addition, the Signatories agree to Staff's volumetric Service Classification ("SC") 11 rate design and acknowledge that the change in SC 11 rate design to a volumetric basis will require conforming structural changes to other charges such as the New York State Assessment (18-a). Any rate moderation will be applied to all classes on a volumetric basis.

3. Customer Bill Impacts

The agreed-upon delivery revenue increases have the estimated bill impacts set forth in Appendix L, reflecting electric and gas bill credits per Section III.C and D.

X. PROVISIONS FOR LOW INCOME CUSTOMERS

A. Enhanced Powerful Opportunities Program ("EPOP")

The Company is authorized to continue its existing Commission-approved EPOP program, with total EPOP funding as shown on the income statements in Appendix A. In the event the actual costs of the program in any Rate Year vary from the authorized expenditure level, any excess costs incurred by the Company will be deferred for future recovery up to 15% of the total program costs and any under expenditures will be rolled over for program use in subsequent Rate Years with carrying charges at the PTROR.

B. Low Income Bill Discount Program

The Company is authorized to continue its Low Income Bill Discount program for the Home Energy Assistance Program ("HEAP") recipients as modified and approved by the Acquisition Order. The bill discount credits are as follows:

Service Type	Electric Only	Gas Only	Both Electric & Gas
Heating	$17.50	$17.50	$23.00
Non-Heating	$5.50	$5.50	$11.00

The bill discount credits will be applied up to the total corresponding funding in rates, as has been reflected in the Appendix A Income Statements. Any accumulated balances of program under-spending will remain in the Low Income Bill Discount program and carrying charges will be applied at the PTROR. In the event that increases in the numbers of customers qualifying for HEAP occur and the funding for the discounts provided in Appendix A is inadequate to provide the discounts to all qualifying customers, the Company is authorized to defer the difference between the rate allowance and the actual discounts for future recovery with carrying charges at the PTROR.

The Signatories acknowledge that the Commission has initiated a new Low Income Proceeding in Case 14-M-0565 that may modify the Company's low income programs. To the extent the Commission orders modification to the Company's low income programs, the Company will be held harmless from the change in expenses associated with the revised or new low income programs and will be authorized to defer the difference between the rate allowance during each Rate Year and the actual costs for low income programs for future recovery with carrying charges at the PTROR.

C. Weatherization

Staff, UIU and other interested parties will work with NYSERDA's EmPower program (or any successor program) and Homes and Community Renewal's Weatherization Assistance Program ("WAP") to address the waiting list maintained by WAP of Central Hudson gas customers seeking weatherization services. In the event gas delivery revenues materialize from the operation of Danskammer and in the event the Commission determines that EmPower (or any successor program) does not have sufficient funds to provide weatherization services to the gas customers on WAP's waiting list, UIU may petition the Commission for use of the portion of Danskammer gas delivery revenues allocated to residential customers for this purpose.

D. Same-Day Reconnection Program

The Signatories agree that the Company will implement a Same Day Reconnection Program. The Income Statements set forth in Appendix A reflect a rate allowance of $35,000 in each Rate Year for the implementation of the Same Day Reconnection Program. For the avoidance of doubt, the Same Day Reconnection Project will not be funded by shareholders. Given the additional rate allowance, the Company will strive to achieve not less than 80% reconnection within the same day.

The Company shall file a report on residential same-day reconnections for each calendar quarter ("Reporting Period"). Each report should be filed with the Secretary, with copies by e-mail to interested parties, within 30 days after the end of each Reporting Period. The report will indicate the number of residential electric customer reconnections issued by 5:00 PM, Monday through Friday, and the number of same-day reconnections attempts made to such customers.

XI. TARIFF-RELATED MATTERS

A. Generally

Except as may be clarified or altered below, existing tariff provisions and related rate making will generally be continued.

B. Reconnection Charges

Whenever service is restored to the same customer at the same meter location within twelve months after discontinuance of service, the Company will make a charge of $20 or in the event an electric line crew is required to perform the service reconnection the charge will be $100; if service is restored during the hours from 8:00 AM to 4:30 PM, on days the main business office of the Company is open for business. If service is restored during other hours the charge will be $40 or $140 if an electric line crew is required to perform the service reconnection. Where a customer receives both electric and gas service, the Reconnection Charge for only one service will apply in the event of the simultaneous reconnection of both gas and electric service.

C. <u>Electric Service Classification No. 8 (Public Street and Highway Lighting)</u>

Rate B, wherein the Company maintains customer-owned fixtures, will be closed to new installations effective July 1, 2015. Rate C, wherein the Company provides delivery service to customer-owned and maintained fixtures, will continue to provide customers with the flexibility to choose any type of facility that will service their needs.

D. <u>Economic Development Funding</u>

This Rate Plan includes no expense allowance for Economic Development, with all program funding being provided from existing economic development fund balances.

Central Hudson shall continue its existing Economic Development programs, including its: Shovel Ready Grants; Wired Building Grants; Job Creation Grants; Revitalization Grants; Business Retention Grants; Regional Marketing Funds; Substation Credits; and the Main Street Revitalization Program.

E. <u>Gas Design Day Forecasting</u>

The Company will submit to Staff the detailed work papers supporting its separate capability forecast for design day and winter season demand requirements which is prepared for the annual winter preparedness review commencing with the

2015-2016 winter review. These work papers will be included in all future rate case filings.

F. Unauthorized Use of Gas

The Company will revise its tariffs to clearly state that charges for unauthorized use of gas and non-compliance are by definition penalty charges.

G. Gas SC 11 Electric Generation Subclass

A new SC 11 subclass, Electric Generation ("SC11EG"), will be established as of July 1, 2015 and will be applicable to electric generation facilities with a minimum generation capacity of 50 megawatts taking firm transportation service from Company facilities at transmission pressures. SC11EG rate design will be based on a Maximum Daily Quantity ("MDQ") structure with the Transportation Rate component of the Monthly Rate reflecting a monthly customer charge of $1,200 and a demand charge of $9.25 per Mcf of MDQ for the term of this JP. All other tariff provisions of SC 11 contained in P.S.C. No. 12 – Gas, as they may be modified or superseded by approval of the Commission, will apply to SC11EG.

H. Gas Balancing

The treatment of gas balancing will continue per the 2010 Rate Order, except that the Signatories agree that the current balancing charges for under deliveries applicable to electric generators are not sufficient. All generator customers must be daily balanced. Effective July 1, 2015, the penalty for under delivery during non-operational flow order ("OFO") events will be $2.50 per Ccf in addition to a market based commodity charge per unit. Effective July 1, 2015, the penalty for under delivery during OFO events will be the greater of $5.00 per Ccf plus a market based commodity charge or the price per Dekatherm equal to three times the midpoint of the range of prices reported for the applicable pipeline, as published in Gas Daily, converted to a Ccf basis for billing. Additionally, the default position for all new customers (i.e., new gas loads as opposed to existing gas loads that may change ownership) served under SC 11 will be daily balanced, requiring an affirmative response for the monthly balancing option. The Company reserves the right to apply daily balancing on a new SC 11 customer if monthly balancing will negatively impact its ability to maintain gas distribution system reliability.

I. Remote Operated Valves ("ROV") for Electric Generators

ROVs will be required for existing generators if they fail to comply with tariff provisions. All new generators are required from the start of operation to have ROVs provided and installed at the generator's cost. The Company agrees to amend its SC 14 (Interruptible Transportation to Electric Generation) and SC 11 (Firm Transport) tariff language as follows: "To maintain system reliability, the Company may require the installation of a remote operated valve on the service lateral that supplies the Customer at the Customer's cost. Any Customer that fails to comply with a Company issued interruption will be required to have a remote operated valve installed and to pay for all associated charges. Customers applying for transportation service to serve new electric generation facilities will be responsible for paying all charges associated with the installation of this equipment."

J. Continuation of ECAM, GSC and PPA Allocation

The existing ECAM and GSC mechanisms, including the allocation of Purchased Power Adjustment costs/benefits, will continue per the 2010 Rate Order.

K. Gas Retail Access Operating Procedures

1. Cash-Out

A revised cash-out process for the Retail Access program will be implemented, no earlier than April 2016, to cash-out, in any given month, those accounts with valid meter readings during the month. Cost recovery will be provided for all incremental external costs Central Hudson incurs to implement this "semi-monthly" cash-out process.

2. Winter Bundled Service ("WBS") Pricing

The commodity component of the WBS price will be revised each month to reflect the Company's actual weighted average cost of storage ("WACOS") for the preceding month. The methods utilized to determine the non-commodity components of the WBS price will remain unchanged. The resulting WBS price will be made available on the Company's website. Due to timing differences between the availability of pricing data and filing requirements, the WBS price and the WACOS will be included on the Company's Statement of Firm Transportation Rates on a one month lag.

3. Collaborative Opportunity

Upon expression of written interest from three or more members of the retail access community, the Company will initiate a collaborative for the purpose of discussing and addressing any specific operations or other concerns.

L. Gas Expansion Program

1. Customer Conversion Assistance Program

A $1.0 million annual program for each Rate Year will be jointly designed by Staff and the Company to provide additional incentives and support for customer conversion to gas. Funding for the program will be provided from available rate moderators. Unused funds shall be available for general rate moderation purposes at the conclusion of this JP.

2. Capacity Requirements

The Company will continue to provide the Secretary with confidential reporting regarding the amount of winter capacity reserve as part of the Company's annual Winter Review.

3. Gas Expansion Performance Incentive

The Company is authorized to receive an annual incentive in the form of 1 basis point for every 200 gas customers added above the combined total customer count forecasted for Residential and Commercial customers for each of the Rate Years. The Company will provide a report to the Secretary identifying its annual customer growth by service class within 45 days of the completion of the Rate Year.

M. Electric RDM

The electric revenue decoupling mechanism ("RDM ") will continue to be applicable to SCs 1, 2, and 6 and those customers taking service under SC 14 whose parent service classification would be either SC 1, 2, or 6. The RDM is not applicable to SCs 3, 5, 8, 9 and 13.

1. Structure

The structure and provisions of the electric RDM will continue per the 2010 Rate Order except that the provisions for annual and interim RDM periods will be replaced with a provision for semi-annual RDM periods and the provision for the RDM adjustment period will be revised accordingly.

2. Semi-Annual RDM Periods

Semi-Annual RDM Periods are defined as the six months ending December 31 and June 30 and each succeeding six-month period thereafter.

3. RDM Adjustment Period

The RDM Adjustment Period is defined as the six months beginning February 1 or the six months beginning August 1 immediately following each Semi-Annual RDM Period.

4. Delivery Revenue Targets

Delivery Revenue Targets by month for each service classification or sub classification will be based on delivery revenue targets for each Rate Year as set forth in Appendix M.

5. Determination of RDM Adjustment

At the end of a Semi-Annual RDM Period, total delivery revenue excess/shortfalls and associated interest for each applicable service classification or sub classification will be refunded/surcharged to customers through service classification or sub classification-specific RDM Adjustments applicable during a corresponding RDM Adjustment Period. Following each RDM Adjustment Period, any difference between amounts required to be charged or credited to customers in each service classification or sub classification and amounts actually charged or credited will be charged or credited to customers in that service classification or sub classification, with interest, over a subsequent RDM Adjustment period, or as determined by the Commission if no RDM is in effect.

6. Continuation

Delivery Revenue Targets for the Rate Year ending June 30, 2018 shall remain in effect until otherwise changed by the Commission.

N. <u>Gas RDM</u>

The gas RDM will continue to be applicable to SCs 1, 2, 6, 12 and 13. The RDM is not applicable to SCs 8, 9,11,14,15 and 16.

1. Structure

The structure and provisions of the gas RDM will continue per the 2010 Rate Order except that the structure will be revised from a unit per customer model to a revenue per customer model; the provisions for annual and interim RDM periods will be replaced with a provision for semi-annual RDM periods; and the provision for the RDM adjustment period will be revised accordingly.

2. Revenue per Customer

Revenue per customer ("RPC") Targets set forth in Appendix M are determined for SCs 1 and 12 combined and SCs 2, 6 and 13 combined for each month by dividing base revenue, excluding merchant function charge revenue, by customer months based on the revenue and customer forecasts as set forth in Appendix I. Actual RPC will be calculated in the same manner as the target RPC, on a monthly basis, based on actual billed revenue as adjusted by the Weather Normalization Adjustment described in General Information Section 27 of the Company's Gas Tariff and billed customer months. On a monthly basis, any delivery revenue excess or shortfall will be determined as the difference between the actual RPC and the target RPC multiplied by the actual number of customer months billed.

3. Semi-Annual RDM Periods

Semi-Annual RDM Periods are defined as the six months ending December 31 and June 30 and each succeeding six-month period thereafter.

4. RDM Adjustment Period

RDM Adjustment Periods are defined as the six months beginning February 1 or the six months beginning August 1 immediately following each Semi-Annual RDM Period.

5. Determination of RDM Adjustment

At the end of a Semi-Annual RDM Period, total delivery revenue excess/shortfalls and associated interest for each applicable service classification group will be refunded/surcharged to customers through service classification group-specific RDM Adjustments applicable during a corresponding RDM Adjustment Period.

Following each RDM Adjustment Period, any difference between amounts required to be refunded or surcharged to customers in each service classification group and amounts actually refunded or surcharged will be refunded or surcharged to customers in that service classification group, with interest, over a subsequent RDM Adjustment period, or as determined by the Commission if no RDM is in effect. An example of the reconciliation methodology is found in Appendix M, Sheet 9.

6. Continuation

RPC Targets for the Rate Year ending June 30, 2018 shall remain in effect until otherwise changed by the Commission.

O. Energy Efficiency Surcharge Authority

Effective January 1, 2016, the Company shall implement and continue an Energy Efficiency Tracker as a surcharge mechanism for cost recovery of the Company's internal suite of energy efficiency programs (excluding internal labor costs, which are recovered through base rates). On an annual basis, the Company will reconcile actual recoveries with allowed budgets and recover/refund any differences.

P. Conforming Tariffs

The electric and gas tariffs will be amended, as necessary, to conform to the provisions set forth in this JP.

XII. RATE UNBUNDLING AND RETAIL ACCESS LOST REVENUE RECOVERY

The revised methodology approved by the Commission in the 2010 Rate Order which restructured both Merchant Function Charges ("MFC") applied by the Company will continue. Additionally, the existing retail access migration-related lost revenue mechanism will continue per the 2010 Rate Order for the electric department, in which 50% of retail access migration related lost revenue is collected through the Supply Charge component of the MFC, which is avoided by retail access customers, and 50% through the transition adjustment paid by all customers. Further, electric MFC revenue will continue to be reconciled through the RDM per the 2010 Rate Order.

The current gas MFC Net Lost Revenue mechanism will be replaced with a new gas MFC revenue reconciliation process wherein monthly actual billed MFC revenue, by MFC group, will be compared to the monthly MFC revenue targets for each rate year as set forth in Appendix M, with any monthly over or under billed MFC revenue deferred for refund to or recovery from full service customers. At the end of each rate year, any over or under recovery including estimated interest over the refund or recovery period at the Commission's rate for other customer-provided capital will be divided by estimated sales by MFC group over the refund or recovery period to develop a reconciliation factor to be effective for the twelve months beginning September 1. Any over or under recoveries of any such gas MFC reconciliations will be addressed in a subsequent reconciliation period. MFC Revenue Targets for the Rate Year ending June 30, 2018 shall remain in effect until otherwise changed by the Commission.

A. <u>Lost and Unaccounted For Gas ("LAUF") and Factors of Adjustment ("FOA")</u>

The Signatories agree to the following with respect to LAUF and FOA:

LAUF	
Target FOA (to be updated annually)	1.0044
Top Dead band	1.0182
Bottom Dead band	1.0000

The FOA will be updated annually and will be calculated by averaging the previous five years, ending August 31. The FOA shall be in accordance with Staff's White Paper on LAUF Gas. Line pack and conversion values will be excluded from the calculations. Annual negative values when calculating the five-year average target FOA will be set to zero. The dead band will remain fixed until modified by the Commission.

The electric service level FOA will be set based on the most recent 36 month system average and the methodology per the 2010 Rate Order.

B. <u>Interruptible Imputation</u>

The interruptible imputation structure as set forth in the 2010 Rate Order will be continued and the imputation will be set at $3.0 million for each Rate Year.

XIII. REFORMING THE ENERGY VISION

A REV Working Group was formed as part of this JP to present REV demonstration projects for the Commission's consideration at its June 2015 session. An open, transparent stakeholder collaborative process was initiated on January 7, 2015 to further consider and develop the Company's four REV conceptual programs and any additional REV demonstration projects identified by the REV Working Group. The Company will file a report no later than May 1, 2015 further detailing the REV demonstration projects developed by the collaborative for Commission consideration. The report will provide details on the demonstration projects, including project descriptions, milestones, costs and how those costs would be recovered. The report will identify how the demonstration projects meet the criteria summarized by the Commission in its December 12, 2014 Memorandum and Resolution on Demonstration Projects in Case 14-M-0101 or criteria otherwise adopted by the Commission in Case 14-M-0101. Parties may file comments on the report no later than May 15, 2015. To the extent collaborative members disagree with portions of the report filed by Central Hudson, the fact that the Company – as opposed to a different party – is filing the report does not bestow any preference or priority on its positions vis-à-vis the positions of other parties. Nothing in this JP precludes a party from seeking authorization to respond to any comments that may be filed in response to the report on May 15, 2015.

Individual collaborative members are free to support or object to any project or aspect thereof described in the May 1, 2015 Company report. All collaborative members, however, agree to support or not oppose cost recovery for all of the REV demonstration projects ultimately approved by the Commission.

The REV Working Group may continue to meet as necessary following the resolution of the above-captioned cases to develop future waves of REV demonstration projects and to monitor the progress of demonstration projects approved by the Commission.

The Signatories acknowledge that the Commission has initiated Case 14-M-0101, the determinations from which will take precedence and may require the implementation of certain REV opportunities, procedures, or requirements impacting or effecting Central Hudson and its customers while the terms of this JP are operative. If such implementation of REV opportunities or requirements were to occur, the Signatories agree that Central Hudson may petition to defer any incremental associated costs it incurs and that such a petition will be exempt from compliance with the Commission's traditional three part test for deferral.

XIV. PERFORMANCE MECHANISMS

A. Customer Service

The Customer Service Quality Performance Mechanism and associated reporting requirements will continue per the Acquisition Order and will consist of the following measures: PSC Annual Complaint Rate, the Customer Satisfaction Index, and Appointments Kept measures. All Customer Service Quality Performance Mechanism targets and potential Negative Revenue Adjustments ("NRAs") shall remain in effect until modified by a Commission order.

The criteria for the PSC Annual Complaint Rate and corresponding NRAs are:

PSC Annual Complaint Rate	NRA
<1.1	None
1.1	$950,000
1.2	$1,140,000
1.3	$1,330,000
1.4	$1,520,000
1.5	$1,710,000
1.6 or higher	$1,900,000
Total Amount at Risk	**$1,900,000**

The criteria for the Customer Satisfaction Survey and corresponding potential NRAs are:

CSI Satisfaction Index	NRA
85% or higher	None
84% ≤ CSI < 85%	$475,000
83% ≤ CSI < 84%	$950,000
82% ≤ CSI < 83%	$1,425,000
< 82%	$1,900,000
Total Amount at Risk	**$1,900,000**

The NRAs for the Customer Service Quality Performance Mechanism will be multiplied by 1.5 if targets are missed during a dividend restriction period.

B. <u>Appointments Kept</u>

The Company will credit customers $20 per missed appointment.

C. <u>Service Termination Reductions</u>

The Company and the Signatories desire to reduce service terminations to residential customers. Accordingly, an annual incentive for the Company is authorized in the form of a 5 basis point Positive Revenue Adjustment ("PRA") for each Rate Year in which it has reduced service terminations to residential customers in occupied buildings below 11,000 terminations. The Company will provide a report to the Secretary identifying its efforts to reduce terminations and whether it achieved the positive incentive for that Rate Year within 45 days of the completion of the Rate Year.

D. Electric Reliability

The electric service annual metrics for System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") will be set at targets of 1.30 and 2.50, respectively, and shall continue at these levels throughout the term of the Rate Plan. Electric Reliability Reporting requirements, quarterly meeting requirements, revenue adjustment source, and exclusions are defined in Appendix P. If the Company fails to achieve an annual SAIFI target of 1.30 it will be subject to a 30 basis point (electric, pre-tax) potential NRA. If the Company fails to achieve an annual CAIDI target of 2.50 it will be subject to a 30 basis point (electric, pre-tax) potential NRA.

The NRAs for the Electric Reliability Metrics will be multiplied by 1.5 if targets are missed during a dividend restriction period.

All electric reliability targets shall remain in effect until modified by a Commission order in a subsequent Central Hudson electric rate case.

E. <u>Gas Safety</u>

The Signatories agree to the following Gas Safety Metrics. Emergency response performance and damage performance shall adhere to the reporting criteria for the annual Gas Safety Performance Measures report.

1. Emergency Response Time

The gas emergency response time metrics and associated potential NRAs will be as follows:

Emergency Response Time	**Percent Completed**	**NRA (BP)**
30 Minute Response	75%	8
45 Minute Response	90%	4
60 Minute Response	95%	1

2. Gas Leak Backlog

The Gas Income Statements set forth in Appendix A include rate allowances for the Company's forecast of the number of gas leaks to be repaired and the costs per average repair. The backlog targets per the following table are actionable on a calendar year basis. In the event the Company incurs more costs than provided for in rates, the Company is free to seek deferral for any excess amount expended above the corresponding rate allowances that are based upon a fixed number of leaks assumed to be repaired and the cost per average leak. Should the Company fail to achieve the Gas Leak Backlog targets in any Calendar Year starting in 2015, it will be subject to the basis point ("BP") (gas, pre-tax) potential NRAs listed below.

Gas Leak Backlog	**# of Leaks**	**NRA (BP)**
Total Year-End Backlog	200	12
Repairable Leaks Backlog	16	16

The Signatories agree that the Damage Prevention targets listed above were established with the intent of moving Central Hudson closer to the statewide averages for such targets. The Signatories further agree that the Company's Damage Prevention targets should therefore at no point during the agreement be more stringent than the statewide averages. Accordingly, the Damage Prevention targets listed above will be reevaluated annually following the issuance of Staff's annual Gas Safety Performance Measures Report. Should the statewide Damage Prevention target averages, as reported in Staff's annual Gas Safety Performance Measures Report, increase above the targets set forth herein, Central Hudson's may petition for adjustment of the Damage Prevention targets for the calendar year in which the report was issued. The targets in place for 2018 shall remain in place until changed by the Commission.

3. Gas Total Damage Targets, Mismark Targets, and Company/Company Contractor Damages

The gas Total Damage targets, Mismark targets, and Company/Company Contractor Damages ("CCCD") and corresponding potential NRAs are as follows:

Gas	**Calendar Year End (per 1000 tickets)**			**NRA (BP)**
	2016	**2017**	**2018**	
Total Damages	2.2	2.05	1.90	4
Mismarks	0.45	0.40	0.36	8
CCCD	0.25	0.20	0.10	8

4. Gas Safety Violations Performance Measures

Central Hudson will incur a NRA for instances of noncompliance (occurrences) of certain pipeline safety regulations set forth in 16 NYCRR Parts 255 and 261, as identified during Staff's annual field and record audits. Appendix N sets forth a list of identified high risk and other risk pipeline safety regulations pertaining to this metric. Central Hudson will be assessed a NRA for each high risk or other risk occurrence, up to a combined maximum of 100 basis points on a calendar year basis, as follows:

High Risk Violation	**Occurrences**	**BPs Per Occurrence**
Per Calendar Year	1-25	1/2
	26+	1

Low Risk Violation	**Occurrences**	**BPs Per Occurrence**
Per Calendar Year	1-25	1/9
	26+	1/3

This metric will be measured on a calendar year basis. At the conclusion of each audit, Staff will offer and hold a compliance meeting with Central Hudson where Staff will present its findings to Central Hudson. Central Hudson will have five business days from the date the audit findings are presented to cure any identified document deficiency. Only official Central Hudson records, as defined in Central Hudson's Operating and Maintenance plan, will be considered by Staff as a cure to a document deficiency. Staff will submit its final audit report to the Secretary. If Central Hudson disputes any of Staff's final audit results, Central Hudson may appeal Staff's finding[s] to the Commission. Central Hudson will not incur a NRA on the contested finding until such time as the Commission has issued a final decision on the contested findings. Central Hudson does not waive its right to seek an appeal of any Commission determination regarding a violation under applicable law.

If an alleged high risk or other risk violation set forth in Appendix N is the subject of a separate penalty proceeding by the Commission under Public Service Law Section 25 or 25-a, that instance will not constitute an occurrence under this performance metric.

5. Negative Revenue Adjustments

The NRAs for the Gas Safety Performance Mechanisms identified above will be tripled if targets are missed during a dividend restriction period established under the Acquisition Order. The Signatories also acknowledge that the NRAs set forth above in this Section E on Gas Safety have already been doubled as a result of the Acquisition Order. Accordingly, the calculation of any triple NRA would be 1.50 times the basis points shown above.

6. Continuation

All Gas Safety Metrics shall remain in effect on an annual basis for the target levels identified until modified by a Commission order.

7. Infrastructure Enhancement for Leak Prone Pipe

The Company agrees to capital expenditures for the replacement or elimination of Leak Prone Pipe at a cost of $1.4 million per mile for 2016; $1.5 million per mile for 2017; and $1.6 million per mile for 2018. The Company further agrees to the following targets for the replacement or elimination of Leak Prone Pipe: a) 13 miles for 2016; b) 14 miles for 2017; and c) 15 miles for 2018. The Company shall maintain the 2018 pipe target until such time as it is changed by the Commission.

In addition, the Company and Staff will work jointly to explore development of an internal, and contractor, workforce development program. A report describing these efforts will be filed with the Secretary within 6 months of a Commission order in this proceeding.

In the event the Company fails to meet its Leak Prone Pipe target in any calendar year, the Company will be subject to an 8 basis point NRA in the immediately following Rate Year. In the event that the Company exceeds the pipe replacement/elimination target in any calendar year, the deferral and incentive provisions set forth above in Section V.A.4.L shall apply in the immediately following Rate Year.

The Company will develop a Leak Prone Pipe replacement/elimination prioritization list such that the risk prioritization model will be used in its development but the Company will have flexibility in ultimately determining pipe replacement/elimination project selection. For the avoidance of doubt, not all sections of pipe to be replaced or eliminated will be selected by the Company based on strict adherence to the risk prioritization model, but the decision and rationale to not follow strict adherence to the model will be documented for each segment and provided to Staff if requested.

XV. OUTREACH & EDUCATION

The Company will, during the term of this JP, continue to file an annual Outreach and Education Plan with the Secretary that is consistent in scope with plans filed by the Company under the 2010 Rate Order.

XVI. MONTHLY BILLING

The Company will transition to monthly billing for all customers from its current bi-monthly billing of certain customer classes by July 2016. The costs associated with monthly billing are set forth in the Income Statements for each Rate Year set forth in Appendix A.

XVII. CLIMATE CHANGE

Central Hudson agrees to review the climate change study produced by the Center for Climate Systems Research of Columbia University for Consolidated Edison Company of New York upon its completion, and any other materials on climate projects furnished to Central Hudson by the Sabin Center. Central Hudson will evaluate whether the results of the study and other materials suggest a need for an adjustment associated with its capital expenditure planning or investment or operational procedures and whether further study may be required. If, after consultation with the Sabin Center, Central Hudson determines that incremental capital investment is necessary as a result of the study, it will discuss the need for such investment with interested Signatories to this JP.

XVIII. ADDITIONAL PROVISIONS

A. Submission and Support

The Signatories agree to submit this JP to the Commission and recommend that it be adopted and approved by the Commission without modification as the resolution of these cases. The Signatories hereto believe that the JP will satisfy the requirements of Public Service Law Sections 65(1) and 79(1) that the Company provide safe and adequate service at just and reasonable rates.

B. Acceptance by the Commission

The Signatories intend this JP to be a complete resolution of all the issues in Cases 14-E-0318 and 14-G-0319.[15] It is understood that each provision of this JP is in consideration and in support of all the other provisions and each provision is expressly

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[15] Signatories have agreed to a process to address unresolved REV demonstration project issues in Section XIII.

conditioned upon acceptance by the Commission of this JP in its entirety without change. If the Commission does not approve this JP according to its terms without change, then the parties to the JP will be free to pursue their respective positions in these cases and any remedies at law or in equity without prejudice.

C. Non-Precedential Nature

The JP is a product of compromise and negotiation among the Signatories. The terms and conditions of the JP apply solely to, and are binding on each Signatory only in the context of, the purposes and results of this JP. None of the terms and provisions of this JP, nor any methodology or principle utilized herein, and none of the positions taken herein by any Signatory may be referred to, cited or relied upon by any other Signatory in any fashion as binding precedent including in any other proceedings before the Commission, any other regulatory agency, or before any court of law for any purpose except in furtherance of the purposes and results of the JP and except as may be necessary in explaining derivation of specific costs or accounting treatments as relevant to future ratemaking proceedings. Concessions made by Signatories on various electric and gas issues included in the JP do not preclude those parties from addressing such issues in future rate proceedings or in other proceedings.

D. Mutual Cooperation

The Signatories recognize that certain provisions of this JP require that actions be taken in the future to effectuate fully this JP. Accordingly, the Signatories agree to cooperate with each other in good faith in taking such actions. The Signatories specifically acknowledge that the listing of deferrals set forth in Appendix E was intended to be comprehensive and include all existing deferral accounting employed by the Company. Accordingly, Appendix E may be updated by the Company, with consent of Staff, to incorporate any inadvertently omitted deferral via a letter from the Company to the Secretary identifying the omission, thus amending Appendix E.

E. Procedures in the Event of a Disagreement

In the event of any disagreement over the interpretation of this JP or the implementation of any of the provisions of this JP, which cannot be resolved informally among the Signatories, such disagreement will be resolved as follows: the parties promptly will confer and in good faith will attempt to resolve such disagreement. If any such disagreement cannot be resolved by the Signatories within 15 business days from notification to a Signatory or a longer period if agreed to by the Signatories, any Signatory may petition the Commission for a determination on the disputed matter.

F. Other Permitted Filings

Notwithstanding the other provisions of this JP, the Signatories agree that the following rate changes will be permitted during the effectiveness of this JP, provided that the Commission's approval is granted prior to the implementation of such changes. A minor change is any individual base rate or rates whose revenue effect is *de minimis* or essentially offset by associated changes in other base rates, terms or conditions of service – for example, an increase in a specific base rate charge in the same or in other SCs that is offset by a reduction in a different base rate charge applicable to the same customers or SCs experiencing the increase. The Signatories agree that any Signatory will be allowed to take any position it may wish regarding any such proposed rate change.

It is understood that, over time, such minor changes are routinely made and that they may continue to be made during the effectiveness of this JP provided they will not result in a change (other than a *de minimis* change) in the revenues that Central Hudson's base rates are designed to produce overall before such changes. The Signatories agree that any Signatory will be allowed to take any position it may wish regarding any such proposed rate change.

Notwithstanding the foregoing, while the Company has no intention of changing rates during the effectiveness of this JP, it will make changes if so directed by the Commission.

If a circumstance were to occur that, in the judgment of the Commission, so threatens the Company's economic viability or ability to maintain safe and adequate service as to warrant an exception to this undertaking, then Central Hudson will be permitted to file for an increase in base rates at any time.

The Signatories recognize that the Commission possesses the authority to act on the level of the Company's base rates in the event of unforeseen circumstances that, in the Commission's opinion, have such a substantial impact on the range of earnings levels or equity costs envisioned by this JP so as to render Central Hudson's rates unreasonable or insufficient for the provision of safe and adequate service at just and reasonable rates.

Nothing herein shall preclude Central Hudson from petitioning the Commission for approval of new services or the implementation of new SCs and/or cancellation of existing SCs and rate design or revenue allocation changes associated therewith.

G. Trade Secret Protection

Nothing in this JP prevents the Company from seeking trade secret, personal privacy or critical system infrastructure protection under 16 NYCRR Part 6 for all or any part(s) of any document or report filed (or submitted to Staff) in accordance with the terms of this JP or to seek confidential treatment of material for any other lawful reason, or prohibits or restricts any other party from challenging any such request.

H. Execution in Counterparts

This JP may be executed in two or more counterparts, each of which together shall be deemed an original, but all of which together shall constitute one and the same instrument. This JP will be binding on each and every Signatory when the counterparts have been executed. In the event that any signature is delivered by facsimile transmission or by e-mail delivery of a "pdf" format data file, such signature shall create a valid and binding obligation of the party executing (or on whose behalf such signature is executed) with the same force and effect as if such facsimile or "pdf" signature page were an original thereof.

WHEREFORE, this JP has been agreed to as of the 22nd day of April, 2015, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

M. L. Mosher

Michael Mosher
Central Hudson Gas & Electric
Corporation

WHEREFORE, this JP has been agreed to as of the 22nd day of April, 2015, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

John Favreau, Assistant Counsel
Staff of the New York State Department
of Public Service
Office of General Counsel

WHEREFORE, this JP has been agreed to as of the 22nd day of April, 2015, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Michael B. Mager

Michael B. Mager, Esq.
Couch White, LLP
Counsel for Multiple Intervenors

WHEREFORE, this JP has been agreed to as of the 22nd day of April, 2015, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Usher Fogel, Esq.
Retail Energy Supply Association

WHEREFORE, this JP has been agreed to as of the 22nd day of April, 2015, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Lisa K. Perfetto, Esq.
Earthjustice
Counsel for Pace Energy and Climate Center

NOTE: Party to 14-E-0318 Only

WHEREFORE, this JP has been agreed to as of the 22nd day of April, 2015, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Christopher Forstrom

Student Worker, Columbia Environmental Law Clinic

Representing the Sabin Center for Climate Change Law

APPENDICES

Appendix A, Schedule 1

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric Income Statements
($000)

	Rate Years Ending		
	6/30/16	6/30/17	6/30/18
Operating Revenues			
Delivery Revenues - Before Increase	272,265	287,957	305,415
Rate Increase	15,346	15,987	14,100
Revenue Taxes	5,399	5,871	6,282
Other Operating Revenues	8,904	9,062	9,225
Total Operating Revenues	301,914	318,878	335,023
Operating Expenses			
Production Maintenance	245	250	255
Right of Way Maintenance - Transmission	1,711	1,771	1,833
Right of Way Maintenance - Distribution	13,097	13,555	14,029
Labor	58,381	60,686	62,720
Research and Development	2,373	1,973	1,983
Expenses Projected Based on Inflation	12,929	13,201	13,478
Informational & Institutional Advertising	586	602	617
Miscellaneous General Expenses	2,470	2,522	2,575
Transportation - Depreciation	2,225	2,348	2,486
Fringe Benefits	6,718	7,032	7,312
Other Post Employee Benefits	(2,008)	(2,008)	(2,008)
Pension Plan	12,546	12,307	12,533
Rents	1,987	2,081	2,158
Uncollectible Accounts	2,200	2,324	2,444
Regulatory General Commission Expenses	1,589	1,622	1,656
Information Technology Expense	3,437	3,509	3,583
Other Operating Insurance	674	706	740
Telephone	1,719	1,673	1,644
Legal Services	1,347	1,375	1,404
Special Services	1,056	1,078	1,101
Rate Case Expenses	286	286	286
Injuries and Damages	3,031	3,243	3,478
Major Storm Reserve	700	700	700
Non Major Storm Restoration	5,506	5,622	5,740
Environmental	169	172	291
Enhanced Powerful Opportunities Program	2,032	2,113	2,199
Low Income Bill Discount Program	863	863	863
Expenses Allocated to Affiliates	(21)	(21)	(21)
Stray Voltage Testing	725	740	756
Environmental SIR Cost	5,252	5,362	5,475
Bill Print	401	409	418
Security of Infrastructure	1,391	1,420	1,450
Productivity Imputation	(1,199)	(1,237)	(1,278)
Energy Efficiency	244	504	521
Transition to Monthly Billing	247	1,147	1,114
Common Expenses - Change in Allocation	(2,610)	(2,665)	(2,721)
Total Operating Expenses	142,299	147,266	151,814
Other Deductions			
Property Taxes	34,726	36,984	40,081
Revenue Taxes	5,399	5,871	6,282
Payroll Taxes	4,301	4,469	4,618
Other Taxes	1,815	1,853	1,892
Depreciation	35,652	39,215	41,670
Total Other Deductions	81,893	88,392	94,543
State Income Taxes	2,585	2,925	3,154
Federal Income Taxes	20,185	21,473	23,119
Total Income Taxes	22,770	24,399	26,273
Total Operating Revenue Deductions	246,962	260,056	272,630
Operating Income	$54,952	$58,821	$62,393
Rate Base	$830,092	$888,538	$948,166
Rate of Return	6.62%	6.62%	6.58%

Appendix A, Schedule 2

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Gas Income Statements
($000)

	Rate Years Ending		
	6/30/16	6/30/17	6/30/18
Operating Revenues			
Delivery Revenues - Before Increase	80,585	84,354	90,967
Rate Increase	1,827	4,633	4,379
Revenue Taxes	1,586	1,752	1,911
Interruptible Imputation	3,000	3,000	3,000
Other Operating Revenues	1,393	1,365	1,441
Total Operating Revenues	88,391	95,104	101,698
Operating Expenses			
Labor	15,789	16,407	16,955
Research and Development	397	397	397
Expenses Projected Based on Inflation	5,919	6,043	6,170
Informational & Institutional Advertising	155	160	164
Miscellaneous General Expenses	471	481	491
Transportation - Depreciation	617	651	690
Fringe Benefits	1,730	1,811	1,884
Other Post Employee Benefits (OPEB)	(523)	(523)	(523)
Pension Plan	3,130	3,065	3,133
Environmental	39	40	45
Rents	272	292	308
Uncollectible Accounts	752	784	840
Regulatory General Commission Expenses	355	362	370
Information Technology Expense	607	620	633
Other Operating Insurance	83	86	90
Telephone	293	285	279
Legal Services	179	183	187
Special Services	182	186	190
Rate Case Expenses	72	72	72
Injuries and Damages	612	652	696
Enhanced Powerful Opportunities Program	359	373	388
Low Income Bill Discount Program	986	986	986
Expenses Allocated to Affiliates	(4)	(4)	(4)
Environmental SIR Cost	926	945	965
Bill Print	71	72	74
Gas Leak Repairs - Distribution Main	1,306	1,333	1,361
Security of Infrastructure	241	246	251
Productivity Imputation	(319)	(329)	(340)
Energy Efficiency	15	31	32
Transition to Monthly Billing	64	292	284
Common Expenses - Change in Allocation	2,610	2,665	2,721
Total Operating Expenses	37,386	38,663	39,789
Other Deductions			
Property Taxes	10,966	11,679	12,657
Revenue Taxes	1,586	1,752	1,911
Payroll Taxes	1,121	1,165	1,204
Other Taxes	370	378	386
Depreciation	10,087	11,308	12,361
Total Other Deductions	24,130	26,282	28,519
State Income Taxes	1,155	1,194	1,311
Federal Income Taxes	7,918	8,828	9,674
Total Income Taxes	9,073	10,022	10,985
Total Operating Revenue Deductions	70,589	74,967	79,293
Operating Income	$17,802	$20,138	$22,405
Rate Base	$268,927	$304,190	$340,501
Rate of Return	6.62%	6.62%	6.58%

Appendix A, Schedule 3

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric Rate Base
($000)

	Rate Years Ending		
	6/30/16	6/30/17	6/30/18
Book Cost of Utility Plant	$1,374,981	$1,463,292	$1,554,464
Less: Accumulated Provision for Depreciation and Amortization	(398,476)	(419,390)	(442,734)
Net Plant	976,505	1,043,902	1,111,730
Noninterest-Bearing Construction Work in Progress	25,879	25,761	25,797
Customer Advances for Undergrounding	(553)	(553)	(553)
Deferred Charges	9,065	9,125	8,934
Accumulated Deferred Federal Taxes	(214,950)	(221,406)	(229,541)
Accumulated Deferred State Taxes	(16,946)	(18,446)	(20,044)
Working Capital	42,226	41,289	42,977
Unadjusted Rate Base	821,226	879,672	939,300
Capitalization Adjustment to Rate Base	8,866	8,866	8,866
Total	$830,092	$888,538	$948,166

Appendix A, Schedule 4

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Gas Rate Base
($000)

	Rate Years Ending		
	6/30/16	6/30/17	6/30/18
Book Cost of Utility Plant	$452,784	$497,520	$546,801
Less: Accumulated Provision for Depreciation and Amortization	(136,189)	(142,371)	(149,354)
Net Plant	316,595	355,149	397,447
Noninterest-Bearing Construction Work in Progress	14,376	15,813	15,038
Customer Advances for Undergrounding	(178)	(178)	(178)
Deferred Charges	2,445	2,434	2,371
Accumulated Deferred Federal Taxes	(71,748)	(75,550)	(80,364)
Accumulated Deferred State Taxes	(5,790)	(6,473)	(7,259)
Working Capital	10,870	10,638	11,089
Unadjusted Rate Base	266,570	301,833	338,144
Capitalization Adjustment to Rate Base	2,357	2,357	2,357
Total	$268,927	$304,190	$340,501

Net Plant Targets
($000)

Electric[1]

	RY1	RY2	RY3	
Electric Net Plant Targets[2]:				
Plant In Service	1,374,981	1,463,292	1,554,464	
Accumulated Reserve [3]	(398,476)	(419,390)	(442,734)	
Net Plant	976,505	1,043,902	1,111,730	
NIBCWIP	25,879	25,761	25,797	
Net Electric Plant Targets	1,002,384	1,069,663	1,137,527	5
Depreciation Expense Targets:				
Transportation Depreciation [4]	2,225	2,348	2,486	
Depreciation Expense [4]	35,652	39,215	41,670	
Electric Depreciation Expense Target	37,877	41,563	44,156	5

Gas[1]

	RY1	RY2	RY3	
Gas Net Plant Targets[2]:				
Plant In Service	452,784	497,520	546,801	
Accumulated Reserve [3]	(136,189)	(142,371)	(149,354)	
Net Plant	316,595	355,149	397,447	
NIBCWIP	14,376	15,813	15,038	
Net Gas Plant Targets	330,971	370,962	412,485	5
Depreciation Expense Targets:				
Transportation Depreciation [4]	617	651	690	
Depreciation Expense [4]	10,087	11,308	12,361	
Gas Depreciation Expense Target	10,704	11,959	13,051	5

[1] - Electric and Gas amounts include allocation of Common Plant.

[2] - Electric and Gas Plant, Reserves and NIBCWIP are from the respective Rate Base amounts shown on Appendix A, Schedules 3 and 4.

[3] - Includes Retirement Work-in-Progress.

[4] - Electric and Gas Depreciation are from the respective Income Statement amounts shown on Appendix A, Schedules 1 and 2.

[5] - Net Plant and Depreciation Targets.

Appendix C
Central Hudson Gas and Electric Corporation
Cases 14-E-0318;14-G-0319

Example Calculation of Revenue Requirements on Net Plant Targets
($000)

	Electric[1]			Gas[1]		
	RY1	RY2	RY3	RY1	RY2	RY3
Targets[2]:						
Net Plant & NIBCWIP	1,002,384	1,069,663	1,137,527	330,971	370,962	412,485
Depreciation Expense	37,877	41,563	44,156	10,704	11,959	13,051
Actual (For Illustrative Purposes Only):						
Total Net Plant & NIBCWIP	1,008,000	1,071,000	1,123,000	330,000	371,200	415,500
Depreciation Expense	38,000	42,000	44,000	10,700	12,000	13,200
Difference (For Illustrative Purposes Only):						
Total Net Plant & NIBCWIP	5,616	1,337	(14,527)	(971)	238	3,015
Depreciation Expense	123	437	(156)	(4)	41	149
Determination of Revenue Requirements:						
Return Component:						
Net Plant & NIBCWIP Difference	5,616	1,337	(14,527)	(971)	238	3,015
x Pre-tax WACC	9.43%	9.41%	9.37%	9.43%	9.41%	9.37%
Return Component	530	126	(1,361)	(92)	22	283
Revenue Requirement on Differences:						
Depreciation	123	437	(156)	(4)	41	149
Return Component	530	126	(1,361)	(92)	22	283
Total	653	563	(1,517)	(96)	63	432
Cumulative Revenue Requirement Impact	653	1,215	(302)	(96)	(32)	399
Amount Deferred for Customer Benefit - Smaller of Cumulative Amount at End of RY3 or $0[3]			(302)			-

[1] - Electric and Gas amounts include allocation of Common Plant
[2] - See Appendix B
[3] - Negative amounts indicate Regulatory Liabilities due to Customers.

Appendix D
Sheet 1 of 2
Central Hudson Gas & Electric Corporation
Cases 14-E-0318; 14-G-0319

The annual reports called for in item IV.A.5 of this Proposal will be comprised of the two spreadsheets in this Appendix, appropriately filled out by the Company to reflect actual and forecasted events for the preceding calendar year.

Major Capital Project Report (Projects over $1.0 Million)

		Project Expenditures ($000)										Project I/S Date		
Project Description	**Investment Category**	**Original Estimate**	**Actual to Date**	**2014 and Prior**	**2015**	**2016**	**2017**	**2018**	**2019**	**Future**	**Total**	**Original Estimate**	**Projected**	**Comments**
ELECTRIC PRODUCTION														
ELECTRIC TRANSMISSION														
ELECTRIC SUBSTATION														
DISTRIBUTION IMPROVEMENTS														
COMMON PROGRAM														

Notes:

Appendix D
Sheet 2 of 2
Central Hudson Gas & Electric Corporation
Cases 14-E-0318 and Cases 14-E-0319

20XX Construction Budget

Budget vs Actual Expenditures
Twelve Months Ended 12/31/XX
($000)

	CURRENT MONTH			YEAR TO DATE				20xx BUDGET			
	Original Budget	December Actual Expend	December % Variation (Act/Bud)	12 Months Budgeted Expend.	12 Months Actual Expend.	Variation	% Budget Expend. (Act/Bud) 12 Months	20xx 12 Months Original Budget	20xx 12 Months Adjusted Budget	12 Months Actual Expend.	% Budget Expend. (Act/Bud) 12 Months
Electric Program											
11 Hydro/Gas Turbines	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
12 Transmission	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
13 Substations	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
14 New Business	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
15 Distribution Improvements	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
16 Transformers	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
17 Meters	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
PS&I	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
Total Electric Program	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
Gas Program											
22 Transmission	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
23 Regulator Stations	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
24 New Business	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
25 Distribution Improvements	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
27 Meters	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
PS&I	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
Total Gas Program	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
Common Program											
41 Land & Structures	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
42.10 General Office Equipment	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
42.20 IT Software	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
42.22 IT Equipment/Hardware	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
42.30 EMS Hardware	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
42.35 EMS Software	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
42.40 Security Hardware	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
42.45 Security Software	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
43 Tools & Work Equipment	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
44 Communications	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
45 Transportation	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
PS&I	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
Total Common Program	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
Overheads	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
CORPORATE TOTAL	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%

Major Variation Explanations

Appendix E
Central Hudson Gas & Electric Corporation
Cases 14-E-0318 and 14-G-0319
List of Deferrals

Deferral Item	Deferral Method	Carrying Charges
Asbestos Litigation	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
Competition Education Program	Continued deferral of existing funds until funds are exhausted or until the Commission directs the funds to be used for another purpose.	Not applicable
Deferred Temporary Metro Transit Business Tax Surcharge	Deferral of difference between actual expense and amount collected	Not applicable
Deferred Unbilled Electric Revenues	Deferral of the difference between total unbilled and amount recorded in revenue	Not applicable
Deferred Unbilled Gas Revenues	Deferral of the difference between total unbilled and amount recorded in revenue	Not applicable
Deferred Vacation Pay Accrual	Adjusted annually for current accrual	Not applicable
Earnings Sharing Mechanism	As specified in the Joint Proposal	Pre-tax Authorized Rate of Return
Economic Development	Expenditures will be charged against the existing deferred balance	Not applicable
Enhanced Powerful Opportunities Program	Deferral of costs over / under rate allowance; subject to 15% cap on corporate costs over the corporate rate allowance	Pre-tax Authorized Rate of Return
Low Income Bill Discount Program	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
FAS 109	Adjusted annually for current accrual	Not applicable
Governmental Actions	Deferral of the revenue requirement effect of new governmental actions as specified in the JP	Pre-tax Authorized Rate of Return
Interest Costs on New Issuances of Long Term Debt	As specified in the Joint Proposal	Pre-tax Authorized Rate of Return
Interest Costs on Variable Rate Debt	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
NYSERDA Series B Bonds	Deferral and amortization of the costs associated with the refinancing of this Bond should it occur during the Rate Plan.	Not applicable
International Financial Reporting Standards	Deferral of costs of planning and implementation during term of the Joint Proposal	Pre-tax Authorized Rate of Return
PSC Initiated or Required Management or Operational Audit	Deferral of costs incurred during term of the Joint Proposal	Pre-tax Authorized Rate of Return
Environmental SIR Costs	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
Net Lost Revenues - Merchant Function Charge	Deferral of difference between forecasted and actual lost revenues due to migration for Non-RDM classes	Pre-tax Authorized Rate of Return
Net Plant Targets	As specified in the Joint Proposal	As specified in the JP
Nine Mile Point 2	Deferral of NEIL insurance credits and associated costs during the term of Joint Proposal.	Pre-tax Authorized Rate of Return
NYS Temporary 18-a Surcharge	Deferral of difference between actual expense and amount collected	Pre-tax Authorized Rate of Return
OPEB	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
Pension Plan	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
Property Taxes	As specified in the Joint Proposal	Pre-tax Authorized Rate of Return
PSC General Assessment	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
Purchased Electric Costs	Deferral of difference between actual expense and amount collected	Not applicable
Purchased Gas Costs	Deferral of difference between actual expense and amount collected	Not applicable
Research and Development	Deferral of costs over / under rate allowance	Not applicable
Revenue Decoupling Mechanism - Electric	Deferral of difference between revenues collected and targeted revenues	Other Customer Capital Rate
Revenue Decoupling Mechanism - Gas	Deferral of difference between actual sales and targeted sales	Other Customer Capital Rate
Right of Way Maintenance - Distribution	As specified in the Joint Proposal	Pre-tax Authorized Rate of Return
Right of Way Maintenance - Transmission	As specified in the Joint Proposal	Pre-tax Authorized Rate of Return
RPS and EEPS Surcharge	Deferral of difference between actual expense and amount collected	Not applicable
SBC Surcharge - Electric	Deferral of difference between actual expense and amount collected	Not applicable
SBC Surcharge - Gas	Deferral of difference between actual expense and amount collected	Not applicable
Stray Voltage - Testing & Non Mitigation Costs	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
Security of Infrastructure	Deferral of costs under rate allowance	Pre-tax Authorized Rate of Return
Danskammer Gas Revenues	As specified in the Joint Proposal	Pre-tax Authorized Rate of Return
NYS Income Taxes - Non-Income Based Tax Calculation	As specified in the Joint Proposal	Pre-tax Authorized Rate of Return
Revenue Requirement Impact of Bonus Depreciation	As specified in the Joint Proposal	Pre-tax Authorized Rate of Return
Asset Retirement Obligation Depreciation and Accretion Expense	Deferral of costs as specified in the Joint Proposal	Not applicable
Major Storm Reserve	As specified in the Joint Proposal and Appendix Q	Pre-tax Authorized Rate of Return
External Rate Case Expense	As specified in the Joint Proposal	Pre-tax Authorized Rate of Return
REV Demonstration Projects	As specified in the Joint Proposal	Pre-tax Authorized Rate of Return
Gas Leak Prone Pipe	As specified in the Joint Proposal	Pre-tax Authorized Rate of Return
Clean Energy Fund	As specified in the Joint Proposal	Pre-tax Authorized Rate of Return
Energy Efficiency Incentives (EEPS1 & EEPS 2)	As specified in the Joint Proposal	Pre-tax Authorized Rate of Return

Appendix F
Central Hudson Gas and Electric Corporation
Case Nos. 14-E-0318;14-G-0319

Net Deferred Accounts Available For Moderation

The following accounts are subject to offset as of July 1, 2015, with the net deferred regulatory credit available for rate moderation:

Description	Electric	Gas
Pension Over/Under Collection	X	X
Gas Deferred Balance Carrying Charges	N/A	X
Medicare Subsidy - Deferred Tax	X	X
Management Audit Carrying Charges	X	X
Newburgh Property Tax Refund	X	X
Property Taxes Over/Under Collection	X	X
Newburgh Property Tax Refund Carrying Charges	X	X
Property Taxes Carrying Charges	X	X
PSC General Assessment Over/Under Collection	X	X
PSC General Assessment Carrying Charges	X	X
Preferred Stock & Redemption Premium	X	X
Variable Rate Series G Interest Carrying Charges	X	X
SC 11 Rate Allocation - Gas	N/A	X
SC 11 Rate Allocation Carrying Charges - Gas	N/A	X
Software AG Undercollection	X	X
Variable Rate Interest Undercollection	X	X
Asbestos Litigation Costs	X	N/A
Asbestos Litigation Carrying Charges	X	N/A
Environmental SIR Costs - Carrying Charges	X	X
Software AG Undercollection Carrying Charges	X	X
MTA Surcharge March 2011 Balance	X	X
Tax Repair Refund - Cost to Achieve	X	X
Pension Reserve Carrying Charges	X	X
Research & Development	X	X
NMP2 Costs	X	N/A
NMP2 Costs Carrying Charges	X	N/A
Excess Depreciation Reserve Carrying Charges	X	N/A
Long Term Debt Interest Rate Carrying Charges	X	X
Long Term Debt Interest Rate Overcollection	X	X
Service Quality Incentive/ Dig-In Penalty - Gas	N/A	X
Compliance Metric NRA - Gas	N/A	X
Mismarks CY 2014 NRA - Gas	N/A	X
Revenue Requirement of Sag Mitigation Overcollection	X	N/A
Rate Base Impact of Repair Project	X	X
Rate Base Impact of Repair Project Carrying Charges	X	N/A
Sag Mitigation Capital Projects Carrying Charges	X	N/A
Federal Income Tax Research Credit	X	X
Variable Rate Interest Overcollection	X	X
Variable Rate Interest Carrying Charges	X	X
OPEB Medicare Subsidy Over/Under	X	X
OPEB Over/Under Collection	X	X
OPEB Reserve Carrying Charges	X	X
Shared Earnings - Gas	N/A	X
Shared Earnings Carrying Charges - Gas	N/A	X
Depreciation Expense Target Shortfall	X	N/A
Net Plant Target Shortfall	X	N/A
PBA's from Fortis	X	X
PBA's from Fortis Carrying Charges	X	X
Synergies Savings	X	X
Stray Voltage Overcollection	X	N/A
Stray Voltage Overcollection Carrying Charges	X	N/A
Statutory Rate Adjustment - (Federal Tax only)	X	X

This listing of accounts is presented without prejudice with respect to any error or omission and the Company or Staff reserves the right to revise this listing, which will be subject to Staff review and approval.

Revenue Matching Factors

	Rate Year #1	Rate Year #2	Rate Year #3
ELECTRIC:			
Research & Development:			
Rate Allowance ($000)	$2,373	$1,973	$1,983
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	4,939,743	4,939,833	4,964,453
Revenue Matching Factor - $/kWh	$0.000480	$0.000399	$0.000399
Pension Plan:			
Rate Allowance ($000)	$12,546	$12,307	$12,533
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	4,939,743	4,939,833	4,964,453
Revenue Matching Factor - $/kWh	$0.002540	$0.002491	$0.002525
OPEB - Excluding Medicare Subsidy			
Rate Allowance ($000)	($2,399)	($2,399)	($2,399)
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	4,939,743	4,939,833	4,964,453
Revenue Matching Factor - $/kWh	($0.000486)	($0.000486)	($0.000483)
OPEB - Medicare Subsidy			
Rate Allowance ($000)	$391	$391	$391
SC 1, 2, 3, 5, 6, 8, 9, 12 & 13 Sales (mWh)	4,939,743	4,939,833	4,964,453
Revenue Matching Factor - $/kWh	$0.000079	$0.000079	$0.000079

	Rate Year #1	Rate Year #2	Rate Year #3
GAS:			
Research & Development:			
Rate Allowance ($000)	$397	$397	$397
SC 1, 2, 6, 12 & 13 Sales (Mcf)	12,097,537	12,475,310	12,830,686
Revenue Matching Factor - $/Mcf	$0.032817	$0.031823	$0.030941
Pension Plan:			
Rate Allowance ($000)	$3,130	$3,065	$3,133
SC 1, 2, 6, 12 & 13 Sales (Mcf)	12,097,537	12,475,310	12,830,686
Revenue Matching Factor - $/Mcf	$0.258730	$0.245685	$0.244180
OPEB - Excluding Medicare Subsidy			
Rate Allowance ($000)	($625)	($625)	($625)
SC 1, 2, 6, 12 & 13 Sales (Mcf)	12,097,537	12,475,310	12,830,686
Revenue Matching Factor - $/Mcf	($0.051663)	($0.050099)	($0.048711)
OPEB - Medicare Subsidy			
Rate Allowance ($000)	$102	$102	$102
SC 1, 2, 6, 12 & 13 Sales (Mcf)	12,097,537	12,475,310	12,830,686
Revenue Matching Factor - $/Mcf	$0.008431	$0.008176	$0.007950

Appendix H, Schedule 1
Central Hudson Gas and Electric Corporation
Cases 14-E-0318 & 14-G-0319

Capital Structure and Allowed Rate of Return

Rate Year 1:	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$ 604,367	51.4%	4.45%	2.29%	2.29%
Customer Deposits	7,000	0.6%	1.15%	0.01%	0.01%
Common Equity	564,254	48.0%	9.00%	4.32%	7.13%
	$1,175,621	100.0%		6.62%	9.43%

Rate Year 2:	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$ 658,950	51.4%	4.45%	2.29%	2.29%
Customer Deposits	7,000	0.5%	1.15%	0.01%	0.01%
Common Equity	615,325	48.0%	9.00%	4.32%	7.11%
	$1,281,275	99.9%		6.62%	9.41%

Rate Year 3:	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$ 721,950	51.5%	4.36%	2.25%	2.25%
Customer Deposits	7,000	0.5%	1.15%	0.01%	0.01%
Common Equity	674,150	48.0%	9.00%	4.32%	7.11%
	$1,403,100	100.0%		6.58%	9.37%

Appendix H, Schedule 2
Sheet 1 of 3
Central Hudson Gas and Electric Corporation
Average Cost of Long Term Debt
Cases 14-E-0318;14-G-0319

For the Rate Year Ending June 30, 2016($000)

Outstanding Issues	Maturity Date	Interest Rate %	Principal Amount Outstanding 6/30/2015	Charges During Rate Year	Months Outstanding	Average Amount Outstanding During Rate Year	Interest Expense During Rate Year
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1999 NYSERDA Series B Variable	07/01/34	0.09	33,700	-	12	33,700	31
2004 MTN Series E @ 5.05%	11/04/19	5.05	27,000	-	12	27,000	1,364
2005 MTN Series E @ 5.84%	12/05/35	5.84	24,000	-	12	24,000	1,402
2006 MTN Series E @ 5.76%	11/17/31	5.76	27,000	-	12	27,000	1,555
2007 MTN Series F @ 5.80%	03/23/37	5.80	33,000	-	12	33,000	1,915
2007 MTN Series F @ 6.03%	09/19/17	6.03	33,000	-	12	33,000	1,989
2009 MTN Series F @ 5.80%	11/01/39	5.80	24,000	-	12	24,000	1,392
2010 MTN Series G @ 2.756%	04/01/16	2.76	8,000	(8,000)	9	6,000	165
2010 MTN Series G @ 4.15%	04/01/21	4.15	44,150	-	12	44,150	1,832
2010 MTN Series G @ 5.716%	04/01/41	5.72	30,000	-	12	30,000	1,715
2011 MTN Series G @ 3.378%	04/01/22	3.38	23,400	-	12	23,400	790
2011 MTN Series G @ 4.707%	04/01/42	4.71	10,000	-	12	10,000	471
2012 MTN Series G @ 4.776%	04/01/42	4.78	48,000	-	12	48,000	2,292
2012 MTN Series G @ 4.065%	10/01/42	4.07	24,000	-	12	24,000	976
2010 Senior Note Series A @ 4.30%	09/21/20	4.30	16,000	-	12	16,000	688
2010 Senior Note Series B @ 5.64%	09/21/40	5.64	24,000	-	12	24,000	1,354
2013 Senior Note Series C @ 2.45%	11/01/18	2.45	30,000	-	12	30,000	735
2013 Senior Note Series D @ 4.09%	12/02/28	4.09	16,700	-	12	16,700	683
2014 Series E Variable	03/26/24	1.24	30,000	-	12	30,000	372
2015 New Issuance (January 2015)	01/01/35	4.24	47,000	-	12	47,000	1,993
2015 New Issuance (June 2015)	06/01/35	4.24	24,000	-	12	24,000	1,018
2015 New Issuance (Dec 2015)	12/02/35	4.24	-	14,000	7	8,167	346
2016 New Issuance (Jan 2016)	01/01/36	4.24	-	20,000	6	10,000	424
2016 New Issuance (April 2016)	04/01/36	4.24	-	45,000	3	11,250	477
Average Long Term Debt Outstanding			576,950	71,000		$ 604,367	
Interest Charges for the Rate Year							$ 25,978
Plus: Amortization of Debt Discount and Expense							898
Less: Amortization of Premium on Debt							-
Total Cost of Debt Amount							$ 26,877
% of Average Long Term Debt Outstanding							4.45%

Central Hudson Gas and Electric Corporation
Cases 14-E-0318;14-G-0319

Average Cost of Long Term Debt
For the Rate Year Ending June 30, 2017($000)

Outstanding Issues	Maturity Date	Interest Rate %	Principal Amount Outstanding 6/30/2016	Charges During Rate Year	Months Outstanding	Average Amount Outstanding During Rate Year	Interest Expense During Rate Year
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1999 NYSERDA Series B Variable	07/01/34	0.09	33,700	-	12	33,700	31
2004 MTN Series E @ 5.05%	11/04/19	5.05	27,000	-	12	27,000	1,364
2005 MTN Series E @ 5.84%	12/05/35	5.84	24,000	-	12	24,000	1,402
2006 MTN Series E @ 5.76%	11/17/31	5.76	27,000	-	12	27,000	1,555
2007 MTN Series F @ 5.80%	03/23/37	5.80	33,000	-	12	33,000	1,915
2007 MTN Series F @ 6.03%	09/19/17	6.03	33,000	-	12	33,000	1,989
2009 MTN Series F @ 5.80%	11/01/39	5.80	24,000	-	12	24,000	1,392
2010 MTN Series G @ 4.15%	04/01/21	4.15	44,150	-	12	44,150	1,832
2010 MTN Series G @ 5.716%	04/01/41	5.72	30,000	-	12	30,000	1,715
2011 MTN Series G @ 3.378%	04/01/22	3.38	23,400	-	12	23,400	790
2011 MTN Series G @ 4.707%	04/01/42	4.71	10,000	-	12	10,000	471
2012 MTN Series G @ 4.776%	04/01/42	4.78	48,000	-	12	48,000	2,292
2012 MTN Series G @ 4.065%	10/01/42	4.07	24,000	-	12	24,000	976
2010 Senior Note Series A @ 4.30%	09/21/20	4.30	16,000	-	12	16,000	688
2010 Senior Note Series B @ 5.64%	09/21/40	5.64	24,000	-	12	24,000	1,354
2013 Senior Note Series C @ 2.45%	11/01/18	2.45	30,000	-	12	30,000	735
2013 Senior Note Series D @ 4.09%	12/02/28	4.09	16,700	-	12	16,700	683
2014 Series E Variable	03/26/24	1.24	30,000	-	12	30,000	372
2015 New Issuance (January 2015)	01/01/25	4.24	47,000	-	12	47,000	1,993
2015 New Issuance (June 2015)	06/01/35	4.24	24,000	-	12	24,000	1,018
2015 New Issuance (Dec 2015)	12/01/35	4.24	14,000	-	12	14,000	594
2016 New Issuance (Jan 2016)	01/01/36	4.24	20,000	-	12	20,000	848
2016 New Issuance (April 2016)	04/01/36	4.24	45,000	-	12	45,000	1,908
2016 New Issuance (Dec 2016)	12/01/36	4.24	-	6,000	7	3,500	148
2017 New Issuance (Mar 2017)	03/01/37	4.24	-	10,000	4	3,333	141
2017 New Issuance (June 2017)	06/01/37	4.24	-	50,000	1	4,167	177
Average Long Term Debt Outstanding			647,950	66,000		$ 658,950	
Interest Charges for the Rate Year							$ 28,382
Plus: Amortization of Debt Discount and Expense							915
Less: Amortization of Premium on Debt							-
Total Cost of Debt Amount							$ 29,296
% of Average Long Term Debt Outstanding							4.45%

Central Hudson Gas and Electric Corporation
Cases 14-E-0318;14-G-0319

Average Cost of Long Term Debt
For the Rate Year Ending June 30, 2018($000)

Outstanding Issues	Maturity Date	Interest Rate %	Principal Amount Outstanding 6/30/2017	Charges During Rate Year	Outstanding	Average Amount Outstanding During Rate Year	Interest Expense During Rate Year
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1999 NYSERDA Series B Variable	07/01/34	0.09	33,700	-	12	33,700	31
2004 MTN Series E @ 5.05%	11/04/19	5.05	27,000	-	12	27,000	1,364
2005 MTN Series E @ 5.84%	12/05/35	5.84	24,000	-	12	24,000	1,402
2006 MTN Series E @ 5.76%	11/17/31	5.76	27,000	-	12	27,000	1,555
2007 MTN Series F @ 5.80%	03/23/37	5.80	33,000	-	12	33,000	1,915
2007 MTN Series F @ 6.03%	09/19/17	6.03	33,000	(33,000)	3	6,875	414
2009 MTN Series F @ 5.80%	11/01/39	5.80	24,000	-	12	24,000	1,392
2010 MTN Series G @ 4.15%	04/01/21	4.15	44,150	-	12	44,150	1,832
2010 MTN Series G @ 5.716%	04/01/41	5.72	30,000	-	12	30,000	1,715
2011 MTN Series G @ 3.378%	04/01/22	3.38	23,400	-	12	23,400	790
2011 MTN Series G @ 4.707%	04/01/42	4.71	10,000	-	12	10,000	471
2012 MTN Series G @ 4.776%	04/01/42	4.78	48,000	-	12	48,000	2,292
2012 MTN Series G @ 4.065%	10/01/42	4.07	24,000	-	12	24,000	976
2010 Senior Note Series A @ 4.30%	09/21/20	4.30	16,000	-	12	16,000	688
2010 Senior Note Series B @ 5.64%	09/21/40	5.64	24,000	-	12	24,000	1,354
2013 Senior Note Series C @ 2.45%	11/01/18	2.45	30,000	-	12	30,000	735
2013 Senior Note Series D @ 4.09%	12/02/28	4.09	16,700	-	12	16,700	683
2014 Series E Variable	03/26/24	1.24	30,000	-	12	30,000	372
2015 New Issuance (January 2015)	01/01/25	4.24	47,000	-	12	47,000	1,993
2015 New Issuance (June 2015)	06/01/35	4.24	24,000	-	12	24,000	1,018
2015 New Issuance (Dec 2015)	12/01/35	4.24	14,000	-	12	14,000	594
2016 New Issuance (Jan 2016)	01/01/36	4.24	20,000	-	12	20,000	848
2016 New Issuance (April 2016)	04/01/36	4.24	45,000	-	12	45,000	1,908
2016 New Issuance (Dec 2016)	12/01/36	4.24	6,000	-	12	6,000	254
2017 New Issuance (March 2017)	03/01/37	4.24	10,000	-	12	10,000	424
2017 New Issuance (June 2017)	06/01/37	4.24	50,000	-	12	50,000	2,120
2017 New Issuance (December 2017)	12/01/37	4.24	-	36,000	7	21,000	890
2018 New Issuance (Mar 2018)	03/15/38	4.24	-	45,000	4	13,125	557
Average Long Term Debt Outstanding			713,950	48,000		$ 721,950	
Interest Charges for the Rate Year							$ 30,586
Plus: Amortization of Debt Discount and Expense							911
Less: Amortization of Premium on Debt							-
Total Cost of Debt Amount							$ 31,497
% of Average Long Term Debt Outstanding							4.36%

Appendix H, Schedule 3

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric and Gas Basis Point Values

Basis Point Values:	Electric		
	RY1	**RY2**	**RY3**
Rate Base ($000)	$830,092	$888,538	$948,166
x Equity Ratio	48%	48%	48%
Equity component of Rate Base ($000)	$398,444	$426,498	$455,120
x 1 BP	0.01%	0.01%	0.01%
After-tax value of 1 BP - whole dollars	$39,800	$42,600	$45,500
Pre-tax value of 1 BP - whole dollars	$65,700	$70,100	$74,900

Basis Point Values:	Gas		
	RY1	**RY2**	**RY3**
Rate Base ($000)	$268,927	$304,190	$340,501
x Equity Ratio	48%	48%	48%
Equity component of Rate Base ($000)	$129,085	$146,011	$163,440
x 1 BP	0.01%	0.01%	0.01%
After-tax value of 1 BP - whole dollars	$12,900	$14,600	$16,300
Pre-tax value of 1 BP - whole dollars	$21,300	$24,000	$26,800

Central Hudson Gas and Electric Corporation
Cases 14-E-0318;14-G-0319

Summary of Electric Sales (MWh) by Service Classification

		Twelve Months Ended June 30, 2016	Twelve Months Ended June 30, 2017	Twelve Months Ended June 30, 2018
Service Classification No. 1				
	Heating	324,260	328,558	331,959
	EEPS Lost MWh	(24,976)	(27,583)	(29,715)
	Nonheating	1,866,493	1,898,702	1,929,021
	EEPS Lost MWh	(139,219)	(154,744)	(170,636)
	PV Lost MWh	(20,618)	(27,659)	(35,661)
	Unbilled	-	-	-
		2,005,940	2,017,274	2,024,968
Service Classification No. 2				
	Nondemand	176,456	178,089	179,375
	EEPS Lost MWh	(15,325)	(15,324)	(15,323)
	Primary	231,103	230,416	231,706
	EEPS Lost MWh	(20,113)	(20,113)	(20,113)
	Secondary	1,501,320	1,490,160	1,503,020
	EEPS Lost MWh	(132,160)	(132,162)	(132,162)
	PV Lost MWh	(17,692)	(17,692)	(17,692)
	Unbilled			
		1,723,589	1,713,375	1,728,811
Service Classification No. 3		296,100	295,070	296,560
	EEPS Lost MWh	(25,806)	(25,806)	(25,806)
		270,294	269,264	270,754
Service Classification No. 5		12,560	12,560	12,560
Service Classification No. 6		20,000	20,000	20,000
Service Classification No. 8		21,820	21,820	21,820
Service Classification No. 9		2,540	2,540	2,540
Service Classification No. 13				
	Transmission	752,830	752,830	752,830
	Substation	130,170	130,170	130,170
		883,000	883,000	883,000
Interdepartmental		950	950	950
Total Own Territory		4,940,693	4,940,783	4,965,403

Appendix I Sheet 2 of 20

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Summary of Electric Base Delivery Revenues by Service Classification

		Twelve Months Ended June 30, 2016	Twelve Months Ended June 30, 2017	Twelve Months Ended June 30, 2018
Service Classification No. 1				
	Heating	$ 26,164,940	$ 28,119,680	$ 29,850,310
	EEPS Lost Revenue	$ (1,355,920)	$ (1,617,880)	$ (1,883,110)
	Nonheating	$ 175,323,530	$ 188,154,140	$ 199,861,330
	EEPS Lost Revenue	$ (7,560,720)	$ (9,073,220)	$ (10,662,420)
	PV Lost Revenue	$ (1,155,620)	$ (1,718,700)	$ (2,343,970)
	Unbilled	$ 42,660	$ 42,650	$ 42,660
		$ 191,458,870	$ 203,906,670	$ 214,864,800
Service Classification No. 2				
	Nondemand	$ 15,576,380	$ 16,903,140	$ 18,151,120
	EEPS Lost Revenue	$ (185,460)	$ (199,070)	$ (206,230)
	Primary	$ 5,324,889	$ 5,418,670	$ 5,785,159
	EEPS Lost Revenue	$ (401,260)	$ (421,970)	$ (439,850)
	Secondary	$ 60,560,190	$ 62,104,360	$ 64,374,630
	EEPS Lost Revenue	$ (4,284,500)	$ (4,452,590)	$ (4,597,090)
	PV Lost Revenue	$ (1,665,290)	$ (1,746,720)	$ (1,798,390)
	Unbilled	$ (640)	$ (650)	$ (640)
		$ 74,924,309	$ 77,605,170	$ 81,268,709
Service Classification No. 3		$ 6,684,200	$ 6,969,705	$ 7,275,180
	EEPS Lost Revenue	$ (549,660)	$ (575,330)	$ (597,370)
		$ 6,134,540	$ 6,394,375	$ 6,677,810
Service Classification No. 5		$ 1,555,730	$ 1,689,530	$ 1,808,690
Service Classification No. 6		$ 1,394,400	$ 1,437,320	$ 1,474,000
Service Classification No. 8		$ 5,087,510	$ 5,287,630	$ 5,473,030
Service Classification No. 9		$ 184,050	$ 195,310	$ 205,480
Service Classification No. 13				
	Transmission	$ 5,151,290	$ 5,469,760	$ 5,748,040
	Substation	$ 1,868,170	$ 1,981,930	$ 2,082,510
		$ 7,019,460	$ 7,451,690	$ 7,830,550
Interdepartmental		$ 10,180	$ 10,180	$ 10,180
Total Own Territory		$ 287,769,049	$ 303,977,875	$ 319,613,249

Summary of Electric Customers by Service Classification

	Twelve Months Ended June 30, 2016	Twelve Months Ended June 30, 2017	Twelve Months Ended June 30, 2018
Service Classification No. 1			
Heating	26,309	26,346	26,380
Nonheating	228,312	228,744	229,125
Unbilled	-	-	-
	254,621	255,089	255,506
Service Classification No. 2			
Nondemand	29,477	29,654	29,805
Primary	163	163	165
Secondary	11,711	11,725	11,912
Unbilled	-	-	-
	41,350	41,543	41,881
Service Classification No. 3	32	33	33
Service Classification No. 5	4,133	4,084	4,035
Service Classification No. 6	1,150	1,150	1,150
Service Classification No. 8	209	209	209
Service Classification No. 9	226	221	217
Service Classification No. 13			
Transmission	6	6	6
Substation	6	6	6
	12	12	12
Interdepartmental	1	1	1
Total Own Territory	301,735	302,341	303,043

Summary of Electric Demand Determinants by Service Classification

	Twelve Months Ended June 30, 2016	Twelve Months Ended June 30, 2017	Twelve Months Ended June 30, 2018
Service Classification No. 2			
Primary kW	610,000	590,000	610,000
EEPS Lost kW	(52,110)	(52,110)	(52,110)
Secondary kW	4,729,890	4,694,180	4,735,220
EEPS Lost kW	(416,121)	(416,121)	(416,121)
PV Lost kW	(182,659)	(182,659)	(182,659)
	4,689,000	4,633,290	4,694,330
Service Classification No. 3 kW	666,101	663,789	667,140
EEPS Lost kW	(59,640)	(59,640)	(59,640)
	606,461	604,149	607,500
Service Classification No. 13			
Transmission kw	1,242,911	1,242,911	1,242,911
Substation kW	234,877	234,877	234,877
	1,477,788	1,477,788	1,477,788
Total kW	6,773,249	6,715,227	6,779,618
Service Classification No. 3 RkVa	141,876	141,385	142,166
EEPS Lost RkVa	(12,643)	(12,643)	(12,643)
	129,233	128,742	129,523
Service Classification No. 13 RkVa			
Transmission RkVa	50,700	50,700	50,700
Substation RkVa	59,860	59,860	59,860
	110,560	110,560	110,560
Total RkVa	239,793	239,302	240,083

Central Hudson Gas and Electric Corporation
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Summary of Electric Sales (MWh) by Service ClassificationRate Year 1 (Twelve Months Ended June 30, 2016)

	July 2015	August 2015	September 2015	October 2015	November 2015	December 2015	January 2016	February 2016	March 2016	April 2016	May 2016	June 2016	Total
Service Classification No. 1													
Heating	18,438	19,152	19,327	16,904	20,370	29,377	40,834	44,100	42,576	31,258	24,311	17,613	324,260
EEPS Lost MWh	(1,335)	(1,397)	(1,390)	(1,233)	(1,471)	(2,140)	(3,254)	(3,525)	(3,395)	(2,495)	(1,934)	(1,407)	(24,976)
Nonheating	164,708	188,953	177,869	147,950	134,224	147,332	166,380	166,910	154,599	143,924	133,651	139,993	1,866,493
EEPS Lost MWh	(11,737)	(13,453)	(12,666)	(10,528)	(9,546)	(10,483)	(13,017)	(13,053)	(12,093)	(11,256)	(10,446)	(10,941)	(139,219)
PV Lost MWh	(1,500)	(1,549)	(1,545)	(1,648)	(1,643)	(1,751)	(1,739)	(1,673)	(1,843)	(1,834)	(1,951)	(1,942)	(20,618)
	168,574	191,706	181,595	151,445	141,934	162,335	189,204	192,759	179,844	159,597	143,631	143,316	2,005,940
Service Classification No. 2													
Nondemand	13,671	15,950	14,089	13,836	12,256	15,109	15,921	18,026	15,288	15,037	12,980	14,293	176,456
EEPS Lost MWh	(1,109)	(1,281)	(1,128)	(1,118)	(980)	(1,225)	(1,507)	(1,660)	(1,423)	(1,389)	(1,189)	(1,316)	(15,325)
Primary	20,748	19,665	19,602	19,676	18,482	19,248	19,998	18,780	19,060	17,825	18,687	19,332	231,103
EEPS Lost MWh	(1,678)	(1,611)	(1,585)	(1,584)	(1,490)	(1,559)	(1,855)	(1,764)	(1,789)	(1,674)	(1,744)	(1,778)	(20,113)
Secondary	141,650	140,060	132,720	118,250	111,990	122,760	132,220	125,340	118,620	112,780	116,980	127,950	1,501,320
EEPS Lost MWh	(11,604)	(11,541)	(10,879)	(9,670)	(9,179)	(10,049)	(12,427)	(11,864)	(11,219)	(10,671)	(11,058)	(12,000)	(132,160)
PV Lost MWh	(1,232)	(1,272)	(1,269)	(1,354)	(1,350)	(1,438)	(1,548)	(1,490)	(1,640)	(1,633)	(1,737)	(1,729)	(17,692)
	160,446	159,970	151,549	138,036	129,729	142,846	150,801	145,368	136,897	130,274	132,920	144,751	1,723,589
Service Classification No. 3	27,003	26,316	24,144	24,673	23,091	26,052	25,094	23,041	23,937	22,964	24,675	25,110	296,100
EEPS Lost MWh	(2,186)	(2,162)	(1,959)	(1,989)	(1,872)	(2,113)	(2,328)	(2,169)	(2,250)	(2,161)	(2,308)	(2,309)	(25,806)
	24,817	24,154	22,185	22,684	21,219	23,939	22,766	20,872	21,687	20,803	22,367	22,801	270,294
Service Classification No. 5	820	910	1,010	1,170	1,260	1,390	1,310	1,100	1,060	940	840	750	12,560
Service Classification No. 6													
Heating	450	630	360	540	450	900	1,080	1,350	1,170	900	630	540	9,000
Nonheating	1,100	1,100	1,100	770	660	770	1,100	990	990	880	770	770	11,000
	1,550	1,730	1,460	1,310	1,110	1,670	2,180	2,340	2,160	1,780	1,400	1,310	20,000
Service Classification No. 8	1,430	1,590	1,760	2,030	2,190	2,410	2,280	1,900	1,840	1,630	1,460	1,300	21,820
Service Classification No. 9	220	220	210	210	210	210	210	210	210	210	210	210	2,540
Service Classification No. 13													
Transmission	72,260	69,270	63,690	64,810	59,700	59,050	57,200	52,530	58,340	61,780	67,080	67,120	752,830
Substation	13,530	12,970	10,870	10,080	9,450	9,650	10,060	9,320	10,090	10,050	11,470	12,630	130,170
	85,790	82,240	74,560	74,890	69,150	68,700	67,260	61,850	68,430	71,830	78,550	79,750	883,000
Interdepartmental	80	90	90	70	80	80	80	90	80	70	70	70	950
Total	443,727	462,610	434,419	391,845	366,882	403,580	436,091	426,489	412,208	387,134	381,448	394,258	4,940,693

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Summary of Electric Base Delivery Revenues (Excluding Revenue Tax) by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2016)

	July 2015	August 2015	September 2015	October 2015	November 2015	December 2015	January 2016	February 2016	March 2016	April 2016	May 2016	June 2016	Total
Service Classification No. 1													
Heating	$ 1,730,020	$ 1,764,110	$ 1,775,260	$ 1,608,870	$ 1,830,490	$ 2,286,350	$ 2,949,360	$ 3,085,910	$ 3,049,110	$ 2,388,780	$ 2,048,670	$ 1,648,010	$ 26,164,940
EEPS Lost Revenue	$ (72,710)	$ (75,700)	$ (75,800)	$ (66,790)	$ (79,990)	$ (116,020)	$ (176,800)	$ (191,570)	$ (184,240)	$ (135,100)	$ (104,960)	$ (76,240)	$ (1,355,920)
Nonheating	$ 15,083,150	$ 16,424,480	$ 15,783,670	$ 14,205,970	$ 13,422,540	$ 14,192,450	$ 15,226,330	$ 15,228,990	$ 14,585,050	$ 13,995,140	$ 13,392,160	$ 13,783,600	$ 175,323,530
EEPS Lost Revenue	$ (636,940)	$ (730,870)	$ (687,990)	$ (571,770)	$ (518,560)	$ (569,600)	$ (707,050)	$ (708,780)	$ (656,650)	$ (611,140)	$ (567,220)	$ (594,150)	$ (7,560,720)
PV Lost Revenue	$ (84,060)	$ (86,800)	$ (86,610)	$ (92,360)	$ (92,100)	$ (98,130)	$ (97,470)	$ (93,780)	$ (103,280)	$ (102,820)	$ (109,380)	$ (108,830)	$ (1,155,620)
Unbilled	$ (138,160)	$ 440,480	$ 461,160	$ 76,310	$ 106,050	$ (202,560)	$ 103,910	$ 180,820	$ (521,000)	$ 108,840	$ (444,220)	$ (128,970)	$ 42,660
	$ 15,881,300	$ 17,735,700	$ 17,169,690	$ 15,160,230	$ 14,668,430	$ 15,492,490	$ 17,298,280	$ 17,501,590	$ 16,168,990	$ 15,643,700	$ 14,215,050	$ 14,523,420	$ 191,458,870
Service Classification No. 2													
Nondemand	$ 1,237,610	$ 1,355,150	$ 1,245,100	$ 1,330,470	$ 1,222,370	$ 1,347,390	$ 1,269,000	$ 1,382,650	$ 1,263,730	$ 1,347,760	$ 1,234,140	$ 1,341,010	$ 15,576,380
EEPS Lost Revenue	$ (13,410)	$ (15,520)	$ (13,660)	$ (13,530)	$ (11,870)	$ (14,830)	$ (18,230)	$ (20,090)	$ (17,220)	$ (16,820)	$ (14,360)	$ (15,920)	$ (185,460)
Primary	$ 511,790	$ 437,780	$ 439,440	$ 439,250	$ 435,970	$ 437,080	$ 368,297	$ 435,994	$ 437,933	$ 435,669	$ 436,709	$ 508,977	$ 5,324,889
EEPS Lost Revenue	$ (36,860)	$ (31,450)	$ (31,050)	$ (30,940)	$ (30,670)	$ (30,970)	$ (31,870)	$ (32,690)	$ (34,290)	$ (35,000)	$ (36,880)	$ (38,590)	$ (401,260)
Secondary	$ 5,617,510	$ 5,324,820	$ 5,319,010	$ 5,182,740	$ 4,735,090	$ 4,820,770	$ 4,959,040	$ 4,762,770	$ 4,778,520	$ 4,763,190	$ 4,960,680	$ 5,336,050	$ 60,560,190
EEPS Lost Revenue	$ (378,890)	$ (358,370)	$ (355,270)	$ (343,080)	$ (307,670)	$ (311,780)	$ (372,010)	$ (359,310)	$ (356,790)	$ (357,700)	$ (375,740)	$ (407,890)	$ (4,284,500)
PV Lost Revenue	$ (115,940)	$ (119,730)	$ (119,480)	$ (127,400)	$ (127,050)	$ (135,380)	$ (145,740)	$ (140,210)	$ (154,390)	$ (153,730)	$ (163,520)	$ (162,720)	$ (1,665,290)
Unbilled	$ 44,400	$ (47,720)	$ 51,260	$ (50,300)	$ 50,400	$ (52,970)	$ 50,510	$ (46,330)	$ 47,400	$ (42,150)	$ 46,650	$ (51,790)	$ (640)
	$ 6,866,210	$ 6,544,960	$ 6,535,350	$ 6,387,210	$ 5,966,570	$ 6,059,310	$ 6,078,997	$ 5,982,784	$ 5,964,893	$ 5,941,219	$ 6,087,679	$ 6,509,127	$ 74,924,309
Service Classification No. 3	$ 599,840	$ 578,790	$ 574,540	$ 550,880	$ 521,940	$ 602,120	$ 544,350	$ 494,760	$ 506,000	$ 528,670	$ 583,100	$ 599,210	$ 6,684,200
EEPS Lost Revenue	$ (46,140)	$ (45,140)	$ (44,170)	$ (41,870)	$ (39,930)	$ (46,360)	$ (47,580)	$ (43,430)	$ (44,290)	$ (46,710)	$ (51,690)	$ (52,350)	$ (549,660)
	$ 553,700	$ 533,650	$ 530,370	$ 509,010	$ 482,010	$ 555,760	$ 496,770	$ 451,330	$ 461,710	$ 481,960	$ 531,410	$ 546,860	$ 6,134,540
Service Classification No. 5	$ 127,640	$ 128,580	$ 129,620	$ 131,300	$ 132,240	$ 133,600	$ 132,030	$ 129,840	$ 129,420	$ 128,160	$ 127,120	$ 126,180	$ 1,555,730
Service Classification No. 6	$ 110,170	$ 119,600	$ 105,760	$ 99,020	$ 88,610	$ 116,680	$ 141,060	$ 149,510	$ 140,080	$ 122,060	$ 102,830	$ 99,020	$ 1,394,400
Service Classification No. 8	$ 424,960	$ 425,010	$ 425,060	$ 425,140	$ 425,190	$ 425,250	$ 424,310	$ 424,200	$ 422,180	$ 422,120	$ 422,070	$ 422,020	$ 5,087,510
Service Classification No. 9	$ 15,720	$ 15,660	$ 15,570	$ 15,500	$ 15,440	$ 15,380	$ 15,310	$ 15,220	$ 15,160	$ 15,090	$ 15,030	$ 14,970	$ 184,050
Service Classification No. 13													
Transmission	$ 481,520	$ 458,130	$ 481,240	$ 442,530	$ 416,050	$ 402,240	$ 370,610	$ 365,000	$ 388,400	$ 429,990	$ 454,410	$ 461,170	$ 5,151,290
Substation	$ 183,080	$ 178,150	$ 167,980	$ 143,900	$ 131,410	$ 130,930	$ 143,010	$ 139,310	$ 144,290	$ 158,290	$ 169,050	$ 178,770	$ 1,868,170
	$ 664,600	$ 636,280	$ 649,220	$ 586,430	$ 547,460	$ 533,170	$ 513,620	$ 504,310	$ 532,690	$ 588,280	$ 623,460	$ 639,940	$ 7,019,460
Interdepartmental	$ 860	$ 960	$ 960	$ 750	$ 860	$ 860	$ 860	$ 960	$ 860	$ 750	$ 750	$ 750	$ 10,180
Total Base Revenue	$ 24,645,160	$ 26,140,400	$ 25,561,600	$ 23,314,590	$ 22,326,810	$ 23,332,500	$ 25,101,237	$ 25,159,744	$ 23,835,983	$ 23,343,339	$ 22,125,399	$ 22,882,287	$ 287,769,049
Total Base Revenue Excluding Unbilled	$ 24,738,920	$ 25,747,640	$ 25,049,180	$ 23,288,580	$ 22,170,360	$ 23,588,030	$ 24,946,817	$ 25,025,254	$ 24,309,583	$ 23,276,649	$ 22,522,969	$ 23,063,047	$ 287,727,029

Central Hudson Gas and Electric Corporation
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Summary of Electric Customers by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2016)

	July 2015	August 2015	September 2015	October 2015	November 2015	December 2015	January 2016	February 2016	March 2016	April 2016	May 2016	June 2016	Average
Service Classification No. 1													
Heating	26,993	25,582	26,885	25,591	26,829	25,600	27,114	25,603	27,305	25,609	26,983	25,615	26,309
Nonheating	227,387	228,308	226,866	228,602	227,194	229,345	229,330	228,363	229,271	228,893	227,220	228,965	228,312
	254,380	253,890	253,751	254,193	254,023	254,945	256,444	253,966	256,576	254,502	254,203	254,580	254,621
Service Classification No. 2													
Nondemand	28,216	30,583	28,280	30,606	28,266	30,647	28,325	30,646	28,388	30,679	28,343	30,739	29,477
Primary	164	159	163	162	160	160	168	162	167	163	162	164	163
Secondary	11,752	11,558	11,674	11,699	11,622	11,987	11,858	11,454	11,921	11,643	11,676	11,686	11,711
	40,132	42,300	40,117	42,467	40,048	42,794	40,351	42,262	40,476	42,485	40,181	42,589	41,350
Service Classification No. 3	32	31	32	32	31	33	32	32	34	33	33	33	32
Service Classification No. 5	4,221	4,116	4,180	4,127	4,142	4,174	4,037	4,017	4,142	4,161	4,068	4,213	4,133
Service Classification No. 6													
Heating	370	460	370	460	370	460	370	460	370	460	370	460	415
Nonheating	770	700	770	700	770	700	770	700	770	700	770	700	735
Service Classification No. 6	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,150
Service Classification No. 8	209	209	209	209	209	209	209	209	209	209	209	209	209
Service Classification No. 9	228	228	226	227	226	226	226	226	226	224	224	223	226
Service Classification No. 13													
Transmission	6	6	6	6	6	6	6	6	6	6	6	6	6
Substation	6	6	6	6	6	6	6	6	6	6	6	6	6
	12	12	12	12	12	12	12	12	12	12	12	12	12
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Customers	300,355	301,947	299,668	302,428	299,832	303,554	302,452	301,885	302,816	302,787	300,071	303,020	301,735

Summary of Electric Demand Determinants by Service ClassificationRate Year 1 (Twelve Months Ended June 30, 2016)

	July 2015	August 2015	September 2015	October 2015	November 2015	December 2015	January 2016	February 2016	March 2016	April 2016	May 2016	June 2016	Total
Service Classification No. 2													
Primary kW	60,000	50,000	50,000	50,000	50,000	50,000	40,000	50,000	50,000	50,000	50,000	60,000	610,000
EEPS Lost kW	(4,820)	(4,070)	(4,013)	(3,998)	(3,993)	(4,016)	(4,101)	(4,230)	(4,448)	(4,562)	(4,812)	(5,047)	(52,110)
Secondary kW	449,690	418,090	421,320	414,910	367,180	366,450	377,780	363,310	364,970	369,760	389,930	426,500	4,729,890
EEPS Lost kW	(36,837)	(34,453)	(34,540)	(33,933)	(30,096)	(29,997)	(35,507)	(34,390)	(34,523)	(34,991)	(36,859)	(39,995)	(416,121)
PV Lost kW	(12,504)	(12,912)	(13,315)	(13,739)	(14,158)	(14,600)	(15,717)	(16,164)	(16,650)	(17,132)	(17,635)	(18,133)	(182,659)
	455,529	416,655	419,452	413,240	368,933	367,837	362,455	358,526	359,349	363,075	380,624	423,325	4,689,000
Service Classification No. 3 kW	60,006	57,836	57,484	54,827	51,890	60,583	54,552	49,023	49,868	52,189	58,057	59,786	666,101
EEPS Lost kW	(4,870)	(4,870)	(4,870)	(4,870)	(4,870)	(4,870)	(5,070)	(5,070)	(5,070)	(5,070)	(5,070)	(5,070)	(59,640)
	55,136	52,966	52,614	49,957	47,020	55,713	49,482	43,953	44,798	47,119	52,987	54,716	606,461
Service Classification No. 13													
Transmission kW	116,931	110,923	116,966	106,877	100,085	96,650	88,800	87,264	93,103	103,700	109,967	111,645	1,242,911
Substation kW	23,580	22,912	21,375	17,886	16,088	16,041	17,813	17,283	17,251	20,074	21,609	22,965	234,877
	140,511	133,835	138,341	124,763	116,173	112,691	106,613	104,547	110,354	123,774	131,576	134,610	1,477,788
Total kW	651,176	603,456	610,407	587,960	532,126	536,241	518,550	507,026	514,501	533,968	565,187	612,651	6,773,249
Service Classification No. 3 RkVa	15,001	14,460	12,646	12,062	11,416	9,088	7,365	7,354	9,974	13,048	14,515	14,947	141,876
EEPS Lost RkVa	(1,218)	(1,218)	(1,071)	(1,071)	(1,071)	(731)	(684)	(761)	(1,014)	(1,268)	(1,268)	(1,268)	(12,643)
	13,783	13,242	11,575	10,991	10,345	8,357	6,681	6,593	8,960	11,780	13,247	13,679	129,233
Service Classification No. 13													
Transmission RkVa	5,230	4,910	4,720	4,880	4,480	3,780	2,090	2,450	3,560	4,500	4,870	5,230	50,700
Substation RkVa	5,650	5,110	5,260	4,410	3,880	3,690	3,930	3,750	10,010	4,090	4,660	5,420	59,860
	10,880	10,020	9,980	9,290	8,360	7,470	6,020	6,200	13,570	8,590	9,530	10,650	110,560
Total RkVa	24,663	23,262	21,555	20,281	18,705	15,827	12,701	12,793	22,530	20,370	22,777	24,329	239,793

Central Hudson Gas and Electric Corporation
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Summary of Electric Sales (MWh) by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2017)

	July 2016	August 2016	September 2016	October 2016	November 2016	December 2016	January 2017	February 2017	March 2017	April 2017	May 2017	June 2017	Total
Service Classification No. 1													
Heating	18,654	19,382	19,548	17,118	20,657	29,804	41,446	44,753	43,124	31,667	24,587	17,818	328,558
EEPS Lost MWh	(1,481)	(1,549)	(1,542)	(1,369)	(1,638)	(2,382)	(3,587)	(3,883)	(3,737)	(2,743)	(2,128)	(1,544)	(27,583)
Nonheating	167,405	191,808	180,810	150,333	136,652	149,766	169,403	170,207	157,384	146,531	136,143	142,260	1,898,702
EEPS Lost MWh	(13,099)	(15,000)	(14,139)	(11,747)	(10,672)	(11,706)	(14,406)	(14,475)	(13,382)	(12,460)	(11,567)	(12,091)	(154,744)
PV Lost MWh	(2,064)	(2,123)	(2,111)	(2,241)	(2,227)	(2,364)	(2,336)	(2,160)	(2,455)	(2,436)	(2,582)	(2,560)	(27,659)
	169,415	192,518	182,566	152,094	142,772	163,118	190,520	194,442	180,934	160,559	144,453	143,883	2,017,274
Service Classification No. 2													
Nondemand	13,913	16,358	14,403	14,155	12,211	15,281	16,238	18,055	15,371	15,306	12,490	14,308	178,089
EEPS Lost MWh	(1,109)	(1,281)	(1,127)	(1,117)	(980)	(1,225)	(1,507)	(1,660)	(1,422)	(1,389)	(1,190)	(1,316)	(15,324)
Primary	20,732	19,788	19,748	19,525	18,679	19,319	19,795	18,649	18,956	17,791	18,318	19,116	230,416
EEPS Lost MWh	(1,678)	(1,611)	(1,585)	(1,584)	(1,490)	(1,559)	(1,855)	(1,764)	(1,789)	(1,674)	(1,744)	(1,778)	(20,113)
Secondary	140,900	140,970	133,830	116,460	113,630	123,120	129,660	123,540	117,250	112,170	113,180	125,450	1,490,160
EEPS Lost MWh	(11,604)	(11,541)	(10,880)	(9,671)	(9,179)	(10,049)	(12,427)	(11,864)	(11,220)	(10,671)	(11,058)	(11,999)	(132,162)
PV Lost MWh	(1,232)	(1,272)	(1,269)	(1,354)	(1,350)	(1,438)	(1,548)	(1,490)	(1,640)	(1,633)	(1,737)	(1,729)	(17,692)
	159,922	161,411	153,119	136,414	131,521	143,449	148,355	143,466	135,506	129,899	128,259	142,052	1,713,375
Service Classification No. 3	26,961	26,469	24,309	24,480	23,326	26,129	24,815	22,867	23,798	22,909	24,182	24,825	295,070
EEPS Lost MWh	(2,186)	(2,162)	(1,959)	(1,989)	(1,872)	(2,113)	(2,328)	(2,169)	(2,250)	(2,161)	(2,308)	(2,309)	(25,806)
	24,775	24,307	22,350	22,491	21,454	24,016	22,487	20,698	21,548	20,748	21,874	22,516	269,264
Service Classification No. 5	820	910	1,010	1,170	1,260	1,390	1,310	1,100	1,060	940	840	750	12,560
Service Classification No. 6													
Heating	450	630	360	540	450	900	1,080	1,350	1,170	900	630	540	9,000
Nonheating	1,100	1,100	1,100	770	660	770	1,100	990	990	880	770	770	11,000
	1,550	1,730	1,460	1,310	1,110	1,670	2,180	2,340	2,160	1,780	1,400	1,310	20,000
Service Classification No. 8	1,430	1,590	1,760	2,030	2,190	2,410	2,280	1,900	1,840	1,630	1,460	1,300	21,820
Service Classification No. 9	220	220	210	210	210	210	210	210	210	210	210	210	2,540
Service Classification No. 13													
Transmission	72,260	69,270	63,690	64,810	59,700	59,050	57,200	52,530	58,340	61,780	67,080	67,120	752,830
Substation	13,530	12,970	10,870	10,080	9,450	9,650	10,060	9,320	10,090	10,050	11,470	12,630	130,170
	85,790	82,240	74,560	74,890	69,150	68,700	67,260	61,850	68,430	71,830	78,550	79,750	883,000
Interdepartmental	80	90	90	70	80	80	80	90	80	70	70	70	950
Total	444,002	465,016	437,125	390,679	369,747	405,043	434,682	426,096	411,768	387,666	377,116	391,841	4,940,783

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Summary of Electric Base Delivery Revenues (Excluding Revenue Tax) by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2017)

	July 2016	August 2016	September 2016	October 2016	November 2016	December 2016	January 2017	February 2017	March 2017	April 2017	May 2017	June 2017	Total
Service Classification No. 1													
Heating	$ 1,850,760	$ 1,853,860	$ 1,900,440	$ 1,721,340	$ 1,963,830	$ 2,464,890	$ 3,190,580	$ 3,341,620	$ 3,295,240	$ 2,574,920	$ 2,199,140	$ 1,763,060	$ 28,119,680
EEPS Lost Revenue	$ (87,110)	$ (90,750)	$ (90,800)	$ (80,080)	$ (96,080)	$ (139,400)	$ (210,330)	$ (227,860)	$ (219,420)	$ (160,500)	$ (125,100)	$ (90,450)	$ (1,617,880)
Nonheating	$ 16,195,790	$ 17,648,510	$ 16,970,690	$ 15,224,040	$ 14,389,730	$ 15,207,360	$ 16,355,050	$ 16,384,880	$ 15,648,630	$ 15,008,410	$ 14,361,030	$ 14,760,020	$ 188,154,140
EEPS Lost Revenue	$ (767,620)	$ (879,300)	$ (829,120)	$ (688,670)	$ (626,120)	$ (686,030)	$ (844,710)	$ (848,810)	$ (784,920)	$ (730,980)	$ (677,640)	$ (709,300)	$ (9,073,220)
PV Lost Revenue	$ (128,260)	$ (131,920)	$ (131,150)	$ (139,290)	$ (138,390)	$ (146,890)	$ (145,140)	$ (134,240)	$ (152,550)	$ (151,350)	$ (160,430)	$ (159,090)	$ (1,718,700)
Unbilled	$ (138,160)	$ 440,480	$ 461,160	$ 76,310	$ 106,040	$ (202,550)	$ 103,910	$ 180,820	$ (521,000)	$ 108,830	$ (444,210)	$ (128,980)	$ 42,650
	$ 16,925,400	$ 18,840,880	$ 18,281,220	$ 16,113,650	$ 15,599,010	$ 16,497,380	$ 18,449,360	$ 18,696,410	$ 17,265,980	$ 16,649,330	$ 15,152,790	$ 15,435,260	$ 203,906,670
Service Classification No. 2													
Nondemand	$ 1,345,250	$ 1,474,220	$ 1,353,460	$ 1,446,700	$ 1,324,820	$ 1,462,820	$ 1,379,380	$ 1,498,230	$ 1,370,020	$ 1,463,940	$ 1,331,050	$ 1,453,250	$ 16,903,140
EEPS Lost Revenue	(14,410)	(16,640)	(14,650)	(14,510)	(12,730)	(15,910)	(19,570)	(21,590)	(18,480)	(18,060)	(15,420)	(17,100)	$ (199,070)
Primary	$ 535,570	$ 458,050	$ 459,743	$ 459,053	$ 456,285	$ 457,197	$ 384,343	$ 381,330	$ 457,789	$ 455,534	$ 456,064	$ 457,712	$ 5,418,670
EEPS Lost Revenue	(38,770)	(33,070)	(32,650)	(32,540)	(32,270)	(32,560)	(33,530)	(34,380)	(36,060)	(36,800)	(38,770)	(40,570)	$ (421,970)
Secondary	$ 5,774,690	$ 5,525,490	$ 5,528,500	$ 5,283,150	$ 4,940,720	$ 4,982,780	$ 5,035,450	$ 4,855,540	$ 4,882,600	$ 4,891,820	$ 4,983,680	$ 5,419,940	$ 62,104,360
EEPS Lost Revenue	(393,760)	(372,400)	(369,210)	(356,600)	(319,750)	(323,990)	(386,540)	(373,350)	(370,790)	(371,780)	(390,510)	(423,910)	$ (4,452,590)
PV Lost Revenue	$ (121,970)	$ (125,950)	$ (125,690)	$ (134,010)	$ (133,650)	$ (142,410)	$ (153,310)	$ (142,410)	$ (162,410)	$ (161,720)	$ (172,020)	$ (171,170)	$ (1,746,720)
Unbilled	$ 44,400	$ (47,730)	$ 51,260	$ (50,290)	$ 50,400	$ (52,970)	$ 50,510	$ (46,330)	$ 47,400	$ (42,150)	$ 46,650	$ (51,800)	$ (650)
	$ 7,131,000	$ 6,861,970	$ 6,850,763	$ 6,600,953	$ 6,273,825	$ 6,334,957	$ 6,256,733	$ 6,117,040	$ 6,170,069	$ 6,180,784	$ 6,200,724	$ 6,626,352	$ 77,605,170
Service Classification No. 3	$ 626,510	$ 608,585	$ 604,750	$ 572,175	$ 551,200	$ 631,325	$ 563,910	$ 514,070	$ 526,470	$ 551,870	$ 598,650	$ 620,190	$ 6,969,705
EEPS Lost Revenue	$ (48,290)	$ (47,240)	$ (46,240)	$ (43,830)	$ (41,800)	$ (48,540)	$ (49,820)	$ (45,480)	$ (46,360)	$ (48,870)	$ (54,090)	$ (54,770)	$ (575,330)
	$ 578,220	$ 561,345	$ 558,510	$ 528,345	$ 509,400	$ 582,785	$ 514,090	$ 468,590	$ 480,110	$ 503,000	$ 544,560	$ 565,420	$ 6,394,375
Service Classification No. 5	$ 138,810	$ 139,750	$ 140,790	$ 142,470	$ 143,410	$ 144,770	$ 143,160	$ 140,970	$ 140,550	$ 139,290	$ 138,250	$ 137,310	$ 1,689,530
Service Classification No. 6	$ 113,570	$ 123,280	$ 109,030	$ 102,090	$ 91,360	$ 120,260	$ 145,380	$ 154,070	$ 144,370	$ 125,810	$ 106,010	$ 102,090	$ 1,437,320
Service Classification No. 8	$ 440,990	$ 441,040	$ 441,090	$ 441,170	$ 441,220	$ 441,280	$ 440,300	$ 440,190	$ 440,170	$ 440,110	$ 440,060	$ 440,010	$ 5,287,630
Service Classification No. 9	$ 16,680	$ 16,620	$ 16,520	$ 16,450	$ 16,390	$ 16,320	$ 16,250	$ 16,150	$ 16,080	$ 16,020	$ 15,950	$ 15,880	$ 195,310
Service Classification No. 13													
Transmission	$ 511,270	$ 486,440	$ 510,990	$ 469,860	$ 441,750	$ 427,120	$ 393,600	$ 387,620	$ 412,420	$ 456,550	$ 482,490	$ 489,650	$ 5,469,760
Substation	$ 194,240	$ 189,030	$ 178,220	$ 152,670	$ 139,430	$ 138,930	$ 151,750	$ 147,820	$ 152,800	$ 167,980	$ 179,390	$ 189,670	$ 1,981,930
	$ 705,510	$ 675,470	$ 689,210	$ 622,530	$ 581,180	$ 566,050	$ 545,350	$ 535,440	$ 565,220	$ 624,530	$ 661,880	$ 679,320	$ 7,451,690
Interdepartmental	$ 860	$ 960	$ 960	$ 750	$ 860	$ 860	$ 860	$ 960	$ 860	$ 750	$ 750	$ 750	$ 10,180
Total Base Revenue	$ 26,051,040	$ 27,661,315	$ 27,088,093	$ 24,568,408	$ 23,656,655	$ 24,704,662	$ 26,511,483	$ 26,569,820	$ 25,223,409	$ 24,679,624	$ 23,260,974	$ 24,002,392	$ 303,977,875
Total Base Revenue Excluding Unbilled	$ 26,144,800	$ 27,268,565	$ 26,575,673	$ 24,542,388	$ 23,500,215	$ 24,960,182	$ 26,357,063	$ 26,435,330	$ 25,697,009	$ 24,612,944	$ 23,658,534	$ 24,183,172	$ 303,935,875

Central Hudson Gas and Electric Corporation
Cases 14-E-0318;14-G-0319

Summary of Electric Customers by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2017)

	July 2016	August 2016	September 2016	October 2016	November 2016	December 2016	January 2017	February 2017	March 2017	April 2017	May 2017	June 2017	Average
Service Classification No. 1													
Heating	27,029	25,618	26,922	25,628	26,866	25,637	27,151	25,639	27,342	25,646	27,020	25,651	26,346
Nonheating	227,963	228,754	227,585	228,994	227,851	229,573	229,480	228,830	229,440	229,245	227,900	229,309	228,744
	254,992	254,372	254,507	254,622	254,717	255,210	256,631	254,469	256,782	254,891	254,920	254,960	255,089
Service Classification No. 2													
Nondemand	28,403	30,774	28,448	30,800	28,444	30,837	28,499	30,822	28,545	30,858	28,506	30,912	29,654
Primary	164	160	163	162	160	161	168	163	168	163	162	164	163
Secondary	11,766	11,573	11,692	11,714	11,637	12,003	11,873	11,468	11,935	11,657	11,687	11,699	11,725
	40,333	42,507	40,303	42,676	40,241	43,001	40,540	42,453	40,648	42,678	40,355	42,775	41,543
Service Classification No. 3	32	32	32	32	31	33	32	33	34	33	33	33	33
Service Classification No. 5	4,170	4,067	4,130	4,077	4,092	4,124	3,989	3,969	4,092	4,111	4,019	4,162	4,084
Service Classification No. 6													
Heating	370	460	370	460	370	460	370	460	370	460	370	460	415
Nonheating	770	700	770	700	770	700	770	700	770	700	770	700	735
	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,150
Service Classification No. 8	209	209	209	209	209	209	209	209	209	209	209	209	209
Service Classification No. 9	223	223	221	222	221	221	221	221	221	220	220	219	221
Service Classification No. 13													
Transmission	6	6	6	6	6	6	6	6	6	6	6	6	6
Substation	6	6	6	6	6	6	6	6	6	6	6	6	6
	12	12	12	12	12	12	12	12	12	12	12	12	12
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Customers	301,112	302,583	300,555	303,011	300,664	303,971	302,775	302,527	303,139	303,315	300,909	303,531	302,341

Central Hudson Gas and Electric Corporation
Cases 14-E-0318;14-G-0319

Summary of Electric Demand Determinants by Service ClassificationRate Year 2 (Twelve Months Ended June 30, 2017)

	July 2016	August 2016	September 2016	October 2016	November 2016	December 2016	January 2017	February 2017	March 2017	April 2017	May 2017	June 2017	Total
Service Classification No. 2													
Primary kW	60,000	50,000	50,000	50,000	50,000	50,000	40,000	40,000	50,000	50,000	50,000	50,000	590,000
EEPS Lost kW	(4,820)	(4,070)	(4,013)	(3,998)	(3,993)	(4,016)	(4,101)	(4,230)	(4,448)	(4,562)	(4,812)	(5,047)	(52,110)
Secondary kW	447,310	420,810	424,870	408,630	372,540	367,510	370,470	358,070	360,770	367,770	377,260	418,170	4,694,180
EEPS Lost kW	(36,837)	(34,453)	(34,540)	(33,933)	(30,096)	(29,997)	(35,507)	(34,390)	(34,523)	(34,991)	(36,859)	(39,995)	(416,121)
PV Lost kW	(12,504)	(12,912)	(13,315)	(13,739)	(14,158)	(14,600)	(15,717)	(16,164)	(16,650)	(17,132)	(17,635)	(18,133)	(182,659)
	453,149	419,375	423,002	406,960	374,293	368,897	355,145	343,286	355,149	361,085	367,954	404,995	4,633,290
Service Classification No. 3 kW	59,915	58,167	57,874	54,394	52,417	60,767	53,946	48,653	49,579	52,066	56,901	59,110	663,789
EEPS Lost kW	(4,870)	(4,870)	(4,870)	(4,870)	(4,870)	(4,870)	(5,070)	(5,070)	(5,070)	(5,070)	(5,070)	(5,070)	(59,640)
	55,045	53,297	53,004	49,524	47,547	55,897	48,876	43,583	44,509	46,996	51,831	54,040	604,149
Service Classification No. 13													
Transmission kW	116,931	110,923	116,966	106,877	100,085	96,650	88,800	87,264	93,103	103,700	109,967	111,645	1,242,911
Substation kW	23,580	22,912	21,375	17,886	16,088	16,041	17,813	17,283	17,251	20,074	21,609	22,965	234,877
	140,511	133,835	138,341	124,763	116,173	112,691	106,613	104,547	110,354	123,774	131,576	134,610	1,477,788
Total kW	648,705	606,507	614,347	581,247	538,013	537,485	510,634	491,416	510,012	531,855	551,361	593,645	6,715,227
Service Classification No. 3 RkVa	14,979	14,542	12,733	11,967	11,532	9,116	7,283	7,299	9,916	13,016	14,225	14,777	141,385
EEPS Lost RkVa	(1,218)	(1,218)	(1,071)	(1,071)	(1,071)	(731)	(684)	(761)	(1,014)	(1,268)	(1,268)	(1,268)	(12,643)
	13,761	13,324	11,662	10,896	10,461	8,385	6,599	6,538	8,902	11,748	12,957	13,509	128,742
Service Classification No. 13													
Transmission RkVa	5,230	4,910	4,720	4,880	4,480	3,780	2,090	2,450	3,560	4,500	4,870	5,230	50,700
Substation RkVa	5,650	5,110	5,260	4,410	3,880	3,690	3,930	3,750	10,010	4,090	4,660	5,420	59,860
	10,880	10,020	9,980	9,290	8,360	7,470	6,020	6,200	13,570	8,590	9,530	10,650	110,560
Total RkVa	24,641	23,344	21,642	20,186	18,821	15,855	12,619	12,738	22,472	20,338	22,487	24,159	239,302

Appendix I

Central Hudson Gas and Electric Corporation
Cases 14-E-0318;14-G-0319

Summary of Electric Sales (MWh) by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2018

	July 2017	August 2017	September 2017	October 2017	November 2017	December 2017	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	Total
Service Classification No. 1													
Heating	18,861	19,591	19,744	17,306	20,893	30,132	41,872	45,192	43,540	31,986	24,825	18,017	331,959
EEPS Lost MWh	(1,626)	(1,699)	(1,691)	(1,501)	(1,800)	(2,615)	(3,832)	(4,144)	(4,001)	(2,914)	(2,279)	(1,613)	(29,715)
Nonheating	170,082	194,577	183,586	152,638	139,009	152,138	172,026	173,054	159,908	148,929	138,511	144,563	1,929,021
EEPS Lost MWh	(14,464)	(16,541)	(15,604)	(12,966)	(11,799)	(12,926)	(15,854)	(15,959)	(14,733)	(13,734)	(12,732)	(13,324)	(170,636)
PV Lost MWh	(2,712)	(2,780)	(2,755)	(2,916)	(2,888)	(3,056)	(3,005)	(2,772)	(3,140)	(3,107)	(3,283)	(3,247)	(35,661)
	170,141	193,148	183,280	152,561	143,415	163,673	191,207	195,371	181,574	161,160	145,042	144,396	2,024,968
Service Classification No. 2													
Nondemand	14,050	16,505	14,537	14,297	12,319	15,386	16,314	18,128	15,433	15,396	12,586	14,424	179,375
EEPS Lost MWh	(1,109)	(1,281)	(1,127)	(1,117)	(980)	(1,225)	(1,507)	(1,660)	(1,422)	(1,389)	(1,189)	(1,317)	(15,323)
Primary	20,779	19,990	19,876	19,623	18,822	19,184	19,769	18,988	18,956	17,932	18,453	19,334	231,706
EEPS Lost MWh	(1,678)	(1,611)	(1,585)	(1,584)	(1,490)	(1,559)	(1,855)	(1,764)	(1,789)	(1,674)	(1,744)	(1,778)	(20,113)
Secondary	141,170	143,040	135,110	117,310	115,030	121,610	129,300	127,150	117,230	113,660	114,560	127,850	1,503,020
EEPS Lost MWh	(11,604)	(11,541)	(10,880)	(9,671)	(9,179)	(10,049)	(12,427)	(11,864)	(11,220)	(10,671)	(11,058)	(11,999)	(132,162)
PV Lost MWh	(1,232)	(1,272)	(1,269)	(1,354)	(1,350)	(1,438)	(1,548)	(1,490)	(1,640)	(1,633)	(1,737)	(1,729)	(17,692)
	160,376	163,830	154,661	137,504	133,172	141,909	148,045	147,488	135,548	131,620	129,872	144,785	1,728,811
Service Classification No. 3	27,009	26,719	24,455	24,585	23,499	25,922	24,773	23,275	23,790	23,081	24,353	25,099	296,560
EEPS Lost MWh	(2,186)	(2,162)	(1,959)	(1,989)	(1,872)	(2,113)	(2,328)	(2,169)	(2,250)	(2,161)	(2,308)	(2,309)	(25,806)
	24,823	24,557	22,496	22,596	21,627	23,809	22,445	21,106	21,540	20,920	22,045	22,790	270,754
Service Classification No. 5	820	910	1,010	1,170	1,260	1,390	1,310	1,100	1,060	940	840	750	12,560
Service Classification No. 6													
Heating	450	630	360	540	450	900	1,080	1,350	1,170	900	630	540	9,000
Nonheating	1,100	1,100	1,100	770	660	770	1,100	990	990	880	770	770	11,000
	1,550	1,730	1,460	1,310	1,110	1,670	2,180	2,340	2,160	1,780	1,400	1,310	20,000
Service Classification No. 8	1,430	1,590	1,760	2,030	2,190	2,410	2,280	1,900	1,840	1,630	1,460	1,300	21,820
Service Classification No. 9	220	220	210	210	210	210	210	210	210	210	210	210	2,540
Service Classification No. 13													
Transmission	72,260	69,270	63,690	64,810	59,700	59,050	57,200	52,530	58,340	61,780	67,080	67,120	752,830
Substation	13,530	12,970	10,870	10,080	9,450	9,650	10,060	9,320	10,090	10,050	11,470	12,630	130,170
	85,790	82,240	74,560	74,890	69,150	68,700	67,260	61,850	68,430	71,830	78,550	79,750	883,000
Interdepartmental	80	90	90	70	80	80	80	90	80	70	70	70	950
Total	445,230	468,315	439,527	392,341	372,214	403,851	435,017	431,455	412,442	390,160	379,489	395,361	4,965,403

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Summary of Electric Base Delivery Revenues (Excluding Revenue Tax) by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2018)

	July 2017	August 2017	September 2017	October 2017	November 2017	December 2017	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	Total
Service Classification No. 1													
Heating	$ 1,959,230	$ 1,963,610	$ 2,011,540	$ 1,821,290	$ 2,081,330	$ 2,619,930	$ 3,395,580	$ 3,557,980	$ 3,505,930	$ 2,736,160	$ 2,331,380	$ 1,866,350	$ 29,850,310
EEPS Lost Revenue	$ (101,510)	$ (105,810)	$ (105,740)	$ (93,370)	$ (112,030)	$ (162,500)	$ (244,980)	$ (263,950)	$ (255,310)	$ (186,840)	$ (145,140)	$ (105,930)	$ (1,883,110)
Nonheating	$ 17,215,950	$ 18,765,320	$ 18,051,210	$ 16,156,270	$ 15,279,070	$ 16,138,260	$ 17,369,810	$ 17,425,890	$ 16,615,670	$ 15,932,830	$ 15,248,120	$ 15,662,930	$ 199,861,330
EEPS Lost Revenue	$ (900,630)	$ (1,030,080)	$ (971,580)	$ (807,870)	$ (734,440)	$ (804,770)	$ (992,730)	$ (1,001,450)	$ (923,650)	$ (860,790)	$ (798,540)	$ (835,890)	$ (10,662,420)
PV Lost Revenue	$ (178,280)	$ (182,730)	$ (181,060)	$ (191,670)	$ (189,830)	$ (200,850)	$ (197,530)	$ (182,200)	$ (206,410)	$ (204,200)	$ (215,810)	$ (213,400)	$ (2,343,970)
Unbilled	$ (138,160)	$ 440,490	$ 461,150	$ 76,310	$ 106,050	$ (202,560)	$ 103,920	$ 180,810	$ (521,000)	$ 108,840	$ (444,220)	$ (128,970)	$ 42,660
	$ 17,856,600	$ 19,850,800	$ 19,265,520	$ 16,960,960	$ 16,430,150	$ 17,387,510	$ 19,434,070	$ 19,717,080	$ 18,215,230	$ 17,526,000	$ 15,975,790	$ 16,245,090	$ 214,864,800
Service Classification No. 2													
Nondemand	$ 1,445,760	$ 1,583,380	$ 1,453,760	$ 1,554,850	$ 1,423,910	$ 1,570,960	$ 1,479,970	$ 1,606,770	$ 1,469,650	$ 1,571,630	$ 1,429,740	$ 1,560,740	$ 18,151,120
EEPS Lost Revenue	$ (14,940)	$ (17,250)	$ (15,180)	$ (15,040)	$ (13,190)	$ (16,480)	$ (20,280)	$ (22,350)	$ (19,150)	$ (18,710)	$ (15,970)	$ (17,690)	$ (206,230)
Primary	$ 556,410	$ 476,230	$ 477,670	$ 476,889	$ 474,234	$ 474,086	$ 398,479	$ 474,514	$ 475,239	$ 473,516	$ 474,065	$ 553,827	$ 5,785,159
EEPS Lost Revenue	$ (40,410)	$ (34,470)	$ (34,020)	$ (33,910)	$ (33,630)	$ (33,930)	$ (34,960)	$ (35,850)	$ (37,580)	$ (38,360)	$ (40,420)	$ (42,310)	$ (439,850)
Secondary	$ 5,946,840	$ 5,762,590	$ 5,736,140	$ 5,469,570	$ 5,139,350	$ 5,054,300	$ 5,157,950	$ 5,136,580	$ 5,014,770	$ 5,093,970	$ 5,184,360	$ 5,678,210	$ 64,374,630
EEPS Lost Revenue	$ (406,540)	$ (384,470)	$ (381,190)	$ (368,180)	$ (330,140)	$ (334,490)	$ (399,080)	$ (385,470)	$ (382,820)	$ (383,850)	$ (403,190)	$ (437,670)	$ (4,597,090)
PV Lost Revenue	$ (125,580)	$ (129,670)	$ (129,410)	$ (137,980)	$ (137,600)	$ (146,630)	$ (157,840)	$ (146,620)	$ (167,220)	$ (166,500)	$ (177,110)	$ (176,230)	$ (1,798,390)
Unbilled	$ 44,400	$ (47,720)	$ 51,260	$ (50,290)	$ 50,400	$ (52,980)	$ 50,510	$ (46,330)	$ 47,400	$ (42,140)	$ 46,650	$ (51,800)	$ (640)
	$ 7,405,940	$ 7,208,620	$ 7,159,030	$ 6,895,909	$ 6,573,334	$ 6,514,836	$ 6,474,749	$ 6,581,244	$ 6,400,289	$ 6,489,556	$ 6,498,125	$ 7,067,077	$ 81,268,709
Service Classification No. 3	$ 651,780	$ 637,850	$ 632,010	$ 596,770	$ 576,810	$ 650,660	$ 584,720	$ 543,420	$ 546,610	$ 577,290	$ 626,140	$ 651,120	$ 7,275,180
EEPS Lost Revenue	$ (50,140)	$ (49,040)	$ (48,000)	$ (45,500)	$ (43,400)	$ (50,420)	$ (51,740)	$ (47,230)	$ (48,130)	$ (50,740)	$ (56,160)	$ (56,870)	$ (597,370)
	$ 601,640	$ 588,810	$ 584,010	$ 551,270	$ 533,410	$ 600,240	$ 532,980	$ 496,190	$ 498,480	$ 526,550	$ 569,980	$ 594,250	$ 6,677,810
Service Classification No. 5	$ 148,760	$ 149,700	$ 150,740	$ 152,420	$ 153,360	$ 154,720	$ 153,070	$ 150,880	$ 150,460	$ 149,200	$ 148,160	$ 147,220	$ 1,808,690
Service Classification No. 6	$ 116,480	$ 126,410	$ 111,840	$ 104,740	$ 93,770	$ 123,340	$ 149,020	$ 157,920	$ 147,990	$ 129,010	$ 108,740	$ 104,740	$ 1,474,000
Service Classification No. 8	$ 456,460	$ 456,510	$ 456,560	$ 456,640	$ 456,690	$ 456,750	$ 455,730	$ 455,620	$ 455,600	$ 455,540	$ 455,490	$ 455,440	$ 5,473,030
Service Classification No. 9	$ 17,550	$ 17,480	$ 17,380	$ 17,310	$ 17,240	$ 17,170	$ 17,100	$ 16,990	$ 16,920	$ 16,850	$ 16,780	$ 16,710	$ 205,480
Service Classification No. 13													
Transmission	$ 537,260	$ 511,170	$ 536,990	$ 493,740	$ 464,210	$ 448,860	$ 413,690	$ 407,390	$ 433,410	$ 479,770	$ 507,020	$ 514,530	$ 5,748,040
Substation	$ 204,100	$ 198,650	$ 187,270	$ 160,430	$ 146,520	$ 146,010	$ 159,480	$ 155,360	$ 160,320	$ 176,540	$ 188,520	$ 199,310	$ 2,082,510
	$ 741,360	$ 709,820	$ 724,260	$ 654,170	$ 610,730	$ 594,870	$ 573,170	$ 562,750	$ 593,730	$ 656,310	$ 695,540	$ 713,840	$ 7,830,550
Interdepartmental	$ 860	$ 960	$ 960	$ 750	$ 860	$ 860	$ 860	$ 960	$ 860	$ 750	$ 750	$ 750	$ 10,180
Total Base Revenue	$ 27,345,650	$ 29,109,110	$ 28,470,300	$ 25,794,169	$ 24,869,544	$ 25,850,296	$ 27,790,749	$ 28,139,634	$ 26,479,559	$ 25,949,766	$ 24,469,355	$ 25,345,117	$ 319,613,249
Total Base Revenue Excluding Unbilled	$ 27,439,410	$ 28,716,340	$ 27,957,890	$ 25,768,149	$ 24,713,094	$ 26,105,836	$ 27,636,319	$ 28,005,154	$ 26,953,159	$ 25,883,066	$ 24,866,925	$ 25,525,887	$ 319,571,229

Central Hudson Gas and Electric Corporation
Cases 14-E-0318;14-G-0319

Summary of Electric Customers by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2018)

	July 2017	August 2017	September 2017	October 2017	November 2017	December 2017	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	Average
Service Classification No. 1													
Heating	27,066	25,654	26,957	25,663	26,901	25,672	27,186	25,673	27,375	25,679	27,053	25,683	26,380
Nonheating	228,471	229,159	228,191	229,347	228,396	229,795	229,644	229,242	229,624	229,559	228,463	229,613	229,125
	255,537	254,813	255,148	255,010	255,297	255,467	256,830	254,915	256,999	255,238	255,516	255,296	255,506
Service Classification No. 2													
Nondemand	28,560	30,937	28,593	30,964	28,594	30,997	28,645	30,972	28,680	31,009	28,644	31,059	29,805
Primary	165	162	165	164	162	161	169	166	169	166	164	167	165
Secondary	11,858	11,818	11,879	11,884	11,871	11,920	11,911	11,913	12,021	11,916	11,930	12,022	11,912
	40,583	42,917	40,637	43,012	40,627	43,078	40,725	43,051	40,870	43,091	40,738	43,248	41,881
Service Classification No. 3	32	32	32	33	32	33	32	33	34	34	34	34	33
Service Classification No. 5	4,120	4,018	4,080	4,028	4,043	4,075	3,941	3,921	4,043	4,062	3,971	4,112	4,035
Service Classification No. 6													
Heating	370	460	370	460	370	460	370	460	370	460	370	460	415
Nonheating	770	700	770	700	770	700	770	700	770	700	770	700	735
	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,150
Service Classification No. 8	209	209	209	209	209	209	209	209	209	209	209	209	209
Service Classification No. 9	219	219	217	218	217	217	217	217	217	216	216	215	217
Service Classification No. 13													
Transmission	6	6	6	6	6	6	6	6	6	6	6	6	6
Substation	6	6	6	6	6	6	6	6	6	6	6	6	6
	12	12	12	12	12	12	12	12	12	12	12	12	12
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Customers	301,853	303,381	301,476	303,683	301,578	304,252	303,107	303,519	303,525	304,023	301,837	304,287	303,043

Summary of Electric Demand Determinants by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2018)

	July 2017	August 2017	September 2017	October 2017	November 2017	December 2017	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	Total
Service Classification No. 2													
Primary kW	60,000	50,000	50,000	50,000	50,000	50,000	40,000	50,000	50,000	50,000	50,000	60,000	610,000
EEPS Lost kW	(4,820)	(4,070)	(4,013)	(3,998)	(3,993)	(4,016)	(4,101)	(4,230)	(4,448)	(4,562)	(4,812)	(5,047)	(52,110)
Secondary kW	448,160	426,980	428,910	411,630	377,140	363,020	369,440	368,550	360,700	372,670	381,870	426,150	4,735,220
EEPS Lost kW	(36,837)	(34,453)	(34,540)	(33,933)	(30,096)	(29,997)	(35,507)	(34,390)	(34,523)	(34,991)	(36,859)	(39,995)	(416,121)
PV Lost kW	(12,504)	(12,912)	(13,315)	(13,739)	(14,158)	(14,600)	(15,717)	(16,164)	(16,650)	(17,132)	(17,635)	(18,133)	(182,659)
	453,999	425,545	427,042	409,960	378,893	364,407	354,115	363,766	355,079	365,985	372,564	422,975	4,694,330
Service Classification No. 3 kW	60,019	58,722	58,226	54,635	52,807	60,285	53,854	49,522	49,560	52,454	57,299	59,757	667,140
EEPS Lost kW	(4,870)	(4,870)	(4,870)	(4,870)	(4,870)	(4,870)	(5,070)	(5,070)	(5,070)	(5,070)	(5,070)	(5,070)	(59,640)
	55,149	53,852	53,356	49,765	47,937	55,415	48,784	44,452	44,490	47,384	52,229	54,687	607,500
Service Classification No. 13													
Transmission kW	116,931	110,923	116,966	106,877	100,085	96,650	88,800	87,264	93,103	103,700	109,967	111,645	1,242,911
Substation kW	23,580	22,912	21,375	17,886	16,088	16,041	17,813	17,283	17,251	20,074	21,609	22,965	234,877
	140,511	133,835	138,341	124,763	116,173	112,691	106,613	104,547	110,354	123,774	131,576	134,610	1,477,788
Total kW	649,659	613,232	618,739	584,488	543,003	532,513	509,512	512,765	509,923	537,143	556,369	612,272	6,779,618
Service Classification No. 3 RkVa	15,005	14,681	12,810	12,020	11,617	9,043	7,270	7,429	9,912	13,115	14,325	14,939	142,166
EEPS Lost RkVa	(1,218)	(1,218)	(1,071)	(1,071)	(1,071)	(731)	(684)	(761)	(1,014)	(1,268)	(1,268)	(1,268)	(12,643)
	13,787	13,463	11,739	10,949	10,546	8,312	6,586	6,668	8,898	11,847	13,057	13,671	129,523
Service Classification No. 13													
Transmission RkVa	5,230	4,910	4,720	4,880	4,480	3,780	2,090	2,450	3,560	4,500	4,870	5,230	50,700
Substation RkVa	5,650	5,110	5,260	4,410	3,880	3,690	3,930	3,750	10,010	4,090	4,660	5,420	59,860
	10,880	10,020	9,980	9,290	8,360	7,470	6,020	6,200	13,570	8,590	9,530	10,650	110,560
Total RkVa	24,667	23,483	21,719	20,239	18,906	15,782	12,606	12,868	22,468	20,437	22,587	24,321	240,083

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Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Summary of Gas Sales, Base Revenues and Customers By Service Classification
12 Months Ended June 30, 2016, June 30, 2017 & June 30, 2018

		Twelve Months Ended June 30, 2016		Twelve Months Ended June 30, 2017		Twelve Months Ended June 30, 2018
Sales & Transport (Mcf)						
Service Classification Nos. 1 & 12						
Heat*		5,120,290		5,216,556		5,312,756
Nonheating		141,232		135,861		130,558
Unbilled		33,480		33,480		33,480
		5,295,002		5,385,898		5,476,793
Service Classification Nos. 2, 6 & 13						
Heat*		6,053,325		6,342,168		6,609,764
Nonheating		744,300		742,334		739,220
Unbilled		4,910		4,910		4,910
		6,802,535		7,089,412		7,353,893
Service Classification No. 8		332,050		332,050		332,050
Service Classification No. 9		1,336,840		1,336,840		1,336,840
Service Classification No. 11*		2,458,485		2,458,485		2,458,485
Service Classification No. 14		-		-		-
Sales for Resale		-		-		-
Interdepartmental		23,640		23,640		23,640
Total Sales & Transport		16,248,552		16,626,325		16,981,702
Base Revenue ($)						
Service Classification Nos. 1 & 12						
Heat*	$	49,732,700	$	53,558,430	$	57,292,810
Nonheating	$	3,149,910	$	3,187,920	$	3,209,280
Unbilled	$	207,260	$	207,260	$	207,260
	$	53,089,870	$	56,953,610	$	60,709,350
Service Classification Nos. 2, 6 & 13						
Heat*	$	23,805,730	$	26,243,280	$	28,599,300
Nonheating	$	2,757,190	$	2,907,380	$	3,037,730
Unbilled	$	23,440	$	23,440	$	23,440
	$	26,586,360	$	29,174,100	$	31,660,470
Service Classification No. 8	$	695,100	$	695,100	$	695,100
Service Classification No. 9	$	2,304,900	$	2,304,900	$	2,304,900
Service Classification No. 11*	$	2,677,023	$	2,797,411	$	2,910,054
Service Classification No. 14	$	-	$	-	$	-
Sales for Resale	$	-	$	-	$	-
Interdepartmental	$	58,003	$	62,651	$	66,736
Total Own Territory	$	85,411,256	$	91,987,772	$	98,346,610
Customers						
Service Classification Nos. 1 & 12						
Heat*		60,803		62,234		63,666
Nonheating		7,528		7,277		7,027
		68,331		69,512		70,692
Service Classification Nos. 2, 6 & 13						
Heat*		10,335		10,619		10,900
Nonheating		1,188		1,184		1,180
		11,523		11,803		12,080
Service Classification No. 8		25		25		25
Service Classification No. 9		42		42		42
Service Classification No. 11		6		6		6
Interdepartmental		1		1		1
Total Sales & Transport Customers		79,929		81,389		82,846

* Reflects Gas Expansion and EEPS as applicable

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Summary of Gas Customers & Sales by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2016)

Sales & Transport (Mcf)	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat*	85,887	48,765	53,181	145,786	302,606	599,671	764,450	977,133	808,535	699,868	402,777	231,630	5,120,290
Nonheating	5,119	5,136	4,483	7,113	8,919	15,907	17,334	22,960	18,142	16,993	10,540	8,585	141,232
Unbilled	(7,650)	(8,980)	5,610	(180)	158,160	63,700	152,050	(32,360)	(20,070)	(108,810)	(70,930)	(97,060)	33,480
	83,356	44,922	63,274	152,719	469,686	679,278	933,834	967,733	806,608	608,050	342,388	143,155	5,295,002
Service Classification Nos. 2, 6 & 13													
Heat*	159,042	141,942	159,070	217,213	424,792	766,872	1,032,577	1,056,181	876,649	634,637	378,267	206,084	6,053,325
Nonheating	43,341	43,748	45,719	52,047	57,218	80,822	68,272	94,131	83,232	73,250	53,752	48,767	744,300
Unbilled	(3,600)	(170)	(770)	1,660	28,640	11,260	19,300	3,240	(8,450)	(15,630)	(13,920)	(16,650)	4,910
	198,783	185,520	204,019	270,920	510,650	858,954	1,120,149	1,153,552	951,431	692,256	418,099	238,202	6,802,535
Service Classification No. 8	9,100	27,900	30,730	35,870	42,430	46,710	24,410	23,740	38,820	29,540	13,070	9,730	332,050
Service Classification No. 9	61,600	68,230	67,700	92,930	140,470	166,080	157,090	162,300	173,520	114,530	71,380	61,010	1,336,840
Service Classification No. 11*	92,496	87,756	93,225	132,028	239,450	325,935	412,312	357,947	332,086	189,286	117,625	78,339	2,458,485
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	120	70	60	230	1,380	2,990	5,110	5,040	4,690	2,580	1,130	240	23,640
Total Sales & Transport	445,455	414,397	459,008	684,697	1,404,066	2,079,947	2,652,906	2,670,312	2,307,155	1,636,243	963,692	530,675	16,248,552
Base Revenue ($)													
Service Classification Nos. 1 & 12													
Heat*	$ 2,045,360	$ 1,881,250	$ 1,779,090	$ 2,689,490	$ 3,682,610	$ 5,363,310	$ 5,843,240	$ 7,006,390	$ 6,050,860	$ 5,807,280	$ 4,211,120	$ 3,372,700	$ 49,732,700
Nonheating*	$ 203,780	$ 231,840	$ 197,680	$ 251,460	$ 228,800	$ 310,560	$ 284,980	$ 350,650	$ 286,500	$ 306,200	$ 237,650	$ 259,810	$ 3,149,910
Unbilled	$ 112,970	$ (237,590)	$ 233,880	$ (121,540)	$ 1,198,610	$ (193,820)	$ 750,720	$ (401,480)	$ 75,730	$ (574,450)	$ (43,150)	$ (592,620)	$ 207,260
	$ 2,362,110	$ 1,875,500	$ 2,210,650	$ 2,819,410	$ 5,110,020	$ 5,480,050	$ 6,878,940	$ 6,955,560	$ 6,413,090	$ 5,539,030	$ 4,405,620	$ 3,039,890	$ 53,089,870
Service Classification Nos. 2, 6 & 13													
Heat	$ 905,710	$ 876,100	$ 903,060	$ 1,119,490	$ 1,743,080	$ 2,819,150	$ 3,529,530	$ 3,644,880	$ 3,101,480	$ 2,433,680	$ 1,614,360	$ 1,115,210	$ 23,805,730
Nonheating	$ 166,320	$ 175,640	$ 170,920	$ 200,640	$ 214,750	$ 296,010	$ 247,160	$ 336,390	$ 285,680	$ 269,730	$ 201,080	$ 192,870	$ 2,757,190
Unbilled	$ 18,730	$ (21,950)	$ 18,000	$ (16,730)	$ 105,860	$ 3,530	$ 70,530	$ (10,860)	$ (470)	$ (59,620)	$ (15,540)	$ (68,040)	$ 23,440
	$ 1,090,760	$ 1,029,790	$ 1,091,980	$ 1,303,400	$ 2,063,690	$ 3,118,690	$ 3,847,220	$ 3,970,410	$ 3,386,690	$ 2,643,790	$ 1,799,900	$ 1,240,040	$ 26,586,360
Service Classification No. 8	$ 16,460	$ 65,220	$ 72,590	$ 79,820	$ 89,480	$ 97,500	$ 47,150	$ 46,380	$ 80,500	$ 58,910	$ 23,710	$ 17,380	$ 695,100
Service Classification No. 9	$ 108,520	$ 128,410	$ 123,820	$ 166,920	$ 238,710	$ 282,520	$ 263,100	$ 273,080	$ 292,080	$ 192,420	$ 126,850	$ 108,470	$ 2,304,900
Service Classification No. 11*	$ 174,481	$ 173,855	$ 174,645	$ 189,802	$ 236,934	$ 275,242	$ 313,503	$ 289,422	$ 277,967	$ 214,714	$ 183,625	$ 172,831	$ 2,677,023
Service Classification No. 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interdepartmental	$ 294	$ 172	$ 147	$ 564	$ 3,386	$ 7,336	$ 12,538	$ 12,366	$ 11,507	$ 6,330	$ 2,773	$ 589	$ 58,003
Total Own Territory	$ 3,752,625	$ 3,272,946	$ 3,673,832	$ 4,559,917	$ 7,742,220	$ 9,261,339	$ 11,362,451	$ 11,547,219	$ 10,461,835	$ 8,655,194	$ 6,542,477	$ 4,579,200	$ 85,411,256
Customers													
Service Classification Nos. 1 & 12													
Heat*	56,670	63,076	56,531	63,424	56,739	64,627	58,418	65,151	58,507	64,167	57,503	64,824	60,803
Nonheating	6,973	8,263	6,950	8,316	6,778	8,302	6,941	8,179	6,920	7,812	6,723	8,182	7,528
	63,643	71,339	63,481	71,741	63,517	72,929	65,359	73,330	65,427	71,979	64,227	73,006	68,331
Service Classification Nos. 2, 6 & 13													
Heat*	9,737	10,467	9,667	10,544	9,705	10,958	10,126	10,842	10,208	10,895	10,026	10,847	10,335
Nonheating	1,074	1,282	1,072	1,293	1,068	1,321	1,101	1,300	1,097	1,293	1,075	1,285	1,188
	10,811	11,750	10,739	11,836	10,773	12,278	11,227	12,142	11,306	12,187	11,101	12,132	11,523
Service Classification No. 8	25	25	25	25	25	25	25	25	25	25	25	25	25
Service Classification No. 9	42	42	42	42	42	42	42	42	42	42	42	42	42
Service Classification No. 11	6	6	6	6	6	6	6	6	6	6	6	6	6
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	74,528	83,163	74,294	83,651	74,364	85,281	76,660	85,546	76,806	84,241	75,402	85,212	79,929

* Reflects Gas Expansion and EEPS as applicable

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Summary of Gas Customers & Sales by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2017)

Sales & Transport (Mcf)	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat*	87,839	50,105	54,539	148,349	308,263	610,288	779,412	994,714	824,360	712,498	410,547	235,641	5,216,556
Nonheating	4,910	4,955	4,299	6,866	8,548	15,352	16,627	22,153	17,403	16,370	10,097	8,282	135,861
Unbilled	(7,650)	(8,980)	5,610	(180)	158,160	63,700	152,050	(32,360)	(20,070)	(108,810)	(70,930)	(97,060)	33,480
	85,099	46,079	64,448	155,035	474,971	689,340	948,089	984,507	821,693	620,058	349,714	146,863	5,385,898
Service Classification Nos. 2, 6 & 13													
Heat*	167,353	149,067	166,951	227,477	444,793	803,605	1,082,601	1,107,743	918,644	664,099	394,947	214,887	6,342,168
Nonheating	43,281	43,673	45,606	51,917	57,124	80,659	68,037	93,872	83,010	73,008	53,559	48,588	742,334
Unbilled	(3,600)	(170)	(770)	1,660	28,640	11,260	19,300	3,240	(8,450)	(15,630)	(13,920)	(16,650)	4,910
	207,034	192,570	211,787	281,053	530,558	895,524	1,169,938	1,204,854	993,205	721,477	434,586	246,826	7,089,412
Service Classification No. 8	9,100	27,900	30,730	35,870	42,430	46,710	24,410	23,740	38,820	29,540	13,070	9,730	332,050
Service Classification No. 9	61,600	68,230	67,700	92,930	140,470	166,080	157,090	162,300	173,520	114,530	71,380	61,010	1,336,840
Service Classification No. 11*	92,496	87,756	93,225	132,028	239,450	325,935	412,312	357,947	332,086	189,286	117,625	78,339	2,458,485
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	120	70	60	230	1,380	2,990	5,110	5,040	4,690	2,580	1,130	240	23,640
Total Sales & Transport	455,449	422,605	467,950	697,147	1,429,259	2,126,579	2,716,949	2,738,388	2,364,014	1,677,471	987,505	543,008	16,626,325
Base Revenue ($)													
Service Classification Nos. 1 & 12													
Heat*	$ 2,198,570	$ 2,014,450	$ 1,910,120	$ 2,885,840	$ 3,970,050	$ 5,774,840	$ 6,305,590	$ 7,547,470	$ 6,529,900	$ 6,255,740	$ 4,542,310	$ 3,623,550	$ 53,558,430
Nonheating*	$ 205,260	$ 234,710	$ 199,000	$ 254,930	$ 230,630	$ 315,550	$ 288,030	$ 356,620	$ 289,550	$ 310,660	$ 239,550	$ 263,430	$ 3,187,920
Unbilled	$ 112,970	$ (237,590)	$ 233,880	$ (121,540)	$ 1,198,610	$ (193,820)	$ 750,720	$ (401,480)	$ 75,730	$ (574,450)	$ (43,150)	$ (592,620)	$ 207,260
	$ 2,516,800	$ 2,011,570	$ 2,343,000	$ 3,019,230	$ 5,399,290	$ 5,896,570	$ 7,344,340	$ 7,502,610	$ 6,895,180	$ 5,991,950	$ 4,738,710	$ 3,294,360	$ 56,953,610
Service Classification Nos. 2, 6 & 13													
Heat	$ 985,110	$ 949,020	$ 981,340	$ 1,218,090	$ 1,915,280	$ 3,118,760	$ 3,927,070	$ 4,053,430	$ 3,441,130	$ 2,681,750	$ 1,766,220	$ 1,206,080	$ 26,243,280
Nonheating	$ 175,390	$ 184,850	$ 180,310	$ 211,290	$ 226,560	$ 312,380	$ 260,550	$ 355,430	$ 302,170	$ 284,120	$ 211,740	$ 202,590	$ 2,907,380
Unbilled	$ 18,730	$ (21,950)	$ 18,000	$ (16,730)	$ 105,860	$ 3,530	$ 70,530	$ (10,860)	$ (470)	$ (59,620)	$ (15,540)	$ (68,040)	$ 23,440
	$ 1,179,230	$ 1,111,920	$ 1,179,650	$ 1,412,650	$ 2,247,700	$ 3,434,670	$ 4,258,150	$ 4,398,000	$ 3,742,830	$ 2,906,250	$ 1,962,420	$ 1,340,630	$ 29,174,100
Service Classification No. 8	$ 16,460	$ 65,220	$ 72,590	$ 79,820	$ 89,480	$ 97,500	$ 47,150	$ 46,380	$ 80,500	$ 58,910	$ 23,710	$ 17,380	$ 695,100
Service Classification No. 9	$ 108,520	$ 128,410	$ 123,820	$ 166,920	$ 238,710	$ 282,520	$ 263,100	$ 273,080	$ 292,080	$ 192,420	$ 126,850	$ 108,470	$ 2,304,900
Service Classification No. 11*	$ 182,594	$ 181,948	$ 182,765	$ 198,533	$ 247,518	$ 287,323	$ 327,079	$ 302,057	$ 290,154	$ 224,429	$ 192,109	$ 180,900	$ 2,797,411
Service Classification No. 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interdepartmental	$ 318	$ 186	$ 159	$ 610	$ 3,657	$ 7,924	$ 13,543	$ 13,357	$ 12,429	$ 6,838	$ 2,995	$ 636	$ 62,651
Total Own Territory	$ 4,003,922	$ 3,499,254	$ 3,901,984	$ 4,877,763	$ 8,226,355	$ 10,006,507	$ 12,253,362	$ 12,535,484	$ 11,313,174	$ 9,380,797	$ 7,046,794	$ 4,942,376	$ 91,987,772
Customers													
Service Classification Nos. 1 & 12													
Heat*	58,101	64,507	57,962	64,856	58,171	66,058	59,849	66,582	59,938	65,598	58,935	66,255	62,234
Nonheating	6,722	8,012	6,699	8,065	6,527	8,051	6,690	7,928	6,669	7,561	6,473	7,931	7,277
	64,824	72,519	64,661	72,921	64,698	74,109	66,540	74,510	66,607	73,160	65,407	74,186	69,512
Service Classification Nos. 2, 6 & 13													
Heat*	10,014	10,754	9,945	10,831	9,981	11,247	10,407	11,132	10,489	11,183	10,306	11,136	10,619
Nonheating	1,070	1,278	1,068	1,288	1,064	1,316	1,097	1,295	1,094	1,288	1,071	1,280	1,184
	11,084	12,032	11,013	12,119	11,046	12,563	11,503	12,427	11,583	12,471	11,377	12,416	11,803
Service Classification No. 8	25	25	25	25	25	25	25	25	25	25	25	25	25
Service Classification No. 9	42	42	42	42	42	42	42	42	42	42	42	42	42
Service Classification No. 11	6	6	6	6	6	6	6	6	6	6	6	6	6
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	75,982	84,625	75,748	85,114	75,818	86,746	78,117	87,011	78,264	85,705	76,858	86,676	81,389

* Reflects Gas Expansion and EEPS as applicable

Appendix I Sheet 20 of 20

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Summary of Gas Customers & Sales by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2018)

Sales & Transport (Mcf)	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat*	89,787	51,441	55,893	150,913	313,916	620,901	794,353	1,012,286	840,168	725,128	418,314	239,656	5,312,756
Nonheating	4,704	4,775	4,117	6,621	8,181	14,804	15,929	21,355	16,673	15,754	9,660	7,983	130,558
Unbilled	(7,650)	(8,980)	5,610	(180)	158,160	63,700	152,050	(32,360)	(20,070)	(108,810)	(70,930)	(97,060)	33,480
	86,842	47,236	65,621	157,354	480,257	699,405	962,332	1,001,281	836,771	632,072	357,044	150,579	5,476,793
Service Classification Nos. 2, 6 & 13													
Heat*	174,924	155,916	174,448	236,964	463,250	837,350	1,128,104	1,154,277	957,530	691,991	411,250	223,759	6,609,764
Nonheating	43,106	43,549	45,469	51,713	56,853	80,253	67,775	93,492	82,636	72,666	53,299	48,407	739,220
Unbilled	(3,600)	(170)	(770)	1,660	28,640	11,260	19,300	3,240	(8,450)	(15,630)	(13,920)	(16,650)	4,910
	214,431	199,295	219,148	290,338	548,744	928,862	1,215,179	1,251,010	1,031,716	749,027	450,629	255,516	7,353,893
Service Classification No. 8	9,100	27,900	30,730	35,870	42,430	46,710	24,410	23,740	38,820	29,540	13,070	9,730	332,050
Service Classification No. 9	61,600	68,230	67,700	92,930	140,470	166,080	157,090	162,300	173,520	114,530	71,380	61,010	1,336,840
Service Classification No. 11*	92,496	87,756	93,225	132,028	239,450	325,935	412,312	357,947	332,086	189,286	117,625	78,339	2,458,485
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	120	70	60	230	1,380	2,990	5,110	5,040	4,690	2,580	1,130	240	23,640
Total Sales & Transport	464,588	430,486	476,483	708,751	1,452,731	2,169,982	2,776,434	2,801,318	2,417,603	1,717,036	1,010,877	555,413	16,981,702
Base Revenue ($)													
Service Classification Nos. 1 & 12													
Heat*	$ 2,351,070	$ 2,148,850	$ 2,041,900	$ 3,078,280	$ 4,248,290	$ 6,173,820	$ 6,756,560	$ 8,074,850	$ 6,997,400	$ 6,691,110	$ 4,863,420	$ 3,867,260	$ 57,292,810
Nonheating*	$ 205,790	$ 236,740	$ 199,450	$ 257,330	$ 231,190	$ 318,900	$ 289,330	$ 360,440	$ 290,830	$ 313,370	$ 240,100	$ 265,810	$ 3,209,280
Unbilled	$ 112,970	$ (237,590)	$ 233,880	$ (121,540)	$ 1,198,610	$ (193,820)	$ 750,720	$ (401,480)	$ 75,730	$ (574,450)	$ (43,150)	$ (592,620)	$ 207,260
	$ 2,669,830	$ 2,148,000	$ 2,475,230	$ 3,214,070	$ 5,678,090	$ 6,298,900	$ 7,796,610	$ 8,033,810	$ 7,363,960	$ 6,430,030	$ 5,060,370	$ 3,540,450	$ 60,709,350
Service Classification Nos. 2, 6 & 13													
Heat	$ 1,062,340	$ 1,021,400	$ 1,058,580	$ 1,313,980	$ 2,081,490	$ 3,406,690	$ 4,307,170	$ 4,442,870	$ 3,768,400	$ 2,923,180	$ 1,916,070	$ 1,297,130	$ 28,599,300
Nonheating	$ 183,120	$ 192,950	$ 188,620	$ 220,580	$ 236,570	$ 326,200	$ 272,400	$ 372,080	$ 316,350	$ 296,620	$ 221,010	$ 211,230	$ 3,037,730
Unbilled	$ 18,730	$ (21,950)	$ 18,000	$ (16,730)	$ 105,860	$ 3,530	$ 70,530	$ (10,860)	$ (470)	$ (59,620)	$ (15,540)	$ (68,040)	$ 23,440
	$ 1,264,190	$ 1,192,400	$ 1,265,200	$ 1,517,830	$ 2,423,920	$ 3,736,420	$ 4,650,100	$ 4,804,090	$ 4,084,280	$ 3,160,180	$ 2,121,540	$ 1,440,320	$ 31,660,470
Service Classification No. 8	$ 16,460	$ 65,220	$ 72,590	$ 79,820	$ 89,480	$ 97,500	$ 47,150	$ 46,380	$ 80,500	$ 58,910	$ 23,710	$ 17,380	$ 695,100
Service Classification No. 9	$ 108,520	$ 128,410	$ 123,820	$ 166,920	$ 238,710	$ 282,520	$ 263,100	$ 273,080	$ 292,080	$ 192,420	$ 126,850	$ 108,470	$ 2,304,900
Service Classification No. 11*	$ 189,982	$ 189,321	$ 190,158	$ 206,517	$ 257,454	$ 298,865	$ 340,225	$ 314,193	$ 301,810	$ 233,435	$ 199,845	$ 188,250	$ 2,910,054
Service Classification No. 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interdepartmental	$ 339	$ 198	$ 169	$ 649	$ 3,896	$ 8,441	$ 14,426	$ 14,228	$ 13,240	$ 7,283	$ 3,190	$ 678	$ 66,736
Total Own Territory	$ 4,249,320	$ 3,723,549	$ 4,127,167	$ 5,185,806	$ 8,691,550	$ 10,722,646	$ 13,111,610	$ 13,485,781	$ 12,135,870	$ 10,082,258	$ 7,535,505	$ 5,295,547	$ 98,346,610
Customers													
Service Classification Nos. 1 & 12													
Heat*	59,533	65,938	59,394	66,287	59,602	67,489	61,280	68,013	61,369	67,030	60,366	67,686	63,666
Nonheating	6,472	7,761	6,448	7,815	6,277	7,800	6,440	7,678	6,419	7,311	6,222	7,680	7,027
	66,005	73,700	65,842	74,101	65,878	75,290	67,720	75,691	67,788	74,340	66,588	75,367	70,692
Service Classification Nos. 2, 6 & 13													
Heat*	10,291	11,039	10,219	11,116	10,256	11,536	10,685	11,418	10,768	11,471	10,582	11,421	10,900
Nonheating	1,066	1,273	1,064	1,283	1,061	1,311	1,093	1,290	1,090	1,283	1,067	1,276	1,180
	11,357	12,313	11,283	12,399	11,316	12,847	11,778	12,709	11,858	12,754	11,649	12,697	12,080
Service Classification No. 8	25	25	25	25	25	25	25	25	25	25	25	25	25
Service Classification No. 9	42	42	42	42	42	42	42	42	42	42	42	42	42
Service Classification No. 11	6	6	6	6	6	6	6	6	6	6	6	6	6
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	77,435	86,086	77,199	86,574	77,269	88,211	79,572	88,473	79,719	87,168	78,311	88,138	82,846

* Reflects Gas Expansion and EEPS as applicable

Central Hudson Gas & Electric Corporation

Cases 14-E-0318 & 14-G-0319

Electric Revenue Allocation- Rate Year 1

Incremental Revenue Requirement Excluding Taxes	(1)	**$**	**15,346,000**
Percentage On Base Rates	(2)		**5.64%**

	(3) Revenue Allocation Factor	(4) RY Sales at Current Rates	(5)=(2)x(3)x(4) Base Rev Increase	(6) Adjustment **$ 1,325,487**	(7)=(5)+(6) Total	(8) Revenue % Increase	(9) MFC Revenue from Current Base Rates	(10) Total Estimated MFC Revenue	(11)=(9)-(10) MFC Adjustment to Rate Increase	(12)=(7)+(11) Adj Base Rev Increase	(13) Adj Increase as % of System	(14) Delivery Increase Percent
SC 1 Residential	**1.00**	$ 180,287,520	$ 10,163,733	$ 960,870	$ 11,124,603	6.17%	$ 7,401,918	$ 8,083,938	$ (682,020)	$ 10,442,583	72.27%	6.04%
SC 2 Non Demand	**1.50**	$ 14,107,419	$ 1,192,961	$ 112,782	$ 1,305,743	9.26%	$ 779,874	$ 944,228	$ (164,354)	$ 1,141,389	7.90%	8.56%
SC 2 Secondary	**0.50**	$ 52,888,538	$ 1,490,799	$ 140,939	$ 1,631,738	3.09%	$ 324,352	$ 364,896	$ (40,544)	$ 1,591,194	11.01%	3.03%
SC 2 Primary	**0.75**	$ 4,631,884	$ 195,842	$ 18,515	$ 214,357	4.63%	$ 4,220	$ 4,220	$ 0	$ 214,357	1.48%	4.63%
SC 3 Primary	**0.50**	$ 5,950,932	$ 167,742	$ 15,858	$ 183,601	3.09%	$ -	$ -	$ -	$ 183,601	1.27%	3.09%
SC 5 Area Lighting	**1.50**	$ 1,419,420	$ 120,030	$ 11,348	$ 131,378	9.26%	$ 129,240	$ 131,252	$ (2,012)	$ 129,366	0.90%	10.03%
SC 6 Residential TOU	**0.50**	$ 1,352,696	$ 38,129	$ 3,605	$ 41,734	3.09%	$ 31,400	$ 36,600	$ (5,200)	$ 36,534	0.25%	2.77%
SC 8 Street Lighting	**0.75**	$ 4,863,540	$ 205,637	$ 19,441	$ 225,078	4.63%	$ 5,673	$ 6,546	$ (873)	$ 224,205	1.55%	4.62%
SC 9 Traffic Signals	**1.00**	$ 173,319	$ 9,771	$ 924	$ 10,695	6.17%	$ 6,553	$ 7,188	$ (635)	$ 10,059	0.07%	6.03%
SC 13 Substation	**1.00**	$ 1,758,496	$ 99,135	$ 9,372	$ 108,508	6.17%	$ -	$ -	$ -	$ 108,508	0.75%	6.17%
SC 13 Transmission	**1.25**	$ 4,778,451	$ 336,732	$ 31,834	$ 368,567	7.71%	$ -	$ -	$ -	$ 368,567	2.55%	7.71%
Total		$ 272,212,215	$ 14,020,513	$ 1,325,487	$ 15,346,000	5.64%	$ 8,683,230	$ 9,578,868	$ (895,638)	$ 14,450,362	100%	5.48%

Appendix J Sheet 2 of 6

Central Hudson Gas & Electric Corporation

Cases 14-E-0318 & 14-G-0319

Electric Revenue Allocation- Rate Year 2

Incremental Revenue Requirement Excluding Taxes	(1)	**$**	**15,987,000**
Percentage On Base Rates	(2)		**5.55%**

	(3) Revenue Allocation Factor	(4) RY Sales at Current Rates	(5)=(2)x(3)x(4) Base Rev Increase	(6) Adjustment **$ 1,504,705**	(7)=(5)+(6) Total	(8) Revenue % Increase	(9) MFC Revenue from Current Base Rates	(10) Total Estimated MFC Revenue	(11)=(9)-(10) MFC Adjustment to Rate Increase	(12)=(7)+(11) Adj Base Rev Increase	(13) Adj Increase as % of System	(14) Delivery Increase Percent
SC 1 Residential	**1.00**	$ 192,227,628	$ 10,672,219	$ 1,108,840	$ 11,781,059	6.13%	$ 8,129,614	$ 8,089,269	$ 40,345	$ 11,821,404	73.60%	6.42%
SC 2 Non Demand	**1.25**	$ 15,523,909	$ 1,077,333	$ 111,935	$ 1,189,268	7.66%	$ 953,797	$ 919,617	$ 34,180	$ 1,223,448	7.62%	8.40%
SC 2 Secondary	**0.50**	$ 54,179,568	$ 1,503,988	$ 156,264	$ 1,660,252	3.06%	$ 361,883	$ 361,883	$ -	$ 1,660,252	10.34%	3.08%
SC 2 Primary	**0.75**	$ 4,706,021	$ 195,954	$ 20,360	$ 216,314	4.60%	$ 4,206	$ 4,206	$ -	$ 216,314	1.35%	4.60%
SC 3 Primary	**0.75**	$ 6,114,363	$ 254,596	$ 26,452	$ 281,048	4.60%	$ -	$ -	$ -	$ 281,048	1.75%	4.60%
SC 5 Area Lighting	**1.50**	$ 1,547,192	$ 128,847	$ 13,387	$ 142,234	9.19%	$ 131,252	$ 131,252	$ -	$ 142,234	0.89%	10.05%
SC 6 Residential TOU	**0.50**	$ 1,394,424	$ 38,708	$ 4,022	$ 42,730	3.06%	$ 36,600	$ 36,600	$ -	$ 42,730	0.27%	3.15%
SC 8 Street Lighting	**0.75**	$ 5,060,706	$ 210,723	$ 21,894	$ 232,617	4.60%	$ 6,546	$ 6,546	$ -	$ 232,617	1.45%	4.60%
SC 9 Traffic Signals	**1.00**	$ 184,014	$ 10,216	$ 1,061	$ 11,278	6.13%	$ 7,188	$ 7,188	$ -	$ 11,278	0.07%	6.38%
SC 13 Substation	**1.00**	$ 1,868,160	$ 103,718	$ 10,776	$ 114,494	6.13%	$ -	$ -	$ -	$ 114,494	0.71%	6.13%
SC 13 Transmission	**1.00**	$ 5,151,288	$ 285,993	$ 29,715	$ 315,707	6.13%	$ -	$ -	$ -	$ 315,707	1.97%	6.13%
Total		$ 287,957,273	$ 14,482,295	$ 1,504,705	$ 15,987,000	5.55%	$ 9,631,087	$ 9,556,561	$ 74,526	$ 16,061,526	100%	5.77%

Appendix J Sheet 3 of 6

Central Hudson Gas & Electric Corporation

Cases 14-E-0318 & 14-G-0319

Electric Revenue Allocation- Rate Year 3

Incremental Revenue Requirement Excluding Taxes	(1)	**$**	**14,100,000**
Percentage On Base Rates	(2)		**4.62%**

	(3) Revenue Allocation Factor	(4) RY Sales at Current Rates	(5)=(2)x(3)x(4) Base Rev Increase	(6) Adjustment **$ 1,297,572**	(7)=(5)+(6) Total	(8) Revenue % Increase	(9) MFC Revenue from Current Base Rates	(10) Total Estimated MFC Revenue	(11)=(9)-(10) MFC Adjustment to Rate Increase	(12)=(7)+(11) Adj Base Rev Increase	(13) Adj Increase as % of System	(14) Delivery Increase Percent
SC 1 Residential	**1.00**	$ 204,596,122	$ 9,445,525	$ 957,338	$ 10,402,863	5.08%	$ 8,120,122	$ 8,079,622	$ 40,499	$ 10,443,363	73.83%	5.32%
SC 2 Non Demand	**1.25**	$ 16,804,354	$ 969,752	$ 98,288	$ 1,068,040	6.36%	$ 926,883	$ 921,961	$ 4,922	$ 1,072,961	7.59%	6.76%
SC 2 Secondary	**0.50**	$ 56,465,631	$ 1,303,416	$ 132,106	$ 1,435,521	2.54%	$ 365,355	$ 365,355	$ -	$ 1,435,521	10.15%	2.56%
SC 2 Primary	**0.75**	$ 5,074,477	$ 175,704	$ 17,808	$ 193,512	3.81%	$ 4,232	$ 4,232	$ -	$ 193,512	1.37%	3.82%
SC 3 Primary	**0.75**	$ 6,433,279	$ 222,752	$ 22,577	$ 245,329	3.81%	$ -	$ -	$ -	$ 245,329	1.73%	3.81%
SC 5 Area Lighting	**1.50**	$ 1,680,392	$ 116,367	$ 11,794	$ 128,161	7.63%	$ 131,252	$ 131,252	$ -	$ 128,161	0.91%	8.27%
SC 6 Residential TOU	**0.50**	$ 1,437,388	$ 33,180	$ 3,363	$ 36,543	2.54%	$ 36,600	$ 36,600	$ -	$ 36,543	0.26%	2.61%
SC 8 Street Lighting	**0.75**	$ 5,276,346	$ 182,694	$ 18,517	$ 201,210	3.81%	$ 6,546	$ 6,546	$ -	$ 201,210	1.42%	3.82%
SC 9 Traffic Signals	**1.00**	$ 195,364	$ 9,019	$ 914	$ 9,933	5.08%	$ 7,188	$ 7,188	$ -	$ 9,933	0.07%	5.28%
SC 13 Substation	**1.00**	$ 1,981,928	$ 91,499	$ 9,274	$ 100,773	5.08%	$ -	$ -	$ -	$ 100,773	0.71%	5.08%
SC 13 Transmission	**1.00**	$ 5,469,747	$ 252,520	$ 25,594	$ 278,114	5.08%	$ -	$ -	$ -	$ 278,114	1.97%	5.08%
Total		$ 305,415,028	$ 12,802,428	$ 1,297,572	$ 14,100,000	4.62%	$ 9,598,178	$ 9,552,757	$ 45,421	$ 14,145,421	100%	4.78%

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319

Gas Revenue Allocation - Rate Year 1

Incremental Revenue Requirement	(1)	**$ 4,827,000**
Percentage On Base Rates	(2)	**6.01%**

	(3) Revenue Allocation Factor	(4) RY Block Revs at Current Rates (Incl MFC)	(5)=(2)x(3)x(4) Base Rev Increase	(6) Adjustment $ (720,301)	(7)=(5)+(6) Total	(8) Revenue % Increase	(9) MFC Revenue from Current MFC Rates	(10) Total Estimated MFC Revenue	(11)=(9)-(10) MFC Adjustment to Rate Increase	(12)=(7)+(11) Adj Base Rev Increase	(13) Adj Increase as % of System	(14) Delivery Increase Percent
SC 1 & 12	1.00	$ 51,496,818	$ 3,095,693	$ (401,967)	$ 2,693,726	5.23%	$ 1,143,855	$ 942,154	$ 201,701	$ 2,895,427	56.09%	5.75%
SC 2, 6 & 13	1.50	$ 26,200,565	$ 2,362,541	$ (306,769)	$ 2,055,772	7.85%	$ 1,363,604	$ 1,231,401	$ 132,203	$ 2,187,975	42.40%	8.81%
SC 11 Transmission	0.50	$ 1,543,920	$ 46,406	$ (6,026)	$ 40,380	2.62%	$ -	$ -	$ -	$ 40,380	0.78%	2.62%
SC 11 Distribution	0.50	$ 328,725	$ 9,881	$ (1,283)	$ 8,598	2.62%	$ -	$ -	$ -	$ 8,598	0.17%	2.62%
SC 11 - DLM	0.75	$ 727,056	$ 32,780	$ (4,256)	$ 28,523	3.92%	$ -	$ -	$ -	$ 28,523	0.55%	3.92%
Total		80,297,083	$ 5,547,301	$ (720,301)	$ 4,827,000		$ 2,507,458	$ 2,173,555	$ 333,903	$ 5,160,903	100.00%	6.63%

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319

Gas Revenue Allocation - Rate Year 2

Incremental Revenue Requirement	(1)	**$ 7,633,000**
Percentage On Base Rates	(2)	**9.08%**

	(3) Revenue Allocation Factor	(4) RY Block Revs at Current Rates (Incl MFC)	(5)=(2)x(3)x(4) Base Rev Increase	(6) Adjustment $ (1,148,484)	(7)=(5)+(6) Total	(8) Revenue % Increase	(9) MFC Revenue from Current MFC Rates	(10) Total Estimated MFC Revenue	(11)=(9)-(10) MFC Adjustment to Rate Increase	(12)=(7)+(11) Adj Base Rev Increase	(13) Adj Increase as % of System	(14) Delivery Increase Percent
SC 1 & 12	1.00	$ 53,791,940	$ 4,884,203	$ (638,779)	$ 4,245,424	7.89%	$ 958,600	$ 942,154	$ 16,446	$ 4,261,870	55.36%	8.07%
SC 2, 6 & 13	1.50	$ 27,596,720	$ 3,758,593	$ (491,566)	$ 3,267,026	11.84%	$ 1,279,440	$ 1,231,401	$ 48,039	$ 3,315,065	43.07%	12.60%
SC 11 Transmission	0.50	$ 1,584,038	$ 71,914	$ (9,405)	$ 62,509	3.95%	$ -	$ -	$ -	$ 62,509	0.81%	3.95%
SC 11 Distribution	0.50	$ 337,298	$ 15,313	$ (2,003)	$ 13,310	3.95%	$ -	$ -	$ -	$ 13,310	0.17%	3.95%
SC 11 - DLM	0.75	$ 755,686	$ 51,461	$ (6,730)	$ 44,731	5.92%	$ -	$ -	$ -	$ 44,731	0.58%	5.92%
Total		84,065,683	$ 8,781,484	$ (1,148,484)	$ 7,633,000		$ 2,238,040	$ 2,173,555	$ 64,485	$ 7,697,485	100.00%	9.41%

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319

Gas Revenue Allocation - Rate Year 3

Incremental Revenue Requirement	(1)	**$ 7,379,000**
Percentage On Base Rates	(2)	**8.14%**

	(3) Revenue Allocation Factor	(4) RY Block Revs at Current Rates (Incl MFC)	(5)=(2)x(3)x(4) Base Rev Increase	(6) Adjustment $ (1,130,086)	(7)=(5)+(6) Total	(8) Revenue % Increase	(9) MFC Revenue from Current MFC Rates	(10) Total Estimated MFC Revenue	(11)=(9)-(10) MFC Adjustment to Rate Increase	(12)=(7)+(11) Adj Base Rev Increase	(13) Adj Increase as % of System	(14) Delivery Increase Percent
SC 1 & 12	1.00	$ 57,705,790	$ 4,696,089	$ (623,684)	$ 4,072,404	7.06%	$ 958,020	$ 942,154	$ 15,866	$ 4,088,270	54.97%	7.20%
SC 2, 6 & 13	1.50	$ 30,170,350	$ 3,682,888	$ (489,122)	$ 3,193,766	10.59%	$ 1,272,860	$ 1,231,401	$ 41,459	$ 3,235,225	43.51%	11.20%
SC 11 Transmission	0.50	$ 1,646,466	$ 66,995	$ (8,898)	$ 58,097	3.53%	$ -	$ -	$ -	$ 58,097	0.78%	3.53%
SC 11 Distribution	0.50	$ 350,616	$ 14,267	$ (1,895)	$ 12,372	3.53%	$ -	$ -	$ -	$ 12,372	0.17%	3.53%
SC 11 - DLM	0.75	$ 800,329	$ 48,848	$ (6,487)	$ 42,361	5.29%	$ -	$ -	$ -	$ 42,361	0.57%	5.29%
Total		90,673,551	$ 8,509,086	$ (1,130,086)	$ 7,379,000		$ 2,230,880	$ 2,173,555	$ 57,325	$ 7,436,325	100.00%	8.41%

Central Hudson Gas and Electric Corporation
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Electric Billing Determinants
(Excludes S.C. Nos. 5 & 8, Unbilled & Interdepartmental)

		Rate Year 1	Rate Year 2	Rate Year 3
S.C. No. 1				
	Customer Months	3,055,450	3,061,000	3,066,066
	kWh	2,005,940,000	2,017,274,000	2,024,968,000
S.C. No. 2 - Non-Demand				
	Customer Months	353,717	355,846	357,654
	kWh	161,131,000	162,764,000	164,050,000
S.C. No. 2 - Secondary				
	Customer Months	140,527	140,706	142,941
	kWh	1,351,468,000	1,340,308,000	1,353,168,000
	kW	4,131,110	4,095,400	4,136,440
S.C. No. 2 - Primary				
	Customer Months	1,953	1,960	1,980
	kWh	210,990,000	210,303,000	211,593,000
	kW	557,890	537,890	557,890
S.C. No. 3				
	Customer Months	388	390	395
	kWh	270,294,000	269,264,000	270,754,000
	kW	606,461	604,149	607,500
	Rkva	129,233	128,742	129,523
S.C. No. 6				
	Customer Months	13,800	13,800	13,800
	On-Peak kWh	6,800,000	6,800,000	6,800,000
	Off-Peak kWh	13,200,000	13,200,000	13,200,000
S.C. No. 9 - Traffic Signals				
	Signal Face Months	56,340	56,340	56,340
	kWh	2,540,000	2,540,000	2,540,000
S.C. No. 13 - Substation				
	Customer Months	72	72	72
	kWh	130,170,000	130,170,000	130,170,000
	kW	234,877	234,877	234,877
	Rkva	59,860	59,860	59,860
S.C. No. 13 - Transmission				
	Customer Months	72	72	72
	kWh	752,830,000	752,830,000	752,830,000
	kW	1,242,911	1,242,911	1,242,911
	Rkva	50,700	50,700	50,700

Appendix K Sheet 2 of 8

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Summary of Proposed Monthly Electric Base Delivery Rates
(Excludes S.C. Nos. 5 & 8, Unbilled & Interdepartmental)

		Current Rates	Rate Year 1 July 1, 2015	Rate Year 2 July 1, 2016	Rate Year 3 July 1, 2017
S.C. No. 1					
	Customer Charge	$ 24.00	$ 27.00	$ 28.00	$ 29.00
	kWh Delivery	$ 0.04963	$ 0.05027	$ 0.05461	$ 0.05825
S.C. No. 2 - Non-Demand					
	Customer Charge	$ 35.00	$ 38.00	$ 41.00	$ 44.00
	kWh Delivery	$ 0.00588	$ 0.00638	$ 0.00734	$ 0.00784
S.C. No. 2 - Secondary					
	Customer Charge	$ 84.00	$ 84.00	$ 84.00	$ 84.00
	HPP Customer Charge	$ 84.00	$ 114.00	$ 114.00	$ 114.00
	kWh Delivery	$ 0.00540	$ 0.00556	$ 0.00573	$ 0.00591
	kW Delivery	$ 8.10	$ 8.42	$ 8.77	$ 9.06
S.C. No. 2 - Primary					
	Customer Charge	$ 310.00	$ 310.00	$ 310.00	$ 310.00
	HPP Customer Charge	$ 310.00	$ 340.00	$ 340.00	$ 340.00
	kWh Delivery	$ 0.00148	$ 0.00155	$ 0.00162	$ 0.00168
	kW Delivery	$ 6.65	$ 6.95	$ 7.32	$ 7.64
S.C. No. 3					
	Customer Charge	$ 1,400.00	$ 1,400.00	$ 1,450.00	$ 1,500.00
	kWh Delivery	$ -	$ -	$ -	$ -
	kW Delivery	$ 8.74	$ 9.04	$ 9.47	$ 9.84
	Rkva	$ 0.83	$ 0.83	$ 0.83	$ 0.83
S.C. No. 6					
	Customer Charge	$ 27.00	$ 30.00	$ 31.00	$ 32.00
	kWh Delivery On Pk	$ 0.06144	$ 0.08427	$ 0.08687	$ 0.08891
	kWh Delivery Off Pk	$ 0.04022	$ 0.02809	$ 0.02896	$ 0.02964
S.C. No. 9					
	Signal Faces	$ 2.96	$ 3.14	$ 3.34	$ 3.52
S.C. No. 13 - Substation					
	Customer Charge	$ 2,040.00	$ 3,400.00	$ 3,610.00	$ 3,800.00
	kWh Delivery	$ -	$ -	$ -	$ -
	kW Delivery	$ 6.65	$ 6.70	$ 7.12	$ 7.49
	Rkva	$ 0.83	$ 0.83	$ 0.83	$ 0.83
S.C. No. 13 - Transmission					
	Customer Charge	$ 3,810.00	$ 4,500.00	$ 4,780.00	$ 5,020.00
	kWh Delivery	$ -	$ -	$ -	$ -
	kW Delivery	$ 3.59	$ 3.85	$ 4.09	$ 4.30
	Rkva	$ 0.83	$ 0.83	$ 0.83	$ 0.83

Summary of Proposed Electric Merchant Function Charges

	Current Rates	Rate Year 1 July 1, 2015	Rate Year 2 July 1, 2016	Rate Year 3 July 1, 2017
MFC Administration Charge per kWh				
S.C. No. 1 - Residential	$ 0.00183	$ 0.00165	$ 0.00164	$ 0.00163
S.C. No. 2 - Non Demand	$ 0.00240	$ 0.00234	$ 0.00231	$ 0.00230
S.C. No. 2 - Primary Demand	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001
S.C. No. 2 - Secondary Demand	$ 0.00012	$ 0.00011	$ 0.00011	$ 0.00011
S.C. No. 3 - Large Power Primary	$ -	$ -	$ -	$ -
S.C. No. 5 - Area Lighting	$ 0.00510	$ 0.00427	$ 0.00427	$ 0.00427
S.C. No. 6 - Residential Time-of-Use	$ 0.00078	$ 0.00075	$ 0.00075	$ 0.00075
S.C. No. 8 - Street Lighting	$ 0.00013	$ 0.00012	$ 0.00012	$ 0.00012
S.C. No. 9 - Traffic Signals	$ 0.00128	$ 0.00116	$ 0.00116	$ 0.00116
S.C. No. 13 - Substation	$ -	$ -	$ -	$ -
S.C. No. 13 - Transmission	$ -	$ -	$ -	$ -
MFC Supply Charge per kWh				
S.C. No. 1 - Residential	$ 0.00186	$ 0.00238	$ 0.00237	$ 0.00236
S.C. No. 2 - Non Demand	$ 0.00244	$ 0.00338	$ 0.00334	$ 0.00332
S.C. No. 2 - Primary Demand	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001
S.C. No. 2 - Secondary Demand	$ 0.00012	$ 0.00016	$ 0.00016	$ 0.00016
S.C. No. 3 - Large Power Primary	$ -	$ -	$ -	$ -
S.C. No. 5 - Area Lighting	$ 0.00519	$ 0.00618	$ 0.00618	$ 0.00618
S.C. No. 6 - Residential Time-of-Use	$ 0.00079	$ 0.00108	$ 0.00108	$ 0.00108
S.C. No. 8 - Street Lighting	$ 0.00013	$ 0.00018	$ 0.00018	$ 0.00018
S.C. No. 9 - Traffic Signals	$ 0.00130	$ 0.00167	$ 0.00167	$ 0.00167
S.C. No. 13 - Substation	$ -	$ -	$ -	$ -
S.C. No. 13 - Transmission	$ -	$ -	$ -	$ -

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Summary of Proposed Electric Bill Credit

		Current Rates	Rate Year 1 July 1, 2015	Rate Year 2 July 1, 2016	Rate Year 3 July 1, 2017
S.C. No. 1 - Residential	per kWh	$ -	$ (0.00468)	$ (0.00438)	$ (0.00073)
S.C. No. 2 - Non Demand	per kWh	$ -	$ (0.00637)	$ (0.00562)	$ (0.00093)
S.C. No. 2 - Primary Demand	per kWh	$ -	$ (0.00091)	$ (0.00077)	$ (0.00013)
S.C. No. 2 - Secondary Demand	per kWh	$ -	$ (0.00106)	$ (0.00093)	$ (0.00015)
S.C. No. 3 - Large Power Primary	per kW	$ -	$ (0.27000)	$ (0.35000)	$ (0.06000)
S.C. No. 5 - Area Lighting	per kWh	$ -	$ (0.00924)	$ (0.00844)	$ (0.00143)
S.C. No. 6 - Residential Time-of-Use	per kWh	$ -	$ (0.00165)	$ (0.00160)	$ (0.00025)
S.C. No. 8 - Street Lighting	per kWh	$ -	$ (0.00926)	$ (0.00797)	$ (0.00128)
S.C. No. 9 - Traffic Signals	per kWh	$ -	$ (0.00354)	$ (0.00315)	$ (0.00039)
S.C. No. 13 - Substation	per kW	$ -	$ (0.42000)	$ (0.37000)	$ (0.06000)
S.C. No. 13 - Transmission	per kW	$ -	$ (0.27000)	$ (0.19000)	$ (0.03000)

Gas Billing Determinants
(Excludes Unbilled)

		Rate Year 1	Rate Year 2	Rate Year 3
S.C. No. 1 & 12 Res. Heat	Block 1 - Customer Months	729,639	746,813	763,987
	Block 1 - Mcf - Included in Customer Charge	135,621	138,244	140,850
	Block 2 - Mcf	2,339,500	2,383,742	2,427,960
	Block 3 - Mcf	2,645,168	2,694,570	2,743,946
S.C. No. 1 & 12 Res. Non-Heat	Block 1 - Customer Months	90,338	87,330	84,322
	Block 1 - Mcf - Included in Customer Charge	14,553	13,996	13,440
	Block 2 - Mcf	93,280	89,734	86,230
	Block 3 - Mcf	33,399	32,131	30,888
S.C. No. 2, 6 & 13 Heat	Block 1 - Customer Months	124,021	127,424	130,801
	Block 1 - Mcf - Included in Customer Charge	20,799	21,787	22,711
	Block 2 - Mcf	713,874	747,819	779,460
	Block 3 - Mcf	4,060,596	4,254,328	4,433,865
	Block 4 - Mcf	1,258,056	1,318,234	1,373,728
S.C. No. 2, 6 & 13 Non-Heat	Block 1 - Customer Months	14,260	14,209	14,158
	Block 1 - Mcf - Included in Customer Charge	2,448	2,440	2,431
	Block 2 - Mcf	74,890	74,690	74,374
	Block 3 - Mcf	322,582	321,733	320,361
	Block 4 - Mcf	344,380	343,471	342,054
S.C. No. 11 Transmission				
Annual x<300k Mcf	Block 1 - Customer Months	12	12	12
	Block 1 - Mcf - Included in Customer Charge	60,000	60,000	60,000
	Block 2 - Mcf	127,100	127,100	127,100
Annual 300k<x<800k Mcf	Block 1 - Customer Months	12	12	12
	Block 1 - Mcf - Included in Customer Charge	120,000	120,000	120,000
	Block 2 - Mcf	380,805	380,805	380,805
Annual x>800k Mcf	Block 1 - Customer Months	12	12	12
	Block 1 - Mcf - Included in Customer Charge	354,430	354,430	354,430
	Block 2 - Mcf	451,221	451,221	451,221
S.C. No. 11 Distribution				
Annual x<100k Mcf	Block 1 - Customer Months	12	12	12
	Block 1 - Mcf - Included in Customer Charge	38,666	38,666	38,666
	Block 2 - Mcf	21,280	21,280	21,280
Annual x>=100k Mcf	Block 1 - Customer Months	12	12	12
	Block 1 - Mcf - Included in Customer Charge	79,815	79,815	79,815
	Block 2 - Mcf	86,607	86,607	86,607
S.C. No. 11 - DLM	Block 1 - Customer Months	12	12	12
	Block 1 - Mcf - Included in Customer Charge	345,690	345,690	345,690
	Block 2 - Mcf	392,871	392,871	392,871
Interdepartmental (S.C. No. 2)	Block 4 - Mcf	23,640	23,640	23,640

Appendix K Sheet 6 of 8

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Summary of Proposed Monthly Gas Base Delivery Rates

			Current Rates	Rate Year 1 July 1, 2015	Rate Year 2 July 1, 2016	Rate Year 3 July 1, 2017
S.C. No. 1 & 12						
	Billing Block 1	First 2 Ccf	$ 23.00	$ 24.00	$ 25.00	$ 26.00
	Billing Block 2 per Ccf	Next 48 Ccf	$ 0.8603	$ 0.8805	$ 0.9390	$ 0.9904
	Billing Block 3 per Ccf	Additional	$ 0.3944	$ 0.4047	$ 0.4300	$ 0.4542
S.C. No. 2, 6 & 13						
	Billing Block 1	First 2 Ccf	$ 37.00	$ 37.00	$ 38.00	$ 39.00
	Billing Block 2 per Ccf	Next 98 Ccf	$ 0.5494	$ 0.5494	$ 0.5494	$ 0.5494
	Billing Block 3 per Ccf	Next 4900 Ccf	$ 0.2704	$ 0.2793	$ 0.3039	$ 0.3262
	Billing Block 4 per Ccf	Additional	$ 0.2206	$ 0.2273	$ 0.2477	$ 0.2656
S.C. No. 11 Transmission*						
	Customer Charge		$ 1,200.00	N/A	N/A	N/A
	MDQ		$ 9.25	N/A	N/A	N/A
S.C. No. 11 Distribution*						
	Customer Charge		$ 1,200.00	N/A	N/A	N/A
	MDQ		$ 18.75	N/A	N/A	N/A
S.C. No. 11 DLM*						
	Customer Charge		$ 1,200.00	N/A	N/A	N/A
	MDQ		$ 12.12	N/A	N/A	N/A
S.C. No. 11 EG*						
	Customer Charge		N/A	$ 1,200.00	$ 1,200.00	$ 1,200.00
	MDQ		N/A	$ 9.25	$ 9.25	$ 9.25
S.C. No. 11 Transmission						
Annual x<300k Mcf	Billing Block 1	First 50,000 Ccf	N/A	$ 7,000	$ 7,300	$ 7,500
	Billing Block 2 per Ccf	Additional	N/A	$ 0.0274	$ 0.0283	$ 0.0298
Annual 300k<x<800k Mcf	Billing Block 1	First 100,000 Ccf	N/A	$ 35,000	$ 36,600	$ 38,200
	Billing Block 2 per Ccf	Additional	N/A	$ 0.0431	$ 0.0441	$ 0.0447
Annual x>800k Mcf	Billing Block 1	First 300,000 Ccf	N/A	$ 60,000	$ 62,100	$ 64,300
	Billing Block 2 per Ccf	Additional	N/A	$ 0.0357	$ 0.0378	$ 0.0391
S.C. No. 11 Distribution						
Annual x<100k Mcf	Billing Block 1	First 40,000 Ccf	N/A	$ 7,000	$ 7,300	$ 7,500
	Billing Block 2 per Ccf	Additional	N/A	$ 0.0577	$ 0.0586	$ 0.0639
Annual x>=100k Mcf	Billing Block 1	First 70,000 Ccf	N/A	$ 16,000	$ 16,700	$ 17,200
	Billing Block 2 per Ccf	Additional	N/A	$ 0.0566	$ 0.0579	$ 0.0612
S.C. No. 11 DLM	Billing Block 1	First 300,000 Ccf	N/A	$ 45,000	$ 48,000	$ 50,600
	Billing Block 2 per Ccf	Additional	N/A	$ 0.0549	$ 0.0571	$ 0.0599

* Please refer to Section IX.B on S.C. No. 11 Rate Design.

Central Hudson Gas and Electric Corporation
Cases 14-E-0318;14-G-0319

Gas Commodity Related Merchant Function Charges

		Current Rates	Rate Year 1 July 1, 2015	Rate Year 2 July 1, 2016	Rate Year 3 July 1, 2017
MFC Administration Charge per Ccf					
MFC-1	1, 12 & 16	$ 0.00960	$ 0.00449	$ 0.00441	$ 0.00434
MFC-2	2, 6, 13 & 15	$ 0.00886	$ 0.00453	$ 0.00434	$ 0.00419
MFC Supply Charge per Ccf					
MFC-1	1, 12 & 16	$ 0.01214	$ 0.01342	$ 0.01319	$ 0.01297
MFC-2	2, 6, 13 & 15	$ 0.01120	$ 0.01353	$ 0.01298	$ 0.01251

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Summary of Proposed Monthly Gas Bill Credit Rates

Applicable to S.C. No.		$/Ccf Rate Year 1 July 1, 2015	$/Ccf Rate Year 2 July 1, 2016	$/Ccf Rate Year 3 July 1, 2017
1, 12 & 16		$ (0.02716)	$ (0.01759)	$ -
2, 6, 13 & 15		$ (0.01589)	$ (0.01034)	$ -
SC 11 Transmission	Annual x<300k Mcf	$ (0.00082)	$ (0.00055)	$ -
SC 11 Transmission	Annual 300k<x<800k Mcf	$ (0.00148)	$ (0.00102)	$ -
SC 11 Transmission	Annual x>800k Mcf	$ (0.00139)	$ (0.00095)	$ -
SC 11 Distribution	Annual x<100k Mcf	$ (0.00213)	$ (0.00142)	$ -
SC 11 Distribution	Annual x>=100k Mcf	$ (0.00184)	$ (0.00123)	$ -
SC 11 - DLM		$ (0.00190)	$ (0.00134)	$ -
SC 11 - EG*		$ -	$ -	$ -

Gas bill credit rates reflect rate moderation as described in Section III.D excluding the additional $4 million credit for illustration purposes.
* No rate increase to SC 11 - EG therefore no rate moderation allocated to that class.

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric Bill Impacts

S.C. No. 1 - Non Heating

Rate Year 1

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	490	520	550	580	610	640	670	700	730
Present Bill	$ 94.09	$ 98.35	$ 102.61	$ 106.86	$ 111.12	$ 115.38	$ 119.63	$ 123.89	$ 128.15
Without Rate Moderation									
Proposed Bill	$ 97.52	$ 101.80	$ 106.08	$ 110.36	$ 114.64	$ 118.92	$ 123.20	$ 127.48	$ 131.75
$ Delivery Rate Increase	$ 3.43	$ 3.45	$ 3.48	$ 3.50	$ 3.52	$ 3.54	$ 3.56	$ 3.59	$ 3.61
% Increase	3.65%	3.51%	3.39%	3.27%	3.17%	3.07%	2.98%	2.89%	2.82%
With Rate Moderation									
EBC Reduction	$ (2.35)	$ (2.49)	$ (2.63)	$ (2.78)	$ (2.92)	$ (3.07)	$ (3.21)	$ (3.35)	$ (3.50)
Proposed Bill	$ 95.18	$ 99.31	$ 103.45	$ 107.58	$ 111.72	$ 115.85	$ 119.99	$ 124.12	$ 128.26
$ Delivery Rate Increase	$ 1.08	$ 0.96	$ 0.84	$ 0.72	$ 0.60	$ 0.48	$ 0.35	$ 0.23	$ 0.11
% Increase	1.14%	0.97%	0.81%	0.67%	0.53%	0.41%	0.30%	0.19%	0.09%

Rate Year 2

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	500	530	560	590	620	650	680	710	740
Present Bill	$ 95.79	$ 99.93	$ 104.06	$ 108.20	$ 112.33	$ 116.47	$ 120.61	$ 124.74	$ 128.88
Without Rate Moderation									
Proposed Bill	$ 102.16	$ 106.57	$ 110.98	$ 115.39	$ 119.80	$ 124.21	$ 128.62	$ 133.03	$ 137.44
$ Delivery Rate Increase	$ 6.36	$ 6.64	$ 6.91	$ 7.19	$ 7.46	$ 7.74	$ 8.01	$ 8.29	$ 8.56
% Increase	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%
With Rate Moderation									
EBC Reduction	$ (2.24)	$ (2.38)	$ (2.51)	$ (2.65)	$ (2.78)	$ (2.91)	$ (3.05)	$ (3.18)	$ (3.32)
Proposed Bill	$ 99.92	$ 104.19	$ 108.47	$ 112.74	$ 117.02	$ 121.29	$ 125.57	$ 129.84	$ 134.12
$ Delivery Rate Increase	$ 4.12	$ 4.26	$ 4.40	$ 4.54	$ 4.68	$ 4.82	$ 4.96	$ 5.10	$ 5.24
% Increase	4.30%	4.26%	4.23%	4.20%	4.17%	4.14%	4.11%	4.09%	4.07%

Rate Year 3

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	500	530	560	590	620	650	680	710	740
Present Bill	$ 99.92	$ 104.19	$ 108.47	$ 112.74	$ 117.02	$ 121.29	$ 125.57	$ 129.84	$ 134.12
Without Rate Moderation									
Proposed Bill	$ 105.03	$ 109.55	$ 114.07	$ 118.59	$ 123.12	$ 127.64	$ 132.16	$ 136.68	$ 141.20
$ Delivery Rate Increase	$ 5.12	$ 5.36	$ 5.61	$ 5.85	$ 6.10	$ 6.34	$ 6.59	$ 6.84	$ 7.08
% Increase	5.12%	5.15%	5.17%	5.19%	5.21%	5.23%	5.25%	5.26%	5.28%
With Rate Moderation									
EBC Reduction	$ (0.37)	$ (0.40)	$ (0.42)	$ (0.44)	$ (0.46)	$ (0.49)	$ (0.51)	$ (0.53)	$ (0.55)
Proposed Bill	$ 104.66	$ 109.16	$ 113.66	$ 118.15	$ 122.65	$ 127.15	$ 131.65	$ 136.15	$ 140.65
$ Delivery Rate Increase	$ 4.74	$ 4.97	$ 5.19	$ 5.41	$ 5.64	$ 5.86	$ 6.08	$ 6.30	$ 6.53
% Increase	4.53%	4.55%	4.57%	4.58%	4.59%	4.61%	4.62%	4.63%	4.64%

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric Bill Impacts

S.C. No. 1 - Heating

Rate Year 1

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	5,550	5,900	6,250	6,590	6,940	7,290	7,630	7,980	8,330
Present Bill	$ 812.06	$ 861.72	$ 911.38	$ 959.63	$ 1,009.29	$ 1,058.95	$ 1,107.19	$ 1,156.85	$ 1,206.51
Without Rate Moderation									
Proposed Bill	$ 819.21	$ 869.13	$ 919.05	$ 967.55	$ 1,017.47	$ 1,067.38	$ 1,115.88	$ 1,165.80	$ 1,215.72
$ Delivery Rate Increase	$ 7.16	$ 7.41	$ 7.67	$ 7.92	$ 8.18	$ 8.44	$ 8.69	$ 8.94	$ 9.20
% Increase	0.88%	0.86%	0.84%	0.83%	0.81%	0.80%	0.78%	0.77%	0.76%
With Rate Moderation									
EBC Reduction	$ (26.59)	$ (28.26)	$ (29.94)	$ (31.57)	$ (33.25)	$ (34.92)	$ (36.55)	$ (38.23)	$ (39.90)
Proposed Bill	$ 792.63	$ 840.87	$ 889.11	$ 935.98	$ 984.22	$ 1,032.46	$ 1,079.33	$ 1,127.57	$ 1,175.81
$ Delivery Rate Increase	$ (19.43)	$ (20.85)	$ (22.27)	$ (23.65)	$ (25.07)	$ (26.49)	$ (27.86)	$ (29.28)	$ (30.70)
% Increase	-2.45%	-2.48%	-2.50%	-2.53%	-2.55%	-2.57%	-2.58%	-2.60%	-2.61%

Rate Year 2

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	5,630	5,980	6,340	6,690	7,040	7,390	7,740	8,100	8,450
Present Bill	$ 803.65	$ 851.90	$ 901.52	$ 949.76	$ 998.00	$ 1,046.25	$ 1,094.49	$ 1,144.11	$ 1,192.35
Without Rate Moderation									
Proposed Bill	$ 856.23	$ 907.68	$ 960.60	$ 1,012.04	$ 1,063.49	$ 1,114.94	$ 1,166.39	$ 1,219.30	$ 1,270.75
$ Delivery Rate Increase	$ 52.58	$ 55.78	$ 59.08	$ 62.28	$ 65.49	$ 68.69	$ 71.90	$ 75.19	$ 78.40
% Increase	6.54%	6.55%	6.55%	6.56%	6.56%	6.57%	6.57%	6.57%	6.58%
With Rate Moderation									
EBC Reduction	$ (25.24)	$ (26.81)	$ (28.42)	$ (29.99)	$ (31.56)	$ (33.13)	$ (34.70)	$ (36.32)	$ (37.88)
Proposed Bill	$ 830.99	$ 880.87	$ 932.17	$ 982.05	$ 1,031.93	$ 1,081.81	$ 1,131.68	$ 1,182.99	$ 1,232.87
$ Delivery Rate Increase	$ 27.33	$ 28.97	$ 30.65	$ 32.29	$ 33.92	$ 35.56	$ 37.20	$ 38.88	$ 40.51
% Increase	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%

Rate Year 3

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	5,710	6,070	6,430	6,780	7,140	7,500	7,850	8,210	8,570
Present Bill	$ 842.39	$ 893.69	$ 945.00	$ 994.87	$ 1,046.18	$ 1,097.48	$ 1,147.36	$ 1,198.66	$ 1,249.97
Without Rate Moderation									
Proposed Bill	$ 890.15	$ 944.40	$ 998.65	$ 1,051.40	$ 1,105.65	$ 1,159.90	$ 1,212.64	$ 1,266.89	$ 1,321.14
$ Delivery Rate Increase	$ 47.76	$ 50.71	$ 53.66	$ 56.52	$ 59.47	$ 62.41	$ 65.28	$ 68.23	$ 71.17
% Increase	5.67%	5.67%	5.68%	5.68%	5.68%	5.69%	5.69%	5.69%	5.69%
With Rate Moderation									
EBC Reduction	$ (4.27)	$ (4.54)	$ (4.80)	$ (5.07)	$ (5.34)	$ (5.60)	$ (5.87)	$ (6.13)	$ (6.40)
Proposed Bill	$ 885.88	$ 939.87	$ 993.85	$ 1,046.33	$ 1,100.31	$ 1,154.29	$ 1,206.77	$ 1,260.75	$ 1,314.73
$ Delivery Rate Increase	$ 43.50	$ 46.17	$ 48.85	$ 51.45	$ 54.13	$ 56.81	$ 59.41	$ 62.09	$ 64.77
% Increase	4.91%	4.91%	4.92%	4.92%	4.92%	4.92%	4.92%	4.92%	4.93%

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric Bill Impacts

S.C. No. 2 - Non Demand

Rate Year 1

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	370	390	410	440	460	480	510	530	550
Present Bill	$ 72.45	$ 74.43	$ 76.41	$ 79.38	$ 81.36	$ 83.34	$ 86.31	$ 88.29	$ 90.27
Without Rate Moderation									
Proposed Bill	$ 75.67	$ 77.66	$ 79.65	$ 82.63	$ 84.62	$ 86.61	$ 89.59	$ 91.58	$ 93.57
$ Delivery Rate Increase	$ 3.22	$ 3.23	$ 3.24	$ 3.25	$ 3.26	$ 3.27	$ 3.28	$ 3.29	$ 3.30
% Increase	4.45%	4.34%	4.24%	4.09%	4.01%	3.92%	3.80%	3.72%	3.65%
With Rate Moderation									
EBC Reduction	$ (2.41)	$ (2.54)	$ (2.67)	$ (2.87)	$ (3.00)	$ (3.13)	$ (3.33)	$ (3.46)	$ (3.59)
Proposed Bill	$ 73.26	$ 75.12	$ 76.98	$ 79.76	$ 81.62	$ 83.48	$ 86.27	$ 88.12	$ 89.98
$ Delivery Rate Increase	$ 0.81	$ 0.69	$ 0.56	$ 0.38	$ 0.26	$ 0.14	$ (0.05)	$ (0.17)	$ (0.29)
% Increase	1.10%	0.91%	0.73%	0.48%	0.32%	0.16%	-0.05%	-0.19%	-0.32%

Rate Year 2

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	370	390	410	440	460	480	510	530	550
Present Bill	$ 73.26	$ 75.12	$ 76.98	$ 79.76	$ 81.62	$ 83.48	$ 86.27	$ 88.12	$ 89.98
Without Rate Moderation									
Proposed Bill	$ 79.06	$ 81.07	$ 83.07	$ 86.08	$ 88.08	$ 90.09	$ 93.10	$ 95.10	$ 97.11
$ Delivery Rate Increase	$ 5.80	$ 5.95	$ 6.09	$ 6.32	$ 6.46	$ 6.61	$ 6.83	$ 6.98	$ 7.13
% Increase	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%
With Rate Moderation									
EBC Reduction	$ (2.13)	$ (2.24)	$ (2.36)	$ (2.53)	$ (2.65)	$ (2.76)	$ (2.93)	$ (3.05)	$ (3.16)
Proposed Bill	$ 76.93	$ 78.82	$ 80.71	$ 83.55	$ 85.44	$ 87.33	$ 90.16	$ 92.05	$ 93.94
$ Delivery Rate Increase	$ 3.67	$ 3.70	$ 3.74	$ 3.78	$ 3.82	$ 3.85	$ 3.90	$ 3.93	$ 3.96
% Increase	4.77%	4.70%	4.63%	4.53%	4.47%	4.41%	4.32%	4.27%	4.22%

Rate Year 3

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	370	390	410	440	460	480	510	530	550
Present Bill	$ 76.93	$ 78.82	$ 80.71	$ 83.55	$ 85.44	$ 87.33	$ 90.16	$ 92.05	$ 93.94
Without Rate Moderation									
Proposed Bill	$ 82.31	$ 84.32	$ 86.34	$ 89.36	$ 91.38	$ 93.39	$ 96.41	$ 98.43	$ 100.44
$ Delivery Rate Increase	$ 5.38	$ 5.50	$ 5.63	$ 5.81	$ 5.94	$ 6.06	$ 6.25	$ 6.37	$ 6.50
% Increase	6.53%	6.52%	6.52%	6.50%	6.50%	6.49%	6.48%	6.47%	6.47%
With Rate Moderation									
EBC Reduction	$ (0.35)	$ (0.37)	$ (0.39)	$ (0.42)	$ (0.44)	$ (0.46)	$ (0.49)	$ (0.50)	$ (0.52)
Proposed Bill	$ 81.96	$ 83.95	$ 85.95	$ 88.94	$ 90.94	$ 92.93	$ 95.93	$ 97.92	$ 99.92
$ Delivery Rate Increase	$ 5.02	$ 5.13	$ 5.23	$ 5.39	$ 5.50	$ 5.60	$ 5.76	$ 5.87	$ 5.97
% Increase	6.13%	6.11%	6.09%	6.06%	6.05%	6.03%	6.01%	5.99%	5.98%

Appendix L Sheet 4 of 16

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric Bill Impacts

S.C. No. 2 - Secondary Demand

Rate Year 1

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 173.66	$ 196.77	$ 219.88	$ 312.32	$ 358.54					
Without Rate Moderation										
Proposed Bill - RY1	$ 175.28	$ 198.38	$ 221.48	$ 313.89	$ 360.10					
$ Delivery Rate Increase	$ 1.62	$ 1.61	$ 1.61	$ 1.57	$ 1.56					
% Increase	0.93%	0.82%	0.73%	0.50%	0.43%					
With Rate Moderation										
EBC Reduction	$ (0.54)	$ (0.81)	$ (1.09)	$ (2.17)	$ (2.71)					
Proposed Bill	$ 174.74	$ 197.57	$ 220.40	$ 311.72	$ 357.38					
Delivery Rate Increase	$ 1.08	$ 0.80	$ 0.52	$ (0.60)	$ (1.15)					
Total % Increase	0.62%	0.41%	0.24%	-0.19%	-0.32%					
10										
Present Bill	$ 215.11	$ 238.22	$ 261.33	$ 353.77	$ 399.99					
Without Rate Moderation										
Proposed Bill - RY1	$ 218.37	$ 241.48	$ 264.58	$ 356.99	$ 403.19					
$ Delivery Rate Increase	$ 3.26	$ 3.25	$ 3.24	$ 3.21	$ 3.20					
% Increase	1.52%	1.36%	1.24%	0.91%	0.80%					
With Rate Moderation										
EBC Reduction	$ (0.54)	$ (0.81)	$ (1.09)	$ (2.17)	$ (2.71)					
Proposed Bill	$ 217.83	$ 240.66	$ 263.49	$ 354.82	$ 400.48					
Delivery Rate Increase	$ 2.72	$ 2.44	$ 2.16	$ 1.04	$ 0.48					
% Increase	1.26%	1.02%	0.83%	0.29%	0.12%					
15										
Present Bill			$ 302.79	$ 395.23	$ 441.45	$ 672.55	$ 903.64			
Without Rate Moderation										
Proposed Bill - RY1			$ 307.67	$ 400.08	$ 446.28	$ 677.30	$ 908.32			
$ Delivery Rate Increase			$ 4.88	$ 4.85	$ 4.83	$ 4.75	$ 4.68			
% Increase			1.61%	1.23%	1.10%	0.71%	0.52%			
With Rate Moderation										
EBC Reduction			$ (1.09)	$ (2.17)	$ (2.71)	$ (5.43)	$ (8.14)			
Proposed Bill			$ 306.59	$ 397.91	$ 443.57	$ 671.88	$ 900.18			
Delivery Rate Increase			$ 3.80	$ 2.68	$ 2.12	$ (0.67)	$ (3.46)			
% Increase			1.25%	0.68%	0.48%	-0.10%	-0.38%			
20										
Present Bill				$ 436.69	$ 482.90	$ 714.00	$ 945.10	$ 1,176.20		
Without Rate Moderation										
Proposed Bill - RY1				$ 443.17	$ 489.38	$ 720.40	$ 951.41	$ 1,182.43		
$ Delivery Rate Increase				$ 6.49	$ 6.47	$ 6.39	$ 6.31	$ 6.23		
% Increase				1.49%	1.34%	0.90%	0.67%	0.53%		
With Rate Moderation										
EBC Reduction				$ (2.17)	$ (2.71)	$ (5.43)	$ (8.14)	$ (10.85)		
Proposed Bill				$ 441.00	$ 486.66	$ 714.97	$ 943.28	$ 1,171.58		
Delivery Rate Increase				$ 4.32	$ 3.76	$ 0.97	$ (1.82)	$ (4.62)		
% Increase				0.99%	0.78%	0.14%	-0.19%	-0.39%		
30										
Present Bill					$ 565.82	$ 796.91	$ 1,028.01	$ 1,259.11	$ 1,721.31	
Without Rate Moderation										
Proposed Bill - RY1					$ 575.56	$ 806.58	$ 1,037.60	$ 1,268.62	$ 1,730.66	
$ Delivery Rate Increase					$ 9.75	$ 9.67	$ 9.59	$ 9.51	$ 9.35	
% Increase					1.72%	1.21%	0.93%	0.76%	0.54%	
With Rate Moderation										
EBC Reduction					$ (2.71)	$ (5.43)	$ (8.14)	$ (10.85)	$ (16.28)	
Proposed Bill					$ 572.85	$ 801.16	$ 1,029.46	$ 1,257.77	$ 1,714.38	
Delivery Rate Increase					$ 7.03	$ 4.24	$ 1.45	$ (1.34)	$ (6.92)	
% Increase					1.24%	0.53%	0.14%	-0.11%	-0.40%	
50										
Present Bill						$ 962.74	$ 1,193.84	$ 1,424.93	$ 1,887.13	$ 2,349.33
Without Rate Moderation										
Proposed Bill - RY1						$ 978.96	$ 1,209.98	$ 1,440.99	$ 1,903.03	$ 2,365.07
$ Delivery Rate Increase						$ 16.22	$ 16.14	$ 16.06	$ 15.90	$ 15.74
% Increase						1.68%	1.35%	1.13%	0.84%	0.67%
With Rate Moderation										
EBC Reduction						$ (5.43)	$ (8.14)	$ (10.85)	$ (16.28)	$ (21.70)
Proposed Bill						$ 973.53	$ 1,201.84	$ 1,430.14	$ 1,886.76	$ 2,343.37
Delivery Rate Increase						$ 10.79	$ 8.00	$ 5.21	$ (0.37)	$ (5.96)
% Increase						1.12%	0.67%	0.37%	-0.02%	-0.25%
100										
Present Bill						$ 1,377.30	$ 1,608.40	$ 1,839.49	$ 2,301.69	$ 2,763.89
Without Rate Moderation										
Proposed Bill - RY1						$ 1,409.89	$ 1,640.91	$ 1,871.93	$ 2,333.97	$ 2,796.01
$ Delivery Rate Increase						$ 32.60	$ 32.52	$ 32.44	$ 32.28	$ 32.12
% Increase						2.37%	2.02%	1.76%	1.40%	1.16%
With Rate Moderation										
EBC Reduction						$ (5.43)	$ (8.14)	$ (10.85)	$ (16.28)	$ (21.70)
Proposed Bill						$ 1,404.47	$ 1,632.78	$ 1,861.08	$ 2,317.69	$ 2,774.31
Delivery Rate Increase						$ 27.17	$ 24.38	$ 21.59	$ 16.00	$ 10.42
% Increase						1.97%	1.52%	1.17%	0.70%	0.38%

Appendix L Sheet 5 of 16

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric Bill Impacts

S.C. No. 2 - Secondary Demand

Rate Year 2

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill - RY1	$ 174.74	$ 197.57	$ 220.40	$ 311.72	$ 357.38					
Without Rate Moderation										
Proposed Bill - RY2	$ 177.13	$ 200.26	$ 223.39	$ 315.92	$ 362.18					
$ Delivery Rate Increase	$ 2.39	$ 2.69	$ 2.99	$ 4.20	$ 4.80					
% Increase	1.37%	1.36%	1.36%	1.35%	1.34%					
With Rate Moderation										
EBC Reduction	$ (0.48)	$ (0.71)	$ (0.95)	$ (1.90)	$ (2.38)					
Proposed Bill	$ 176.65	$ 199.55	$ 222.44	$ 314.02	$ 359.80					
Delivery Rate Increase	$ 1.92	$ 1.98	$ 2.04	$ 2.29	$ 2.42					
Total % Increase	1.10%	1.00%	0.93%	0.74%	0.68%					
10										
Present Bill - RY1	$ 217.83	$ 240.66	$ 263.49	$ 354.82	$ 400.48					
Without Rate Moderation										
Proposed Bill - RY2	$ 222.02	$ 245.15	$ 268.28	$ 360.80	$ 407.07					
$ Delivery Rate Increase	$ 4.18	$ 4.49	$ 4.79	$ 5.99	$ 6.59					
% Increase	1.92%	1.86%	1.82%	1.69%	1.65%					
With Rate Moderation										
EBC Reduction	$ (0.48)	$ (0.71)	$ (0.95)	$ (1.90)	$ (2.38)					
Proposed Bill	$ 221.54	$ 244.43	$ 267.33	$ 358.90	$ 404.69					
Delivery Rate Increase	$ 3.71	$ 3.77	$ 3.83	$ 4.09	$ 4.21					
% Increase	1.70%	1.57%	1.46%	1.15%	1.05%					
15										
Present Bill - RY1			$ 306.59	$ 397.91	$ 443.57	$ 671.88	$ 900.18			
Without Rate Moderation										
Proposed Bill - RY2			$ 313.16	$ 405.69	$ 451.95	$ 683.27	$ 914.58			
$ Delivery Rate Increase			$ 6.58	$ 7.78	$ 8.38	$ 11.39	$ 14.40			
% Increase			2.15%	1.96%	1.89%	1.70%	1.60%			
With Rate Moderation										
EBC Reduction			$ (0.95)	$ (1.90)	$ (2.38)	$ (4.76)	$ (7.14)			
Proposed Bill			$ 312.21	$ 403.79	$ 449.57	$ 678.51	$ 907.44			
Delivery Rate Increase			$ 5.63	$ 5.88	$ 6.00	$ 6.63	$ 7.26			
% Increase			1.83%	1.48%	1.35%	0.99%	0.81%			
20										
Present Bill - RY1				$ 441.00	$ 486.66	$ 714.97	$ 943.28	$ 1,171.58		
Without Rate Moderation										
Proposed Bill - RY2				$ 450.57	$ 496.84	$ 728.15	$ 959.47	$ 1,190.78		
$ Delivery Rate Increase				$ 9.57	$ 10.17	$ 13.18	$ 16.19	$ 19.20		
% Increase				2.17%	2.09%	1.84%	1.72%	1.64%		
With Rate Moderation										
EBC Reduction				$ (1.90)	$ (2.38)	$ (4.76)	$ (7.14)	$ (9.52)		
Proposed Bill				$ 448.67	$ 494.46	$ 723.39	$ 952.33	$ 1,181.26		
Delivery Rate Increase				$ 7.67	$ 7.79	$ 8.42	$ 9.05	$ 9.68		
% Increase				1.74%	1.60%	1.18%	0.96%	0.83%		
30										
Present Bill - RY1					$ 572.85	$ 801.16	$ 1,029.46	$ 1,257.77	$ 1,714.38	
Without Rate Moderation										
Proposed Bill - RY2					$ 586.61	$ 817.92	$ 1,049.24	$ 1,280.55	$ 1,743.18	
$ Delivery Rate Increase					$ 13.76	$ 16.76	$ 19.77	$ 22.78	$ 28.80	
% Increase					2.40%	2.09%	1.92%	1.81%	1.68%	
With Rate Moderation										
EBC Reduction					$ (2.38)	$ (4.76)	$ (7.14)	$ (9.52)	$ (14.28)	
Proposed Bill					$ 584.23	$ 813.16	$ 1,042.10	$ 1,271.03	$ 1,728.90	
Delivery Rate Increase					$ 11.38	$ 12.00	$ 12.63	$ 13.26	$ 14.52	
% Increase					1.99%	1.50%	1.23%	1.05%	0.85%	
50										
Present Bill - RY1						$ 973.53	$ 1,201.84	$ 1,430.14	$ 1,886.76	$ 2,343.37
Without Rate Moderation										
Proposed Bill - RY2						$ 997.46	$ 1,228.78	$ 1,460.09	$ 1,922.72	$ 2,385.35
$ Delivery Rate Increase						$ 23.93	$ 26.94	$ 29.95	$ 35.96	$ 41.98
% Increase						2.46%	2.24%	2.09%	1.91%	1.79%
With Rate Moderation										
EBC Reduction						$ (4.76)	$ (7.14)	$ (9.52)	$ (14.28)	$ (19.04)
Proposed Bill						$ 992.70	$ 1,221.64	$ 1,450.57	$ 1,908.44	$ 2,366.31
Delivery Rate Increase						$ 19.17	$ 19.80	$ 20.43	$ 21.68	$ 22.94
% Increase						1.97%	1.65%	1.43%	1.15%	0.98%
100										
Present Bill - RY1						$ 1,404.47	$ 1,632.78	$ 1,861.08	$ 2,317.69	$ 2,774.31
Without Rate Moderation										
Proposed Bill - RY2						$ 1,446.31	$ 1,677.63	$ 1,908.94	$ 2,371.57	$ 2,834.20
$ Delivery Rate Increase						$ 41.84	$ 44.85	$ 47.86	$ 53.88	$ 59.89
% Increase						2.98%	2.75%	2.57%	2.32%	2.16%
With Rate Moderation										
EBC Reduction						$ (4.76)	$ (7.14)	$ (9.52)	$ (14.28)	$ (19.04)
Proposed Bill						$ 1,441.55	$ 1,670.49	$ 1,899.42	$ 2,357.29	$ 2,815.16
Delivery Rate Increase						$ 37.08	$ 37.71	$ 38.34	$ 39.60	$ 40.85
% Increase						2.64%	2.31%	2.06%	1.71%	1.47%

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric Bill Impacts

S.C. No. 2 - Secondary Demand

Rate Year 3

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill - RY2	$ 176.65	$ 199.55	$ 222.44	$ 314.02	$ 359.80					
Without Rate Moderation										
Proposed Bill - RY3	$ 178.71	$ 201.88	$ 225.06	$ 317.77	$ 364.12					
$ Delivery Rate Increase	$ 2.05	$ 2.33	$ 2.62	$ 3.75	$ 4.32					
% Increase	1.16%	1.17%	1.18%	1.19%	1.20%					
With Rate Moderation										
EBC Reduction	$ (0.08)	$ (0.12)	$ (0.15)	$ (0.31)	$ (0.38)					
Proposed Bill	$ 178.63	$ 201.77	$ 224.91	$ 317.46	$ 363.73					
Delivery Rate Increase	$ 1.97	$ 2.22	$ 2.46	$ 3.44	$ 3.93					
Total % Increase	1.12%	1.11%	1.11%	1.10%	1.09%					
10										
Present Bill - RY2	$ 221.54	$ 244.43	$ 267.33	$ 358.90	$ 404.69					
Without Rate Moderation										
Proposed Bill - RY3	$ 225.07	$ 248.25	$ 271.43	$ 364.13	$ 410.49					
$ Delivery Rate Increase	$ 3.53	$ 3.82	$ 4.10	$ 5.23	$ 5.80					
% Increase	1.60%	1.56%	1.53%	1.46%	1.43%					
With Rate Moderation										
EBC Reduction	$ (0.08)	$ (0.12)	$ (0.15)	$ (0.31)	$ (0.38)					
Proposed Bill	$ 225.00	$ 248.14	$ 271.27	$ 363.83	$ 410.10					
Delivery Rate Increase	$ 3.46	$ 3.70	$ 3.95	$ 4.93	$ 5.42					
% Increase	1.56%	1.51%	1.48%	1.37%	1.34%					
15										
Present Bill - RY2			$ 312.21	$ 403.79	$ 449.57	$ 678.51	$ 907.44			
Without Rate Moderation										
Proposed Bill - RY3			$ 317.80	$ 410.50	$ 456.86	$ 688.62	$ 920.39			
$ Delivery Rate Increase			$ 5.59	$ 6.72	$ 7.28	$ 10.12	$ 12.95			
% Increase			1.79%	1.66%	1.62%	1.49%	1.43%			
With Rate Moderation										
EBC Reduction			$ (0.15)	$ (0.31)	$ (0.38)	$ (0.77)	$ (1.15)			
Proposed Bill			$ 317.64	$ 410.20	$ 456.47	$ 687.86	$ 919.24			
Delivery Rate Increase			$ 5.43	$ 6.41	$ 6.90	$ 9.35	$ 11.80			
% Increase			1.74%	1.59%	1.53%	1.38%	1.30%			
20										
Present Bill - RY2				$ 448.67	$ 494.46	$ 723.39	$ 952.33	$ 1,181.26		
Without Rate Moderation										
Proposed Bill - RY3				$ 456.87	$ 503.23	$ 734.99	$ 966.76	$ 1,198.53		
$ Delivery Rate Increase				$ 8.20	$ 8.77	$ 11.60	$ 14.43	$ 17.26		
% Increase				1.83%	1.77%	1.60%	1.52%	1.46%		
With Rate Moderation										
EBC Reduction				$ (0.31)	$ (0.38)	$ (0.77)	$ (1.15)	$ (1.54)		
Proposed Bill				$ 456.57	$ 502.84	$ 734.22	$ 965.61	$ 1,196.99		
Delivery Rate Increase				$ 7.90	$ 8.38	$ 10.83	$ 13.28	$ 15.73		
% Increase				1.76%	1.70%	1.50%	1.39%	1.33%		
30										
Present Bill - RY2					$ 584.23	$ 813.16	$ 1,042.10	$ 1,271.03	$ 1,728.90	
Without Rate Moderation										
Proposed Bill - RY3					$ 595.96	$ 827.73	$ 1,059.50	$ 1,291.26	$ 1,754.80	
$ Delivery Rate Increase					$ 11.74	$ 14.57	$ 17.40	$ 20.23	$ 25.90	
% Increase					2.01%	1.79%	1.67%	1.59%	1.50%	
With Rate Moderation										
EBC Reduction					$ (0.38)	$ (0.77)	$ (1.15)	$ (1.54)	$ (2.30)	
Proposed Bill					$ 595.58	$ 826.96	$ 1,058.35	$ 1,289.73	$ 1,752.49	
Delivery Rate Increase					$ 11.35	$ 13.80	$ 16.25	$ 18.70	$ 23.59	
% Increase					1.94%	1.70%	1.56%	1.47%	1.36%	
50										
Present Bill - RY2						$ 992.70	$ 1,221.64	$ 1,450.57	$ 1,908.44	$ 2,366.31
Without Rate Moderation										
Proposed Bill - RY3						$ 1,013.21	$ 1,244.97	$ 1,476.74	$ 1,940.27	$ 2,403.81
$ Delivery Rate Increase						$ 20.51	$ 23.34	$ 26.17	$ 31.83	$ 37.50
% Increase						2.07%	1.91%	1.80%	1.67%	1.58%
With Rate Moderation										
EBC Reduction						$ (0.77)	$ (1.15)	$ (1.54)	$ (2.30)	$ (3.07)
Proposed Bill						$ 1,012.44	$ 1,243.82	$ 1,475.21	$ 1,937.97	$ 2,400.74
Delivery Rate Increase						$ 19.74	$ 22.19	$ 24.63	$ 29.53	$ 34.43
% Increase						1.99%	1.82%	1.70%	1.55%	1.45%
100										
Present Bill - RY2						$ 1,441.55	$ 1,670.49	$ 1,899.42	$ 2,357.29	$ 2,815.16
Without Rate Moderation										
Proposed Bill - RY3						$ 1,476.90	$ 1,708.67	$ 1,940.43	$ 2,403.97	$ 2,867.50
$ Delivery Rate Increase						$ 35.35	$ 38.18	$ 41.01	$ 46.68	$ 52.34
% Increase						2.45%	2.29%	2.16%	1.98%	1.86%
With Rate Moderation										
EBC Reduction						$ (0.77)	$ (1.15)	$ (1.54)	$ (2.30)	$ (3.07)
Proposed Bill						$ 1,476.13	$ 1,707.52	$ 1,938.90	$ 2,401.66	$ 2,864.43
Delivery Rate Increase						$ 34.58	$ 37.03	$ 39.48	$ 44.37	$ 49.27
% Increase						2.40%	2.22%	2.08%	1.88%	1.75%

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric Bill Impacts

S.C. No. 2 - Primary Demand

Rate Year 1

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 395.69	$ 417.86	$ 440.03	$ 528.72	$ 573.06					
Without Rate Moderation										
Proposed Bill - RY1	$ 397.23	$ 419.40	$ 441.57	$ 530.25	$ 574.59					
$ Delivery Rate Increase	$ 1.53	$ 1.53	$ 1.53	$ 1.53	$ 1.53					
% Increase	0.39%	0.37%	0.35%	0.29%	0.27%					
With Rate Moderation										
EBC Reduction	$ (0.47)	$ (0.70)	$ (0.93)	$ (1.86)	$ (2.33)					
Proposed Bill	$ 396.76	$ 418.70	$ 440.64	$ 528.39	$ 572.26					
Delivery Rate Increase	$ 1.07	$ 0.84	$ 0.60	$ (0.33)	$ (0.80)					
Total % Increase	0.27%	0.20%	0.14%	-0.06%	-0.14%					
10										
Present Bill	$ 429.73	$ 451.90	$ 474.07	$ 562.75	$ 607.09					
Without Rate Moderation										
Proposed Bill - RY1	$ 432.80	$ 454.97	$ 477.14	$ 565.82	$ 610.16					
$ Delivery Rate Increase	$ 3.07	$ 3.07	$ 3.07	$ 3.07	$ 3.07					
% Increase	0.71%	0.68%	0.65%	0.55%	0.51%					
With Rate Moderation										
EBC Reduction	$ (0.47)	$ (0.70)	$ (0.93)	$ (1.86)	$ (2.33)					
Proposed Bill	$ 432.33	$ 454.27	$ 476.21	$ 563.96	$ 607.83					
Delivery Rate Increase	$ 2.60	$ 2.37	$ 2.14	$ 1.21	$ 0.74					
Total % Increase	0.61%	0.52%	0.45%	0.21%	0.12%					
15										
Present Bill			$ 508.10	$ 596.79	$ 641.13	$ 862.83	$ 1,084.54			
Without Rate Moderation										
Proposed Bill - RY1			$ 512.71	$ 601.39	$ 645.73	$ 867.43	$ 1,089.14			
$ Delivery Rate Increase			$ 4.61	$ 4.60	$ 4.60	$ 4.60	$ 4.60			
% Increase			0.91%	0.77%	0.72%	0.53%	0.42%			
With Rate Moderation										
EBC Reduction			$ (0.93)	$ (1.86)	$ (2.33)	$ (4.66)	$ (6.99)			
Proposed Bill			$ 511.78	$ 599.53	$ 643.40	$ 862.78	$ 1,082.15			
Delivery Rate Increase			$ 3.67	$ 2.74	$ 2.27	$ (0.06)	$ (2.39)			
Total % Increase			0.72%	0.46%	0.35%	-0.01%	-0.22%			
20										
Present Bill				$ 630.82	$ 675.16	$ 896.87	$ 1,118.57	$ 1,340.28		
Without Rate Moderation										
Proposed Bill - RY1				$ 636.96	$ 681.30	$ 903.00	$ 1,124.71	$ 1,346.41		
$ Delivery Rate Increase				$ 6.14	$ 6.14	$ 6.14	$ 6.13	$ 6.13		
% Increase				0.97%	0.91%	0.68%	0.55%	0.46%		
With Rate Moderation										
EBC Reduction				$ (1.86)	$ (2.33)	$ (4.66)	$ (6.99)	$ (9.31)		
Proposed Bill				$ 635.10	$ 678.97	$ 898.35	$ 1,117.72	$ 1,337.09		
Delivery Rate Increase				$ 4.28	$ 3.81	$ 1.48	$ (0.85)	$ (3.18)		
Total % Increase				0.68%	0.56%	0.16%	-0.08%	-0.24%		
30										
Present Bill					$ 743.23	$ 964.94	$ 1,186.64	$ 1,408.35	$ 1,851.76	
Without Rate Moderation										
Proposed Bill - RY1					$ 752.44	$ 974.14	$ 1,195.85	$ 1,417.55	$ 1,860.95	
$ Delivery Rate Increase					$ 9.21	$ 9.21	$ 9.20	$ 9.20	$ 9.20	
% Increase					1.24%	0.95%	0.78%	0.65%	0.50%	
With Rate Moderation										
EBC Reduction					$ (2.33)	$ (4.66)	$ (6.99)	$ (9.31)	$ (13.97)	
Proposed Bill					$ 750.11	$ 969.49	$ 1,188.86	$ 1,408.23	$ 1,846.98	
Delivery Rate Increase					$ 6.88	$ 4.55	$ 2.22	$ (0.11)	$ (4.78)	
Total % Increase					0.93%	0.47%	0.19%	-0.01%	-0.26%	
50										
Present Bill						$ 1,101.08	$ 1,322.78	$ 1,544.49	$ 1,987.90	$ 2,431.31
Without Rate Moderation										
Proposed Bill - RY1						$ 1,116.43	$ 1,338.13	$ 1,559.83	$ 2,003.24	$ 2,446.64
$ Delivery Rate Increase						$ 15.35	$ 15.35	$ 15.34	$ 15.34	$ 15.33
% Increase						1.39%	1.16%	0.99%	0.77%	0.63%
With Rate Moderation										
EBC Reduction						$ (4.66)	$ (6.99)	$ (9.31)	$ (13.97)	$ (18.63)
Proposed Bill						$ 1,111.77	$ 1,331.14	$ 1,550.52	$ 1,989.26	$ 2,428.01
Delivery Rate Increase						$ 10.69	$ 8.36	$ 6.03	$ 1.37	$ (3.30)
Total % Increase						0.97%	0.63%	0.39%	0.07%	-0.14%
100										
Present Bill						$ 1,441.42	$ 1,663.13	$ 1,884.84	$ 2,328.25	$ 2,771.66
Without Rate Moderation										
Proposed Bill - RY1						$ 1,472.13	$ 1,693.83	$ 1,915.53	$ 2,358.94	$ 2,802.34
$ Delivery Rate Increase						$ 30.70	$ 30.70	$ 30.70	$ 30.69	$ 30.69
% Increase						2.13%	1.85%	1.63%	1.32%	1.11%
With Rate Moderation										
EBC Reduction						$ (4.66)	$ (6.99)	$ (9.31)	$ (13.97)	$ (18.63)
Proposed Bill						$ 1,467.47	$ 1,686.84	$ 1,906.22	$ 2,344.97	$ 2,783.71
Delivery Rate Increase						$ 26.05	$ 23.71	$ 21.38	$ 16.72	$ 12.06
Total % Increase						1.81%	1.43%	1.13%	0.72%	0.44%

Appendix L Sheet 8 of 16

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric Bill Impacts

S.C. No. 2 - Primary Demand

Rate Year 2

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill - RY1	$ 396.76	$ 418.70	$ 440.64	$ 528.39	$ 572.26					
Without Rate Moderation										
Proposed Bill - RY2	$ 399.13	$ 421.30	$ 443.48	$ 532.18	$ 576.52					
$ Delivery Rate Increase	$ 2.37	$ 2.60	$ 2.84	$ 3.79	$ 4.26					
% Increase	0.60%	0.62%	0.64%	0.72%	0.74%					
With Rate Moderation										
EBC Reduction	$ (0.39)	$ (0.59)	$ (0.79)	$ (1.58)	$ (1.97)					
Proposed Bill	$ 398.74	$ 420.71	$ 442.69	$ 530.60	$ 574.55					
Delivery Rate Increase	$ 1.97	$ 2.01	$ 2.05	$ 2.21	$ 2.29					
Total % Increase	0.50%	0.48%	0.47%	0.42%	0.40%					
10										
Present Bill - RY1	$ 432.33	$ 454.27	$ 476.21	$ 563.96	$ 607.83					
Without Rate Moderation										
Proposed Bill - RY2	$ 436.59	$ 458.77	$ 480.94	$ 569.64	$ 613.99					
$ Delivery Rate Increase	$ 4.26	$ 4.50	$ 4.73	$ 5.68	$ 6.16					
% Increase	0.99%	0.99%	0.99%	1.01%	1.01%					
With Rate Moderation										
EBC Reduction	$ (0.39)	$ (0.59)	$ (0.79)	$ (1.58)	$ (1.97)					
Proposed Bill	$ 436.20	$ 458.18	$ 480.15	$ 568.06	$ 612.02					
Delivery Rate Increase	$ 3.87	$ 3.91	$ 3.95	$ 4.11	$ 4.19					
Total % Increase	0.89%	0.86%	0.83%	0.73%	0.69%					
15										
Present Bill - RY1			$ 511.78	$ 599.53	$ 643.40	$ 862.78	$ 1,082.15			
Without Rate Moderation										
Proposed Bill - RY2			$ 518.41	$ 607.10	$ 651.45	$ 873.19	$ 1,094.94			
$ Delivery Rate Increase			$ 6.63	$ 7.58	$ 8.05	$ 10.42	$ 12.79			
% Increase			1.30%	1.26%	1.25%	1.21%	1.18%			
With Rate Moderation										
EBC Reduction			$ (0.79)	$ (1.58)	$ (1.97)	$ (3.94)	$ (5.91)			
Proposed Bill			$ 517.62	$ 605.53	$ 649.48	$ 869.25	$ 1,089.03			
Delivery Rate Increase			$ 5.84	$ 6.00	$ 6.08	$ 6.48	$ 6.88			
Total % Increase			1.14%	1.00%	0.94%	0.75%	0.64%			
20										
Present Bill - RY1				$ 635.10	$ 678.97	$ 898.35	$ 1,117.72	$ 1,337.09		
Without Rate Moderation										
Proposed Bill - RY2				$ 644.57	$ 688.92	$ 910.66	$ 1,132.40	$ 1,354.14		
$ Delivery Rate Increase				$ 9.47	$ 9.94	$ 12.31	$ 14.68	$ 17.05		
% Increase				1.49%	1.46%	1.37%	1.31%	1.28%		
With Rate Moderation										
EBC Reduction				$ (1.58)	$ (1.97)	$ (3.94)	$ (5.91)	$ (7.88)		
Proposed Bill				$ 642.99	$ 686.95	$ 906.72	$ 1,126.49	$ 1,346.26		
Delivery Rate Increase				$ 7.89	$ 7.97	$ 8.37	$ 8.77	$ 9.17		
Total % Increase				1.24%	1.17%	0.93%	0.78%	0.69%		
30										
Present Bill - RY1					$ 750.11	$ 969.49	$ 1,188.86	$ 1,408.23	$ 1,846.98	
Without Rate Moderation										
Proposed Bill - RY2					$ 763.84	$ 985.59	$ 1,207.33	$ 1,429.07	$ 1,872.56	
$ Delivery Rate Increase					$ 13.73	$ 16.10	$ 18.47	$ 20.84	$ 25.57	
% Increase					1.83%	1.66%	1.55%	1.48%	1.38%	
With Rate Moderation										
EBC Reduction					$ (1.97)	$ (3.94)	$ (5.91)	$ (7.88)	$ (11.82)	
Proposed Bill					$ 761.87	$ 981.65	$ 1,201.42	$ 1,421.19	$ 1,860.73	
Delivery Rate Increase					$ 11.76	$ 12.16	$ 12.56	$ 12.95	$ 13.75	
Total % Increase					1.57%	1.25%	1.06%	0.92%	0.74%	
50										
Present Bill - RY1						$ 1,111.77	$ 1,331.14	$ 1,550.52	$ 1,989.26	$ 2,428.01
Without Rate Moderation										
Proposed Bill - RY2						$ 1,135.44	$ 1,357.18	$ 1,578.93	$ 2,022.41	$ 2,465.90
$ Delivery Rate Increase						$ 23.67	$ 26.04	$ 28.41	$ 33.15	$ 37.89
% Increase						2.13%	1.96%	1.83%	1.67%	1.56%
With Rate Moderation										
EBC Reduction						$ (3.94)	$ (5.91)	$ (7.88)	$ (11.82)	$ (15.76)
Proposed Bill						$ 1,131.50	$ 1,351.27	$ 1,571.05	$ 2,010.59	$ 2,450.13
Delivery Rate Increase						$ 19.73	$ 20.13	$ 20.53	$ 21.33	$ 22.12
Total % Increase						1.77%	1.51%	1.32%	1.07%	0.91%
100										
Present Bill - RY1						$ 1,467.47	$ 1,686.84	$ 1,906.22	$ 2,344.97	$ 2,783.71
Without Rate Moderation										
Proposed Bill - RY2						$ 1,510.08	$ 1,731.82	$ 1,953.57	$ 2,397.05	$ 2,840.54
$ Delivery Rate Increase						$ 42.61	$ 44.98	$ 47.35	$ 52.09	$ 56.82
% Increase						2.90%	2.67%	2.48%	2.22%	2.04%
With Rate Moderation										
EBC Reduction						$ (3.94)	$ (5.91)	$ (7.88)	$ (11.82)	$ (15.76)
Proposed Bill						$ 1,506.14	$ 1,725.91	$ 1,945.68	$ 2,385.23	$ 2,824.77
Delivery Rate Increase						$ 38.67	$ 39.07	$ 39.47	$ 40.26	$ 41.06
Total % Increase						2.64%	2.32%	2.07%	1.72%	1.47%

Appendix L Sheet 9 of 16

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric Bill Impacts

S.C. No. 2 - Primary Demand

Rate Year 3

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill - RY2	$ 398.74	$ 420.71	$ 442.69	$ 530.60	$ 574.55					
Without Rate Moderation										
Proposed Bill - RY3	$ 400.80	$ 422.99	$ 445.17	$ 533.93	$ 578.31					
$ Delivery Rate Increase	$ 2.06	$ 2.27	$ 2.48	$ 3.33	$ 3.75					
% Increase	0.52%	0.54%	0.56%	0.63%	0.65%					
With Rate Moderation										
EBC Reduction	$ (0.07)	$ (0.10)	$ (0.13)	$ (0.27)	$ (0.33)					
Proposed Bill	$ 400.73	$ 422.89	$ 445.04	$ 533.66	$ 577.97					
Delivery Rate Increase	$ 1.99	$ 2.17	$ 2.35	$ 3.06	$ 3.42					
Total % Increase	0.50%	0.52%	0.53%	0.58%	0.60%					
10										
Present Bill - RY2	$ 436.20	$ 458.18	$ 480.15	$ 568.06	$ 612.02					
Without Rate Moderation										
Proposed Bill - RY3	$ 439.90	$ 462.09	$ 484.28	$ 573.03	$ 617.41					
$ Delivery Rate Increase	$ 3.70	$ 3.91	$ 4.12	$ 4.97	$ 5.39					
% Increase	0.85%	0.85%	0.86%	0.87%	0.88%					
With Rate Moderation										
EBC Reduction	$ (0.07)	$ (0.10)	$ (0.13)	$ (0.27)	$ (0.33)					
Proposed Bill	$ 439.83	$ 461.99	$ 484.14	$ 572.76	$ 617.08					
Delivery Rate Increase	$ 3.63	$ 3.81	$ 3.99	$ 4.70	$ 5.06					
Total % Increase	0.83%	0.83%	0.83%	0.83%	0.83%					
15										
Present Bill - RY2			$ 517.62	$ 605.53	$ 649.48	$ 869.25	$ 1,089.03			
Without Rate Moderation										
Proposed Bill - RY3			$ 523.38	$ 612.13	$ 656.51	$ 878.40	$ 1,100.28			
$ Delivery Rate Increase			$ 5.76	$ 6.61	$ 7.03	$ 9.14	$ 11.26			
% Increase			1.11%	1.09%	1.08%	1.05%	1.03%			
With Rate Moderation										
EBC Reduction			$ (0.13)	$ (0.27)	$ (0.33)	$ (0.67)	$ (1.00)			
Proposed Bill			$ 523.24	$ 611.87	$ 656.18	$ 877.73	$ 1,099.29			
Delivery Rate Increase			$ 5.63	$ 6.34	$ 6.70	$ 8.48	$ 10.26			
Total % Increase			1.09%	1.05%	1.03%	0.98%	0.94%			
20										
Present Bill - RY2				$ 642.99	$ 686.95	$ 906.72	$ 1,126.49	$ 1,346.26		
Without Rate Moderation										
Proposed Bill - RY3				$ 651.23	$ 695.61	$ 917.50	$ 1,139.39	$ 1,361.27		
$ Delivery Rate Increase				$ 8.24	$ 8.67	$ 10.78	$ 12.90	$ 15.01		
% Increase				1.28%	1.26%	1.19%	1.14%	1.12%		
With Rate Moderation										
EBC Reduction				$ (0.27)	$ (0.33)	$ (0.67)	$ (1.00)	$ (1.33)		
Proposed Bill				$ 650.97	$ 695.28	$ 916.83	$ 1,138.39	$ 1,359.94		
Delivery Rate Increase				$ 7.98	$ 8.33	$ 10.12	$ 11.90	$ 13.68		
Total % Increase				1.24%	1.21%	1.12%	1.06%	1.02%		
30										
Present Bill - RY2					$ 761.87	$ 981.65	$ 1,201.42	$ 1,421.19	$ 1,860.73	
Without Rate Moderation										
Proposed Bill - RY3					$ 773.81	$ 995.70	$ 1,217.59	$ 1,439.48	$ 1,883.25	
$ Delivery Rate Increase					$ 11.94	$ 14.06	$ 16.17	$ 18.29	$ 22.52	
% Increase					1.57%	1.43%	1.35%	1.29%	1.21%	
With Rate Moderation										
EBC Reduction					$ (0.33)	$ (0.67)	$ (1.00)	$ (1.33)	$ (2.00)	
Proposed Bill					$ 773.48	$ 995.04	$ 1,216.59	$ 1,438.15	$ 1,881.26	
Delivery Rate Increase					$ 11.61	$ 13.39	$ 15.17	$ 16.96	$ 20.52	
Total % Increase					1.52%	1.36%	1.26%	1.19%	1.10%	
50										
Present Bill - RY2						$ 1,131.50	$ 1,351.27	$ 1,571.05	$ 2,010.59	$ 2,450.13
Without Rate Moderation										
Proposed Bill - RY3						$ 1,152.11	$ 1,374.00	$ 1,595.88	$ 2,039.66	$ 2,483.43
$ Delivery Rate Increase						$ 20.61	$ 22.72	$ 24.84	$ 29.07	$ 33.30
% Increase						1.82%	1.68%	1.58%	1.45%	1.36%
With Rate Moderation										
EBC Reduction						$ (0.67)	$ (1.00)	$ (1.33)	$ (2.00)	$ (2.66)
Proposed Bill						$ 1,151.44	$ 1,373.00	$ 1,594.55	$ 2,037.66	$ 2,480.77
Delivery Rate Increase						$ 19.94	$ 21.73	$ 23.51	$ 27.07	$ 30.64
Total % Increase						1.76%	1.61%	1.50%	1.35%	1.25%
100										
Present Bill - RY2						$ 1,506.14	$ 1,725.91	$ 1,945.68	$ 2,385.23	$ 2,824.77
Without Rate Moderation										
Proposed Bill - RY3						$ 1,543.13	$ 1,765.01	$ 1,986.90	$ 2,430.68	$ 2,874.45
$ Delivery Rate Increase						$ 36.99	$ 39.10	$ 41.22	$ 45.45	$ 49.68
% Increase						2.46%	2.27%	2.12%	1.91%	1.76%
With Rate Moderation										
EBC Reduction						$ (0.67)	$ (1.00)	$ (1.33)	$ (2.00)	$ (2.66)
Proposed Bill						$ 1,542.46	$ 1,764.02	$ 1,985.57	$ 2,428.68	$ 2,871.79
Delivery Rate Increase						$ 36.32	$ 38.10	$ 39.89	$ 43.45	$ 47.02
Total % Increase						2.41%	2.21%	2.05%	1.82%	1.66%

Appendix L Sheet 10 of 16

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Rates Utilized in Development of Typical Bills

	SC1	SC2ND	SC2SD	SC2PD	SC6
Market Price Charge - On Peak	$ 0.07654	$ 0.07654	$ 0.07654	$ 0.08249	$ 0.08972
Market Price Charge - Off Peak	$ 0.07654	$ 0.07654	$ 0.07654	$ 0.08249	$ 0.06763
Market Price Adjustment - On Peak	$ 0.00584	$ 0.00584	$ 0.00584	$ 0.00080	$ 0.00365
Market Price Adjustment - Off Peak	$ 0.00584	$ 0.00584	$ 0.00584	$ 0.00080	$ 0.00411
Purchased Power Adjustment	$ (0.00004)	$ (0.00003)	$ 0.00001	$ 0.00012	$ (0.00005)
Miscellaneous Charges	$ (0.00650)	$ (0.00650)	$ (0.00650)	$ (0.00650)	$ (0.00650)
System Benefits Charge- Current	$ 0.00850	$ 0.00850	$ 0.00850	$ 0.00850	$ 0.00850
System Benefits Charge-Modified RY1	$ 0.00845	$ 0.00845	$ 0.00845	$ 0.00845	$ 0.00845
System Benefits Charge-Modified RY2	$ 0.00839	$ 0.00839	$ 0.00839	$ 0.00839	$ 0.00839
System Benefits Charge-Modified RY3	$ 0.00839	$ 0.00839	$ 0.00839	$ 0.00839	$ 0.00839
MFC Admin Charge- Current	$ 0.00183	$ 0.00240	$ 0.00012	$ 0.00001	$ 0.00078
MFC Supply Charge- Current	$ 0.00207	$ 0.00337	$ 0.00029	$ 0.00003	$ 0.00087
MFC Transition Adjustment	$ 0.00017	$ 0.00067	$ 0.00007	$ 0.00001	$ 0.00007
New York State Assessment	$ 0.00210	$ 0.00156	$ 0.00156	$ 0.00124	$ 0.00210
Electric Bill Credit- Current	$ -	$ -	$ -	$ -	$ -
Weighted Revenue Tax - Commodity	0.306%	0.306%	0.306%	0.306%	0.306%
Weighted Revenue Tax - Delivery	2.306%	2.306%	2.306%	2.306%	2.306%
MFC Admin Charge - Proposed RY1	$ 0.00165	$ 0.00234	$ 0.00011	$ 0.00001	$ 0.00075
MFC Admin Charge - Proposed RY2	$ 0.00164	$ 0.00231	$ 0.00011	$ 0.00001	$ 0.00075
MFC Admin Charge - Proposed RY3	$ 0.00163	$ 0.00230	$ 0.00011	$ 0.00001	$ 0.00075
MFC Supply Charge - Proposed RY1	$ 0.00238	$ 0.00338	$ 0.00016	$ 0.00001	$ 0.00108
MFC Supply Charge - Proposed RY2	$ 0.00237	$ 0.00334	$ 0.00016	$ 0.00001	$ 0.00108
MFC Supply Charge - Proposed RY3	$ 0.00236	$ 0.00332	$ 0.00016	$ 0.00001	$ 0.00108
Electric Bill Credit - Proposed RY1	$ (0.00468)	$ (0.00637)	$ (0.00106)	$ (0.00091)	$ (0.00165)
Electric Bill Credit - Proposed RY2	$ (0.00438)	$ (0.00562)	$ (0.00093)	$ (0.00077)	$ (0.00160)
Electric Bill Credit - Proposed RY3	$ (0.00073)	$ (0.00093)	$ (0.00015)	$ (0.00013)	$ (0.00025)
Customer Charge - Current	$ 24.00	$ 35.00	$ 84.00	$ 310.00	$ 27.00
Customer Charge - Proposed RY1	$ 27.00	$ 38.00	$ 84.00	$ 310.00	$ 30.00
Customer Charge - Proposed RY2	$ 28.00	$ 41.00	$ 84.00	$ 310.00	$ 31.00
Customer Charge - Proposed RY3	$ 29.00	$ 44.00	$ 84.00	$ 310.00	$ 32.00
On-Peak Delivery - Current	$ 0.04963	$ 0.00588	$ 0.00540	$ 0.00148	$ 0.06144
On-Peak Delivery - Proposed RY1	$ 0.05027	$ 0.00638	$ 0.00556	$ 0.00155	$ 0.08427
On-Peak Delivery - Proposed RY2	$ 0.05461	$ 0.00734	$ 0.00573	$ 0.00162	$ 0.08687
On-Peak Delivery - Proposed RY3	$ 0.05825	$ 0.00784	$ 0.00591	$ 0.00168	$ 0.08891
Off-Peak Delivery - Current	$ 0.04963	$ 0.00588	$ 0.00540	$ 0.00148	$ 0.04022
Off-Peak Delivery - Proposed RY1	$ 0.05027	$ 0.00638	$ 0.00556	$ 0.00155	$ 0.02809
Off-Peak Delivery - Proposed RY2	$ 0.05461	$ 0.00734	$ 0.00573	$ 0.00162	$ 0.02896
Off-Peak Delivery - Proposed RY3	$ 0.05825	$ 0.00784	$ 0.00591	$ 0.00168	$ 0.02964
Demand Rate - Current	N/A	N/A	$ 8.10	$ 6.65	N/A
Demand Rate - Proposed RY1	N/A	N/A	$ 8.42	$ 6.95	N/A
Demand Rate - Proposed RY2	N/A	N/A	$ 8.77	$ 7.32	N/A
Demand Rate - Proposed RY3	N/A	N/A	$ 9.06	$ 7.64	N/A

*SBC rates have been estimated to reflect the phased inclusion of the EEPS for CH programs in base rates. In order to only show the impact of base rate increases, annual bills under proposed rates do not however reflect annual changes to the SBC, or any increases related to the EEPS charge in Case 07-M-0548. NYSA and ECAM have been included at rates effective as of February 6, 2015, the original filing date of the Joint Proposal in this Case.

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Gas Bills Impacts
Rate Year 1 (Twelve Months Ended June 30, 2016)

P.S.C. No. 12 - Gas
Service Classification Nos. 1 & 12

Monthly Usage Ccf	Present Monthly Bill	Without Rate Moderation: Proposed RY 1 Monthly Bill	Without Rate Moderation: Delivery $ Increase	Without Rate Moderation: % Increase	With Rate Moderation: Gas Bill Credit	With Rate Moderation: Proposed RY 1 Monthly Bill	With Rate Moderation: Delivery $ Increase	With Rate Moderation: % Increase
2	$ 25.00	$ 26.01	$ 1.01	4.05%	$ (0.06)	$ 25.96	$ 0.96	3.83%
4	28.17	29.21	1.04	3.69%	(0.11)	29.09	0.93	3.30%
6	31.33	32.40	1.07	3.41%	(0.17)	32.23	0.90	2.88%
8	34.49	35.59	1.10	3.18%	(0.22)	35.37	0.87	2.53%
10	37.66	38.78	1.12	2.98%	(0.28)	38.50	0.84	2.24%
15	45.57	46.76	1.19	2.62%	(0.42)	46.35	0.77	1.70%
20	53.48	54.75	1.26	2.36%	(0.56)	54.19	0.70	1.32%
25	61.40	62.73	1.33	2.17%	(0.70)	62.03	0.64	1.03%
30	69.31	70.71	1.40	2.02%	(0.84)	69.87	0.57	0.82%
35	77.22	78.69	1.47	1.90%	(0.98)	77.71	0.50	0.64%
40	85.13	86.67	1.54	1.81%	(1.11)	85.56	0.43	0.50%
50	100.95	102.63	1.68	1.66%	(1.39)	101.24	0.29	0.28%
60	112.00	113.71	1.72	1.53%	(1.67)	112.04	0.04	0.04%
80	134.08	135.87	1.79	1.34%	(2.23)	133.64	(0.44)	-0.33%
100	156.17	158.03	1.87	1.19%	(2.79)	155.25	(0.92)	-0.59%
130	189.30	191.27	1.98	1.04%	(3.62)	187.65	(1.65)	-0.87%
170	233.47	235.59	2.13	0.91%	(4.74)	230.86	(2.61)	-1.12%
200	266.60	268.84	2.24	0.84%	(5.57)	263.26	(3.34)	-1.25%
300	377.03	379.64	2.61	0.69%	(8.36)	371.28	(5.75)	-1.53%
1000	1,150.03	1,155.24	5.22	0.45%	(27.87)	1,127.37	(22.65)	-1.97%
Average Annual Heating Customer @ 840 Ccf Per Year								
840	1,400.47	1,419.89	19.43	1.39%	(23.41)	1,396.48	(3.99)	-0.28%

Weighted Revenue Tax Factor:		Delivery	0.02549
		Commodity	0.00549
Gas Supply Charge (per Ccf):			$ 0.61375
New York State Assessment Surcharge (per Ccf):			$ 0.02107
		Present	Proposed RY 1
System Benefits Charge (per Ccf):		$ 0.03489	$ 0.03468
S.C. No. 1 & 12 Base Delivery Rates			
Block 1	First 2 Ccf	$ 23.00	$ 24.00
Block 2 per Ccf	Next 48 Ccf	$ 0.8603	$ 0.8805
Block 3 per Ccf	Additional	$ 0.3944	$ 0.4047
Merchant Function Charge (per Ccf):	MFC Admin	$ 0.00960	$ 0.00449
	MFC Supply	$ 0.01360	$ 0.01342
	Transition Adj.	$ 0.00117	$ -
Gas Bill Credit (per Ccf):		$ -	$ (0.02716)

Gas bill credit rates reflect rate moderation as described in Section III.D
SBC rates have been estimated to reflect the phased inclusion of the EEPS for CH programs in base rates. In order to only show the impact of base rate increases, annual bills under proposed rates do not however reflect annual changes to the SBC, or any increases related to the EEPS charge in Case 07-M-0548. NYSA and GSC have been included at rates effective as of February 6, 2015, the original filing date of the Joint Proposal in this Case.

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Gas Bills Impacts
Rate Year 1 (Twelve Months Ended June 30, 2016)

P.S.C. No. 12 - Gas
Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Present Monthly Bill	Without Rate Moderation: Proposed RY 1 Monthly Bill	Without Rate Moderation: Delivery $ Increase	Without Rate Moderation: % Increase	With Rate Moderation: Gas Bill Credit	With Rate Moderation: Proposed RY 1 Monthly Bill	With Rate Moderation: Delivery $ Increase	With Rate Moderation: % Increase
2	$ 38.55	$ 38.51	$ (0.04)	-0.10%	$ (0.03)	$ 38.48	$ (0.07)	-0.18%
10	48.33	48.15	(0.18)	-0.38%	(0.16)	47.99	(0.34)	-0.71%
30	72.80	72.25	(0.55)	-0.76%	(0.48)	71.77	(1.03)	-1.41%
50	97.27	96.36	(0.92)	-0.94%	(0.80)	95.56	(1.72)	-1.76%
100	158.45	156.61	(1.83)	-1.16%	(1.60)	155.02	(3.43)	-2.17%
150	205.59	203.29	(2.30)	-1.12%	(2.40)	200.89	(4.70)	-2.29%
200	252.74	249.97	(2.77)	-1.10%	(3.20)	246.77	(5.97)	-2.36%
250	299.89	296.64	(3.24)	-1.08%	(3.99)	292.65	(7.24)	-2.41%
300	347.03	343.32	(3.71)	-1.07%	(4.79)	338.53	(8.51)	-2.45%
400	441.33	436.68	(4.65)	-1.05%	(6.39)	430.29	(11.04)	-2.50%
500	535.62	530.03	(5.59)	-1.04%	(7.99)	522.04	(13.58)	-2.54%
600	629.92	623.39	(6.53)	-1.04%	(9.59)	613.80	(16.12)	-2.56%
800	818.50	810.09	(8.41)	-1.03%	(12.78)	797.31	(21.19)	-2.59%
1000	1,007.09	996.80	(10.29)	-1.02%	(15.98)	980.83	(26.26)	-2.61%
1500	1,478.56	1,463.58	(14.98)	-1.01%	(23.97)	1,439.61	(38.95)	-2.63%
2000	1,950.03	1,930.35	(19.68)	-1.01%	(31.96)	1,898.39	(51.63)	-2.65%
3000	2,892.96	2,863.89	(29.07)	-1.00%	(47.93)	2,815.96	(77.00)	-2.66%
5000	4,778.84	4,730.98	(47.86)	-1.00%	(79.89)	4,651.09	(127.74)	-2.67%
7500	7,010.99	6,934.12	(76.87)	-1.10%	(119.83)	6,814.29	(196.70)	-2.81%
10000	9,243.15	9,137.27	(105.88)	-1.15%	(159.78)	8,977.49	(265.66)	-2.87%
12000	11,028.87	10,899.78	(129.09)	-1.17%	(191.73)	10,708.05	(320.82)	-2.91%
14000	12,814.59	12,662.30	(152.30)	-1.19%	(223.69)	12,438.61	(375.98)	-2.93%
16000	14,600.32	14,424.81	(175.51)	-1.20%	(255.64)	14,169.17	(431.15)	-2.95%
20000	18,171.76	17,949.84	(221.92)	-1.22%	(319.55)	17,630.29	(541.48)	-2.98%
Average Annual Heating Customer @ 5860 Ccf Per Year								
5860	6,295.45	6,229.67	(65.78)	-1.04%	(93.63)	6,136.04	(159.41)	-2.53%

			Present	Proposed RY 1
Weighted Revenue Tax Factor:		Delivery		0.00549
		Commodity		0.00549
Gas Supply Charge (per Ccf):				$ 0.61375
New York State Assessment Surcharge (per Ccf):				$ 0.01222
System Benefits Charge (per Ccf):			$ 0.00512	$ 0.00509
S.C. No. 2, 6 & 13 Base Delivery Rates				
	Block 1	First 2 Ccf	$ 37.00	$ 37.00
	Block 2 per Ccf	Next 98 Ccf	$ 0.5494	$ 0.5494
	Block 3 per Ccf	Next 4900 Ccf	$ 0.2704	$ 0.2793
	Block 4 per Ccf	Additional	$ 0.2206	$ 0.2273
Merchant Function Charge (per Ccf):		MFC Admin	$ 0.00886	$ 0.00453
		MFC Supply	$ 0.02238	$ 0.01353
		Transition Adj.	$ 0.00503	$ -
Gas Bill Credit (per Ccf):			$ -	$ (0.01589)

Gas bill credit rates reflect rate moderation as described in Section III.D
SBC rates have been estimated to reflect the phased inclusion of the EEPS for CH programs in base rates. In order to only show the impact of base rate increases, annual bills under proposed rates do not however reflect annual changes to the SBC, or any increases related to the EEPS charge in Case 07-M-0548. NYSA and GSC have been included at rates effective as of February 6, 2015, the original filing date of the Joint Proposal in this Case.

Appendix L Sheet 13 of 16

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Gas Bills Impacts
Rate Year 2 (Twelve Months Ended June 30, 2017)

P.S.C. No. 12 - Gas
Service Classification Nos. 1 & 12

Monthly Usage Ccf	Present RY 1 Monthly Bill	Without Rate Moderation: Proposed RY 2 Monthly Bill	Without Rate Moderation: Delivery $ Increase	Without Rate Moderation: % Increase	With Rate Moderation: Gas Bill Credit	With Rate Moderation: Proposed RY 2 Monthly Bill	With Rate Moderation: Delivery $ Increase	With Rate Moderation: % Increase
2	$ 25.96	$ 27.04	$ 1.08	4.16%	$ (0.13)	$ 26.90	$ 0.95	3.65%
4	29.09	30.35	1.26	4.32%	(0.27)	30.08	0.99	3.39%
6	32.23	33.66	1.43	4.44%	(0.40)	33.26	1.03	3.19%
8	35.37	36.97	1.60	4.54%	(0.54)	36.44	1.07	3.02%
10	38.50	40.28	1.78	4.62%	(0.67)	39.61	1.11	2.88%
15	46.35	48.56	2.22	4.78%	(1.01)	47.56	1.21	2.61%
20	54.19	56.84	2.65	4.90%	(1.34)	55.50	1.31	2.42%
25	62.03	65.12	3.09	4.98%	(1.68)	63.44	1.41	2.28%
30	69.87	73.40	3.53	5.05%	(2.01)	71.39	1.51	2.17%
35	77.71	81.68	3.96	5.10%	(2.35)	79.33	1.61	2.08%
40	85.56	89.96	4.40	5.14%	(2.68)	87.27	1.72	2.01%
50	101.24	106.51	5.27	5.21%	(3.36)	103.16	1.92	1.89%
60	112.04	117.85	5.81	5.18%	(4.03)	113.82	1.78	1.59%
80	133.64	140.52	6.87	5.14%	(5.37)	135.15	1.50	1.12%
100	155.25	163.19	7.94	5.11%	(6.71)	156.47	1.23	0.79%
130	187.65	197.19	9.54	5.08%	(8.72)	188.46	0.81	0.43%
170	230.86	242.52	11.67	5.05%	(11.41)	231.12	0.26	0.11%
200	263.26	276.53	13.27	5.04%	(13.42)	263.11	(0.16)	-0.06%
300	371.28	389.87	18.59	5.01%	(20.13)	369.74	(1.54)	-0.41%
1000	1,127.37	1,183.27	55.89	4.96%	(67.11)	1,116.16	(11.22)	-0.99%
			Average Annual Heating Customer @ 840 Ccf Per Year					
840	1,396.97	1,467.66	70.69	5.06%	(56.37)	1,411.29	14.32	1.02%

Weighted Revenue Tax Factor:		Delivery		0.02549
		Commodity		0.00549
Gas Supply Charge (per Ccf):				$ 0.61375
New York State Assessment Surcharge (per Ccf):				$ 0.02107
			Present RY 1	Proposed RY 2
System Benefits Charge (per Ccf):			$ 0.03468	$ 0.03446
S.C. No. 1 & 12 Base Delivery Rates				
Block 1	First 2 Ccf		$ 24.00	$ 25.00
Block 2 per Ccf	Next 48 Ccf		$ 0.8805	$ 0.9390
Block 3 per Ccf	Additional		$ 0.4047	$ 0.4300
Merchant Function Charge (per Ccf):	MFC Admin		$ 0.00449	$ 0.00441
	MFC Supply		$ 0.01342	$ 0.01319
Gas Bill Credit (per Ccf):			$ (0.02716)	$ (0.06540)

Gas bill credit rates reflect rate moderation and an additional $4 million credit for illustration purposes only as described in Section III.D. SBC rates have been estimated to reflect the phased inclusion of the EEPS for CH programs in base rates. In order to only show the impact of base rate increases, annual bills under proposed rates do not however reflect annual changes to the SBC, or any increases related to the EEPS charge in Case 07-M-0548. NYSA and GSC have been included at rates effective as of February 6, 2015, the original filing date of the Joint Proposal in this Case.

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Gas Bills Impacts
Rate Year 2 (Twelve Months Ended June 30, 2017)

P.S.C. No. 12 - Gas
Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Present RY 1 Monthly Bill	Without Rate Moderation: Proposed RY 2 Monthly Bill	Without Rate Moderation: Delivery $ Increase	Without Rate Moderation: % Increase	With Rate Moderation: Gas Bill Credit	With Rate Moderation: Proposed RY 2 Monthly Bill	With Rate Moderation: Delivery $ Increase	With Rate Moderation: % Increase
2	$ 38.48	$ 39.51	$ 1.04	2.69%	$ (0.06)	$ 39.46	$ 0.98	2.54%
10	47.99	49.15	1.16	2.41%	(0.29)	48.86	0.87	1.81%
30	71.77	73.24	1.46	2.04%	(0.87)	72.36	0.59	0.82%
50	95.56	97.32	1.77	1.85%	(1.45)	95.87	0.31	0.33%
100	155.02	157.54	2.53	1.63%	(2.90)	154.64	(0.38)	-0.24%
150	200.89	205.42	4.52	2.25%	(4.36)	201.06	0.16	0.08%
200	246.77	253.29	6.52	2.64%	(5.81)	247.48	0.71	0.29%
250	292.65	301.17	8.52	2.91%	(7.26)	293.90	1.25	0.43%
300	338.53	349.04	10.51	3.11%	(8.71)	340.33	1.80	0.53%
400	430.29	444.79	14.51	3.37%	(11.62)	433.17	2.89	0.67%
500	522.04	540.54	18.50	3.54%	(14.52)	526.02	3.98	0.76%
600	613.80	636.29	22.49	3.66%	(17.43)	618.86	5.06	0.83%
800	797.31	827.79	30.48	3.82%	(23.24)	804.55	7.24	0.91%
1000	980.83	1,019.29	38.47	3.92%	(29.05)	990.24	9.42	0.96%
1500	1,439.61	1,498.05	58.44	4.06%	(43.57)	1,454.47	14.86	1.03%
2000	1,898.39	1,976.80	78.40	4.13%	(58.10)	1,918.70	20.31	1.07%
3000	2,815.96	2,934.30	118.34	4.20%	(87.15)	2,847.15	31.19	1.11%
5000	4,651.09	4,849.31	198.21	4.26%	(145.25)	4,704.06	52.97	1.14%
7500	6,814.29	7,101.79	287.50	4.22%	(217.87)	6,883.92	69.63	1.02%
10000	8,977.49	9,354.27	376.78	4.20%	(290.49)	9,063.78	86.29	0.96%
12000	10,708.05	11,156.26	448.21	4.19%	(348.59)	10,807.66	99.61	0.93%
14000	12,438.61	12,958.24	519.63	4.18%	(406.69)	12,551.55	112.94	0.91%
16000	14,169.17	14,760.23	591.06	4.17%	(464.79)	14,295.44	126.27	0.89%
20000	17,630.29	18,364.20	733.91	4.16%	(580.99)	17,783.21	152.92	0.87%
Average Annual Heating Customer @ 5970 Ccf Per Year								
5970	6,236.98	6,457.78	220.80	3.54%	(173.43)	6,284.35	47.38	0.76%

Weighted Revenue Tax Factor:		Delivery			0.00549
		Commodity			0.00549
Gas Supply Charge (per Ccf):				$	0.61375
New York State Assessment Surcharge (per Ccf):				$	0.01222
		Present RY 1		Proposed RY 2	
System Benefits Charge (per Ccf):		$	0.00509	$	0.00506
S.C. No. 2, 6 & 13 Base Delivery Rates					
Block 1	First 2 Ccf	$	37.00	$	38.00
Block 2 per Ccf	Next 98 Ccf	$	0.5494	$	0.5494
Block 3 per Ccf	Next 4900 Ccf	$	0.2793	$	0.3039
Block 4 per Ccf	Additional	$	0.2273	$	0.2477
Merchant Function Charge (per Ccf):	MFC Admin	$	0.00453	$	0.00434
	MFC Supply	$	0.01353	$	0.01298
Gas Bill Credit (per Ccf):		$	(0.01589)	$	(0.02889)

Gas bill credit rates reflect rate moderation and an additional $4 million credit for illustration purposes only as described in Section III.D.
SBC rates have been estimated to reflect the phased inclusion of the EEPS for CH programs in base rates. In order to only show the impact of base rate increases, annual bills under proposed rates do not however reflect annual changes to the SBC, or any increases related to the EEPS charge in Case 07-M-0548. NYSA and GSC have been included at rates effective as of February 6, 2015, the original filing date of the Joint Proposal in this Case.

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Gas Bills Impacts
Rate Year 3 (Twelve Months Ended June 30, 2018)

P.S.C. No. 12 - Gas
Service Classification Nos. 1 & 12

Monthly Usage Ccf	Present RY 2 Monthly Bill	Without Rate Moderation: Proposed RY 3 Monthly Bill	Without Rate Moderation: Delivery $ Increase	Without Rate Moderation: % Increase	With Rate Moderation: Gas Bill Credit	With Rate Moderation: Proposed RY 3 Monthly Bill	With Rate Moderation: Delivery $ Increase	With Rate Moderation: % Increase
2	$ 26.90	$ 28.06	$ 1.16	4.31%	$ (0.10)	$ 27.97	$ 1.06	3.95%
4	30.08	31.48	1.40	4.65%	(0.19)	31.29	1.21	4.01%
6	33.26	34.90	1.64	4.92%	(0.29)	34.61	1.35	4.06%
8	36.44	38.31	1.88	5.15%	(0.38)	37.93	1.49	4.10%
10	39.61	41.73	2.12	5.34%	(0.48)	41.25	1.64	4.13%
15	47.56	50.27	2.71	5.71%	(0.72)	49.55	1.99	4.19%
20	55.50	58.81	3.31	5.97%	(0.96)	57.85	2.35	4.24%
25	63.44	67.35	3.91	6.16%	(1.20)	66.15	2.71	4.27%
30	71.39	75.89	4.51	6.31%	(1.44)	74.45	3.07	4.30%
35	79.33	84.43	5.10	6.43%	(1.68)	82.75	3.42	4.32%
40	87.27	92.97	5.70	6.53%	(1.92)	91.05	3.78	4.33%
50	103.16	110.06	6.90	6.69%	(2.40)	107.66	4.50	4.36%
60	113.82	121.64	7.81	6.87%	(2.88)	118.76	4.93	4.33%
80	135.15	144.79	9.65	7.14%	(3.84)	140.95	5.81	4.30%
100	156.47	167.95	11.48	7.34%	(4.80)	163.15	6.68	4.27%
130	188.46	202.69	14.23	7.55%	(6.24)	196.45	7.99	4.24%
170	231.12	249.01	17.89	7.74%	(8.16)	240.85	9.73	4.21%
200	263.11	283.75	20.64	7.85%	(9.60)	274.15	11.04	4.20%
300	369.74	399.54	29.81	8.06%	(14.40)	385.14	15.40	4.17%
1000	1,116.16	1,210.11	93.95	8.42%	(48.00)	1,162.10	45.94	4.12%
			Average Annual Heating Customer @ 830 Ccf Per Year					
830	1,399.58	1,498.96	99.38	7.10%	(39.84)	1,459.12	59.54	4.25%

Weighted Revenue Tax Factor:		Delivery	0.02549
		Commodity	0.00549
Gas Supply Charge (per Ccf):			$ 0.61375
New York State Assessment Surcharge (per Ccf):			$ 0.02107
		Present RY 2	Proposed RY 3
System Benefits Charge (per Ccf):		$ 0.03446	$ 0.03444
S.C. No. 1 & 12 Base Delivery Rates			
Block 1	First 2 Ccf	$ 25.00	$ 26.00
Block 2 per Ccf	Next 48 Ccf	$ 0.9390	$ 0.9904
Block 3 per Ccf	Additional	$ 0.4300	$ 0.4542
Merchant Function Charge (per Ccf):	MFC Admin	$ 0.00441	$ 0.00434
	MFC Supply	$ 0.01319	$ 0.01297
Gas Bill Credit (per Ccf):		$ (0.06540)	$ (0.04678)

Gas bill credit rates reflect rate moderation and an additional $4 million credit for illustration purposes only as described in Section III.D.
SBC rates have been estimated to reflect the phased inclusion of the EEPS for CH programs in base rates. In order to only show the impact of base rate increases, annual bills under proposed rates do not however reflect annual changes to the SBC, or any increases related to the EEPS charge in Case 07-M-0548. NYSA and GSC have been included at rates effective as of February 6, 2015, the original filing date of the Joint Proposal in this Case.

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Gas Bills Impacts
Rate Year 3 (Twelve Months Ended June 30, 2018)

P.S.C. No. 12 - Gas
Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Present RY 2 Monthly Bill	Without Rate Moderation: Proposed RY 3 Monthly Bill	Without Rate Moderation: Delivery $ Increase	Without Rate Moderation: % Increase	With Rate Moderation: Gas Bill Credit	With Rate Moderation: Proposed RY 3 Monthly Bill	With Rate Moderation: Delivery $ Increase	With Rate Moderation: % Increase
2	$ 39.46	$ 40.52	$ 1.06	2.69%	$ (0.04)	$ 40.48	$ 1.03	2.60%
10	48.86	50.15	1.29	2.64%	(0.18)	49.97	1.11	2.27%
30	72.36	74.22	1.86	2.57%	(0.55)	73.68	1.31	1.81%
50	95.87	98.30	2.43	2.53%	(0.91)	97.39	1.52	1.58%
100	154.64	158.48	3.85	2.49%	(1.82)	156.66	2.03	1.31%
150	201.06	207.45	6.39	3.18%	(2.73)	204.72	3.66	1.82%
200	247.48	256.41	8.93	3.61%	(3.64)	252.77	5.29	2.14%
250	293.90	305.38	11.47	3.90%	(4.56)	300.82	6.92	2.35%
300	340.33	354.34	14.02	4.12%	(5.47)	348.88	8.55	2.51%
400	433.17	452.27	19.10	4.41%	(7.29)	444.99	11.81	2.73%
500	526.02	550.20	24.19	4.60%	(9.11)	541.09	15.08	2.87%
600	618.86	648.13	29.27	4.73%	(10.93)	637.20	18.34	2.96%
800	804.55	843.99	39.44	4.90%	(14.58)	829.42	24.86	3.09%
1000	990.24	1,039.85	49.61	5.01%	(18.22)	1,021.63	31.39	3.17%
1500	1,454.47	1,529.50	75.03	5.16%	(27.33)	1,502.17	47.70	3.28%
2000	1,918.70	2,019.16	100.46	5.24%	(36.44)	1,982.72	64.02	3.34%
3000	2,847.15	2,998.46	151.30	5.31%	(54.66)	2,943.80	96.64	3.39%
5000	4,704.06	4,957.06	253.00	5.38%	(91.10)	4,865.96	161.90	3.44%
7500	6,883.92	7,252.97	369.06	5.36%	(136.65)	7,116.32	232.41	3.38%
10000	9,063.78	9,548.89	485.11	5.35%	(182.20)	9,366.69	302.91	3.34%
12000	10,807.66	11,385.62	577.96	5.35%	(218.64)	11,166.98	359.32	3.32%
14000	12,551.55	13,222.35	670.80	5.34%	(255.08)	12,967.27	415.72	3.31%
16000	14,295.44	15,059.09	763.65	5.34%	(291.52)	14,767.57	472.13	3.30%
20000	17,783.21	18,732.55	949.34	5.34%	(364.40)	18,368.15	584.94	3.29%
Average Annual Heating Customer @ 6070 Ccf Per Year								
6070	6,377.20	6,671.00	293.80	4.61%	(110.60)	6,560.40	183.20	2.87%

			Present RY 2	Proposed RY 3
Weighted Revenue Tax Factor:		Delivery		0.00549
		Commodity		0.00549
Gas Supply Charge (per Ccf):				$ 0.61375
New York State Assessment Surcharge (per Ccf):				$ 0.01222
System Benefits Charge (per Ccf):			$ 0.00506	$ 0.00505
S.C. No. 2, 6 & 13 Base Delivery Rates				
	Block 1	First 2 Ccf	$ 38.00	$ 39.00
	Block 2 per Ccf	Next 98 Ccf	$ 0.5494	$ 0.5494
	Block 3 per Ccf	Next 4900 Ccf	$ 0.3039	$ 0.3262
	Block 4 per Ccf	Additional	$ 0.2477	$ 0.2656
Merchant Function Charge (per Ccf):		MFC Admin	$ 0.00434	$ 0.00419
		MFC Supply	$ 0.01298	$ 0.01251
Gas Bill Credit (per Ccf):			$ (0.02889)	$ (0.01812)

Gas bill credit rates reflect rate moderation and an additional $4 million credit for illustration purposes only as described in Section III.D.
SBC rates have been estimated to reflect the phased inclusion of the EEPS for CH programs in base rates. In order to only show the impact of base rate increases, annual bills under proposed rates do not however reflect annual changes to the SBC, or any increases related to the EEPS charge in Case 07-M-0548. NYSA and GSC have been included at rates effective as of February 6, 2015, the original filing date of the Joint Proposal in this Case.

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric RDM Targets

		Rate Year 1	Rate Year 2	Rate Year 3
S.C. No. 1				
	Customer Months	3,055,453	3,061,073	3,066,066
	kWh	2,005,940,000	2,017,274,000	2,024,968,000
	Revenue	$ 191,416,210	$ 203,864,020	$ 214,822,140
S.C. No. 2 - Non-Demand				
	Customer Months	353,718	355,848	357,654
	kWh	161,130,593	162,765,418	164,051,593
	Revenue	$ 15,390,920	$ 16,704,070	$ 17,944,890
S.C. No. 2 - Secondary				
	Customer Months	140,530	140,704	142,943
	kWh	1,351,467,640	1,340,306,050	1,353,166,050
	kW	4,131,110	4,095,400	4,136,440
	Revenue	$ 54,610,400	$ 55,905,050	$ 57,979,150
S.C. No. 2 - Primary				
	Customer Months	1,954	1,958	1,980
	kWh	210,990,296	210,303,296	211,593,296
	kW	557,890	537,890	557,890
	Revenue	$ 4,923,629	$ 4,996,700	$ 5,345,309
S.C. No. 6				
	Customer Months	13,800	13,800	13,800
	kWh	20,000,000	20,000,000	20,000,000
	Revenue	$ 1,394,400	$ 1,437,320	$ 1,474,000
RDM Revenue Target		**$ 267,735,559**	**$ 282,907,160**	**$ 297,565,489**

Note: Revenues are derived from customer charges, base rate energy delivery charges, base rate demand delivery charges and Merchant Function Charges

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric RDM Targets
Rate Year 1 (Twelve Months Ended June 30, 2016)

	July 2015	August 2015	September 2015	October 2015	November 2015	December 2015	January 2016	February 2016	March 2016	April 2016	May 2016	June 2016	Total
Service Classification No. 1													
Customer Months	254,380	253,890	253,751	254,193	254,023	254,945	256,444	253,966	256,576	254,502	254,203	254,580	3,055,453
MWh	168,574	191,706	181,595	151,445	141,934	162,335	189,204	192,759	179,844	159,597	143,631	143,316	2,005,940
Revenue	$ 16,019,460	$ 17,295,220	$ 16,708,530	$ 15,083,920	$ 14,562,380	$ 15,695,050	$ 17,194,370	$ 17,320,770	$ 16,689,990	$ 15,534,860	$ 14,659,270	$ 14,652,390	$ 191,416,210
Service Classification No. 2													
Nondemand													
Customer Months	28,216	30,583	28,280	30,606	28,266	30,647	28,325	30,646	28,388	30,679	28,343	30,739	353,718
MWh	12,562	14,669	12,961	12,718	11,276	13,884	14,414	16,366	13,865	13,648	11,791	12,977	161,131
Revenue	$ 1,224,200	$ 1,339,630	$ 1,231,440	$ 1,316,940	$ 1,210,500	$ 1,332,560	$ 1,250,770	$ 1,362,560	$ 1,246,510	$ 1,330,940	$ 1,219,780	$ 1,325,090	$ 15,390,920
Primary													
Customer Months	164	159	163	162	160	160	168	162	167	163	162	164	1,954
MWh	19,070	18,054	18,017	18,092	16,992	17,689	18,143	17,016	17,271	16,151	16,943	17,554	210,990
kW	55,180	45,930	45,987	46,002	46,007	45,984	35,899	45,770	45,552	45,438	45,188	54,953	557,890
Revenue	$ 474,930	$ 406,330	$ 408,390	$ 408,310	$ 405,300	$ 406,110	$ 336,427	$ 403,304	$ 403,643	$ 400,669	$ 399,829	$ 470,387	$ 4,923,629
Secondary													
Customer Months	11,752	11,558	11,674	11,699	11,622	11,987	11,858	11,454	11,921	11,643	11,676	11,686	140,530
MWh	128,814	127,247	120,572	107,226	101,461	111,273	118,245	111,986	105,761	100,476	104,185	114,221	1,351,468
kW	400,349	370,725	373,465	367,238	322,926	321,853	326,556	312,756	313,797	317,637	335,436	368,372	4,131,110
Revenue	$ 5,122,680	$ 4,846,720	$ 4,844,260	$ 4,712,260	$ 4,300,370	$ 4,373,610	$ 4,441,290	$ 4,263,250	$ 4,267,340	$ 4,251,760	$ 4,421,420	$ 4,765,440	$ 54,610,400
Service Classification No. 6													
Customer Months	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	13,800
MWh	1,550	1,730	1,460	1,310	1,110	1,670	2,180	2,340	2,160	1,780	1,400	1,310	20,000
Revenue	$ 110,170	$ 119,600	$ 105,760	$ 99,020	$ 88,610	$ 116,680	$ 141,060	$ 149,510	$ 140,080	$ 122,060	$ 102,830	$ 99,020	$ 1,394,400
Total RDM Revenue Target	**$ 22,951,440**	**$ 24,007,500**	**$ 23,298,380**	**$ 21,620,450**	**$ 20,567,160**	**$ 21,924,010**	**$ 23,363,917**	**$ 23,499,394**	**$ 22,747,563**	**$ 21,640,289**	**$ 20,803,129**	**$ 21,312,327**	**$ 267,735,559**

Appendix M Sheet 3 of 13

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric RDM Targets
Rate Year 2 (Twelve Months Ended June 30, 2017)

	July 2016	August 2016	September 2016	October 2016	November 2016	December 2016	January 2017	February 2017	March 2017	April 2017	May 2017	June 2017	Total
Service Classification No. 1													
Customer Months	254,992	254,372	254,507	254,622	254,717	255,210	256,631	254,469	256,782	254,891	254,920	254,960	3,061,073
MWh	169,415	192,518	182,566	152,094	142,772	163,118	190,520	194,442	180,934	160,559	144,453	143,883	2,017,274
Revenue	$ 17,063,560	$ 18,400,400	$ 17,820,060	$ 16,037,340	$ 15,492,970	$ 16,699,930	$ 18,345,450	$ 18,515,590	$ 17,786,980	$ 16,540,500	$ 15,597,000	$ 15,564,240	$ 203,864,020
Service Classification No. 2													
Nondemand													
Customer Months	28,403	30,774	28,448	30,800	28,444	30,837	28,499	30,822	28,545	30,858	28,506	30,912	355,848
MWh	12,804	15,077	13,276	13,038	11,231	14,056	14,731	16,395	13,949	13,917	11,300	12,992	162,765
Revenue	$ 1,330,840	$ 1,457,580	$ 1,338,810	$ 1,432,190	$ 1,312,090	$ 1,446,910	$ 1,359,810	$ 1,476,640	$ 1,351,540	$ 1,445,880	$ 1,315,630	$ 1,436,150	$ 16,704,070
Primary													
Customer Months	164	160	163	162	160	161	168	163	168	163	162	164	1,958
MWh	19,054	18,177	18,163	17,941	17,189	17,760	17,940	16,885	17,167	16,117	16,574	17,338	210,303
kW	55,180	45,930	45,987	46,002	46,007	45,984	35,899	35,770	45,552	45,438	45,188	44,953	537,890
Revenue	$ 496,800	$ 424,980	$ 427,093	$ 426,513	$ 424,015	$ 424,637	$ 350,813	$ 346,950	$ 421,729	$ 418,734	$ 417,294	$ 417,142	$ 4,996,700
Secondary													
Customer Months	11,766	11,573	11,692	11,714	11,637	12,003	11,873	11,468	11,935	11,657	11,687	11,699	140,704
MWh	128,064	128,157	121,681	105,435	103,101	111,633	115,685	110,186	104,390	99,866	100,385	111,722	1,340,306
kW	397,969	373,445	377,015	360,958	328,286	322,913	319,246	307,516	309,597	315,647	322,766	360,042	4,095,400
Revenue	$ 5,258,960	$ 5,027,140	$ 5,033,600	$ 4,792,540	$ 4,487,320	$ 4,516,380	$ 4,495,600	$ 4,339,780	$ 4,349,400	$ 4,358,320	$ 4,421,150	$ 4,824,860	$ 55,905,050
Service Classification No. 6													
Customer Months	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	13,800
MWh	1,550	1,730	1,460	1,310	1,110	1,670	2,180	2,340	2,160	1,780	1,400	1,310	20,000
Revenue	$ 113,570	$ 123,280	$ 109,030	$ 102,090	$ 91,360	$ 120,260	$ 145,380	$ 154,070	$ 144,370	$ 125,810	$ 106,010	$ 102,090	$ 1,437,320
Total RDM Revenue Target	**$ 24,263,730**	**$ 25,433,380**	**$ 24,728,593**	**$ 22,790,673**	**$ 21,807,755**	**$ 23,208,117**	**$ 24,697,053**	**$ 24,833,030**	**$ 24,054,019**	**$ 22,889,244**	**$ 21,857,084**	**$ 22,344,482**	**$ 282,907,160**

Appendix M Sheet 4 of 13

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric RDM Targets
Rate Year 3 (Twelve Months Ended June 30, 2018)

	July 2017	August 2017	September 2017	October 2017	November 2017	December 2017	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	Total
Service Classification No. 1													
Customer Months	255,537	254,813	255,148	255,010	255,297	255,467	256,830	254,915	256,999	255,238	255,516	255,296	3,066,066
MWh	170,141	193,148	183,280	152,561	143,415	163,673	191,207	195,371	181,574	161,160	145,042	144,396	2,024,968
Revenue	$ 17,994,760	$ 19,410,310	$ 18,804,370	$ 16,884,650	$ 16,324,100	$ 17,590,070	$ 19,330,150	$ 19,536,270	$ 18,736,230	$ 17,417,160	$ 16,420,010	$ 16,374,060	$ 214,822,140
Service Classification No. 2													
Nondemand													
Customer Months	28,560	30,937	28,593	30,964	28,594	30,997	28,645	30,972	28,680	31,009	28,644	31,059	357,654
MWh	12,941	15,224	13,410	13,180	11,339	14,161	14,807	16,468	14,011	14,007	11,397	13,107	164,052
Revenue	$ 1,430,820	$ 1,566,130	$ 1,438,580	$ 1,539,810	$ 1,410,720	$ 1,554,480	$ 1,459,690	$ 1,584,420	$ 1,450,500	$ 1,552,920	$ 1,413,770	$ 1,543,050	$ 17,944,890
Primary													
Customer Months	165	162	165	164	162	161	169	166	169	166	164	167	1,980
MWh	19,101	18,379	18,291	18,039	17,332	17,625	17,914	17,224	17,167	16,258	16,709	17,556	211,593
kW	55,180	45,930	45,987	46,002	46,007	45,984	35,899	45,770	45,552	45,438	45,188	54,953	557,890
Revenue	$ 516,000	$ 441,760	$ 443,650	$ 442,979	$ 440,604	$ 440,156	$ 363,519	$ 438,664	$ 437,659	$ 435,156	$ 433,645	$ 511,517	$ 5,345,309
Secondary													
Customer Months	11,858	11,818	11,879	11,884	11,871	11,920	11,911	11,913	12,021	11,916	11,930	12,022	142,943
MWh	128,334	130,227	122,961	106,285	104,501	110,123	115,325	113,796	104,370	101,356	101,765	114,122	1,353,166
kW	398,819	379,615	381,055	363,958	332,886	318,423	318,216	317,996	309,527	320,547	327,376	368,022	4,136,440
Revenue	$ 5,414,720	$ 5,248,450	$ 5,225,540	$ 4,963,410	$ 4,671,610	$ 4,573,180	$ 4,601,030	$ 4,604,490	$ 4,464,730	$ 4,543,620	$ 4,604,060	$ 5,064,310	$ 57,979,150
Service Classification No. 6													
Customer Months	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	1,140	1,160	13,800
MWh	1,550	1,730	1,460	1,310	1,110	1,670	2,180	2,340	2,160	1,780	1,400	1,310	20,000
Revenue	$ 116,480	$ 126,410	$ 111,840	$ 104,740	$ 93,770	$ 123,340	$ 149,020	$ 157,920	$ 147,990	$ 129,010	$ 108,740	$ 104,740	$ 1,474,000
Total RDM Revenue Target	**$ 25,472,780**	**$ 26,793,060**	**$ 26,023,980**	**$ 23,935,589**	**$ 22,940,804**	**$ 24,281,226**	**$ 25,903,409**	**$ 26,321,764**	**$ 25,237,109**	**$ 24,077,866**	**$ 22,980,225**	**$ 23,597,677**	**$ 297,565,489**

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Gas RDM Targets

S.C. Nos. 1 & 12

	Rate Year 1	Rate Year 2	Rate Year 3
Revenue Forecast*	$ 51,940,300	$ 55,804,320	$ 59,559,870
Customer Forecast	68,331	69,512	70,692
Rev/Cust Target**	$ 757.68	$ 800.25	$ 839.86

S.C. Nos. 2, 6 & 13

	Rate Year 1	Rate Year 2	Rate Year 3
Revenue Forecast*	$ 25,335,280	$ 27,923,650	$ 30,409,750
Customer Forecast	11,523	11,803	12,080
Rev/Cust Target**	$ 2,186.95	$ 2,353.27	$ 2,503.98

*Base revenue excluding MFC revenue
**Please refer to sum of monthly values shown on Appendix M Sheet 6-8.

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Rate Year 1 (Twelve Months Ended June 30, 2016) RDM Targets

S.C. Nos. 1 & 12

	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
Revenue Forecast*	$ 2,232,830	$ 2,103,440	$ 1,966,440	$ 2,913,570	$ 3,855,610	$ 5,563,620	$ 5,988,200	$ 7,177,930	$ 6,189,310	$ 5,985,100	$ 4,374,760	$ 3,589,490	$ 51,940,300
Customer Forecast	63,643	71,339	63,481	71,741	63,517	72,929	65,359	73,330	65,427	71,979	64,227	73,006	68,331
Rev/Cust Target	$ 35.08	$ 29.49	$ 30.98	$ 40.61	$ 60.70	$ 76.29	$ 91.62	$ 97.89	$ 94.60	$ 83.15	$ 68.11	$ 49.17	$ 757.68

S.C. Nos. 2, 6 & 13

	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
Revenue Forecast*	$ 1,035,490	$ 1,018,210	$ 1,036,990	$ 1,271,500	$ 1,870,790	$ 2,962,060	$ 3,577,870	$ 3,773,530	$ 3,213,810	$ 2,575,560	$ 1,737,420	$ 1,262,050	$ 25,335,280
Customer Forecast	10,811	11,750	10,739	11,836	10,773	12,278	11,227	12,142	11,306	12,187	11,101	12,132	11,523
Rev/Cust Target	$ 95.78	$ 86.66	$ 96.56	$ 107.42	$ 173.65	$ 241.25	$ 318.69	$ 310.79	$ 284.27	$ 211.33	$ 156.51	$ 104.03	$ 2,186.95

*Base revenue excluding MFC revenue

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Rate Year 2 (Twelve Months Ended June 30, 2017) RDM Targets

S.C. Nos. 1 & 12

	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Total
Revenue Forecast*	$ 2,387,500	$ 2,239,470	$ 2,098,760	$ 3,113,450	$ 4,144,920	$ 5,980,280	$ 6,453,530	$ 7,725,120	$ 6,671,300	$ 6,438,120	$ 4,707,820	$ 3,844,050	$ 55,804,320
Customer Forecast	64,824	72,519	64,661	72,921	64,698	74,109	66,540	74,510	66,607	73,160	65,407	74,186	69,512
Rev/Cust Target	$ 36.83	$ 30.88	$ 32.46	$ 42.70	$ 64.07	$ 80.70	$ 96.99	$ 103.68	$ 100.16	$ 88.00	$ 71.98	$ 51.82	$ 800.25

S.C. Nos. 2, 6 & 13

	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Total
Revenue Forecast*	$ 1,124,020	$ 1,100,480	$ 1,124,830	$ 1,380,990	$ 2,054,920	$ 3,277,980	$ 3,988,340	$ 4,200,750	$ 3,569,820	$ 2,838,200	$ 1,900,290	$ 1,363,030	$ 27,923,650
Customer Forecast	11,084	12,032	11,013	12,119	11,046	12,563	11,503	12,427	11,583	12,471	11,377	12,416	11,803
Rev/Cust Target	$ 101.41	$ 91.46	$ 102.14	$ 113.95	$ 186.04	$ 260.92	$ 346.72	$ 338.04	$ 308.19	$ 227.58	$ 167.03	$ 109.78	$ 2,353.27

*Base revenue excluding MFC revenue

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Rate Year 3 (Twelve Months Ended June 30, 2018) RDM Targets

S.C. Nos. 1 & 12

	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Total
Revenue Forecast*	$ 2,540,500	$ 2,375,860	$ 2,230,960	$ 3,308,340	$ 4,423,730	$ 6,382,680	$ 6,905,630	$ 8,256,370	$ 7,139,920	$ 6,876,240	$ 5,029,440	$ 4,090,200	$ 59,559,870
Customer Forecast	66,005	73,700	65,842	74,101	65,878	75,290	67,720	75,691	67,788	74,340	66,588	75,367	70,692
Rev/Cust Target	$ 38.49	$ 32.24	$ 33.88	$ 44.65	$ 67.15	$ 84.77	$ 101.97	$ 109.08	$ 105.33	$ 92.50	$ 75.53	$ 54.27	$ 839.86

S.C. Nos. 2, 6 & 13

	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Total
Revenue Forecast*	$ 1,209,050	$ 1,181,040	$ 1,210,470	$ 1,486,350	$ 2,231,210	$ 3,579,660	$ 4,379,850	$ 4,606,570	$ 3,911,040	$ 3,092,110	$ 2,059,500	$ 1,462,900	$ 30,409,750
Customer Forecast	11,357	12,313	11,283	12,399	11,316	12,847	11,778	12,709	11,858	12,754	11,649	12,697	12,080
Rev/Cust Target	$ 106.46	$ 95.92	$ 107.28	$ 119.88	$ 197.17	$ 278.64	$ 371.88	$ 362.48	$ 329.84	$ 242.44	$ 176.79	$ 115.22	$ 2,503.98

*Base revenue excluding MFC revenue

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Example of Gas Revenue Decoupling Mechanism

S.C. Nos. 1 & 12 for Rate Year 1 (Twelve Months Ended June 30, 2016)

	July	August	September	October	November	December	January	February	March	April	May	June
Revenue Forecast (Appendix M Sheet 6 of 13)	$ 2,232,830	$ 2,103,440	$ 1,966,440	$ 2,913,570	$ 3,855,610	$ 5,563,620	$ 5,988,200	$ 7,177,930	$ 6,189,310	$ 5,985,100	$ 4,374,760	$ 3,589,490
Customer Forecast (Appendix M Sheet 6 of 13)	63,643	71,339	63,481	71,741	63,517	72,929	65,359	73,330	65,427	71,979	64,227	73,006
Revenue/Customer Target (Appendix M Sheet 6 of 13)	$ 35.08	$ 29.49	$ 30.98	$ 40.61	$ 60.70	$ 76.29	$ 91.62	$ 97.89	$ 94.60	$ 83.15	$ 68.11	$ 49.17
Actual Customers*	63,743	71,439	63,581	71,841	63,617	73,029	65,459	73,430	65,527	72,079	64,327	73,106
Revenue Target	$ 2,236,324	$ 2,106,393	$ 1,969,549	$ 2,917,646	$ 3,861,663	$ 5,571,251	$ 5,997,363	$ 7,187,715	$ 6,198,803	$ 5,993,382	$ 4,381,600	$ 3,594,406
Actual Revenues*	$ 2,200,000	$ 2,100,000	$ 2,100,000	$ 2,800,000	$ 3,900,000	$ 5,700,000	$ 6,400,000	$ 7,700,000	$ 6,500,000	$ 5,900,000	$ 4,500,000	$ 3,700,000
Less Actual Weather Normalization Adjustment*	$ -	$ -	$ -	$ 100,000	$ 200,000	$ (200,000)	$ 300,000	$ 400,000	$ 300,000	$ (200,000)	$ 100,000	$ -
Total WNA Adjusted Actual Revenue*	$ 2,200,000	$ 2,100,000	$ 2,100,000	$ 2,700,000	$ 3,700,000	$ 5,900,000	$ 6,100,000	$ 7,300,000	$ 6,200,000	$ 6,100,000	$ 4,400,000	$ 3,700,000
Total Over/(Under) Revenue	$ (36,324)	$ (6,393)	$ 130,451	$ (217,646)	$ (161,663)	$ 328,749	$ 102,637	$ 112,285	$ 1,197	$ 106,618	$ 18,400	$ 105,594
					Six Month Total Over/(Under) Revenue	$ 37,174					Six Month Total Over/(Under) Revenue	$ 446,731
					RDM Adjustment Period Mcf (Appendix I)	3,289,912					RDM Adjustment Period Mcf (Appendix I)	2,007,603
					RDM Factor per Ccf	$ 0.0011					RDM Factor per Ccf	$ 0.0223

* Numbers selected for illustrative purposes only.

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Gas MFC Targets

MFC-1 (S.C. Nos. 1, 12 & 16)

	Rate Year 1	Rate Year 2	Rate Year 3
Revenue Target	$ 942,310	$ 942,030	$ 942,220

MFC-2 (S.C. Nos. 2, 6, 13 & 15)

	Rate Year 1	Rate Year 2	Rate Year 3
Revenue Target	$ 1,227,640	$ 1,227,010	$ 1,227,280

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Rate Year 1 (Twelve Months Ended June 30, 2016) MFC Targets

MFC-1 (S.C. Nos. 1, 12 & 16)

	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
Revenue Target	$ 16,310	$ 9,650	$ 10,330	$ 27,380	$ 55,800	$ 110,250	$ 140,020	$ 179,110	$ 148,050	$ 128,380	$ 74,010	$ 43,020	$ 942,310

MFC-2 (S.C. Nos. 2, 6, 13 & 15)

	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
Revenue Target	$ 36,540	$ 33,530	$ 36,990	$ 48,630	$ 87,040	$ 153,100	$ 198,820	$ 207,740	$ 173,350	$ 127,850	$ 78,020	$ 46,030	$ 1,227,640

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Rate Year 2 (Twelve Months Ended June 30, 2017) MFC Targets

MFC-1 (S.C. Nos. 1, 12 & 16)

	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Total
Revenue Target	$ 16,330	$ 9,690	$ 10,360	$ 27,320	$ 55,760	$ 110,110	$ 140,090	$ 178,970	$ 148,150	$ 128,280	$ 74,040	$ 42,930	$ 942,030

MFC-2 (S.C. Nos. 2, 6, 13 & 15)

	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Total
Revenue Target	$ 36,480	$ 33,390	$ 36,820	$ 48,390	$ 86,920	$ 153,160	$ 199,280	$ 208,110	$ 173,480	$ 127,670	$ 77,670	$ 45,640	$ 1,227,010

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Rate Year 3 (Twelve Months Ended June 30, 2018) MFC Targets

MFC-1 (S.C. Nos. 1, 12 & 16)

	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Total
Revenue Target	$ 16,360	$ 9,730	$ 10,390	$ 27,270	$ 55,750	$ 110,040	$ 140,260	$ 178,920	$ 148,310	$ 128,240	$ 74,080	$ 42,870	$ 942,220

MFC-2 (S.C. Nos. 2, 6, 13 & 15)

	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Total
Revenue Target	$ 36,410	$ 33,310	$ 36,730	$ 48,210	$ 86,850	$ 153,230	$ 199,720	$ 208,380	$ 173,710	$ 127,690	$ 77,580	$ 45,460	$ 1,227,280

Central Hudson Gas and Electric Corporation
Cases 14-E-0318; 14-G-0319
Part 255 / 261
High and Other Gas Risk Safety Violations

HIGH RISK SECTIONS PART 255

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Material - General	255.53(a),(b),(c)	HIGH
Transportation of Pipe	255.65	HIGH
Pipe Design - General	255.103	HIGH
Design of Components - General Requirements	255.143	HIGH
Design of Components - Flexibility	255.159	HIGH
Design of Components - Supports and anchors	255.161	HIGH
Compressor Stations: Emergency shutdown	255.167	HIGH
Compressor Stations: Pressure limiting devices	255.169	HIGH
Compressor Stations: Ventilation	255.173	HIGH
Valves on pipelines to operate at 125 psig or more	255.179	HIGH
Distribution line valves	255.181	HIGH
Vaults: Structural Design requirements	255.183	HIGH
Vaults: Drainage and waterproofing	255.189	HIGH
Protection against accidental overpressuring	255.195	HIGH
Control of the pressure of gas delivered from high pressure distribution systems	255.197	HIGH
Requirements for design of pressure relief and limiting devices	255.199	HIGH
Required capacity of pressure relieving and limiting stations	255.201	HIGH
Qualification of welding procedures	255.225	HIGH
Qualification of Welders	255.227	HIGH
Protection from weather	255.231	HIGH
Miter Joints	255.233	HIGH
Preparation for welding	255.235	HIGH
Inspection and test of welds	255.241(a),(b)	HIGH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(a)-(e)	HIGH
Welding inspector	255.244(a),(b),(c)	HIGH
Repair or removal of defects	255.245	HIGH
Joining Of Materials Other Than By Welding - General	255.273	HIGH
Joining Of Materials Other Than By Welding - Copper Pipe	255.279	HIGH
Joining Of Materials Other Than By Welding - Plastic Pipe	255.281	HIGH
Plastic pipe: Qualifying persons to make joints	255.285(a),(b),(d)	HIGH
Notification requirements	255.302	HIGH
Compliance with construction standards	255.303	HIGH
Inspection: General	255.305	HIGH
Inspection of materials	255.307	HIGH
Repair of steel pipe	255.309	HIGH
Repair of plastic pipe	255.311	HIGH
Bends and elbows	255.313(a),(b),(c)	HIGH
Wrinkle bends in steel pipe	255.315	HIGH
Installation of plastic pipe	255.321	HIGH
Underground clearance	255.325	HIGH
Customer meters and service regulators: Installation	255.357(d)	HIGH
Service lines: Installation	255.361(e),(f),(g),(h),(i)	HIGH
Service lines: Location of valves	255.365(b)	HIGH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455(d),(e)	HIGH
External corrosion control: Buried or submerged pipelines installed before August 1, 1971	255.457	HIGH
External corrosion control: Protective coating	255.461(c)	HIGH
External corrosion control: Cathodic protection	255.463	HIGH
External corrosion control: Monitoring	255.465(a),(e)	HIGH
Internal corrosion control: Design and construction of transmission line	255.476(a),(c)	HIGH
Remedial measures: General	255.483	HIGH
Remedial measures: transmission lines	255.485(a),(b)	HIGH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255.505(a),(b),(c),(d)	HIGH
General requirements (UPGRADES)	255.553 (a),(b),(c),(f)	HIGH
Upgrading to a pressure of 125 PSIG or more in steel pipelines	255.555	HIGH
Upgrading to a pressure less than 125 PSIG	255.557	HIGH
Conversion to service subject to this Part	255.559(a)	HIGH
General provisions	255.603	HIGH
Operator Qualification	255.604	HIGH
Essentials of operating and maintenance plan	255.605	HIGH
Change in class location: Required study	255.609	HIGH
Damage prevention program	255.614	HIGH
Emergency Plans	255.615	HIGH
Customer education and information program	255.616	HIGH
Maximum allowable operating pressure: Steel or plastic pipelines	255.619	HIGH
Maximum allowable operating pressure: High pressure distribution systems	255.621	HIGH
Maximum and minimum allowable operating pressure: Low pressure distribution systems	255.623	HIGH
Odorization of gas	255.625(a),(b)	HIGH

Central Hudson Gas and Electric Corporation
Cases 14-E-0318; 14-G-0319
Part 255 / 261
High and Other Gas Risk Safety Violations

Tapping pipelines under pressure	255.627	HIGH
Purging of pipelines	255.629	HIGH
Control Room Management	255.631(a)	HIGH
Transmission lines: Patrolling	255.705	HIGH
Leakage Surveys - Transmission	255.706	HIGH
Transmission lines: General requirements for repair procedures	255.711	HIGH
Transmission lines: Permanent field repair of imperfections and damages	255.713	HIGH
Transmission lines: Permanent field repair of welds	255.715	HIGH
Transmission lines: Permanent field repair of leaks	255.717	HIGH
Transmission lines: Testing of repairs	255.719	HIGH
Distribution systems: Leak surveys and procedures	255.723	HIGH
Compressor stations: procedures	255.729	HIGH
Compressor stations: Inspection and testing relief devices	255.731	HIGH
Compressor stations: Additional inspections	255.732	HIGH
Compressor stations: Gas detection	255.736	HIGH
Pressure limiting and regulating stations: Inspection and testing	255.739(a),(b)	HIGH
Regulator Station Overpressure Protection	255.743(a),(b)	HIGH
Transmission Line Valves	255.745	HIGH
Prevention of accidental ignition	255.751	HIGH
Protecting cast iron pipelines	255.755	HIGH
Replacement of exposed or undermined cast iron piping	255.756	HIGH
Replacement of cast iron mains paralleling excavations	255.757	HIGH
Leaks: Records	255.807(d)	HIGH
Leaks: Instrument sensitivity verification	255.809	HIGH
Leaks: Type 1	255.811(b),(c),(d),(e)	HIGH
Leaks: Type 2A	255.813(b),(c),(d)	HIGH
Leaks: Type 2	255.815	HIGH
Leak Follow-up	255.819(a)	HIGH
High Consequence Areas	255.905	HIGH
Required Elements (IMP)	255.911	HIGH
Knowledge and Training (IMP)	255.915	HIGH
Identification of Potential Threats to Pipeline Integrity and Use of the Threat Identification in an Integrity Program (IMP)	255.917	HIGH
Baseline Assessment Plan(IMP)	255.919	HIGH
Conducting a Baseline Assessment (IMP)	255.921	HIGH
Direct Assessment (IMP)	255.923	HIGH
External Corrosion Direct Assessment (ECDA) (IMP)	255.925	HIGH
Internal Corrosion Direct Assessment (ICDA) (IMP)	255.927	HIGH
Confirmatory Direct Assessment (CDA) (IMP)	255.931	HIGH
Addressing Integrity Issues (IMP)	255.933	HIGH
Preventive and Mitigative Measures to Protect the High Consequence Areas (IMP)	255.935	HIGH
Continual Process of Evaluation and Assessment (IMP)	255.937	HIGH
Reassessment Intervals (IMP)	255.939	HIGH
General requirements of a GDPIM plan	255.1003	HIGH
Implementation requirements of a GDPIM plan.	255.1005	HIGH
Required elements of a GDPIM plan.	255.1007	HIGH
Required report when compression couplings fail.	255.1009	HIGH
Requirements a small liquefied petroleum gas (LPG) operator must satisfy to implement a GDPIM plan	255.1015	HIGH

HIGH RISK SECTIONS PART 261		
Operation and maintenance plan	261.15	HIGH
Leakage Survey	261.17(a),(c)	HIGH
Carbon monoxide prevention	261.21	HIGH
Warning tag procedures	261.51	HIGH
HEFPA Liaison	261.53	HIGH
Warning Tag Inspection	261.55	HIGH
Warning tag: Class A condition	261.57	HIGH
Warning tag: Class B condition	261.59	HIGH

OTHER RISK SECTIONS PART 255

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Preservation of records	255.17	OTH
Compressor station: Design and construction	255.163	OTH
Compressor station: Liquid removal	255.165	OTH
Compressor stations: Additional safety equipment	255.171	OTH
Vaults: Accessibility	255.185	OTH
Vaults: Sealing, venting, and ventilation	255.187	OTH
Calorimeter or calorimeter structures	255.190	OTH
Design pressure of plastic fittings	255.191	OTH
Valve installtion in plastic pipe	255.193	OTH
Instrument, control, and sampling piping and components	255.203	OTH
Limitations On Welders	255.229	OTH
Quality assurance program	255.230	OTH
Preheating	255.237	OTH
Stress relieving	255.239	OTH
Inspection and test of welds	255.241(c)	OTH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(f)	OTH
Plastic pipe: Qualifying joining procedures	255.283	OTH
Plastic pipe: Qualifying persons to make joints	255.285(c),(e)	OTH
Plastic pipe: Inspection of joints	255.287	OTH
Bends and elbows	255.313(d)	OTH
Protection from hazards	255.317	OTH
Installation of pipe in a ditch	255.319	OTH
Casing	255.323	OTH
Cover	255.327	OTH
Customer meters and regulators: Location	255.353	OTH
Customer meters and regulators: Protection from damage	255.355	OTH
Customer meters and service regulators: Installation	255.357(a),(b),(c)	OTH
Customer meter installations: Operating pressure	255.359	OTH
Service lines: Installation	255.361(a),(b),(c),(d)	OTH
Service lines: valve requirements	255.363	OTH
Service lines: Location of valves	255.365(a),(c)	OTH
Service lines: General requirements for connections to main piping	255.367	OTH
Service lines: Connections to cast iron or ductile iron mains	255.369	OTH
Service lines: Steel	255.371	OTH
Service lines: Cast iron and ductile iron	255.373	OTH
Service lines: Plastic	255.375	OTH
Service lines: Copper	255.377	OTH
New service lines not in use	255.379	OTH
Service lines: excess flow valve performance standards	255.381	OTH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455(a)	OTH
External corrosion control: Examination of buried pipeline when exposed	255.459	OTH
External corrosion control: Protective coating	255.461(a),(b),(d),(e),(f),(g)	OTH
Rectifier Inspection	255.465 (b),(c),(f)	OTH
External corrosion control: Electrical isolation	255.467	OTH
External corrosion control: Test stations	255.469	OTH
External corrosion control: Test lead	255.471	OTH
External corrosion control: Interference currents	255.473	OTH
Internal corrosion control: General	255.475(a),(b)	OTH
Atmospheric corrosion control: General	255.479	OTH
Atmospheric corrosion control: Monitoring	255.481	OTH
Remedial measures: transmission lines	255.485(c)	OTH
Remedial measures: Pipelines lines other than cast iron or ductile iron lines	255.487	OTH
Remedial measures: Cast iron and ductile iron pipelines	255.489	OTH
Direct Assessment	255.490	OTH
Corrosion control records	255.491	OTH
General requirements (TESTING)	255.503	OTH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255.505(e),(h),(i)	OTH

Central Hudson Gas and Electric Corporation
Cases 14-E-0318; 14-G-0319
Part 255 / 261
High and Other Gas Risk Safety Violations

Test requirements for pipelines to operate at less than 125 PSIG	255.507	OTH
Test requirements for service lines	255.511	OTH
Environmental protection and safety requirements	255.515	OTH
Records (TESTING)	255.517	OTH
Notification requirements (UPGRADES)	255.552	OTH
General requirements (UPGRADES)	255.553(d),(e)	OTH
Conversion to service subject to this Part	255.559(b)	OTH
Change in class location: Confirmation or revision of maximum allowable operating pressure	255.611(a),(d)	OTH
Continuing surveillance	255.613	OTH
Odorization	255.625(e),(f)	OTH
Pipeline Markers	255.707(a),(c),(d),(e)	OTH
Transmission lines: Record keeping	255.709	OTH
Distribution systems: Patrolling	255.721(b)	OTH
Test requirements for reinstating service lines	255.725	OTH
Inactive Services	255.726	OTH
Abandonment or inactivation of facilities	255.727(b)-(g)	OTH
Compressor stations: storage of combustible materials	255.735	OTH
Pressure limiting and regulating stations: Inspection and testing	255.739(c),(d)	OTH
Pressure limiting and regulating stations: Telemetering or recording gauges	255.741	OTH
Regulator Station MAOP	255.743 (c)	OTH
Service Regulator - Min.& Oper. Load	255.744 (d),(e)	OTH
Distribution Line Valves	255.747	OTH
Valve maintenance: Service line valves	255.748	OTH
Regulator Station Vaults	255.749	OTH
Caulked bell and spigot joints	255.753	OTH
Reports of accidents	255.801	OTH
Emergency lists of operator personnel	255.803	OTH
Leaks General	255.805(a),(b),(e),(g),(h)	OTH
Leaks: Records	255.807(a),(b),(c)	OTH
Type 2	255.815(b),(c),(d)	OTH
Type 3	255.817	OTH
Interruptions of service	255.823(a),(b)	OTH
Logging and analysis of gas emergency reports	255.825	OTH
Annual Report	255.829	OTH
Reporting safety-related conditions	255.831	OTH
General (IMP)	255.907	OTH
Changes to an Integrity Management Program (IMP)	255.909	OTH
Low Stress Reassessment (IMP)	255.941	OTH
Measuring Program Effectiveness (IMP)	255.945	OTH
Records (IMP)	255.947	OTH
Records an operator must keep	255.1011	OTH

OTHER RISK SECTIONS PART 261		
High Pressure Piping - Annual Notice	261.19	OTH
Warning tag: Class C condition	261.61	OTH
Warning tag: Action and follow-up	261.63(a)-(h)	OTH
Warning Tag Records	261.65	OTH

Central Hudson Gas & Electric Corporation
Summary of Performance Mechanisms and Revenue Adjustments
Positive Revenue Adjustment (PRA) / Negative Revenue Adjustment (NRA)

	Target	Basis Point PRA / (NRA)	NRA [1]
Customer Service Quality Performance Mechanism			
Customer Satisfaction Index	85 or Higher		None
	<85 but >=84		($475,000)
	<84 but >=83		($950,000)
	<83 by >=82		($1,425,000)
	<82		($1,900,000)
PSC Complaint Rate	<1.1		None
	1.1		($950,000)
	1.2		($1,140,000)
	1.3		($1,330,000)
	1.4		($1,520,000)
	1.5		($1,710,000)
	1.6		($1,900,000)
Appointments Kept	$20 Customer Credit Per missed appointment		
Number of Annual Residential Service Terminations	< 11,000	5	
Electric Reliability Performance Mechanism [1]			
Duration - CAIDI	2.50	(30)	
Frequency - SAIFI	1.30	(30)	
Gas Safety Performance Mechanism [1]			
Leak Management			
Total Year-End Backlog	200 Leaks	(12)	
Repairable Leak Backlog	16 Leaks	(16)	
Excavation Damages (Per 1000 Tickets)	2016/2017/2018		
Gas Total Damage	2.2 / 2.05 / 1.90	(4)	
Mismark Damages	0.45 / 0.40 / 0.36	(8)	
Company & Company/Contractor Damages ("CCCD")	0.25 / 0.20 / 0.10	(8)	
Emergency Response			
30 Minute Response	75%	(8)	
45 Minute Response	90%	(4)	
60 Minute Response (New)	95%	(1)	
Gas Safety Violations [2] NYCRR Parts 255 & 261			
	HIGH RISK - CY		
	1-25	(1/2)	
	26 +%	(1)	
	LOW RISK - CY		
	1-25	(1/9)	
	26 +%	(1/3)	
Infrastructure Enhancement			
	2016 / 2017 / 2018		
Annual Leak Prone Gas Pipe Replacement [3]	13 / 14 /15 miles	(8)	
Gas Expansion			
Gas Expansion Every 200 Customers Above Forecast [4]		1	

(1)Note : The Customer Service Customer Satisfaction Index and PSC Complaint Rate Revenue Adjustments and the BPs for the Electric Reliability and Gas Leak Management, Excavation Damages and Emergency Response Performance Mechanisms presented in this Appendix are the Case 12-M-0192 Fortis-CH Section 70 Merger JP Revenue Adjustments and are already doubled. Revenue Adjustments in this case shall be tripled (multiplied by 1.5) if targets are missed during a dividend restriction period. There is no quadrupling of Revenue Adjustments if targets are missed.

(2) Maximum Exposure - 100 BP in each calendar year.

(3) Effective January 1, 2016, 2017, 2018, for each mile in excess of 13, 14 and 15 miles replaced respectively, PRA of 2 BP, capped at annual maximum of 10 BPs.

(4) Maximum PRA - 5 BP in each Rate Year for every 200 combined residential and commercial customers above the forecast count.

Electric Reliability Performance Mechanism

Electric Reliability

Operation of Mechanism

This electric service Reliability Performance Mechanism ("reliability mechanism" or "RPM") structure has been in effect for Central Hudson Gas & Electric Corporation beginning on June 18, 2010 per the Order in Case 09-E-0888. The reliability mechanism targets were continued per the June 26, 2013 Acquisition Order in Case 12-M-0192 and the Negative Revenue Adjustments ("NRAs") were doubled. The performance metrics adopted in this Joint Proposal are described below and will remain in effect until reset by the Commission. The measurement periods for the reliability mechanism metrics will be on a calendar year basis.

The reliability mechanism establishes the following performance metrics:

(a) threshold standards, consisting of system-wide performance targets for frequency and duration of electric service interruption defined as:

1. CAIDI - Customer Average Interruption Duration Index. The average interruption duration time (customers-hours interrupted) for those customers that experience an interruption during the year.

2. SAIFI - System Average Interruption Frequency Index. It is the average number of times that a customer is interrupted per 1, 000 customers served during the year.

The electric service annual metrics for System Average Frequency Index (SAIFI) and Customer Average Duration Index (CAIDI) shall be a 30 basis point (electric, pre-tax) potential negative revenue adjustment for failure to achieve an annual SAIFI target of 1.30, and a 30 basis point (electric, pre-tax) potential negative revenue adjustment for failure to achieve an annual CAIDI of 2.50. The NRAs for SAIFI and CAIDI will be multiplied by 1.5 if targets are missed during a dividend restriction period

(b) The Quarterly Meeting process will continue.

All revenue adjustments related to this reliability mechanism will come from shareholder funds and will be deferred for the benefit of ratepayers.

Exclusions

The following exclusions will be applicable to operating performance under this reliability mechanism:

(a) Any outages resulting from a major storm, as defined in 16 NYCRR Part 97 (i. e., at least 10% of the customers interrupted within an operating area or customers out of service for at least 24 hours) , except as otherwise noted.

Electric Reliability Performance Mechanism

(b) Any incident resulting from a catastrophic event beyond the control of the Company, including but not limited to plane crash, water main break, or natural disasters (e. g. , hurricanes, floods, earthquakes).

(c) Any incident where problems beyond the Company's control involving generation or the bulk transmission system is the key factor in the outage, including, but not limited to, NYISO mandated load shedding. This criterion is not intended to exclude incidents that occur as a result of unsatisfactory performance by the Company.

Reporting

The Company will prepare an annual report(s) on its performance under this reliability mechanism. The annual report(s) will be filed by March 31st of each year to the Secretary.

The reports will state the:

(a) Company's annual system-wide performance under the RPM and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment;

(b) Company's performance under the other metrics and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment; and

(c) Basis for requesting and provide adequate support for all exclusions.

Major Storm Reserve Funding

The electric Income Statements set forth in Appendix [A] incorporate $700,000 in funding for a Major Storm Reserve for each Rate Year. To the extent that the Company incurs incremental major storm damage costs in excess of the amount accrued in the Major Storm Reserve over the term of the rate plan, the Company will defer expenses for the future recovery from customers, and the rate allowance for the Major Storm Reserve will be adjusted accordingly during the Company's next rate proceeding. To the extent that the Company incurs major storm damage expenses less than the amount accrued in the Major Storm Reserve over the term of the rate plan, the Company will defer the variation to serve as an offset for future major storm events. The reserve balance, whether a debit balance or credit balance, will accrue carrying charges at the Company's pre-tax rate of return.

Costs Chargeable to the Major Storm Reserve

A major storm event will be defined as a period of adverse weather during which service interruptions affect at least 10 percent of customers in an operating area and/or result in customers being without electric service for durations of at least 24 hours (16 NYCRR Part 97). Except as otherwise provided herein, once the Commission definition of a major storm has been satisfied, incremental restoration costs incurred as a result of the event must reach a level of at least $500,000, before consideration of the 3% deductible described below, in order for expenses related to the adverse weather event to be chargeable to the major storm reserve.

Specifically, the following types of incremental restoration costs are authorized to be charged to the major storm reserve: incremental labor and the applicable payroll taxes and incremental accounts payable. Incremental labor is overtime paid to union and management employees in conjunction with the storm event. Incremental accounts payable includes, but is not limited to, tree trimming, mutual aid, other contractor/temp employees, communication (excluding communication costs for cell phone usage) dry ice, water, lodging, food, miscellaneous employee expenses, transportation expenses that do not originate from the Company, and materials and supplies costs that Central Hudson would not have incurred, except for the major storm event.

The Company will be able to charge costs against the Major Storm Reserve for restoration activity for a period up to 10 days following the date on which the Company is able to serve all customers. If Central Hudson incurs incremental expenses more than 10 days following restoration of the ability to serve all customers, Central Hudson has the right to petition the Commission for authorization to charge these costs to the Major Storm Reserve, and the petition will not be subject to the Commission's traditional three-part deferral test.

Any proceeds or reimbursements from insurance, the Federal Emergency Management Agency (FEMA), New York State or any other reimbursement or proceeds received to cover such costs should be deducted from expenses charged to the Major Storm Reserve.

Major Storm Reserve

The Company will exclude as a deductible from costs chargeable to the Major Storm Reserve an amount equal to 3 percent of the incremental costs incurred (net of insurance and other recoveries) as a result of the occurrence of the storm event. The Company will charge the deductible amount to non-major storm expense, as well as all other expenses not charged to the reserve.

The Company is authorized to charge the Major Storm Reserve for costs incurred to obtain the assistance of contractors and/or utility companies providing mutual assistance in reasonable anticipation that a storm will affect its electric operations to the degree meeting the criteria of a Major Storm, but which ultimately does not do so, when the costs exceed $500,000. The Company is authorized, not more than twice per rate year, to charge the Major Storm Reserve for costs incurred to obtain the assistance of contractors and/or utility companies providing mutual assistance in reasonable anticipation that a storm will affect its electric operations to the degree meeting the criteria of a Major Storm, but which ultimately does not do so, when the costs exceed $250,000. The cost to obtain mutual assistance includes the cost of travel to and from Central Hudson. If the costs associated with securing and obtaining the mutual assistance for a storm that does not ultimately meet the definition of a major storm is less than the $500,000, or $250,000 as described above, threshold, the Company will charge the costs to its non-major storm expense (O&M expense).

Documentation and Review

Central Hudson will report the costs for each major storm on a separate work order. The Company will file data demonstrating that the adverse weather event qualified as a major storm and documentation of the storm costs for audit to the Office of Accounting, Audits and Finance within 90 days of the date on which the Company is able to serve all customers. All costs charged to the Major Storm Reserve are subject to audit by Staff. Staff will review documented costs and communicate any concerns to the Company within 180 days of receipt of storm cost documentation from the Company, in order to satisfy the needs of the Company’s external auditors that storm costs are properly charged to the reserve and recoverability of incremental costs is highly probable. Such communication will not limit Staff’s further review and will have no binding effect in the next rate case. Final incremental costs and the method of recovery are subject to Commission review and approval in Central Hudson’s next rate case.

Consistent with current practice, Staff will continue to allow the inclusion of estimated costs in the Company’s storm cost documentation. As such, to the extent that final invoices are not received within the 180 day audit period noted above, the Company will provide Staff final bills upon receipt, and costs charged to the Major Storm Reserve will be adjusted accordingly.

Appendix R, Sheet 1 of 3

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 and 14-G-0319
Depreciation Factors and Rates

		Effective as of 7/1/09				Effective as of 7/1/15			
	ELECTRIC								
Account	Account Description	ASL	Curve Type	Net Salv. %	Annual Rate	ASL	Curve Type	Net Salv. %	Annual Rate
HYDRO PRODUCTION									
331-00-1	STRUCTURES & IMPROVEMENTS	65	R3	-45	0.0223	75	S0	-45	0.0193
332-00-1	RESERVOIRS, DAMS	75	L5	-60	0.0213	85	S1	-45	0.0171
333-00-1	TURBINES & GENERATORS	60	R4	-70	0.0283	70	S1	-55	0.0221
334-10-1	ACCESSORY ELEC. EQUIP.	55	L0	-70	0.0309	55	R1.5	-55	0.0282
335-00-1	MISC. POWER PLANT EQUIP.	45	S2.5	-40	0.0311	45	L1.5	-25	0.0278
OTHER PRODUCTION									
341-00-1	STRUCTURES AND IMPROVEMENTS	40	S4	-5	0.0263	50	R4	-10	0.0220
342-00-1	FUEL HOLDERS, PRODUCERS & ACCESSORIES	35	S3	-20	0.0343	45	R5	-5	0.0233
343-00-1	PRIME MOVERS	25	R4	-5	0.0420	25	R4	-5	0.0420
344-00-1	GENERATORS	40	S4	-20	0.0300	40	R1	-10	0.0275
345-00-1	ACCESSORY ELECTRIC EQUIPMENT	35	R2.5	-25	0.0357	38	R2	-15	0.0303
346-00-1	MISCELLANEOUS POWER PLANT EQUIPMENT	30	R2.5	0	0.0333	35	R2.5	0	0.0286
TRANSMISSION									
350-11&15-1	LAND & LAND RIGHTS	70	R3	0	0.0143	80	R3	0	0.0125
352-00-1	STRUCTURES & IMPROVEMENTS	65	R3	-30	0.0200	75	R3	-15	0.0153
353-11,20-1	STATION EQUIPMENT	52	R1	-10	0.0212	53	R1	-20	0.0226
353-12-1	SUPERVISORY EQUIPMENT- IN USE	28	S1	-10	0.0393	33	L1.5	-20	0.0364
353-30-1	STATION EQUIP-ELECTRONIC	52	R1	-10	0.0212	30	S2	-20	0.0400
354-00-1	TOWERS & FIXTURES	65	R3	-30	0.0200	75	R1	-25	0.0167
355-00&10&15-1	POLES & FIXTURES	55	R3	-50	0.0273	55	R2.5	-45	0.0264
356-10-1	OVERHEAD COND. & DEVICES	60	R2	-30	0.0217	65	R2	-30	0.0200
356-15-1	OVERHEAD COND. & DEV. 345KV	60	R2	-30	0.0217	65	R2	-30	0.0200
356-20&25-1	OVERHEAD LINES, CLEARING	60	R2	-30	0.0217	65	R2	-30	0.0200
357-00-1	UNDERGROUND CONDUIT	40	R0.5	0	0.0250	40	R0.5	0	0.0250
358-00-1	UNERGROUND COND. & DEVICES	40	R3	-20	0.0300	50	R0.5	-5	0.0210
DISTRIBUTION									
360-11&22-1	LAND & LAND RIGHTS	60	R3	0	0.0167	70	S3	0	0.0143
361-00-1	STRUCTURES & IMPROVEMENTS	80	R3	-25	0.0156	80	O1	-15	0.0144
362-11-1	STATION EQUIPMENT-IN USE	55	R1.5	-20	0.0218	57	R1.5	-25	0.0219
362-12-1	SUPERVISORY EQUIPMENT	30	R2	-15	0.0383	30	R2	-25	0.0417
362-20-1	STATION EQUIPMENT-HELD	55	R1.5	-20	0.0218	45	S1	-25	0.0278
362-30-1	STATION EQUIP-ELECTRONICS	55	R1.5	-20	0.0218	32	S0	-25	0.0391
364-00-1	POLES & FIXTURES	55	R.05	-25	0.0227	60	L0	-30	0.0217
365-10&20-1	OVHD. CONDUCTORS & DEVICES	60	R.05	-30	0.0217	65	R0.5	-40	0.0215
366-11&22-1	UNDERGROUND CONDUIT	65	R3	-25	0.0192	75	R3	-15	0.0153
367-00-1	UNDERGROUND COND. & DEVICES	60	R2.5	-10	0.0183	70	R2	-15	0.0164
368-00-1	TRANSFORMERS	43	L1	-10	0.0256	41	S0	-15	0.0280
369-10-1	OVERHEAD SERVICES	60	R1	-75	0.0292	65	R1.5	-65	0.2540
369-21&22-1	UNDERGROUND SERVICES	60	R1	-25	0.0208	65	R0	-15	0.0177
370-11&20-1	METERS & INSTALLATION	30	O2	0	0.0333	30	O1	0	0.0333
371-00-1	INSTALLATION ON CUST. PREMISES	22	R0.5	-15	0.0523	30	O2	-15	0.0383
372-10-1	LEASED PROP. ON CUST. PREMISES	7	S1.5	5	0.1357	7	R1	5	0.1357
373-00-1	STREET LIGHTS & CONDUCTORS	30	R0.5	-25	0.0417	35	O2	-15	0.0329
GENERAL PLANT									
390-00-1	STRUCTURES AND IMPROVEMENTS	37	R0.5	-40	0.0378	40	O2	-40	0.0350

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 and 14-G-0319
Depreciation Factors and Rates

		Effective as of 7/1/09				Effective as of 7/1/15			
	GAS								
Account	Account Description	ASL	Curve Type	Net Salv. %	Annual Rate	ASL	Curve Type	Net Salv. %	Annual Rate
PRODUCTION									
305-00-2	STRUCTURES & IMPROVEMENTS	60	R3	-10	0.0184				
311-00-2	LIQUIFIED PETROLEUM GAS EQUIP.	55	R2.5	-40	0.0255				
320-10-2	OTHER PRODUCTION EQUIPMENT	25	S3	+0	0.0347				
TRANSMISSION									
365-11&20-2	LAND & LAND RIGHTS	70	S4	0	0.0143	70	R4	0	0.0143
366-20-2	STRUCTURES & IMPROVEMENTS	45	S2	-40	0.0311	50	S1	-55	0.0310
367-00-2	MAINS	70	R2.5	-30	0.0186	80	R3	-25	0.0156
369-11-2	STATION EQUIPMENT	33	R2	-25	0.0379	40	L0	-25	0.0313
369-12-2	SUPERVISORY EQUIPMENT	18	S0.5	-25	0.0694	19	L2	-25	0.0658
DISTRIBUTION									
374-11-2	LAND & LAND RIGHTS	70	R3	0	0.0143	75	R3	0	0.0133
375-00-2	STRUCTURES & IMPROVEMENTS	50	R2.5	-30	0.0260	55	S1.5	-15	0.0209
376-00-&11, 12,13-2	MAINS	85	R2.5	-60	0.0188	95	R2.5	-45	0.0153
378-11-2	STATION EQUIPMENT	32	R1.5	-60	0.0500	38	L0.5	-45	0.0382
378-12-2	SUPERVISORY EQUIPMENT	25	L0	-60	0.0640	38	L0.5	-45	0.0382
380-00-2	SERVICES	70	R2.5	-60	0.0229	80	R2	-60	0.0200
381-00-2	METERS	27	L1.5	-2	0.0378	28	L1.5	-2	0.0364
382-00-2	METER INSTALLATIONS	27	L1.5	-2	0.0378	28	L1.5	-2	0.0364
385-00-2	INDUSTRIAL-STATION EQUIPMENT	40	R2.5	-25	0.0313	45	R2	-30	0.0289
385-10-2	INDUSTRIAL-STATION EQUIPMENT	25	S2.5	-25	0.0500	30	S2.5	-30	0.0433
	IROQUOIS TRANSMISSION								
365-50-2 ASL	LAND & LAND RIGHTS	70	S4	0	0.0143	70	R4	0	0.0143
365-50-2 RL	LAND & LAND RIGHTS- **original cost only fully amortized 12/31/2007**			0	0.0000			0	0.0000
366-50-2 ASL	STRUCTURES & IMPROVEMENTS	45	S2	-40	0.0311	50	S1	-55	0.0310
366-50-2 RL	STRUCTURES & IMPROVEMENTS- **original cost only fully amortized**			-40	0.0089			-55	0.0110
367-50-2 ASL	MAINS	70	R2.5	-30	0.0186	80	R3	-25	0.0156
367-50-2 RL	MAINS- **original cost only fully amortized**			-30	0.0043			-25	0.0031
369-51-2 ASL	STATION EQUIPMENT	33	R2	-25	0.0379	40	L0	-25	0.0313
369-51-2 RL	STATION EQUIPMENT -**original cost only fully amortized**			-25	0.0076			-25	0.0063
369-52-2 ASL	SUPERVISORY EQUIPMENT	18	S0.5	-25	0.0694	19	L2	-25	0.0658
369-52-2 RL	SUPERVISORY EQUIPMENT- **original cost only fully amortized**			-25	0.0139			-25	0.0132

Appendix R, Sheet 3 of 3

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 and 14-G-0319
Depreciation Factors and Rates

COMMON

		Effective as of 7/1/09				Effective as of 7/1/15			
Account	Account Description	ASL	Curve Type	Net Salv. %	Annual Rate	ASL	Curve Type	Net Salv. %	Annual Rate
390-00 & 11-4	General Structures & Improvements	50	O1	-55	0.0310	50	O1	-55	0.0310
392-10-4	Transportation Equip- Electric	10	L2.5	+10	0.0870	10	L2.5	+10	0.0870
392-20-4	Transportation Equip- Gas	10	L2.5	+10	0.0900	10	L2.5	+10	0.0900
392-40-4	Transportation Equip- Common	10	L2.5	+10	0.0900	10	L2.5	+10	0.0900
396-10-4	Power Operated Equip- Electric	12	L3	+10	0.0750	12	L3	+10	0.0750
396-20-4	Power Operated Equip- Gas	12	L3	+15	0.0708	12	L3	+15	0.0708
396-40-4	Power Operated Equip- Common	12	L3	+15	0.0708	12	L3	+15	0.0708

COMMON VINTAGE

Account	Account Description	ASL	Type	%	Rate	ASL	Type	%	Rate
391-11-4	EDP Equip- System and Main Frame	8	SQ	+0	0.1250	8	SQ	+0	0.1250
391-12-4	EDP- Systems Operations - SCADA	12	SQ	+0	0.0833	12	SQ	+0	0.0833
391-21-4	Data Handling Equipment	20	SQ	+0	0.0500	20	SQ	+0	0.0500
391-22-4	Office Furniture	20	SQ	+0	0.0500	20	SQ	+0	0.0500
393-00-4	Stores Equipment	35	SQ	+0	0.0286	35	SQ	+0	0.0286
393-20-4	Stores Equipment- Forklifts	35	SQ	+0	0.0286	35	SQ	+0	0.0286
394-10-4	Garage & Repair Equipment	30	SQ	+0	0.0333	30	SQ	+0	0.0333
394-20-4	Shop Equipment	30	SQ	+0	0.0333	30	SQ	+0	0.0333
394-30-4	Tools & Work Equipment	30	SQ	+0	0.0333	30	SQ	+0	0.0333
395-10-4	Laboratory Equipment	35	SQ	+0	0.0286	35	SQ	+0	0.0286
395-20-4	Laboratory Equipment- R&D	35	SQ	+0	0.0286	35	SQ	+0	0.0286
397-10-4	Communication Equipment - Radio	20	SQ	+0	0.0500	20	SQ	+0	0.0500
397-20-4	Communication Equipment - Telephone	10	SQ	+0	0.1000	10	SQ	+0	0.1000
398-00-4	Miscellaneous General Equipment	30	SQ	+0	0.0333	30	SQ	+0	0.0333

SUBJECT: Filing by CENTRAL HUDSON GAS & ELECTRIC CORPORATION

Amendments to Schedule P.S.C. No. 15 – Electricity

First Revised Leaf No. 163.5.4.1
Third Revised Leaf No. 94
Fifth Revised Leaf No. 163.5.5
Sixth Revised Leaf No. 205.2
Seventh Revised Leaves Nos. 163.3, 218.2
Eighth Revised Leaves Nos. 135, 163.5.2, 231
Eleventh Revised Leaves Nos. 163.5.4, 218.1, 219, 221
Twelve Revised Leaves Nos. 165, 185, 205.1, 217
Thirteenth Revised Leaves Nos. 220, 222, 226, 246
Fourteenth Revised Leaves Nos. 205, 218
Fifteenth Revised Leaves Nos. 169, 246.1
Sixteenth Revised Leaf No. 104
Seventeenth Revised Leaf No. 210

Suspension Supplement Nos. 72 and 73

Amendments to Schedule P.S.C. No. 12 – Gas

Original Leaf No. 129.2
Third Revised Leaf No. 63
Fourth Revised Leaves Nos. 126.2, 129.1
Fifth Revised Leaf No. 181.1
Sixth Revised Leaf No. 129
Eighth Revised Leaves Nos. 75, 121, 195, 212
Tenth Revised Leaves Nos. 151, 153
Eleventh Revised Leaf No. 73
Twelfth Revised Leaf No. 187
Thirteenth Revised Leaves Nos. 126.1, 152, 158
Fourteenth Revised Leaves Nos. 181, 188, 192, 193, 206
Sixteenth Revised Leaves Nos. 149, 186, 191
Seventeenth Revised Leaf No. 159

Suspension Supplement Nos. 40 and 41