STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service
Commission held in the City of
Albany on October 24, 2001

COMMISSIONERS PRESENT:

Maureen O. Helmer, Chairman
Thomas J. Dunleavy
James D. Bennett
Leonard A. Weiss
Neal N. Galvin

CASE 00-E-1273 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Central Hudson Gas & Electric Corporation for Electric Service.

CASE 00-G-1274 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.

ORDER ESTABLISHING RATES

(Issued and Effective October 25, 2001)

BY THE COMMISSION:

The following order generally adopts terms set forth in a Joint Proposal submitted by Central Hudson Gas & Electric Corporation (Central Hudson, the company); staff of the Department of Public Service (Staff); the Consumer Protection Board (CPB); Multiple Intervenors (MI); and Strategic Power Management, Inc., an energy services company (ESCO). We thereby establish a rate and regulatory plan intended to take effect as of July 1, 2001 and to continue for at least three years from that date.

Today's order determines the rates Central Hudson will charge for delivery of electricity and gas to customers that purchase those commodities from Central Hudson, and to customers that purchase the commodities elsewhere and rely on Central

Hudson for delivery only. (The commodity portion of the bill is determined by energy prices in markets outside our regulatory jurisdiction.) The order will freeze electric and gas delivery rates for three years, after initially reducing electric delivery rates by 1.2% overall.

In addition to rate levels, a major issue in this case has been the disposition of a "benefit fund" that will have accumulated as a result of Central Hudson's operations pursuant to the Rate and Restructuring Plan instituted in February 1998.[1] The fund includes, most significantly, the proceeds from the company's sale of its Danskammer and Roseton generating plants and its interest in the Nine Mile Point No. 2 (NMP2) generating plant. For purposes of the joint proposal, the parties have estimated the benefit fund as $164 million. Under a proposal pending in another proceeding,[2] the fund might be augmented by additional amounts related to the NMP2 sale.

Under today's order, $42.5 million of the benefit fund will be used to offset rate base and thereby achieve the three-year rate freeze noted above. Another $45 million will be used as refunds to customers over the three years of the rate plan. As the $45 million is a net-of-tax amount, the refunds actually received by customers will total about $72 million. The remainder will be applied toward other customer benefits which may include additional refunds, reliability improvements, bill mitigation in the event of commodity price volatility, and economic development programs. To the extent that portions of the fund are held in reserve rather than used immediately, they will accrue interest on the customers' behalf.

We also are adopting more stringent service quality criteria, and expanded programs to help residential customers that have difficulty paying their utility bills. And, to enhance

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[2] Case 96-E-0909, Central Hudson Gas & Electric Corp. - Electric Rates and Restructuring, Opinion No. 98-14 (issued June 30, 1998).

[2] Case 01-E-0011, Niagara Mohawk Power Corp. et al., Petition under Public Service Law §70.

customers' ability to obtain energy supplies from providers competing with Central Hudson, we are prescribing backout credits which will determine what portion of the Central Hudson bill a customer may avoid by shopping elsewhere for the electric or gas commodity. We also will require that Central Hudson reimburse ESCOs for ancillary service charges imposed on them by the Independent System Operator, a cost element whose volatility has deterred market entry by ESCOs.

BACKGROUND AND PROCEDURAL HISTORY

Central Hudson serves about 260,000 customers in eight mid-Hudson counties. In the February 1998 Rate and Restructuring Plan, we set rates intended to continue through June 2001 and directed the company to divest its electric generating plants, unbundle its rates, and institute full retail access. The current proceedings were instituted to consider new tariffs for unbundled delivery service only, proposed in August 2000 and amended in October 2000 after sale of the Roseton and Danskammer plants. The company designed the proposed tariffs to increase its annual electric and gas delivery revenues by about $14.1 million (8.8%) and $3.6 million (4.7%) respectively for the year ending June 30, 2002.

After full evidentiary hearings and numerous public statement hearings, a recommended decision (RD) issued April 24, 2001 called for electric and gas revenue decreases of $1.7 million and $2.1 million respectively. The RD provisionally addressed the disposition of the benefit fund, but it recommended further negotiations on that issue and others. Settlement discussions had been conducted intermittently throughout the proceedings, on notice to potentially interested parties (in compliance with 16 NYCRR 3.9). After two rounds of briefs on or opposing exceptions to the RD, negotiations resumed, and culminated in the joint proposal under review here. To allow for negotiations and Commission review of any resulting proposal, the company has waived the expiration of the statutory suspension period through October 31, 2001.

The joint proposal was filed August 21, 2001 and was followed by two rounds of written statements in support or in opposition. Supporting statements and replies have been filed by Central Hudson, Staff, CPB, and MI. Statements opposing at least some elements of the joint proposal have been filed by the Office of the Attorney General (OAG); Small Customer Marketer Coalition (SCMC), representing certain ESCOs; and John J. Mavretich, pro se.

TERMS SUBMITTED PURSUANT TO THE JOINT PROPOSAL

Should we adopt the terms proposed by the parties, significant results would include the following:[3]

Revenue Requirement

Delivery rates would be frozen for three years through June 2004,[4] at levels designed to produce (over the three years) a $2 million decrease in annual electric delivery revenues and no change in gas delivery revenues. Within certain limits, the company could use deferral accounting as a means of extending the freeze beyond three years.

The implicit return on common equity would be 10.3%, assuming that the 47% equity ratio declines to a target of 45% by the third year. To the extent that the equity return for the electric or gas department exceeded 11.3%, the excess would be shared 50:50 between shareholders and customers. Excesses over 14% would be allocated entirely to customers. The rate plan would be subject to reopening if either department's equity return fell below 8.5%.

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[3] For a complete statement of the joint proposal's terms, one must rely on the text of the proposal itself (Attachment B of this order).

[4] Under orders in these proceedings extending the suspension period (issued June 25, August 29, and September 28, 2001), rates are to be set as if the new revenue allowance had taken effect July 1, 2001.

The benefit fund would be applied for the following purposes (in amounts that remain to be quantified through further negotiations, if not specified here):

a. $45 million (about $74 million, stated on a net-of-tax basis), for three annual refunds of about $24 million each year, to customers on a per-kWh basis;

b. $42.5 million as a permanent offset to electric rate base;

c. $13 million over three years for distribution system reinforcement and increased tree trimming;

d. $10 million for site remediation at a former gas manufacturing site in Newburgh;

e. recovery of stranded costs caused by competitive electric rate restructuring, if consistent with Commission policy to be established in other proceedings;

f. economic development initiatives (other than the present Revitalization Rate Program), to be formulated through collaboration among the parties starting November 1, 2001; and

g. other items to be proposed through collaboration starting in mid-January 2002, which might include additional refunds, delivery rate mitigation after the three-year plan expires, and commodity price spike mitigation.

Cost Allocation and Rate Design

In lieu of the present fuel adjustment clause, a purchased power recovery (PPR) charge would recover energy and capacity costs that Central Hudson incurs to serve its remaining electric sales ("full service") customers. The PPR charge would be calculated separately for each class, rather than on a uniform per-kWh basis as the company had advocated.[5] A

[5] In addition to the PPR, a variable cost recovery (VCR) charge would recover non-avoidable variable energy costs, including purchases from qualifying facilities and fuel for the company's remaining generators.

variable cost recovery (VCR) charge for all customers would reflect the costs and benefits associated with Central Hudson's remaining generating plants and independent power producer contracts.

Central Hudson will have access to relatively low-cost power supplied by Dynegy, from the Roseton and Danskammer plants (under a Transition Power Agreement or TPA); and by Constellation, from NMP2 (under a Purchase Power Agreement or PPA), if NMP2 is transferred as proposed in Case 01-E-0111, supra. Under the terms submitted in the joint proposal, TPA/PPA power would be allocated to both full service and delivery customers, based on each class's kWh as a percentage of total system kWh sales, and among customers within classes based on each customer's usage characteristics.

Class electric rate decreases would range from 0.5 to 1.25 times the overall electric revenue decrease, as needed to reduce variances between class and system rates of return.

For residential electric service,

a. the $7.15 monthly customer charge would increase to $12.00 in three steps between now and June 2004 (moving it closer toward the estimated marginal per-customer cost that the charge is intended to recover), with offsetting decreases in other residential charges;

b. the space heating discount would be eliminated; and

c. time of use metering would continue to be offered.

Restoration of disconnected residential electric or gas service, now billed at $10 for restoration during workdays and $25 after hours, would increase to $20 workdays and $40 after hours or, if a work crew is needed, $100 workdays and $140 after hours.

Customer Service

Bills could be paid by credit card.

The service quality incentive formulas would continue to provide potential penalties only, without affirmative rewards for good service. The maximum annual disallowance would be 25 basis points (bp) of common equity return for customer service, 25 bp for electric reliability, 6 bp for gas reliability, and 3 bp for non-emergency gas leak repair.

The low-income customer program would limit the monthly gas and electric minimum charge to $5.00 for eligible customers, and require that participating customers pay at least $5.00 per month toward arrears if a local community action agency certifies their ability to pay.

Competitive Initiatives

To encourage retail access, Central Hudson would:

a. offer a single-bill format;

b. bill customers for Independent System Operator (ISO) ancillary services, and reimburse ESCOs for ancillary charges that the ESCO pays the ISO;

c. develop metrics to be used in an ESCO/marketer satisfaction incentive mechanism, including potentially an award of 10 bp on common equity, and designate an ESCO/marketer ombudsman; and

d. improve the company's outreach program to enhance public understanding of competitive options, with a potential award of up to 10 bp of common equity return for a successful program.

Pending the outcome of the generic rate unbundling proceeding,[6] electric backout credits would be set at $.0005 (0.5 mills) per kWh (S.C. 13), $.002/kWh (S.C. 3), $.003/kWh (S.C. 2 demand), or $.004/kWh

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[6] Case 00-M-0504, Competitive Energy Markets and Retail Competitive Opportunities, Order Directing Expedited Consideration of Rate Unbundling (issued March 29, 2001).

(S.C. 1, S.C. 2 non-demand, and S.C. 6). The gas backout credit would be $.15/mcf.

UNRESOLVED ISSUES

The following matters require discussion here because the joint proposal does not expressly address them or because the parties disagree.

Metering Programs

As noted above, the joint proposal calls for collaborative efforts to consider disposition of benefit fund amounts not immediately addressed in today's order. According to the joint proposal, potential future uses of the fund could include competition-related initiatives that we might designate.

As one such initiative which we are prepared to designate now, the company and parties should explore the development of advanced pricing and metering offerings for a broader range of its customers, including approaches that would better enable customers to respond optimally to improved price signals. Properly implemented, this initiative could result in multiple benefits, including lower customer bills; reduced wholesale market prices due to improved demand responsiveness; and reduced costs, to the utility and other load-serving entities, of recording and transmitting customer usage and billing data. In particular, the company and parties should consider:

> the potential benefits resulting from enhanced pricing offerings for a broad range of customers beyond those now eligible for the company's existing real-time pricing tariffs;
>
> appropriate methods for providing customers access to the education and control technologies that may be necessary to adjust their usage in response to actual market prices; and

appropriate sources of funding for enhanced metering and meter reading technologies, ideally through competitive means, to effectively record and transmit usage and billing data among customers, the utility, and competitive load-serving entities.

Credit Cards

The joint proposal includes an uncontested provision that the company would be allowed to collect bill payments by credit card. In adopting this element of the proposal, we note that it leaves unresolved several matters of implementation. First, we seek assurances that Central Hudson will not use the availability of the credit card option as leverage to extract payments from financially troubled customers for whom the payment and interest charges are not truly affordable. Second, future determinations of the company's revenue requirement will require recognition of cost offsets, such as reductions in working capital and uncollectibles, resulting from credit card usage subsequent to the three-year rate plan. Third, the joint proposal is silent regarding a significant disagreement that arose during the litigation of this issue: whether costs associated with the credit card option should be allocated to all customers, or to some classes exclusively, or only as a service fee to those customers who actually make a credit card payment. To address these concerns, Central Hudson should provide our staff the details of any proposed credit card payment program before implementing it.

Service Quality and Marketer Satisfaction Incentives

Regarding the proposed service quality program and the program to gauge marketer satisfaction, we assume the parties recognize that we need to review the progress and results of the company's efforts periodically. Therefore, in adopting the proposed terms, we do so with the understanding that compliance with today's order will require an annual report concerning these programs. The company should consult with the Director of our

Office of Consumer Education and Advocacy as to specific details of this requirement.

Refunds vs. Rate Base Reductions

OAG advocates that we reject the joint proposal's terms insofar as they would limit the rate base reduction to $42.5 million. OAG says we should enlarge this amount by reallocating, into additional rate base offsets, the $45 million that would be used for direct customer refunds under the joint proposal. OAG notes that a rate base offset is permanent, while a refund is transitory. Therefore, OAG argues, rate base offsets would be preferable, because they would not culminate in a bill increase upon exhaustion of the benefit fund and because their permanence assures customers a larger dollar benefit over time than any finite amount of refunds. OAG adds that any benefit fund balance not specifically allocated to other purposes should be applied toward immediate rate base reductions, instead of being held in reserve pending collaborative discussions as contemplated in the joint proposal.

OAG misstates the comparison between rate base reductions and refunds, and (as MI observes) misreads the RD's comments about the relative advantages of rate base offsets and refunds. The RD regarded refunds as preferable from the customer's standpoint, in view of tax considerations which nearly double the effective short-term benefit to customers from refunds as compared with rate base offsets.[7] And the customer benefit from a refund may be just as permanent as the benefit of a rate base offset, because any refund is a potential earnings source for the customer. For these reasons, an immediate refund may well provide a customer greater long-term economic benefits than a rate base offset of the same dollar amount, even if (as OAG emphasizes) the rate base offset may provide a larger long-term

[7] MI's analysis, uncontradicted on the record, estimates that each dollar allocated to refunds engenders approximately a $0.40 tax savings. This benefit is unavailable in connection with amounts allocated to rate base reduction.

reduction in the customer's utility bill. Finally, as Staff observes, the possible consequences of the massive rate base reduction implicit in OAG's position have not been examined on the record or addressed by the parties.[8]

The proposed allocation from the benefit fund provides a rate base reduction designed to stabilize rates at a slightly reduced level, provides a similar amount in refunds, and creates the possibility of additional allocations in the future to bill mitigation and additional refunds. Notwithstanding OAG's comments, we find that the proposal strikes an entirely reasonable balance among those objectives. Moreover, OAG has not shown that additional rate base reductions are preferable to using the benefit fund for competitive initiatives, bill mitigation, or other possible purposes besides refunds. The joint proposal aptly calls for further collaboration to explore such options in the future, in light of evolving circumstances which may not be clearly foreseeable now. Meanwhile, any portion of the benefit fund not used immediately will accrue interest at a rate equal to the company's pre-tax rate of return, thus providing customers the same benefit as if the amount thus reserved were a rate base offset.

[8] Staff, the company, and MI object to OAG's arguments, regarding this and other issues, on the ground that OAG raised them initially in the second round of statements instead of the first. OAG responds that its statement legitimately addressed the initial round of other parties' statements; the objections to OAG's statement constitute unauthorized surreplies; and OAG's statement cannot have come as a surprise to other parties, as it reflected positions advocated by OAG throughout the proceeding. The parties objecting are correct that OAG's submittal was inconsistent with the procedural schedule, which specified that the initial round would be the occasion for both supporting and opposing statements. Cases 00-E-1273 and 00-G-1274, Procedural Ruling (issued August 22, 2001). In any event, we find OAG's points unpersuasive for reasons discussed in the accompanying text.

Backout Credits

Pending the redetermination of unbundled rates in the unbundling proceeding,[9] the joint proposal calls for backout credits of $.004 (four mills) per kWh for S.C. 1 residential and S.C. 2 general non-demand customers. SCMC advocates, instead, a credit of $.007/kWh for these classes. SCMC says the larger credit is necessary because Central Hudson, with almost no retail access penetration several years after the initial order directing its restructuring, is in a position analogous to that of other utilities years ago when we adopted more robust stimuli to "jump-start" competition simultaneously with restructuring. SCMC argues that, in allowing other utilities to offer non-volumetric, lump-sum incentive payments to retail access customers or ESCOs, our primary objective has been to stimulate competition rather than calibrate rates to reflect avoided costs. SCMC adds that Central Hudson has an equitable obligation to promote competition more vigorously, because the company has benefited from generation divestiture whose purpose was to create competition.

However, we agree with Staff that the $.004/kWh provision in the joint proposal is a reasonable measure at this time, given that it will be adjusted if necessary on the basis of the record in the unbundling proceeding. Staff notes that $.004/kWh is the same temporary proxy that we also have adopted for other companies. Conversely (as Central Hudson observes), there is no evidence in this case either to rebut a $.004/kWh approximation of avoided costs or to support a $.007/kWh credit as SCMC advocates. In these circumstances, SCMC's asserted dichotomy between encouraging competition and gauging costs is overstated; at this moment, our most effective means of promoting competition is to establish cost-based rates on the basis of a full record in the unbundling proceeding.

OAG objects in principle to any backout credits as proposed, on the ground that such credits would subsidize retail access customers at other customers' expense. We agree with

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[9] Case 00-M-0504, supra.

Staff that OAG's argument errs in two respects. First, to the extent that the benefit fund can be used to promote competitive initiatives through measures such as backout rates, it serves the interests of customers in general and therefore cannot properly be deemed an unfair burden on full-service customers. Second, unless we adopt backout rates here (at least as an interim proxy for Central Hudson's avoided costs while awaiting more accurate cost determinations in the unbundling proceeding), it is retail access customers that will be burdened with a subsidy, insofar as they must continue to pay delivery rates that include costs related to the merchant function. Thus, rather than create subsidies as OAG alleges, the backout credit will offset them.

PPR Volatility

OAG says the proposed purchased power recovery (PPR) mechanism should be modified so that the risk of commodity price volatility would rest "primarily with the company" rather than with low-usage customers. OAG argues that Central Hudson, as compared with its customers, can better avoid the consequences of supply shortages during a transition to competition.

OAG's criticism of the PPR is inappropriate in several respects. First, the joint proposal already incorporates the results of efforts by Central Hudson to mitigate volatility, by providing customers an allocation of TPA power. Second, OAG presents no specific mechanism for carrying out its proposed risk reallocation. Third, the joint proposal already addresses OAG's concern by calling for further exploration of how the benefit fund might be used to mitigate price volatility.

Return on Equity and NMP2 Issues

Mr. Mavretich contends that there is only a superficial resemblance between the joint proposal's 10.3% implicit return on equity and the 10.28% return allowance recommended in the RD, because the joint proposal's 100 basis point deadband would allow Central Hudson to retain any earnings up to 11.3%.

Mr. Mavretich, opposed by Central Hudson and Staff, argues that the deadband should be eliminated so that 50:50 sharing between shareholders and customers would be applicable to any excess over 10.3%.

This criticism of the joint proposal is a non sequitur. The proposal's various provisions are designed to create a reasonable opportunity for the company to earn a return of 10.3%, corresponding to the cost of equity as indicated by the record on which the RD relied and which Mr. Mavretich seems to invoke now. Absent any showing that adoption of the proposed terms would produce a return greater than 10.3%, we are adopting them so as to establish rates that reflect the cost of equity. The joint proposal's earnings sharing provisions are not an indication that the earned return is expected to exceed 10.3%, as Mr. Mavretich suggests, but only a mechanism to reasonably balance investor and shareholder if it does.

As a more general matter, Mr. Mavretich supports this and his other criticisms of the joint proposal (noted below) by arguing that we should take into consideration Central Hudson's continuing failure to answer interrogatories regarding the long-term costs of its alleged managerial errors in connection with the NMP2 generating unit. The company responds by asserting a record of managerial success. While we would not condone the company's disregard of a discovery ruling if the issue were directly presented, here the issue is moot in two respects. First, Central Hudson is not pursuing any challenge to the Judge's discovery rulings, or to the RD's finding that the lack of interrogatory responses should be construed against the company pursuant to 16 NYCRR 5.10(1) when estimating NMP2's costs. Second, the company has abandoned its request for an allocation from the benefit fund as a reward for exemplary performance. It was that request which, in Mr. Mavretich's view, established the relevance of the history surrounding NMP2 for purposes of these proceedings. Thus, the NMP2 discovery issue does not affect our assessment of the balancing of interests in the joint proposal.[10]

Stock Symbol

Central Hudson received $2.5 million from the sale of its stock trading symbol, after its shares ceased to be publicly traded because it became a subsidiary wholly owned by a new parent company. Staff's litigating position, accepted in the RD, was that the sale proceeds should be viewed as an offset to corporate reorganization costs and that $1.0 million of the proceeds therefore should be used to reduce rate base. Under the joint proposal, we are asked to reject that approach and disregard the sale proceeds for ratemaking purposes. Mr. Mavretich opposes this resolution of the issue.

Staff and the company correctly respond that Mr. Mavretich has not accurately characterized the asset in question. Contrary to his assertions, the sale of the stock symbol did not occur pursuant to provisions resembling those that governed the auction of the company's generating plants. Nor is it true that the stock symbol was a rate base item like other assets "supported through customers['] rates," as Mr. Mavretich says; and, even if it were, we have broad discretion over the ratemaking treatment of sale proceeds regardless of whether the asset has been held in rate base. In this instance, there is nothing unreasonable about the proposed allocation of the proceeds to shareholders.

Reliability Improvement Program

Mr. Mavretich notes that the RD, in approving an infrastructure program similar in some respects to the Reliability Improvement Program described in the joint proposal, called for a progress report after the initial expenditures. He

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[10] We need not decide here whether, as Staff suggests, Mr. Mavretich's arguments about Central Hudson's NMP2 participation "are best addressed in Case 01-E-0011" (the proceeding to consider ownership transfer of NMP2).

criticizes the lack of a comparable reporting requirement in the joint proposal. Central Hudson responds that the program's efficacy would be reflected in the proposed incentive provisions related to system reliability, while Staff points out that the joint proposal expressly provides for an annual plan subject to Staff review. Thus, Mr. Mavretich's concern about the company's accountability is unfounded.[11]

DISCUSSION

Subject to our determinations described above, we find that the joint proposal's sponsors have satisfied their burden of showing that adoption of the proposed terms would satisfy the Public Service Law's requirement of safe and adequate service at just and reasonable rates. They also have shown that implementation of their proposals would achieve a fair balance of interests among the parties and customers, and would produce constructive results that may not have been achievable except through a negotiated agreement.

In particular, the rates we are establishing reasonably reflect Central Hudson's cost of service and protect the company's financial integrity, thus striking a fair balance between customer and investor interests; and the proposed terms ensure rate stability for at least three years beyond the end of the current rate plan. The economic benefits the company will have secured, in negotiating the prices it will pay for electric output from its former generating plants, will be allocated among customer classes in a fair and competitively neutral fashion. To encourage progress toward retail competition among energy suppliers in Central Hudson's service territory, the proposed terms specify reasonable backout credits, incentives and other mechanisms to promote cooperation between Central Hudson and

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[11] OAG raises concerns similar to Mr. Mavretich's, regarding both the Reliability Improvement Program and the Newburgh gas manufacturing site remediation project. In both instances, however, we expect that the company's activities will be subject to ongoing Commission review.

ESCOs, and enhanced efforts to inform customers about their supply options.

The disposition of the benefit fund serves a diverse array of customer interests, including rate stabilization and an equitable distribution of refunds among customer classes; bill mitigation; measures to attract and retain jobs; environmental remediation; backout credits and other competitive initiatives; and infrastructure reinforcement to improve service reliability. Reliability, as well as safety and service quality, also will be enhanced as a result of new performance measures and incentive mechanisms. Low-income customers in particular will benefit from new programs addressing their needs.

Finally, adoption of the proposed terms will accomplish these goals within the context of a rate allowance consistent with an extensive record in the litigated phase, concerning the company's revenue requirement and cost of capital. Moreover, the proposals reflect the parties' best efforts to find a reasonable resolution of issues that the RD identified as potentially productive areas for further negotiation, particularly the uses of the benefit fund and the design of cost recovery mechanisms and backout credits.

CONCLUSION

For the reasons stated, we find that our adoption of the joint proposal's provisions subject to the discussion above will serve the public interest and satisfy our statutory obligation to ensure safe and adequate service at just and reasonable rates pursuant to Public Service Law §66. We therefore will direct the company to file tariff revisions consistent with this finding. To comply with the orders issued in these proceedings June 25, August 29, and September 28, 2001, the filing should be designed to implement the tariff revisions as if they had taken effect July 1, 2001, notwithstanding the November 1, 2001 effective date specified in Order Clause 3 (below).

The Commission orders:

1. Subject to the foregoing discussion and the determinations and understandings set forth therein, the terms of the Joint Proposal filed in these proceedings August 21, 2001 are adopted in their entirety and are incorporated as part of this order.

2. Central Hudson Gas & Electric Corporation (the company) shall submit a written statement of unconditional acceptance of this order, within five days following the order's issuance date, signed and acknowledged by a duly authorized officer of the company. If an acceptance statement is not so filed, the adoption of the joint proposal's terms may be revoked. The acceptance statement should be filed with the Secretary of the Commission and served on the parties to these proceedings.

3. The company is directed to cancel, no later than October 31, 2001, the tariff amendments and supplements listed in Attachment A of this order. The company is directed to file on not less than one day's notice, to take effect no later than November 1, 2001 on a temporary basis, such further tariff changes as are necessary to effectuate the provisions adopted in this order. The company shall serve copies of its filing upon all parties to these proceedings. Any comments on the compliance filings must be received at the Commission's offices within ten days of service of the company's proposed amendments. The amendments specified in the 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. 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, provided that the company shall file with the Commission, not later than six weeks following the amendments' effective date, 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.

4. These proceedings are continued.

By the Commission,

(SIGNED) JANET HAND DEIXLER
Secretary

ATTACHMENT B

CASE 00-E-1273 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Central Hudson Gas & Electric Corporation for Electric Service.

CASE 00-G-1274 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.

JOINT PROPOSAL AND
JOINT PROPOSAL'S ATTACHMENTS A THROUGH I

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to rates, charges, rules and regulations of Central Hudson Gas & Electric Corporation for electric service;	Case 00-E-1273
and	
Proceeding on Motion of the Commission as to rates, charges, rules and regulations of Central Hudson Gas & Electric Corporation for gas service	Case 00-G-1274

JOINT PROPOSAL

I. Introduction

This is a Joint Proposal, dated as of August 15, 2001, for the resolution of the above-captioned cases by and among the following parties and participants ("Signatories"): Central Hudson Gas & Electric Corporation ("Central Hudson" or the "Company"); the Consumer Protection Board; Multiple Intervenors; the Staff of the Department of Public Service ("Staff") and Strategic Power Management, Inc.

This Joint Proposal is the product of negotiations among parties to the proceeding on due notice in accord with the Commission's Settlement Guidelines and of compromises among the Signatories. It has been made on the basis of the Conditions of the Joint Proposal described below and is intended to resolve all issues in these proceedings.

In general, both electric and gas rates are frozen at specified delivery rate revenue levels until June 30, 2004 and specifically identified amounts of delivery rate revenues are deferred from July 1, 2001 through June 30, 2002 ("Rate Year One" or "RY1") to July 1, 2003 through June 30, 2004 ("Rate Year Three" or "RY3").[1] Additional provisions address enhancements of competition in gas and electric services and establish uses and procedures for reviewing additional uses of the "Benefit Fund."[2]

II. Joint Proposal

A. Electric Rate Freeze: Electric delivery rates will be designed to recover $153 million in delivery revenues annually and will be frozen through June 30, 2004.

B. Gas Rate Freeze: Gas delivery rates will be designed to recover $36.6 million in delivery revenues annually and will be frozen through June 30, 2004.

C. Term of Electric and Gas Delivery Rate Freezes: The electric and gas delivery rate freezes are effective through June 30, 2004 and are further subject to the understandings that:

1. Nothing in this Joint Proposal or the Commission's adoption of it is intended to prevent Central

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[1] The twelve month period ending June 30, 2003 is "Rate Year Two" or "RY2."

[2] The Benefit Fund results from Central Hudson's prior rate proceeding, Case 96-E-0909. *See*, Opinion No. 98-14, issued June 30, 1998 and Order Adopting Terms of Settlement Subject to Modifications and Conditions, issued February 19, 1998.

Hudson from filing with the Commission requests for changes in rates to be effective (after any applicable suspension) as of July 1, 2004;

2. Rate mechanisms for the pass-through of the purchase price of electricity or gas are an integral part of this Joint Proposal. Nothing in the rate freeze provisions of this Joint Proposal is intended to preclude those mechanisms from passing through the purchase prices of electricity or gas.

3. Central Hudson is authorized to reopen this Joint Proposal if its achieved regulatory return on actual common equity in either its electric or gas department (or both) falls below 8.5%.

D. Treatment of Litigated Issues:

1. The Signatories have agreed to levels of delivery rate revenues, which agreements are for settlement purposes only, and not necessarily on the disposition of any particular issue raised during the litigation, other than as described in this Joint Proposal.

2. The terms and provisions of this Joint Proposal apply solely to, and are binding only in the context of, the purposes and results of the mutual

agreements reflected in the Signatories' settlement. None of the terms and provisions of this Joint Proposal and none of the positions taken herein by any party may be cited or relied upon by any other party in any fashion as precedent in any proceeding before the Commission, or before any other regulatory agency or any court of law for any purpose except in furtherance of the purposes and results of the Signatories' settlement.

E. Income Statements

1. The Income Statements for Electric (Attachment A) and Gas (Attachment B) services that have been attached to this Joint Proposal are intended to show that the Joint Proposal is reasonable and do not necessarily represent the views of any Signatory.

2. The Income Statements attached hereto have incorporated the following items:

a. Return on Common Equity: An assumed return on common equity of 10.3% has been agreed to as a fall out from the agreed-to revenue requirements shown in the Income Statements.

b. Equity Ratio: 47% first year, 46% second year and 45% third year.

c. Cost of Long-Term Debt and Redemption Premiums: As shown in Attachment C, updated costs and amounts of long term debt issuances, including the costs of redemption, and the costs of preferred stock redemption premiums and unamortized expenses, have been employed in determining the revenue requirements shown in the attached Income Statements. Central Hudson is authorized to recover the debt redemption premiums and unamortized debt expense over the remaining life of the redeemed debt and to recover the preferred stock redemption premiums and unamortized expenses ratably over the period ending 2028.

d. Rate base details have been reflected on Attachment H.

e. Electric Loss Factor: The electric loss factor will be 1.0437.

f. Lost & Unaccounted For Gas: The factor for lost and unaccounted for gas will be 1.025.

F. Agreed-to Dispositions of Specific Items and Other Conditions

1. Required Deferrals and Restorations of Electric Delivery Revenues: As shown on the attached Electric Income Statement, electric delivery revenues of $3.1 million in RY1 will be deferred for restoration in RY3 without regard for the amount of electric delivery revenues actually received in any of the RYs. The deferrals and restorations of revenues will be recognized for purposes of determining regulatory earnings and regulatory return on common equity (i.e., revenues in RY1 will be reduced by the deferred amount and RY3 revenues will be increased by the restored amount).

2. Required Utilization of Benefit Fund:

   a. An amount of $42.5 Million will be removed from the Benefit Fund and will be included as a credit to electric rate base for the three Rate Years.

   b. The credit will be applied to electric plant transmission and distribution book depreciation reserves in proportion to the relative book cost of plant in service at

August 31, 2001 for such plant categories, subject to the provisions of item 13.b of this Part II.F. of this Joint Proposal.

c. The $42.5 Million amount will be maintained as a rate base credit after the end of RY3, subject to other potential treatment by order of the Commission in a subsequent Central Hudson electric rate case.

d. This $42.5 Million rate base credit amount will be recognized in calculation of the achieved regulatory rate of return on common equity for the electric department.

3. Required Deferrals and Restorations of Gas Delivery Revenues: Gas delivery revenues of $0.9 million will be deferred in RY1 for restoration in RY3 without regard for the amount of gas delivery revenues actually received in any cf the three RYs. The deferral and restoration of revenues will be recognized for purposes of determining regulatory earnings and regulatory rate of return on common equity (i.e., revenues in RY1 will be reduced by the deferred amount and RY3 revenues will be increased by the restored amount).

4. Earnings Sharing:

a. There is a regulatory rate of return on common equity deadband by department between 8.5% and 11.3%.

b. In the event that Central Hudson achieves a regulatory rate of return on common equity above 11.3% in either the electric or gas department, the earnings above 11.3% and up to 14.00% in such department(s) will be shared 50/50 between the Company and ratepayers. The ratepayers' portion of such earnings in the electric department will be added to the Benefit Fund and in the gas department, deferred subject to further order of the Commission.

c. In the event that Central Hudson achieves a regulatory rate of return on common equity above 14.00% in either the electric or gas department, the earnings above 14.00% in the electric department will be added to the Benefit Fund and in the gas department, deferred subject to further order of the Commission. The 14.00% value is subject to adjustment pursuant to Parts IX. F and H.

5. Measurement of Achieved Regulatory Rate of Return on Common Equity for Earnings Sharing Purposes:

a. Separate determinations of the achieved regulatory rate of return on common equity for gas and electric operations will be made annually, on a rate year basis.

b. The achieved regulatory return on common equity will be measured by department on the basis of Central Hudson's actual capitalization for the period being measured; provided, however, that if the actual equity ratio in a given RY exceeds the applicable rate year target equity ratio (RY1: 47%; RY2: 46%; and RY3: 45%), then the target ratio for that RY will be used.

c. The financial consequences of the Part VII Service Quality Mechanisms, the Part V.A.2. Gas Interruptible Sharing incentive and the Parts IX. F. and H. incentives will be excluded in determinations of regulatory rate of return on common equity.

d. Within 90 days following the end of RY1, RY2 and RY3, Central Hudson shall provide Staff with a computation of achieved regulatory rate of return on common equity by department for the preceding RY period.

6. Reopener: Central Hudson is authorized to file for increased rates for either the gas or electric department anytime that the respective regulatory rate of return on common equity for a trailing 12-month period, measured in the fashion used for the annual RY determination, falls below 8.5%.

7. Deferrals:

   a. The Company is authorized to defer the following kinds of items for recovery in the next electric or gas, as appropriate, base rate change or other Commission-ordered disposition:

      (1) The Company is authorized to continue its use of deferral accounting with respect to the following expenses and costs and all other expenses and costs for which Commission authorization for deferral accounting is currently effective whether by reason of Commission order or policy of general applicability or by reason of a Commission determination with specific reference to the Company:

(a) Pension Expense under Statement of Financial Accounting Standards No. 87;

(b) Post Employment Benefits Other than Pensions under Statement of Financial Accounting Standards No. 106;

(c) Interest Costs on Variable Rate Debt;

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

(e) Research and Development costs under the Commission's Technical Release No. 17.

(2) Changes in accounting standards, subject to the understanding that this specific authority to defer is subject to such orders as the Commission may issue that provide for generic treatment of accounting practices;

(3) Changes in federal or state regulations;

(4) Force Majeure; and

(5) Others addressed herein.

b. All previously authorized uses of deferral accounting continue and shall not terminate because of the end of the term of this Joint Proposal.

c. Central Hudson retains the right to petition the Commission for authorization to defer extraordinary expenditures not otherwise addressed by this Joint Proposal.

d. Additional Deferral Provisions Related to Changes in Federal, State or Other Tax Laws:

(1) The Signatories agree that the attached Income Statements do not reflect implementation of the tax law changes resulting from the 2000 Legislative Session. Accordingly, tax differences between the prior State Tax Laws and the 2000 Legislative enactments will be deferred, in accordance with the Commission's Order of June 28, 2001 in Case 00-M-1556 for disposition as determined subsequently by the Commission. The deferral of state income taxes on earnings shall be permitted up to the sharing trigger level of 11.3%. The calculation of

regulatory earnings and achieved rate of return on common equity for purposes of Parts II.F.4 and 5 shall recognize the calculation of state income tax on earnings.

(2) In addition, the company is authorized to defer increases or decreases in costs related to changes in federal, state and local tax law or regulations for the period through RY 3.

8. Net deferred debit and credit balances for the electric department items shown on Attachment D-2 have been reflected in the determination of the Benefit Fund. Deferred debit and credit offsets for the gas department, using actual deferred balances at June 30, 2001 for the deferred items listed on Attachment E, will be subject to balance sheet offset accounting to the extent necessary to achieve a net of tax offset of zero.

9. Central Hudson is authorized to record electric or gas revenue amounts post-June 30, 2004 subject to the following:

a. The annual amount recorded by department may not exceed the lesser of the revenue requirement deficiency for RY3 shown on

Attachment A or B, as appropriate, or the amount of revenues needed by department to provide a regulatory rate of return on common equity of 10.5% for the 12-month ‘RY" periods subsequent to June 30, 2004.

b. Estimated amounts of revenue will be recorded on a monthly basis and adjusted to the final amount within the above constraints in the last month of the appropriate ‘RY" period.

c. The amount of revenues that are recorded may be based on the measurement of earnings for periods of time that are less than a twelve month RY period. Earnings for partial periods will be calculated by determining the level of earnings for the twelve month period ending on the date new rates are established and comparing it to the level of earnings required to provide a 10.5% equity return. If a deficiency in earnings results, the amount of revenues recorded for the partial period will be determined by the ratio of sales for the partial period to the sales for the twelve month period ending as of the date new rates are established.

d. Central Hudson will submit reports showing any revenues recorded under this provision, and the measurement of earnings used in the calculation of the revenues recorded, for each annual period beyond June 30, 2004 or period of time ending on the date new rates take effect. These reports will be submitted no later than 90 days from the end each annual period or the date when new rates take effect.

e. Central Hudson may charge the electric department amounts accrued hereunder each month against the Benefit Fund, subject to a subsequent final Order by the Commission directing otherwise, in which event Central Hudson shall be deemed to have fully reserved its rights and nothing in this Joint Proposal or Central Hudson's participation in it shall be deemed to prejudice Central Hudson's position.

f. Central Hudson may record a regulatory asset for the gas department amounts accrued hereunder each month.

g. This authority continues until the earlier of June 30, 2006 or, with respect to electric department revenue deferrals, the effective date of new base electric rates as a result of a general electric rate filing by Central Hudson and, with respect to gas department revenue deferrals, the effective date of new base gas rates as a result of a general gas rate filing by Central Hudson.

10. Common Cost Allocation Factor: 85% electric, 15% gas.

11. Payment By Credit Card: The Company is authorized, but not required, to accept payments for service by credit card from residential and small commercial customers.

12. The Company's accounting for the sale of its stock symbol is affirmed.

13. Depreciation:

    a. The Company's electric, gas and common depreciation studies and methods as presented in its initial filing are accepted, except for depreciation of Gas Distribution Mains, which will be based on an Average Service Life of 85 years and a net salvage factor of negative 60% (actual negative net salvage in excess of negative 60% will be charged to maintenance expense).

b. A method will be developed for reducing, in the next rate case after the end of the term hereof, the electric book depreciation reserve so that it exceeds the theoretical depreciation reserve by no more than 10 percent. Any Benefit Fund amounts transferred to the book depreciation reserve will be excluded from the measurement of the book to theoretical reserve ratio.

14. The amounts shown on Attachment A, B and H will be used as the rate allowances for purposes of revenue matching accounting or other deferral purposes as appropriate.

III. <u>Electric Issues</u>

A. The Company will implement a Reliability Improvement Program, subject to the following conditions:

1. The Program will be funded up to a total of $20 Million (pre-tax) over the period ending June 30, 2004.
2. Funding will be from the Benefit Fund.
3. Capital amounts funded will be removed from rate base and treated as Contributions in Aid of Construction, and as a result will carry a book balance of zero.

4. Expense amounts related to the capital projects are included in the $20 Million allowance and will also be funded from the Benefit Fund.

5. Outside contractors and labor will be used for the Program, and none of the Benefit Fund-will be allocated to Company labor expense.

6. Plans:

   a. An Annual Plan will be developed and reviewed with Staff before the start of RY2 for the remaining two years of the program.

   b. Central Hudson will review RY1 projects with Staff on an expedited basis following approval of this Joint Proposal.

B. The outcomes of generic Commission proceedings such as the Unbundling, Competitive Markets or Stand-by Rates Proceedings, and any others during the term of this Joint Proposal that may affect implementation of electric competition will be reflected prospectively, subject to the understanding that any stranded or similar costs resulting from any such proceedings, as determined by the Commission, may be recovered out of the Benefit Fund to the extent not inconsistent with any applicable Commission Order or, if recovery out of the Benefit Fund is inconsistent with the applicable Commission Order, Central Hudson shall be deemed to have fully reserved its rights and nothing in this Joint Proposal or Central Hudson's participation in it shall be deemed to prejudice Central Hudson's position. Nothing in this Joint Proposal shall be interpreted to preclude Central Hudson from participating in any Commission proceeding in any manner it may deem advisable.

IV. Electric Rate Desian

A. Unbundling: The revenue allocation, as shown in Attachment F will be utilized to design rates, as amplified below.

B. Purchased Power Recovery ("PPR"):

1. Mechanism will vary by class;
2. Recover all commodity related costs using market prices;
3. Use bimonthly averaging for bimonthly billed customers;
4. Include uncollectibles & working capital costs; and
5. Be determined and reconciled monthly.

C. Variable Cost Recovery ("VCR"): This mechanism will be reconciled monthly and will recover the costs of ancillary services and the variable costs and benefits of the Company's remaining generating facilities.

D. Central Hudson has entered into a Transition Power Agreement ("TPA") with Dynegy that provides for the purchase and sale of specified amounts of power to Central Hudson. The TPA was approved by the Commission in an Order issued December 20, 2000 in Case 96-E-0909. In addition, Central Hudson has entered into a Purchase Power Agreement ("PPA") with Constellation that provides for the purchase and sale of specified portions of the output of Nine Mile Point 2 ("NMP2"). The PPA has been filed with the Commission in Case 01-E-0011 and that Case is currently pending before the Commission. The prices in the TPA and PPA will not necessarily equal the market prices and the differences are referred to herein as "TPA and PPA Benefits." The TPA and PPA Benefits will be apportioned to full service and delivery customers as follows:

1. TPA and PPA Benefits will be apportioned among service classes on the basis of each class' sales (kWh) as a portion of the total system sales (kWh) in a given month;
2. Within a given class, TPA and PPA Benefits will be apportioned among customers on the basis of relative usage in a month as a portion of the total class usage;

3. Central Hudson shall have no obligation, other than as specifically provided for herein, to track the amount of any TPA and PPA Benefits by individual customer. In Service Classifications 3 and 13, the TPA and PPA Benefits will be subject to the constraints that:

   (1) The total TPA and PPA Benefits credited to a customer will not exceed the total Central Hudson delivery charges for that customer in a billing period; and

   (2) Any TPA and PPA Benefits not received by a customer due to operation of the above constraint will be reallocated to that customer in the subsequent billing period. In any such reallocation, the constraint that the total TPA and PPA Benefits not exceed the total Central Hudson delivery charges in the billing period will continue to be applicable and may entail reallocation to subsequent billing periods.

E. Billing Format: Separate line items will be provided for the following items:

1. PPR;
2. PPR under/over recovery;

3. VCR;

4. TPA/PPA Benefits; and

5. System Benefit Charge ("SBC").

F. Cost of Service Study & Revenue Allocation

1. The rate changes will be allocated as follows:

a. Service classifications which have a rate of return below the lower tolerance level of 85% of the system average would receive a minimum decrease of 0.5 times the average overall decrease.

b. Service classifications which have a rate of return exceeding the upper tolerance of 115% of the system average would receive a maximum decrease of 1.25 times the average overall decrease.

c. Application of these maximum and minimum decreases results in revenues different from the rate decrease revenue. This difference is allocated to the unconstrained decreases for S.C. 1, S.C. 2, S.C. 5 and S.C. 13 - Transmission.

2. Peaker & Hydro Costs: The investment in combustion turbine production plant is classified as demand-related. The investment in

hydroelectric production plant is classified as energy-related.

3. The marginal customer cost for S.C. 1 is $23.67 per month and for S.C. 2 is $32.79 per month.

4. Rate design for S.C. 13 will include flat energy charges, a single basic monthly demand charge and a $500/month customer charge.

G. Customer Charges

1. S.C.l residential customer charges will increase from the current $7.15 to $9.75 for RY1 and RY2 and to $11.50 after RY2 until June 29, 2004. On June 30, 2004 the customer charge will be increased to $12.00.

2. S.C.2 small commercial (non-demand) customer charge will increase from the current $6.25 to $12 for RY1 to $13 for RY2 and to $14 for RY3.

3. The above changes will be made on a revenue neutral basis within the affected customer classes.

4. The remaining monthly customer charges are as follows: S.C. 2 Secondary Demand: $20.00; S.C. 2 Primary Demand: $80.00; S.C. 3: $250 and S.C. 6: $12.00.

5. All customer charges agreed to herein are without prejudice to the filing by the Company of

superseding rate change filings, effective after June 30, 2004.

H. Time of Use ("TOU") & Space Heating Rates

1. Continue offering S.C. 6 residential TOU.
2. Elimination of S.C. 12 commercial TOU.
3. Elimination of S.C. 2 heating discount.

I. Charges for restoration of service to the same customer at the same meter location within twelve months of discontinuation of service will be as shown below.

During Normal Work Hours:	
Without Line or Gas Crew	$ 20.00
With Line or Gas Crew	$100.00
Outside Normal Work Hours:	
Without Line or Gas Crew	$ 40.00
With Line or Gas Crew	$140.00

J. Treatment of Central Hudson's NMP2 Costs:

1. The existing ratemaking for Central Hudson's NMP2 costs, approved by the Commission effective February 1, 2001 includes two components: a Competitive Transition Charge ("CTC") (reflecting property taxes and certain O&M costs), and variable cost recovery through the existing ESC.
2. Upon the effectiveness of the rates produced by this Joint Proposal, Central Hudson's NMP2 costs

will be recovered through three components: a CTC, the PPR and the VCR.

a. Until such time as the Commission approves the pending PSL §70 asset transfer and the closing for Central Hudson's NMP2 interests takes place:

   (1) the CTC will recover NMP2 property tax and fixed O&M elements (hydro and GT costs will be recovered through base rates);

   (2) The PPR will recover the market price of Central Hudson's share of the power produced at NMP2; and

   (3) The VCR will recover transmission costs, IS0 charges, and recover/pass back the difference between the market price and the variable production costs of Central Hudson's share of NMP2 output.

b. After the Commission approves the pending PSL §70 asset transfer and the closing for Central Hudson's NMP2 interests takes place:

   (1) The CTC will cease.

   (2) The PPR will reflect the Market Price of Central Hudson's share of the power produced at NMP2 under the NMP2 PPA.

(3) The VCR will recover transmission costs and IS0 charges.

(4) The TPA/PPA Benefits will recover/pass back the difference between the market price and the costs of the PPA for Central Hudson's share of NMP2 output.

V. <u>Gas Rate Issues</u>

A. Revenue Sharing

1. The imputation for interruptible and electric generation sales is set at $1,900,000.

2. Accounting:

a. Each August, the Company will reconcile the annual IT profit received in the prior RY. Profit realized by the Company pursuant to this mechanism will be excluded from any determination of achieved regulatory rate of return on common equity.

(1) If the Company's IT profits exceed the annual imputation of $1,900,000, the sharing mechanism will be as follows:

(a) From $1,900,000 up to $2,299,999: Profit will be shared in an 85% customer/15% shareholder ratio;

(b) Profit above $2,300,000 will be shared in an 80% customer/20% shareholder ratio.

(2) If the Company's IT profits are less than the annual imputation of $1,900,000, the sharing mechanism will be as follows:

(a) From $0 up to $1,499,999 in IT revenue, the short-fall below $1,900,000 will be borne by the Company;

(b) From $1,500,000 up to $1,899,999 the short-fall below $1,900,000 will be shared in an 15% shareholder/85% customer ratio.

b. In addition, the Company shall be permitted to attempt to minimize potential monthly short-falls or over collections through the Gas Supply Charge ("GSC"):

(1) Each month the Company will compare the profit received from customers taking service under Service Class Nos. 8, 9 and 14 ("IT Profit": to $158,333 (1/12 of the annual imputation of $1,900,000), and

(2) If the IT Profit differs significantly from the monthly imputation, the Company may refund or surcharge, as appropriate, through the GSC in a subsequent month.

B. Agreed-to Dispositions of Specific Gas Items:

1. Gas Manufacturing Site Remediation

a. Write off Newburgh site costs from Benefit Fund.

b. Case 95-M-0874 requirements remain in force for Newburgh site.

2. The prudence of the Company's gas purchasing policies and load management practices prior to the date of this Joint proposal have been reviewed and have not been challenged in these proceedings.

VI. <u>Gas Rate Desiun</u>

A. Unbundling and GSC

1. The GSC mechanism will recover all commodity related and upstream pipeline demand costs.

2. The GSC will be determined monthly and reconciled annually.

3. The GSC will include uncollectibles, working capital and carrying costs on cash working capital requirements and materials and supplies.

B. S.C. 9 Customers Eligible for S.C. 11: The Company's current rate design methodology, which uses the load factors of existing customers to establish the price caps, will remain in effect.

C. Minimum Charge and Tail Blocks: The minimum charges in firm Service Classification Nos. 1,2,6,12 and 13 are increased to $7.20. To offset the increase in the minium charge, the second block of S.C. 1 and 12 has been reduced and the third block of S.C. 2, 6 and 13 has been reduced. No rate changes are made to current tail block prices.

VII. <u>Service Qualitv Mechanisms</u>

A. Customer Service Quality Program:

1. Twenty-five basis point total potential penalty on combined Company basis, per calendar year commencing January 1, 2002.

   a. Of the twenty-five basis point total, twelve and one-half basis points are for the PSC Complaint Rate (12.5 basis points) and

   b. twelve and one-half basis points (12.5 basis points) are for the Customer Satisfaction Index ("CSI").

2. PSC Complaint Rate:

   a. Targets and penalties for the PSC Complaint Rate (chargeable complaints per 100,000 customers, based on a 12-month rolling average at the end of each performance period) follow:

Penalty Basis Points	From a PSC Complaint Rate of	To a PSC Complaint Rate of
None	0	<6.0
2.5	≥6.0	<6.5
5.0	≥6.5	<7.0
7.5	≥7.0	<7.5
10.0	≥7.5	<8.0
12.5	≥8.0	

b. The PSC Complaint Rates set forth above are predicated upon existing PSC practices and procedures for chargeable complaints per 100,000 customers. In the event of a change to those practices and procedures, the Signatories will discuss in good faith whether alteration of the above target and penalty levels are appropriate to maintain the incentive to the Company at levels comparable to those above. Any disputes will be referred to the Commission.

3. CSI:

a. The CSI will be based on the calculations performed by Central Hudson consistent with the procedures adopted as a result of Case 96-E-0909.

b. Targets and penalties for the CSI follow:

Basis Point Penalty	CHGE CSI From	To
None	≥83	NA
3.125	≥82	<83
6.25	≥81	<82
9.375	≥80	<81
12.5	Below 80	

4. For purposes of this Joint Proposal, the performance periods are the calendar years ending December 31, 2002 and 2003 and the six months ending June 30, 2004 (for which the basis point penalties will be halved).

5. The "Appointments Kept" incentive remains at $20 per missed appointment.

B. Electric Reliability

1. Twenty-five (25) basis point total potential penalty on electric operations, per calendar year commencing January 1, 2002.

a. Of the twenty-five basis point total, twelve and one-half basis points (12.5 basis points) are for SAIFI and

b. twelve and one-half basis points (12.5 basis points) are for CAIDI.

2. SAIFI indices and penalties, as shown below:

>1.10	6.25 basis point penalty
>1.20	12.5 basis point penalty

3. CAIDI indices and penalties, as shown below:

>2.10	6.25 basis point penalty
>2.20	12.5 basis point penalty

4. The SAIFI and CAIDI indices are based on electric service interruptions that are not related to major storms.

   a. The initial SAIFI index levels will be reduced by 2% from 2002 to 2003 and by 4% from 2003 to 2004.

   b. The Company may petition for appropriate adjustment to the final CAIDI and SAIFI indices for each performance period to recognize the effects, if any, of Outage Management System ("OMS") implementation or interventions by the IS0 or similar authority causing service interruptions.

5. For purposes of this Joint Proposal, the performance periods are the calendar years ending December 31, 2002 and 2003 and the six months

ending June 30, 2004 (for which the basis point penalties will be halved).

6. Penalties will be calculated with respect to electric operations.

c. Gas Reliability

1. Number of One-Call Ticket Mis-marks per Thousand One Call Tickets.

Basis Point Penalty	From Mis-marks/1000 of	To Mis-marks/1000 of
Zero	0	1.25
2	1.26	1.45
3	1.46	1.65
6	1.66 or higher	

2. Penalties will be calculated with respect to gas operations. Mis-marks will be determined based on Central Hudson's current procedures, including recognition of the Tolerance Zone as defined in 16 NYCRR Part 753-1.2(t).

3. The measurement periods will be the calendar years ending December 31, 2002 and 2003 and the six months ending June 30, 2004. The basis point penalty applicable to the six month period ending June 30, 2004 will be one-half of that set forth in the above table.

D. Gas Leak Management:

1. Applicable to Type 3 leaks only;

2. Penalty-only plan over the three year term. No penalty for Type 3 leak inventory levels at cr below 362 at December 31, 2002, 337 at December 31, 2003 or 325 at June 30, 2004 or in any calendar year in which 140 or more Type 3 leak repairs are completed. In addition, no penalty will be applicable to the six months ending June 30, 2004 if 70 or more Type 3 leak repairs are completed in that time period.

3. A penalty of 3 basis points is applicable to gas operations in any calendar year in which 140 Type 3 leak repairs are not completed and the specified Type 3 inventory level is not achieved (362 at Y.E. 2002 or 337 at Y.E. 2003). A penalty of 1.5 basis points is applicable to gas operations in the six months ending June 30, 2004 if 70 Type 3 leak repairs are not completed and the specified Type 3 inventory level (325) is not achieved.

4. If, in any year during the term of this Joint Proposal the target level for Type 3 leak inventory is not met, but a penalty is not due because 140 Type 3 leak repairs were completed, the leak inventory target level for the subsequent

year shall be 25 less than the actual ending inventory level for that prior period.

E. Central Hudson will, by March 31, 2003 and 2004 and by September 30, 2004, file a report or reports on its performance under each of the above incentive programs during the prior performance period, with the format and contents to be developed in collaboration, commencing on or about November 1, 2001, between the Company and Staff.

F. The Service Quality Incentive Plan of Case 96-E-0909 is extended from July 1, 2001 to and including December 31, 2001.

VIII. Low Income Proaram

A. The Company will implement a Low Income Program consistent with Attachment G.

B. The costs of the program, funded out of the revenue requirements, will be limited to the expense allowances shown on Attachments A and B. In the event that the costs of the program differ from those levels, the difference will be deferred and, after review,

1. Any electric shortfall will be added to the Benefit Fund and any gas shortfall will be returned to customers through the GSC and;

2. Any electric excess will be recovered from the Benefit Fund and any gas excess will be recovered through the GSC.

C. Commencing on or about November 1, 2001, the Company and Staff shall collaborate in the development of any program reporting requirements, with the Commission resolving any disputes over those requirements.

IX. Competitive Issues

A. Consolidated Bills will be made available per the May 18, 2001 Billing Proceeding Order.

B. Single Bill: Central Hudson will pursue offering a Single Bill using the Rate Ready format. In order to utilize this option, each ESCO or marketer must provide Central Hudson monthly with the Central Hudson customer account number and a billing rate per kWh or CCF for each customer in sufficient time in advance (minimum period to be established) of the billing dates set forth on Central Hudson's web site. Central Hudson will comply with the criteria established in the Billing Proceeding Order and ED1 Proceeding related to single bills.

C. Ancillary Services: The Company will bill all delivery customers for ancillary services commencing three months after Commission approval of this Joint Proposal. This non-by-passable charge will be collected from customers through the Variable Cost Recovery factor. Central Hudson will reimburse ESCOs for ancillary service charges incurred to serve Central Hudson load.

1. Each ESCO serving load in Central Hudson's retail access program must provide the Company with a copy of its NYISO bill which identifies the ancillary services for the ESCO's Central Hudson load served (PTID) within a day of billing by the NYISO. The invoice provided by the ESCO must detail the load (kWh), rate for each service and total amount requested for reimbursement.
2. Bills and credits issued by the NYISO to the ESCO for prior periods must also be provided to Central Hudson in the month received by the ESCO. Central Hudson will be authorized to collect all such amounts through its VCR. Reimbursement to ESCOs by Central Hudson for ancillary service charges will be made prior to the date ESCOs are required to pay the NYISO for such charges.
3. The Company reserves the right to file a petition with the Commission to modify this process, including potentially terminating billing or reimbursing ESCOs for NYISO ancillary services.

D. Electric Back Out Credits: Credit levels would be set at 0.5 mills per kWh for S.C. 13 customers; 2.0 mills per kWh for S.C. 3 customers; 3.0 mills per kWh for S.C. 2 demand customers; and 4 mills per kWh for S.C. 2 non-demand, S.C. 6 and S.C. 1 customers pending the outcome of the Unbundling Proceeding and are subject to being superseded by the Unbundling Proceeding as provided for in Part III.B. hereof. Prior to that time, the cost of the credits will be recovered from the Benefit Fund, subject to a penetration limit of 20% of electric customers. If it appears likely that the 20% penetration level will be exceeded, the penetration level and recovery mechanism will be reviewed.

E. Gas Merchant Back Out Credit: The gas merchant function back-out credit will be set at $.15 per mCf pending the outcome of the Unbundling Proceeding, and is subject to being superceded by the Unbundling Proceeding as provided for in Part III.B hereof. Prior to that time, the cost of the credit will be recovered through the GSC, subject to a penetration limit of 20% of gas customers. If it appears likely that the 20% penetration level will be exceeded, the penetration level and recovery mechanism will be reviewed.

F. ESCO & Marketer Satisfaction Mechanism

1. ESCO/Marketer Satisfaction Survey: After consultation between Staff and the Company, a survey will be developed as a baseline for an incentive mechanism.

2. The survey metrics would include the performance of the Company in satisfying the terms of the UBP and other operational arrangements (e.g., GTOP) between it and ESCOs (electric) and marketers (gas). The survey should include relevant questions for both ESCOs and gas marketers.

3. The survey would be implemented on an annual basis by an objective third party selected after consultation commencing on or about November 1, 2001 between Staff and the Company.

4. Prior to implementation of the survey, Staff and the Company will agree to a threshold number of participating marketers as a basis for implementation of an incentive mechanism. If the threshold number of marketers participate, an incentive allowing the Company to receive up to 10 basis points of earnings in excess of 11.3% on a combined Company basis will be implemented after the baseline results are available. In this

event, the overall earnings cap will also be increased by ten basis points.

5. Once the results of the satisfaction survey are available, the company will have 60 days to report to Staff and interested parties on how it plans to address marketer concerns, if any, that were expressed in the survey.

G. The Company will consult with Staff concerning the suitability of potential aggregation initiatives within the Central Hudson service territory, subject to the funding provisions of Part X.G.

H. Electric and Gas Outreach and Education Mechanisms

1. Improvements in outreach and education (O&E), to increase customer awareness and understanding of energy competition, will be measured by using Central Hudson's existing residential survey.

2. The survey will be enhanced for better measurement of awareness and understanding, according to a list of criteria that will be established after consultation commencing on or about November 1, 2001 between the Company and Staff. A method to evaluate the awareness and understanding of energy competition among small commercial customers will be established.

3. An incentive allowing the Company to receive up to 10 basis points of earnings in excess of 11.3% on a combined company basis will be implemented, based on criteria, developed through consultation commencing on or about November 1, 2001 between the Company and Staff, for measuring improvements in customer awareness. In this event, the overall earnings cap will be increased by 10 basis points.

I. Small Customer Aggregation: The potential funding of aggregation initiatives will be considered in the Benefit Fund Review process.

J. ESCO/marketer Ombudsman: The company will designate a vice-president level ombudsman to address ESCO/marketers' unresolved concerns and serve as a liaison with marketers.

X. <u>Benefit Fund</u>

A. The total amount of the Benefit Fund is currently estimated at $164 million, including an assumed $36.5 million in net gain from a sale of NMP2, or $127.5 Million excluding the estimated NMP2 gain. The components have been shown in Attachment D-l.

B. The Signatories have agreed upon the following general approach: Allocate a portion of the fund to "Identified Uses" and reserve the remainder, future NMP2 gain and any unutilized portion of the Identified

Uses to annual collaborations. The Identified Uses are further defined as "Quantified Identified Uses" and "Non-Quantified Identified Uses."

C. The "Quantified Identified Uses" of the Benefit Fund are (net of tax):

1. Rate base offset - $42.5 Million;
2. Gas site remediation - $10 Million;
3. Reliability Improvement Program - $13 Million; and
4. Refunds: $15 Million per RY.

D. The Non-Quantified Identified Uses of the Benefit Fund are:

1. Other items provided for in this Joint Proposal, including possible additional customer refunds, offset to potential post-June 30, 2004 electric rate increases, back out credits and future stranded or similar costs subject to the provisions of Part III.B hereof; and
2. Economic Development - to be developed and dispensed in accordance with below discussion.

E. Refunds: The total net of tax amounts for the three RYs of $45 Million, as shown on Attachment D-l, will be refunded to customers through a per kWh credit, commencing in the month following the Commission's approval of this Joint Proposal. The credit will be developed from the total RY billing units, prorated for the total number of months until June 30, 2004 following the Commission's approval of this Joint Proposal. Central Hudson will track and reconcile the amounts credited. In the event that the entire $45 Million is not credited prior to June 30, 2004, the un-dispensed credit will be carried forward subject to further order of the Commission.

F. A carrying charge at an annual rate equal to the pre-tax rate of return set forth on Attachment C will be applied monthly to the net remaining balance in the Benefit Fund.

G. Other Potential Uses of Net Benefit Fund

1. Potential uses include possible future use for price spike mitigation; for small customer aggregation efforts; and to fund such other competitive-related initiatives as the Commission may approve.

2. These uses would be addressed in the Benefit Fund Review discussed below.

3. Benefit Fund Review Process: On or about January 15, 2002, and 2003 a collaborative effort will commence on the use of the remaining Benefit Pool amounts not otherwise allocated to specific purposes. The collaborative will be completed and reported to the Commission by April 1, 2002 and

2003. The Commission will expedite its review of the Collaborative Report (and any dissents).

H. Economic Development

1. An Economic Development Program will be established and funded from the Benefit Pool in accordance with the procedure set forth below. The program's purposes would be to encourage the relocation, growth, expansion, and retention of business customers in the Company's service territory and include consideration of any situations in which reductions in employers' substation costs will lead to employee retention.

2. The administration of the program would be facilitated by Staff, through consultation commencing on or about November 1, 2001 among the Company, the Empire State Development Authority, local government officials and interested parties. Tariff provisions, guidelines and procedures would be developed as appropriate in that consultation and would be submitted to the Commission for approval.

3. Existing electric programs will be terminated with the exception of the Revitalization Rate.

4. Revitalization Rate:

   a. Current electric customers will receive their existing discounts until the time set for expiration in their existing agreements.

   b. For new'customers, a rate discount would be offered on the delivery rate for those who meet the existing program's criteria.

   c. The discounts would be set at percentage levels comparable to those in the existing program, but applied to the delivery prices.

   d. The discounts will be funded from the Benefit Fund.

   e. Customers receiving the rate would be contacted in writing 6 months prior to the end of their Revitalization Rate term informing them of the expiration and providing them with a contact at the Company to answer any questions or concerns.

XI. <u>Conditions of Joint Proposal</u>

A. This Joint Proposal is intended by the Signatories to be a complete resolution of all issues in Cases 00-E-1273 and 00-G-1274. Each Signatory is obliged to support the Joint Proposal before the Commission. The Signatories to the Joint Proposal agree that the provisions of the Joint Proposal are, in aggregate, a reasonable resolution of each of the proceedings.

B. It is understood that each provision hereof is in consideration and support of all the other provisions, and each Signatory has expressly conditioned its support upon the acceptance of this Joint Proposal in its entirety by the Commission. In the event that the Commission proposes to alter any provision of the Joint Proposal, no Signatory has any further obligation relative to the Joint Proposal other than the obligation to discuss in good faith with the other Signatories whether any such alteration is acceptable to it. In addition, Staff will make its best efforts to present to the Commission by September 25, 2001, the Company's Petition of May, 2001, as updated, in Case 01-M-0323.

C. In the event that the Commission alters any provision of the Joint Proposal, each Signatory will be deemed to have fully reserved its rights to contest the altered Joint Proposal, and any such alteration. In the event that the Commission fails to adopt this Joint Proposal according to its terms, then each Signatory shall be free to pursue its respective positions in this proceeding, without prejudice, upon reasonable notice to the other Signatories. This Joint Proposal is an integrated whole, with each provision in consideration for, in support of, and dependent on the others. Thus, if the Commission does not approve this Joint Proposal in its entirety without modification, each of the Signatories reserves the right to withdraw its participation and support by serving written notice on the Commission and the other Signatories and, if necessary, to litigate, without prejudice, any or all issues as to which such signatory agreed in this Joint Proposal; in such event, any such Signatory shall not be bound by the provisions of this Proposal, as executed or as modified.

D. In the event of any disagreement over the interpretation of this Proposal or the implementation of any of the provisions hereof, which cannot be resolved informally among the Signatories, such disagreement shall be resolved in the following manner: The Signatories shall promptly convene a conference and in good faith shall attempt to resolve such disagreement. If any such disagreement cannot be resolved by the Signatories, a Signatory may petition the Commission for relief on a disputed matter.

E. This Joint Proposal represents a negotiated agreement and settlement and, except as otherwise expressly stated herein, none of the Signatories shall be deemed to have approved, agreed to, or consented to any principle, methodology, or interpretation of law underlying or supposed to underlie any provision hereof, and this Joint Proposal shall not be cited or relied upon with respect to any matters other than those specifically addressed herein.

F. The Signatories recognize that certain provisions hereof require that actions be taken in the future to effectuate fully the agreements and compromises set forth in this Joint Proposal. Accordingly, each Signatory agrees to cooperate with each other Signatory in good faith in taking such actions.

G. Survival of Conditions: All reservations of rights of any Signatory (including, but not limited to, Parts XI.A. through XI.F., inclusive), the continuation of deferral accounting authority, the post-June 30, 2004 revenue deferral provisions, the provision concerning development of a method for reducing the book to theoretical depreciation reserve, and the Benefit Fund provisions shall survive the June 30, 2004 term of this Joint Proposal.

H. The Supplemental Environmental Assessment Form attached hereto as Appendix I accurately describes the potential environmental impacts, if any, that could result from implementation of the terms of this Joint Proposal, and the Commissions' determination of significance regarding this Joint Proposal should be the adoption of a negative declaration.

I. All titles, subject headings, section titles and similar items are provided for the purpose of reference and convenience only and are not intended to affect the meaning, content or interpretation of this Joint Proposal.

J. The Commission reserves the authority to act on the level of the company's base electric and gas 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 Joint Proposal as to render the company's return unreasonable or insufficient for the provision of safe and adequate service at just and reasonable rates and in the event that the Commission exercises such authority as it possesses in that regard, each Signatory reserves its rights and no Signatory shall be bound or prejudiced by its entry into, or performance under, this Joint Proposal.

K. Submission of Settlement: This Joint Proposal is being executed in counterpart originals and shall be binding on each Signatory. Each person executing this Joint Proposal represents by his or her signature that he or she has full authority to bind his or her principal. The Signatories hereto agree to submit this Joint Proposal to the Commission and individually to support and request adoption by the Commission of their mutual settlement as set forth herein.

WHEREFORE, this Joint Proposal has been agreed to by and among each of the following, who, by its signature, each represents that it is fully authorized to execute this Joint Proposal and, if executing this Joint Proposal in a representative capacity, that it is fully authorized to execute it on behalf of its principals.

SIGNATURE PAGE

The undersigned party to Public Service Commission Case Nos. 00-E-1273 and 00-G-1274 has participated in the negotiations among the parties which led to the Joint Proposal dated August 15, 2001 and agrees to the provisions of such Joint Proposal.

Central Hudson Gas & Electric Corporation

By: Arthur R. Upright

Arthur R. Upright

Dated: Augusta 2001

SIGNATURE PAGE

The undersigned party to Public Service Commission Case Nos. OG-E-1273 and 00-G-1274 has participated in the negotiations among the parties which led to the Joint Proposal dated August 15, 2001 and agrees to the provisions of such Joint Proposal.

Consumer Protection Board

By:

C. Adrienne Rhodes

Dated: August 17, 2001

SIGNATURE PAGE

The undersigned party to Public Service Commission Case Nos. 00-E-1273 and 00-G-1274 has participated in the negotiations among the parties which led to the Joint Proposal dated August 15, 2001 and agrees to the provisions of such Joint Proposal.

Multiple Intervenors

By: Michael B. Mager

Dated: August 17, 2001

Michael B. Mager, Esq.
COUCH WHITE, LLP
Attorneys for Multiple Intervenors

SIGNATURE PAGE

The undersigned party to Public Service Commission Case Nos. 00-E-1273 and 00-G-1274 has participated in the negotiations among the parties which led to the Joint Proposal dated August 15, 2001 and agrees to the provisions of such Joint Proposal.

Staff of the Department of Public Service

By: Leonard Van Ryn

Leonard Van Ryn

Dated: August 20, 2001

SIGNATURE PAGE

The undersigned party to Public Service Commission Case Nos. OG-E-1273 and 00-G-1274 has participated in the negotiations among the parties which led to the Joint Proposal dated August 15, 2001 and agrees to the provisions of such Joint Proposal.

Strategic Power Management, Inc.

By: Daniel P Duthie

'Daniel P. Duthie
Vice President and General Counsel

Dated: August 16, 2001

List of Attachments

1. Attachment A: Electric Income Statements
2. Attachment B: Gas Income Statements
3. Attachment C: Cost of Capital, Debt and Preferred Redemption Costs and Related Expenses
4. Attachment D-l: Estimate of Benefit Fund Balance
5. Attachment D-2: Electric Department Deferred Items Included on Attachment D-l
6. Attachment E: Gas Department Deferred Items for Balance Sheet Offset
7. Attachment F: Electric Department Revenue Allocation
8. Attachment G: Low Income Program
9. Attachment H: Rate Base Details, Gas and Electric
10. Attachment I: Supplemental Environmental Assessment Form

Filing by: CENTRAL HUDSON GAS & ELECTRIC CORPORATION

Amendments to Schedule P.S.C. No. 15 - Electricity

Original Leaf No. 206.1
First Revised Leaves Nos. 4, 5, 14, 94, 104, 105, 106, 107, 108, 123, 124, 136, 164, 165, 168, 169, 170, 171, 172, 185, 186, 199, 200, 204, 209, 210, 211, 213, 215, 217, 219, 225, 237, 238, 239, 240, 241, 242, 243, 244, 245, 246, 247, 253, 254, 255, 256, 273, 274, 275, 276, 277, 278, 279, 281, 282, 283, 284, 285, 286, 287, 288, 289, 290, 291, 292, 293, 294, 295, 296, 297, 298, 299, 300, 301, 302, 303, 304, 305, 306, 307, 308, 309, 310, 311, 312, 313, 314, 315, 316, 317, 318, 319, 320, 321, 322, 323, 324, 325, 326, 327, 328
Second Revised Leaves Nos. 166, 205, 206, 212, 216, 218, 220
Supplement No. 2
Supplement No. 3
Supplement No. 10
Supplement No. 12
Supplement No. 13

Amendments to Schedule P.S.C. No. 12 - Gas

First Revised Leaves Nos. 4, 63, 68, 69, 71, 72, 148, 149, 150, 151, 152, 153, 154, 158, 188, 193
Second Revised Leaves Nos. 70, 73
Third Revised Leaves Nos. 186, 191
Fourth Revised Leaf No. 159
Supplement No. 2
Supplement No. 4
Supplement No. 7
Supplement No. 8
Supplement No. 9

Central Hudson Gas & Electric Corporation
Case Nos. 00-E-1273 & 00-G-1274
Joint Proposal - Electric Revenue Requirements

	Settlement Period $(000) RY1	RY2	RY3
Operating Revenues:			
Own Territory Base Revenues	153,000	154,407	155,633
Revenue (Surplus) / Deficiency	(3,072)	(0)	3,072
Total Revenue Requirement	149,928	154,407	158,706
NMP2 CTC	21,302	21,309	21,316
Other Operating Revenues	6,093	5,938	5,831
Total Operating Revenues	177,323	181,654	185,853
Operating Expenses:			
Non Fossil Production Maintenance	187	191	195
Right of Way Maintenance	4,838	4,944	5,123
NMP2 Operations	16,309	16,316	16,323
Direct Labor	37,996	39,332	39,674
Research and Development	1,667	1,692	1,747
Expenses Projected Based on Inflation	8,899	9,087	9,268
Miscellaneous General Expenses	1,895	1,922	1,949
Transportation Depreciation	1,434	1,519	1,605
Fringe Benefits	4,666	4,825	4,869
Other Post Employee Benefits (OPEB)	1,429	1,429	1,429
Pension Plan	(10,210)	(10,210)	(10,210)
Major Rents	1,974	1,986	1,998
Uncollectible Accounts	784	791	798
Regulatory Commission Expenses	1,278	1,305	1,333
Data Processing Costs	2,719	2,631	2,674
Other Operating Insurance	543	554	567
Telephone	1,377	1,406	1,434
Legal Services	1,434	1,464	1,493
Special Services	951	971	991
Injuries and Damages	1,465	1,496	1,526
Storms Expense	2,900	2,961	3,023
Environmental	244	249	254
Low Income Program	306	530	995
Expenses Allocated to Affiliates	(506)	(506)	(506)
Total Operating Expenses	84,579	86,885	88,552
Other Deductions:			
NMP2 Decommissioning	999	999	999
Taxes Other Than Income Taxes:			
Property	16,450	17,112	17,797
Revenue	6,805	6,812	6,842
Payroll	2,911	2,989	3,054
Other	2,125	2,088	2,052
NMP2	3,061	3,061	3,061
Depreciation	19,035	19,888	20,696
Total Other Deductions	51,386	52,949	54,501
Federal Income Tax	12,728	12,770	12,911
Total Operating Revenue Deductions	148,693	152,604	155,964
Operating Income	28,630	29,050	29,889
Rate Base	380,215	386,309	399,582
Rate of Return	7.53%	7.52%	7.48%
Return on Common Equity	10.30%	10.30%	10.30%

Central Hudson Gas & Electric Corporation
Case Nos. 00-E-1273 & 00-G-1274
Joint Proposal - Gas Revenue Requirements

	Settlement Period $(000) RY1	RY2	RY3
Operating Revenues:			
Own Territory Base Revenues	36,597	37,007	37,378
Revenue (Surplus) / Deficiency	(885)	(0)	885
Total Revenue Requirement	35,712	37,007	38,263
Interruptible & Sales to Generators	1,900	1,900	1,900
Other Operating Revenues	2,077	2,002	1,921
Total Operating Revenues	39,689	40,909	42,084
Operating Expenses:			
Labor	9,007	9,285	9,632
Research and Development	331	303	303
Expenses Projected Based on Inflation	2,302	2,350	2,399
Miscellaneous General Expenses	287	291	294
Transportation - Depreciation	307	325	344
Fringes	986	1,009	1,029
Other Post Employee Benefits (OPEB)	307	307	307
Pension Plan	(2,273)	(2,273)	(2,273)
Environmental	43	44	44
Major Rents	123	125	127
Uncollectible Accounts	210	220	227
Regulatory Commission Expenses	258	263	269
Data Processing Costs	423	481	526
Other Operating Insurance	90	92	94
Telephone	201	206	210
Legal Services	377	385	392
Special Services	171	175	178
Injuries and Damages	374	382	390
Low Income Program	48	82	153
Expenses Allocated to Affiliates	(89)	(89)	(89)
Total Operating Expenses	13,483	13,963	14,556
Other Deductions:			
Taxes Other Than Income Taxes:			
Property	4,559	4,737	4,923
Revenue	1,598	1,661	1,719
Payroll	641	659	672
Other	277	280	283
Depreciation	5,757	6,013	6,227
Total Other Deductions	12,832	13,350	13,824
Federal Income Tax	4,361	4,457	4,511
Total Operating Revenue Deductions	30,676	31,770	32,891
Operating Income	9,013	9,139	9,193
Rate Base	119,695	121,525	122,904
Rate of Return	7.53%	7.52%	7.48%
Return on Common Equity	10.30%	10.30%	10.30%

Central Hudson Gas & Electric Corporation
Case Nos. 00-E-1273 & 00-G-1274
Joint Proposal - Cost of Capital
$(000)

Rate Year 1:

	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	257,887	48%	5.09%	2.46%	2.46%
Customer Deposits	4,436	1%	6.00%	0.05%	0.05%
Preferred Stock	21,005	4%	4.61%	0.18%	0.28%
Common Equity	251,153	47%	10.30%	4.84%	7.45%
Total Capitalization	534,481	100%		7.53%	10.23%

Rate Year 2:

	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	268,450	49%	5.15%	2.54%	2.54%
Customer Deposits	4,470	1%	6.00%	0.05%	0.05%
Preferred Stock	21,042	4%	4.61%	0.18%	0.28%
Common Equity	251,176	46%	10.30%	4.75%	7.31%
Total Capitalization	545,138	100%		7.52%	10.17%

Rate Year 3:

	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	281,778	50%	5.21%	2.63%	2.63%
Customer Deposits	4,412	1%	6.00%	0.05%	0.05%
Preferred Stock	21,057	4%	4.61%	0.17%	0.26%
Common Equity	251,282	45%	10.30%	4.63%	7.12%
Total Capitalization	558,529	100%		7.48%	10.06%

Central Hudson Gas & Electric Corporation
Case Nos. 00-E-1273 & 00-G-1274
Joint Proposal - Cost of Long-Term Debt
$(000)

Cost of Long Term Debt - RY1:	Rate	Outstanding 6/30/01	Changes	Months Outstanding	Average Outstanding	Interest Expense
PCB - August 1, 2027 Series A	5.45%	33,400	-	12	33,400	1,820
PCB - August 1, 2034 Series B	2.80%	33,700	-	12	33,700	944
PCB - August 1, 2028 Series C	2.65%	41,150	-	12	41,150	1,090
PCB - August 1, 2028 Series D	2.64%	41,000	-	12	41,000	1,082
PCB - December 1, 2028	4.20%	16,700	-	12	16,700	701
MTN - September 10, 2001	5.93%	15,000	(15,000)	2	2,750	163
MTN - July 2, 2004	7.85%	15,000	-	12	15,000	1,178
MTN - January 1, 2007	6.50%	-	65,000	10	54,187	3,522
MTN - January 15, 2009	6.00%	20,000	-	12	20,000	1,200
Totals					257,887	11,701
Amortization of Debt Discount & Expense						1,414
Total Cost of Debt						13,115
Cost Rate						5.09%

Cost of Long Term Debt - RY2:	Rate	Outstanding 6/30/01	Changes	Months Outstanding	Average Outstanding	Interest Expense
PCB - August 1, 2027 Series A	5.45%	33,400	-	12	33,400	1,820
PCB - August 1, 2034 Series B	2.80%	33,700	-	12	33,700	944
PCB - August 1, 2028 Series C	2.65%	41,150	-	12	41,150	1,090
PCB - August 1, 2028 Series D	2.64%	41,000	-	12	41,000	1,082
PCB - December 1, 2028	4.20%	16,700	-	12	16,700	701
MTN - January 1, 2007	6.50%	65,000	-	12	65,000	4,225
MTN - July 2, 2004	7.85%	15,000	-	12	15,000	1,178
MTN - April 1, 2008	6.50%	-	10,000	3	2,500	162
MTN - January 15, 2009	6.00%	20,000	-	12	20,000	1,200
Totals					268,450	12,403
Amortization of Debt Discount & Expense						1,420
Total Cost of Debt						13,823
Cost Rate						5.15%

Cost of Long Term Debt - RY3:	Rate	Outstanding 6/30/01	Changes	Months Outstanding	Average Outstanding	Interest Expense
PCB - August 1, 2027 Series A	5.45%	33,400	-	12	33,400	1,820
PCB - August 1, 2034 Series B	2.80%	33,700	-	12	33,700	944
PCB - August 1, 2028 Series C	2.65%	41,150	-	12	41,150	1,090
PCB - August 1, 2028 Series D	2.64%	41,000	-	12	41,000	1,082
PCB - December 1, 2028	4.20%	16,700	-	12	16,700	701
MTN - January 1, 2007	6.50%	65,000	-	12	65,000	4,225
MTN - July 2, 2004	7.85%	15,000	-	12	15,000	1,178
MTN - April 1, 2008	6.50%	10,000	-	12	10,000	650
MTN - April 1, 2009	6.50%	-	8,742	8	5,828	379
MTN - January 15, 2009	6.00%	20,000	-	12	20,000	1,200
Totals					281,778	13,269
Amortization of Debt Discount & Expense						1,425
Total Cost of Debt						14,694
Cost Rate						5.21%

Central Hudson Gas & Electric Corporation
Case Nos. 00-E-1273 & 00-G-1274
Joint Proposal - Amortization of Debt and Predarred Stock Expenses

	Estimated Redemption Premium	Unamortized Expense 6/30/01	Total Unrecovered Cost of Redemption	Amortization - RYE 6/30/02	6/30/03	6/30/04
Unamortized Debt Expense:						
6-1/4% MORTGAGE BONDS - 2007		53,973	53,973	9,156	9,156	9,156
9 1/4% MORTGAGE BONDS-2021		860,846	860,846	43,404	43,404	43,404
7.97% MTN 6/11/2003 SERIES A		28,587	28,587	15,516	13,071	-
7.97% MTN 6/13/2003 SERIES A		29,978	29,978	14,328	14,328	1,322
7.85% MTN 6/2/2004 SERIES A		47,665	47,665	15,528	15,528	15,528
8.12% MTN 8/29/22 SERIES A		146,034	146,034	6,888	6,888	6,888
8.14% MTN 8/29/22 SERIES A		146,005	146,005	6,900	6,900	6,900
6.46% MTN 8/11/03 SERIES A		41,891	41,891	19,332	19,332	3,227
Tax Exempt NYSERDA 4.20% Due 12/1/28		537,586	537,586	19,608	19,608	19,608
6.00% MTN 1/15/09 Series C		176,915	176,915	23,580	23,580	23,580
5.45% Series A NYSERDA Bonds 8/1/27		646,345	646,345	24,780	24,780	24,780
Var Rate Ser B NYSERDA Bonds 7/1/34		570,240	570,240	17,477	17,477	17,477
Var Rate Series C NYSERDA Bonds 8/1/28		643,020	643,020	31,332	31,332	31,332
Var Rate Series D NYSERDA Bonds 8/1/28		641,714	641,714	29,400	29,400	29,400
$65,000 MTN Issued 9/1/01 Due 1/1/07	208,000	-	208,000	32,500	39,000	39,000
$10,000 MTN Issued 4/1/03 Due 4/1/08	32,000	-	32,000	-	1,600	6,400
$10,000 MTN Issued 10/1/03 Due 4/1/09	32,000	-	32,000	-	-	4,299
Total	272,000	4,570,799	4,842,799	309,729	315,384	282,300
Unamortized Loss on Reacquired Debt:						
REDEMPTION 9 1/4% MTG. BONDS	-	160,082	160,082	57,324	57,324	57,324
REDEMPTION 10 5/8 MTG BONDS 11/1/05	-	381,108	381,108	87,948	87,948	87,948
REDEMPTION 10 3/4 MTG BONDS 9/15/09	-	741,496	741,496	90,324	90,324	90,324
7 1/2% POLLUTION CONTROL NOTES-2014	-	1,850,442	1,850,442	139,656	139,656	139,656
ADJ RTE POLL CTRL NOTES-DUE 11/1/2020	-	592,800	592,800	187,200	187,200	187,200
ADJ RATE POLL CTRL NOTES-DUE 6/1/27	-	393,193	393,193	15,168	15,168	15,168
REDEEMD 11 1/4% POLL CTL BDS-9/1/12	-	298,284	298,284	26,712	26,712	26,712
8.375% MORTGAGE BONDS-2028	-	720,510	720,510	26,280	26,280	26,280
Redeem 9 1/4% Mortgage Bond	2,856,000	-	2,856,000	144,000	144,000	144,000
Redeem 7.97% MTN Due 6/11/03	300,000	-	300,000	150,000	150,000	150,000
Redeem 7.97% MTN Due 6/13/03	300,000	-	300,000	150,000	150,000	150,000
Redeem 8.12% MTN Due 8/29/22	500,000	-	500,000	23,810	23,810	23,810
Redeem 8.14% MTN Due 8/29/22	500,000	-	500,000	23,810	23,810	23,810
Redeem 6.46% MTN Due 8/11/03	(100,000)	-	(100,000)	(46,154)	(46,154)	(7,692)
Total	4,356,000	5,137,915	9,493,915	1,076,077	1,076,077	1,114,539
Unamortized Discount on L/T Debt:						
First Mtg Bonds - 9 1/4% due 5/1/21	-	512,640	512,640	25,632	25,632	25,632
5.45% Ser A NYSERDA Bonds due 8/1/27	-	78,045	78,045	2,976	2,976	2,976
Total	-	590,685	590,685	28,608	28,608	28,608
Total Debt Issuance and Redemption Expenses	4,628,000	10,299,399	14,927,399	1,414,414	1,420,069	1,425,447
Preferred Stock:						
6.20% Cumulative Preferred	675,000	412,554	1,087,554	150,007	150,007	150,007
6.80% Cumulative Preferred	1,600,000	454,230	2,054,230	78,256	78,256	78,256
Total Preferred Stock Issuance and Redemption Expenses	2,275,000	866,784	3,141,784	228,264	228,264	228,264

Central Hudson Gas & Electric Corporation
Case Nos. 00-E-1273 & 00-G-1274
Joint Proposal - Benefit Pool

	Settlement Period RY1	RY2	($000, Net of Tax) RY3
Net Benefit Fund:			
Net Fossil Proceeds	76,708		
Deferred Excess Earnings	9,377		
Net Settlement Benefits	41,621		
NMP2 Proceeds	36,500		
Total Benefit Pool	164,206		
Less: Rate Base Credit	(42,500)		
Net Benefit Fund Available	121,706	100,692	88,204
Identified Uses (net of tax):			
Reliability Program - $20 million, 3 Yr Program	(4,333)	(4,333)	(4,333)
Offset of Gas Site Remediation Costs - $15 million	(9,750)	-	-
Refunds	(15,000)	(15,000)	(15,000)
Remaining Balance	92,623	81,359	68,871
Add Cumulative Carrying Charges - Net of Tax	8,069	6,845	5,875
Net Benefit Fund Balance	100,692	88,204	74,745

Identified uses include electric backout credits, and other new stranded costs; potential uses include economic development fund, price spike mitigation, small customer aggregation, othercompetitive initiatives and additional refunds.

ELECTRIC DEFERRED ITEMS INCLUDED IN BENEFIT FUND

The June 30, 2001 balances of the following deferred debit and deferred credit accounts, net of tax, are included in the Benefit Fund. No subsequent deferrals to these accounts will be included in the Benefit Fund except for those to make accounting adjustments to the June 30, 2001 balance.

Deferred Debits

Adjustable Rate PCB Notes
Deferred DSM Costs
Tax Rate Change - 1993
Storm Costs - April 1997
Restructuring Costs - Formation of Holding Company
Lost Revenues - Job Retention Provision (COPS)
Pension Carrying Charge
Pension Fund Withdrawal

Deferred Credits

Research & Development Costs
Management Audit
Adjustable Rate Preferred Dividends Over/Under Collection
NMP-2 Vendor Litigation - Ratepayer
NMP-2 Vendor Litigation Carrying Charge
NMP-2 Deferred Settlement Agreement Costs
Carrying Charge on NMP-2 Settlement Agreement Costs
Carrying Charge on DSM Rate Base
DSM Lost Revenues
Customer Benefits Account (COPS)
Royalty Charge (COPS)
R&D 1994 Audit Adjustment
Deferred Letter of Credit/Remarketing Fees
Deferred Pension Cost Over/Under Collection
Deferred OPEB Expense
OPEB Carrying Charge
Deferred Excess Earnings

GAS DEFERRED ITEMS FOR BALANCE SHEET OFFSET

The following gas department deferred debit and deferred credit items will be subject to balance sheet offset accounting to the extent that a net of tax offset of zero is achieved using actual deferred amounts at June 30, 2001.

Deferred Debits

Adjustable Rate PCB Notes
Amortization of Unbilled Revenue (Case 90-G-0673)
Carrying Charge of Newburgh Site Investigation
ULIEEP Over/Under Collection (Including Carrying Charges)
Pension Carrying Charge

Deferred Credits

Unamortized Interruptible Gas Depreciation
Research & Development Costs
Management Audit
Gas Special Franchise Tax
R&D 1994 Audit Adjustment
Deferred Letter of Credit/Remarketing Fees
Deferred Pension Cost Over/Under Collection
Deferred OPEB Expense
OPEB Carrying Charge

Attachment F

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Electric Interclass Revenue Allocation
ALLOCATION OF PROPOSED REVENUE INCREASE (DECREASE) EXCLUDING REVENUE TAX
Using 15% Tolerance Band on Rate of Return
Case 00-E-1273 Compliance Filing
($000)

LINE NO.		Total	SC No. 1 Residential	S.C.Nos.2&12 Small General	SC No. 3 Primary	S.C. No. 5 Area Lighting	S.C.No. 6 Residential Time of Use	S.C. No. 8 Street Lighting	S.C. No. 13 Substation	S.C. No. 13 Transmission
1.	Net Income (1)	$22,717	$10,984	$7,323	$1,708	$198	$1,232	($34)	$345	$961
2.	% Rate of Return	5.34	4.58	5.89	11.67	4.51	10.08	(0.49)	10.73	5.02
3.	5.34 +/- 15%	5.09	4.58	5.89	6.14	4.54	6.14	4.54	6.14	5.02
4.	Adjusted Net Income	$21,652	$10,985	$7,347	$898	$199	$750	$314	$197	$961
5.	Adjusted to Initial Net Income	$22,717	$11,525	$7,708	$942	$209	$787	$330	$207	$1,009
6.	Difference		$541	$385	($766)	$11	($445)	$364	($138)	$48
7.	Revenue (Line 7/.66)		$819	$583	($1,161)	$17	($674)	$552	($209)	$73
8.	Revenue Increase (Decrease) - NET OF FUEL Excludes Revenue Tax	($2,297)	($1,300)	($692)	($95)	($12)	($87)	($37)	($19)	($55)
9.	Total Revenue Decrease	($2,297)	($481)	($109)	($1,256)	$5	($761)	$515	($228)	$18
10.	Present Rate Revenues (Excluding Revenue Tax)	$149,179	$84,441	$44,966	$6,160	$758	$5,623	$2,406	$1,225	$3,600
11.	Percent Increase(Decrease) Unconstrained	(1.54)	(0.57)	(0.24)	(20.39)	0.66	(13.53)	21.40	(18.61)	0.50
12.	Percent Increase(Decrease) Constrained	(1.54)	(1.52)	(1.52)	(1.93)	(0.79)	(1.94)	(0.79)	(1.96)	(1.50)
13.	Total Revenue Increase Constrained	($2,297)	($1,283)	($683)	($119)	($6)	($109)	($19)	($24)	($54)
14.	DSM Adjustment	($42)	($6)	($29)	($7)					
15.	Final Total Revenue Increase	($2,339)	($1,289)	($712)	($126)	($6)	($109)	($19)	($24)	($54)

(1) PRO FORMA COST OF SERVICE STUDY FOR THE RATE YEAR ENDING JUNE 30, 2002, WITH HYDRO CLASSIFIED 100% ENERGY AND TURBINES CLASSIFIED 100% DEMAND.

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

LOW INCOME PROGRAM

POWERFUL OPPORTUNITIES

Plan Objectives:

An effective low income program should provide a practical opportunity for customers who, due to an illness or disability or loss of job, have fallen behind in their utility payments and are struggling to pay their arrears. An effective low income program should empower customers by developing a comprehensive plan to improve their overall financial situation to become self-reliant. An effective low income program should teach customers about the cost of electricity --- and how energy conservation and energy efficiency does make a difference for affordability. An effective low income program should bring peace of mind to the customers --- that their utility bills can be worked out at a level they can handle. An effective low income program should build a stronger relationship between customers, Central Hudson and the community. And lastly, an effective low income program should enable Central Hudson to focus its collection efforts on customers who can but don't pay their utility bills.

Plan Design & Administration

Powerful Opportunities is a managed approach, designed to accomplish three primary goals: (1) Provide customers with an affordable payment plan for past and future utility bills; (2) Provide customers with the tools to obtain long-term, overall financial stability and self-sufficiency; and (3) Provide customers with the energy services and education required to enable them to reduce their energy usage and potentially their payment amount. In addition, our low income program is designed to include an incentive to encourage customers to meet their Powerful Opportunities obligations.

To attain the first goal, "provide customers with an affordable payment plan for past and future utility bills" the following actions are recommended:

- Place the customer on budget billing for future bills.

- Place the customer's arrears in suspend; no LPCs will be charged to this amount while the customer is a participant of the Program.

- Give an incentive: a $ for $ match on payments made above the current budget amount. The maximum match paid by Central Hudson will be $20 per month per customer.

- If the customer is a heating customer, give one additional GNF benefit at the end of the Program (last $125 of arrears).

- Offer a lower basic service charge of $5.00 per month for both gas and electric customer participants.

It is recommended Central Hudson collaborate with community resources to attain the second goal of "providing customers with the tools to obtain overall financial stability and self-sufficiency"; and the third goal, "providing customers with the energy services and education required to enable them to reduce their energy usage". A partnership with a community-based organization, such as Dutchess County Community Action Agency (DCCAA), would contribute to the overall integrity of the Program. DCCAA has established trust and credibility in helping families with their self-sufficiency goals. In addition, DCCAA is a well-known and respected entity within the network of community assistance agencies. DCCAA can effectively coordinate community resources, educate consumers, establish individual customer assessments and referrals, and provide program administration and outreach to our mutual clients.

A partnership with DCCAA would provide:

- A multi-county network, which spans our entire service territory, with the ability to disseminate, support and monitor implementation of the program.

- Referrals to local, state and federal assistance programs, and coordinate with the NYS Weatherization Program.

- Expertise in assisting low income customers with the ability to gain greater competency in their household management through energy efficient products and consumer education.

- Family development training to promote greater self-sufficiency and self-reliance to the Program participants, and internal sensitivity training to our customer-contact employees.

Customer's Eligibility and Obligations

Eligibility for participation in this Program is outlined below:

- Must be a CHG&E customer whose bills are not directly paid to the Company by a local department of social services office, and the account must be their primary residence.

- Customer must have an account that is 60 days or more in arrears.

- Customer who has a household income equal to or less than 200% of poverty level, as determined for that program year.

- Customers will be considered categorically eligible if they are enrolled in the New York State Home Energy Assistance Program or any other federal or state assistance program with similar or stricter income eligibility requirements than 200% of the poverty level.

- Customer must complete a Program application form and financial statement (DSS 3596), submit required documentation and be approved for participation.

- Customers in an energy crisis (locked for non-payment) at the time of application may be eligible to participate, however, the amount they are required to pay for turn-on will not be matched by Central Hudson.

- The maximum Program enrollment targets are:

Year	**Target**
1	250
2	500
3	1000

In order for the customer to become a participant of Powerful Opportunities, they must agree (in writing) to the following terms and responsibilities:

- Only if consistent with a DCCAA assessment of an individual participant's ability to pay, participants shall pay at least an additional $5 per month (for $60 per year) on their arrears.

- Participate in energy conservation/efficiency training and budget counseling sessions as prescribed by their Family Development Specialist.

- Agree to the recommended follow-up schedule, and meet with their designated Family Development Specialist according to that schedule.

- Apply for community and government assistance as suggested by the Family Development Specialist.

- Customers who become delinquent on a current bill will be dropped from the Program after 60 days delinquency and will not be eligible for re-entry for the same arrears. A minimum $10/month DPA will be offered and then regular collection cycle will begin.

- Re-entry to the program, however, will be permitted if a participant who is dropped from the program for non-payment of current bills subsequently receives emergency assistance through a Department of Social Services program and the amount of the delinquency after the customer's prior enrollment in the program is paid in full.

<u>Other Assistance</u>

- HEAP payments (regular and emergency) will be applied to the customer's current charges and will not be matched by Central Hudson. If a HEAP payment is more than the current amount due, the excess will be applied to the arrears, with no Company match.

- Other community assistance (i.e., Red Cross, Church Charities, etc.) will be matched by Central Hudson if the funding is paid to the customer for payment of bills, and the customer passes the payment to Central Hudson to be applied to their arrears. Community assistance payments made directly to Central Hudson on behalf of the customer will be applied to the current bill first, then to the arrears, with no match.

<u>DCCAA Role:</u>

DCCAA will work closely with Consumer Outreach to develop and maintain an effective low income program. Upon approval of this draft proposal, DCCAA will prepare and submit for our review and approval a Program outline and fee for their part in Powerful Opportunities. The Program outline will include:

- Implementation Plan (including targeted outreach, toll-free number, etc.)

- Procedures (including forms, letters, follow-up, collaboration with neighboring Community Action Agencies located in our service territory, etc.)

- Community and Government Assistance Referrals

- Weatherization Plan (including appliance repair and replacement)

- Case Management:

    Family Development Training Outline (for long-term self-sufficiency)

    Energy Efficiency/Conservation

    Budget Counseling

- Sensitivity Training Outline (for CHG&E employees)

- Evaluation Process

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
RATE BASE - SUMMARY
Final Settlement Position
($000)

	ELECTRIC			GAS		
	RY 1	RY 2	RY 3	RY 1	RY 2	RY 3
Book Cost of Utility Plant	$671,892	$703,930	$743,956	$190,346	$196,552	$204,205
Less: Accumulated Provision for Depreciation and Amortization	(244,559)	(256,038)	(270,252)	(69,798)	(72,956)	(78,056)
Net Plant	427,333	447,892	473,704	120,548	123,596	126,149
Reliability Capital Program	(5,354)	(16,196)	(26,650)			
Net Settlement Benefits	(42,500)	(42,500)	(42,500)			
Noninterest-Bearing Construction Work in Progress	30,160	28,731	29,088	8,434	8,501	8,556
Customer Advances for Undergrounding	(603)	(615)	(627)			
Deferred Charges	17,559	15,948	14,228	4,290	4,010	3,919
Accumulated Deferred Taxes	(66,670)	(67,869)	(69,353)	(17,760)	(18,908)	(20,206)
Working Capital	23,507	24,135	24,909	5,181	5,324	5,484
Unadjusted Rate Base	383,432	389,526	402,799	120,693	122,523	123,902
Capitalization Adjustment to Rate Base	(3,217)	(3,217)	(3,217)	(998)	(998)	(998)
Total Rate Base	$380,215	$386,309	$399,582	$119,695	$121,525	$122,904

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
DEFERRED CHARGES, DEFERRED TAXES & WORKING CAPITAL
Final Settlement Position
($000)

	ELECTRIC			GAS		
	RY 1	RY 2	RY 3	RY 1	RY 2	RY 3
Deferred Charges						
Software Purchases	$2,647	$2,221	$1,564	$1,197	$1,253	$1,349
MTA Tax	2,426	2,426	2,426	769	769	769
Unamortized Debt Expense	8,211	8,459	7,710	1,337	1,377	1,255
Incremental Deferred Debt Expense	3,783	2,375	2,085	780	535	474
Unamortized Discount Long-Term Debt	492	467	443	80	76	72
Carrying Charge on Newburgh Site Investigation	0	0	0	127	0	0
Total Deferred Charges	$17,559	$15,948	$14,228	$4,290	$4,010	$3,919
Deferred Taxes						
MTA Tax	($849)	($849)	($849)	($269)	($269)	($269)
Normalized Depreciation	(59,588)	(62,728)	(66,162)	(18,639)	(19,993)	(21,439)
Investment Tax Credit	(3,102)	(2,800)	(2,498)	(700)	(637)	(576)
Cost of Removal	(1,510)	(1,536)	(1,572)	(174)	(87)	(32)
Construction Overheads	(1,438)	(1,329)	(1,220)			
Contributions in Aid of Construction	1,662	1,651	1,638	341	336	330
Deferred Avoided Cost Interest Capitalized	1,303	1,288	1,276	294	299	302
Unbilled Revenue	4,231	4,231	4,231	1,811	1,811	1,811
Repair Allowance	(6,044)	(6,149)	(6,244)			
ACRS Method Change	(97)	(87)	(77)	(24)	(22)	(20)
Mortgage Taxes	(134)	(121)	(108)	(21)	(19)	(17)
Bonds Redeemed	(716)	(806)	(726)	(117)	(133)	(119)
Carrying Charge on Newburgh Site Investigation	0	0	0	(45)	0	0
Redemption Premiums	(1,230)	(1,097)	(1,005)	(217)	(194)	(177)
Reliability Expenditures	842	2,463	3,963			
Total Deferred Taxes	($66,670)	($67,869)	($69,353)	($17,760)	($18,908)	($20,206)
Working Capital						
Other Material and Supply Working Capital	$4,248	$4,336	$4,422	$1,408	$1,437	$1,466
Prepaid Property Taxes - Other	8,571	8,916	9,272	1,623	1,686	1,752
Prepaid Insurance - Other	398	406	415	112	114	116
Other Prepayments	592	605	617	105	107	109
Operation and Maintenance Cash Working Capital	9,698	9,872	10,183	1,933	1,980	2,041
Total Working Capital	$23,507	$24,135	$24,909	$5,181	$5,324	$5,484

Attachment I

STATE OF NEW YORK PUBLIC SERVICE COMMISSION

Case 00-E-1273 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service

Case 00-G-1274 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service

SUPPLEMENTAL ENVIRONMENTAL ASSESSMENT FORM

Prepared By:
CENTRAL HUDSON GAS & ELECTRIC CORPORATION,
STAFF of the DEPARTMENT OF PUBLIC SERVICE,
and the other SIGNATORY PARTIES to the JOINT PROPOSAL

Dated: Albany, New York
August 27, 2001

I. Introduction

This document provides the substantive information solicited by Appendix A of 6 NYCRR 617.20, part of the regulations promulgated by the New York State Department of Environmental Conservation pursuant to the State Environmental Quality Review Act ("SEQRA"), Article 8 of the New York Environmental Conservation Law. An environmental assessment is an evaluation of the known or potential environmental consequences of a proposed action. Such an assessment also determines whether additional relevant information about such impacts is needed. Environmental assessments help involved and interested agencies identify their concerns about the action and provide guidance to the lead agency in making its determination of significance.

An Environmental Assessment Form ("EAF") provides an organized approach to identifying the information needed by the lead agency to make its determination of significance. A properly completed EAF describes a proposed action, its location, its purpose and its potential impacts on the environment. The EAF is the first step in the environmental impact review process and leads to either a positive declaration (requiring further analysis of the potentially significant adverse environmental impacts) or a negative declaration (requiring no further analysis).

II. Environmental Assessment Form Information (Part I of EAF)

A. Applicant / Sponsor:

Central Hudson Gas & Electric Corporation
("Central Hudson" or "Company")
284 South Avenue
Poughkeepsie, New York 12601

B. Name of Action:

Public Service Commission ("Commission") approval of the terms of the Joint Proposal for the resolution of Cases 00-E-1273 and 00-G-1274

C. Location of Action:

Central Hudson electric and gas service territories

D. Description of Action:

The Company and other Signatory Parties to the Joint Proposal are petitioning the Commission under the Public Service Law of the State of New York for approval of the terms of their Joint Proposal for the resolution of Cases 00-E-1273 and 00-G-1274. These cases relate to the rates, charges, rules and regulations of the Company for electric and gas service, respectively, and to the Commission's restructuring and competitive market development policies in Case 94-E-0952[1] (electricity) and Cases 93-G-0932 and 97-G-1380[2] (gas). The Commission's consideration of the rate-related aspects of the Joint Proposal is a "Type II exempt rate action"[3] that does not require SEQRA analysis. Accordingly, the Commission's consideration of the restructuring and competitive market development- related aspects of the Joint Proposal is the potential action that has been evaluated in this Assessment.

The Joint Proposal does not require any construction activities which would directly affect the environment. As a result, consideration of the terms of the Joint Proposal is an "unlisted" action as defined in 6 NYCRR 617. While 6 NYCRR 617.6 generally calls for the use of the short EAF set forth at 6 NYCRR 617.20, Appendix C, because this action does not involve physical construction as contemplated by the short EAF, a narrative EAF has been utilized.[4]

1. Case 00-E-1273

Case 00-E-1273 was occasioned by the implementation of the Commission's policy of supporting increased competition in electricity markets, which it adopted in Opinion No. 96-12 in Case 94-E-0952. Case 00-E-1273 was preceded and required by Case 96-E-0909[5] in which, by an Order issued February 19, 1998 and by Opinion No. 98-14 issued June 30, 1998, the Commission adopted an electric rate and restructuring plan for the Company pursuant to the Commission's policy of supporting increased electricity market competition as adopted in Case 94-E-0952.

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[1] In the Matter of Competitive Opportunities Regarding Electric Service

[2] Respectively, Proceeding on Motion of the Commission to Address Issues Associated with the Restructuring of the Emerging Competitive Natural Gas Market and In the Matter of Issues Associated with the Future of the Natural Gas Industry and the Role of the Local Distribution Companies

[3] Opinion No. 98-14 at 41.

[4] A narrative EAF has also been used in similar cases. See, Case 99-G-0336, Niagara Mohawk Power Corporation - Gas Multi-Year Rate and Restructuring Proposal, Opinion No. 00-9 issued July 27, 2000; Case 99 -G-1469, Brooklyn Union Gas Company - Multi-Year Restructuring Agreement, Order Establishing Interim Rate Plan issued December 26, 2000; Case 98-G-1589, Rochester Gas and Electric Corporation - Plans for Gas Rates and Restructuring, Order Adopting Terms of Joint Proposal issued February 28, 2001.

[5] In the Matter of Central Hudson Gas & Electric Corporation's Plans for Electric Rates and Restructuring Pursuant to Opinion No. 96-12

Case 00-E-1273 and the Joint Proposal address ratemaking associated with the restructuring of the Company from a vertically integrated utility to a delivery service company, as envisioned by the Commission in Case 94-E-0952 and implemented, to the extent of the Company's divestiture of its fossil fueled generating units and measures to promote retail access, in Case 96-E-0909. This is in the form of removing from rates those charges associated with the Company's former interests in fossil fueled generating units and establishing the methods and procedures for customer acquisition of and payment for electric supply provided by marketers. Case 00-E-1273 and the Joint Proposal additionally address the furtherance of the Commission's policy of supporting increased competition in electricity markets by unbundling rate elements and providing back-out credits to customers who take supply service from ESCOs or marketers, funding increased customer understanding of competitive electricity supply options and efforts to obtain input from ESCOs and marketers regarding the furtherance of the development of a competitive retail electricity supply market in the Company's service territory.

On May 3, 1996, the Commission issued a Final Generic Environmental Impact Statement ("FGEIS") in Case 94-E-0952 with respect to the proposed action of adopting a policy supporting increased competition in electricity markets. In adopting such policy in Opinion No. 96-12, the Commission found that the FGEIS "did not identify reasonably likely significant adverse impacts" of the action except with respect to air quality, energy efficiency and research and development in response to which the Commission adopted mitigation measures including monitoring the environmental impacts of the action.[6] By Opinion No. 98-14 in Case 96-E-0909, based on an EAF filed by the Company on June 17, 1997,[7] the Commission found the potential environmental impacts of the rate and restructuring plan for the Company therein adopted to be "within the range of thresholds and conditions set forth in the FGEIS" thereby requiring no further SEQRA action, but, "as a matter of discretion," monitoring of the Company's restructuring and environmental impacts was implemented.[8]

2. Case 00-G-1274

On November 3, 1998, the Commission issued its Policy Statement Concerning the Future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment in Cases 93-G-0932 and 97-G-1380 ("Gas Policy Statement"). In the Gas Policy Statement, the Commission articulated its vision of the future of the natural gas industry, which is to "facilitate development of a competitive market; eliminate barriers to competition; provide guidance to LDCs and marketers, especially with regard to expiring capacity contracts; and

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[6] Opinion 96-12 at 76-81.

[7] Opinion 98-14, Appendix D.

[8] Opinion 98-14 at 41-42.

address customer inertia."[9] The Commission conducted an analysis under the State Environmental Quality Review Act, determined that there would be no significant environmental impact from adoption of the Gas Policy Statement and issued a Notice of Determination of Non-Significance.[10]

Case 00-G-1274 and the Joint Proposal address the furtherance of the Commission's policy of supporting increased competition in natural gas retail supply markets by unbundling rate elements and providing back-out credits to customers who take supply service from marketers, funding increased customer understanding of competitive gas supply options and funding efforts to obtain input from marketers regarding the furtherance of the development of a competitive retail gas supply market in the Company's service territory. In that regard the Joint Proposal is similar in principle to gas restructuring settlements pursuant to the Gas Policy Statement of other companies that have been approved by the Commission.[11]

III. Evaluation of Environmental Impacts (Part 2 of EAF)

Specific environmental impacts that might result from the Joint Proposal are highly unlikely. The Joint Proposal will not cause direct environmental effects because the Joint Proposal does not involve physical activities that might have impacts on the environment. Instead, the Joint Proposal might contribute to the creation of circumstances that subsequently induce activities which might cause environmental effects.

In preparing this environmental assessment, the Signatory Parties have set out an evaluation of a range of potentially conceivable secondary consequences of the Joint Proposal in order to assist the Commission in its evaluation of this matter. The Signatory Parties have relied on qualitative judgments as to the potential changes resulting from the proposed actions and the magnitude and importance of the corresponding potential environmental impacts.

A. Impact on Air

The Signatory Parties were unable to identify any direct effects on air emissions resulting from the Joint Proposal. The Commission, however, clearly contemplated the possibility that

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[9] Gas Policy Statement at 3-4.

[10] Gas Policy Statement at 9.

[11] Case 99-G-0336, Niagara Mohawk Power Corporation - Gas Multi-Year Rate and Restructuring Proposal, Opinion No. 00-9 issued July 27, 2000; Case 99 -G-1469, Brooklyn Union Gas Company - Multi-Year Restructuring Agreement, Order Establishing Interim Rate Plan issued December 26, 2000; Case 98-G-1589, Rochester Gas and Electric Corporation - Plans for Gas Rates and Restructuring, Order Adopting Terms of Joint Proposal issued February 28, 2001.

increased competition could promote increased energy usage and, thereby, have adverse air quality impacts. The Signatory Parties believe that the provisions of the Joint Proposal intended to further the Commission's policy of supporting the development of competitive markets for retail energy will neither directly nor indirectly affect the supply market prices in a manner that would encourage increased energy usage not within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952 or not within that contemplated by the Commission in its Determination of Non-Significance reached in connection with the Gas Policy Statement. The Signatory Parties also believe that the associated unbundling of the Company's rates as provided for in the Joint Proposal will not result in delivery service rates that would encourage energy usage not within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952 or not within that contemplated by the Commission in its Determination of Non-Significance reached in connection with the Gas Policy Statement. As a result, the Signatory Parties believe that any impacts on air quality resulting from the Joint Proposal are within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952 and within those contemplated by the Commission in its Determination of Non-Significance reached in connection with the Gas Policy Statement.

B. Impact on Water

The Signatory Parties were unable to identify any direct effects on water quality resulting from the Joint Proposal. As discussed in the Impact on Air section above, the Joint Proposal could result in an increased demand for electricity or natural gas. This increased demand in turn could contribute to the need to construct new production, transmission or distribution facilities to serve the increased demand. With such new construction there could be the need to conduct work in environmentally sensitive areas such as wetlands or streams. While this work could potentially impact the environment, it would be subject to all applicable federal and state environmental regulatory requirements including SEQRA review prior to construction. As a result and as the Commission found with respect to gas restructuring, "these speculative impacts need not be considered at this time."[12] With regard to electric restructuring, this similar potential effect would be within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952.

C. Impact on Land

The Signatory Parties were unable to identify any direct effects on land use resulting from the Joint Proposal. However, as indicated above, new construction or expansion of production, transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and SEQRA review at the time as noted by the Commission in its Determination of Non-Significance reached in connection with the Gas Policy Statement and within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952.

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[12] Gas Policy Statement, Notice of Determination of Non-Significance at 1-2.

D. **Impact on Plants and Animals**

The Signatory Parties were unable to identify any direct effects on plants and animals resulting from the Joint Proposal. However, as indicated above, new construction or expansion of production, transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and SEQRA review at the time as noted by the Commission in its Determination of Non-Significance reached in connection with the Gas Policy Statement and within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952.

E. **Impact on Agricultural Land Resources**

The Signatory Parties were unable to identify any direct effects on agricultural land resources resulting from the Joint Proposal. However, as indicated above, new construction or expansion of production, transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and SEQRA review at the time as noted by the Commission in its Determination of Non-Significance reached in connection with the Gas Policy Statement and within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952.

F. **Impact on Aesthetic Resources**

The Signatory Parties were unable to identify any direct effects on aesthetic resources resulting from the Joint Proposal. However, as indicated above, new construction or expansion of production, transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and SEQRA review at the time as noted by the Commission in its Determination of Non-Significance reached in connection with the Gas Policy Statement and within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952.

G. **Impact on Historic and Archeological Resources**

The Signatory Parties were unable to identify any direct effects on historic and archeological resources resulting from the Joint Proposal. However, as indicated above, new construction or expansion of production, transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and SEQRA review at the time as noted by the Commission in its Determination of Non-Significance reached in connection with the Gas Policy Statement and within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952.

H. Impact on Open Space and Recreation

The Signatory Parties were unable to identify any direct effects on open space and recreation resulting from the Joint Proposal. However, as indicated above, new construction or expansion of production, transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and SEQRA review at the time as noted by the Commission in its Determination of Non-Significance reached in connection with the Gas Policy Statement and within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952.

I. Impact on Transportation

The Signatory Parties were unable to identify any direct effects on transportation resulting from the Joint Proposal. However, as indicated above, new construction or expansion of production, transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and SEQRA review at the time as noted by the Commission in its Determination of Non-Significance reached in connection with the Gas Policy Statement and within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952.

J. Impact on Energy

The Commission clearly contemplated the possibility that increased competition could promote increased energy usage. The Signatory Parties believe that the provisions of the Joint Proposal intended to further the Commission's policy of supporting the development of competitive markets for retail energy will neither directly nor indirectly affect the supply market prices in a manner that would encourage increased energy usage not within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952 or not within that contemplated by the Commission in its Determination of Non-Significance reached in connection with the Gas Policy Statement. The Signatory Parties also believe that the associated unbundling of the Company's rates as provided for in the Joint Proposal will not result in delivery service rates that would encourage energy usage not within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952 or not within that contemplated by the Commission in its Determination of Non-Significance reached in connection with the Gas Policy Statement.

K. Noise and Odor Impact

The Signatory Parties were unable to identify any direct noise and odor effects resulting from the Joint Proposal. However, as indicated above, new construction or expansion of production, transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and SEQRA review at the time as noted by the Commission in its Determination of Non-Significance reached in connection with the Gas Policy Statement and within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952.

L. Impact on Public Health

The Signatory Parties were unable to identify any direct effects on public health resulting from the Joint Proposal because under the Joint Proposal the Company would continue to have the responsibility to maintain its facilities for the transmission and distribution of natural gas and electricity in conformance with all applicable regulatory requirements.

M. Impact on Growth and Character of Community or Neighborhood

The Joint Proposal's effect of reducing the cost of electricity and gas to consumers will have a positive effect on the economic well-being of communities in the Company's service territory. Price reductions along with the funding of economic development initiatives as provided for in the Joint Proposal will encourage local business growth and the retention and growth of employment. They will also encourage the relocation of businesses to the Company's service territory from outside New York State. In addition, the Joint Proposal includes incentive regulation provisions which encourage the education of consumers regarding energy competition to facilitate the development of the competitive retail energy supply market.

It is possible that lower gas prices could lead to a potential for gas distribution franchise expansions, as the Commission has recognized previously. The potential for such expansions under the Joint Proposal is limited, however, in light of the 20% penetration limitations on the availability of the gas back out credits. Therefore, the potential impacts are considered to be indistinguishable from those that would occur in the absence of the Joint Proposal.

IV. Significance of Environmental Impacts

After a review of the changes called for under the Joint Proposal, the Signatory Parties conclude that no further environmental review is necessary with respect to the Joint Proposal. No significant environmental impact which would result from the subject Joint Proposal was identified. Any potential effects are within the range of thresholds and conditions set forth in the FGEIS in Case 94-E-0952 with respect to electric restructuring and within the Commission's Determination of Non-Significance in Cases 93-G-0932 and 97-G-1380 with respect to gas restructuring.