STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter

- of -

Case 02-E-0779 -- Ordinary Tariff Filing of New York State Electric & Gas Corporation to Establish a New Standby Service in Accordance with Commission Order Issued October 26, 2001 in Case 99-E-1470

EVIDENTIARY HEARING

Nineteenth Floor Board Room
Public Service Commission
Three Empire State Plaza
Albany, New York

May 19, 2003
10:15 a.m.

PRESIDING:

RAFAEL A. EPSTEIN

Administrative Law Judge

APPEARANCES:

For New York State Electric & Gas Corporation:

HUBER LAWRENCE & ABELL
605 Third Avenue
New York, New York 10158
(NICHOLAS A. GIANNASCA, ESQ. and
KATHY DANDY, ESQ., of Counsel)

For the Department of Public Service Staff:

LEONARD VAN RYN
Staff Counsel
Public Service Commission
Three Empire State Plaza
Albany, New York

For MULTIPLE INTERVENORS:

COUCH WHITE LLP
540 Broadway
Albany, New York
(MICHAEL B. MAGER, ESQ., of Counsel)

For Independent Power Producers of New York:

READ & LANIADO, LLP
25 Eagle Street
Albany, New York 12207-1901
(DAVID B. JOHNSON, ESQ., of Counsel)

For the "E" Cubed Company and Joint Supporters:

RUBEN S. BROWN, CHRISTOPHER YOUNG and
L. KEITH O'NEAL
215 East 79th Street
New York, New York 10023

For National Fuel Gas Distribution Corporation:

ALICE A. CURTISS
Senior Regulatory Attorney
10 Lafayette Square, Suite 1700
Buffalo, New York 14203

APPEARANCES: (Continued)

For Joint Supporters:

WILLIAM CRISTOFARO
3445 Winters Place, Suite 102
Rochester, New York

For Lake Shore Hospital (TLC Health Network)

RONALD KRAWIEC
4682 Pineview
Hamburg, New York 14075

For JOINT SUPPORTERS:

GARRY GEARTZ
7349 Graydon Drive
North Tonawanda, New York 14120

P R O C E E D I N G S

JUDGE EPSTEIN: Okay. Good morning. I call Case 02-E-0779, NYSEG Standby Electric Rates.

May we have appearances for the record? Can you hear me, first of all?

VOICE: Judge, we can hear you.

MR. GIANNASCA: Okay. Nick Giannasca for New York State Electric & Gas Corporation.

Judge, we thought it may be advisable, perhaps a good idea, to spend a few minutes off the record before we go on the record, to discuss a few procedural points much like you did in Con Ed. I think it will take no more than five minutes.

(Discussion off the record.)

JUDGE EPSTEIN: Okay. We're back on the record. We had a discussion about the sequencing of witnesses and the numbering of exhibits.

May we have appearances for the record, please?

MS. DANDY: For New York State Electric & Gas Corporation, Huber Lawrence &

Abell, by Kathy Constan...Kathy Dandy. Just got married. And Nick Giannasca.

JUDGE EPSTEIN: Who else?

MR. BROWN: The "E" Cubed Company by Ruben Brown, Christopher Young, Keith O'Neal, Mark Lively, for the Joint Supporters.

Joining us from the Joint Supporters are Ron Krawiec, K-r-a-w-i-e-c, Chief Operating Officer of Lake Share Hospital - TLC Health Care, and Garry Geartz, Master of -- Manager of Customer Relations for Siemens Building Technologies. We're joined at the table by Wyoming Community College -- or Community Hospital, who will make their own appearance.

JUDGE EPSTEIN: Thank you. Wyoming?

MR. KUCZMARSKI: First of all, Wyoming Community Hospital, by (inaudible) Kuczmarski.

JUDGE EPSTEIN: You will have to repeat that for the reporter, I think, that second name.

MR. KUCZMARSKI: It's K-u-c-z-m-a-r-s-k-i.

MR. VAN RYN: Your Honor, for the

Department of Public Service Staff, Leonard VanRyn, Staff Counsel.

MR. MAGER: For Multiple Intervenors, the law firm of Couch White by Michael B. Mager, of Counsel.

MR. JOHNSON: The law firm of Read & Laniado, LLP, by David Johnson, for the Independent Power Producers of New York.

MS. CURTISS: For National Fuel Gas Corporation, Alice Curtiss.

MR. ECK: Also for National Fuel Gas, Robert Eck, E-c-k.

JUDGE EPSTEIN: Any other appearances?

MR. BROWN: Your Honor, I overlooked William Cristofaro of Energy Concepts Engineering, for the Joint Supporters also.

JUDGE EPSTEIN: Okay. And are there any other preliminary matters?

(There was no response.)

JUDGE EPSTEIN: Okay. Mr. Giannasca or Ms. Dandy, do you want to call your witnesses?

MS. DANDY: Your Honor, before the NYSEG panel takes the stand, should we have

the exhibits marked for identification, the Joint Proposal, the qualifications and our February 7th filing?

JUDGE EPSTEIN: Okay. That's all right.

MS. DANDY: I'm going to hand the reporter the documents to be marked for identification as Exhibit 1.

(Exhibit No. 1 was marked for identification, this date.)

JUDGE EPSTEIN: And I should state for the record that this was already stated off the record that Exhibit 1 is NYSEG's February 2003 tariff filing with two versions of a related appendix. That's Appendix A?

MS. DANDY: Correct.

JUDGE EPSTEIN: No. 1 for identification.

MS. DANDY: I now am going to hand the court reporter the Joint Proposal which is marked for identification as Exhibit 2.

(Exhibit No. 2 was marked for identification, this date.)

MS. DANDY: And lastly I'm going to -- Nick Giannasca is going to hand the court

reporter the qualifications for the NYSEG panel to be marked for identification as Exhibit 3.

(Exhibit No. 3 was marked for identification, this date.)

MS. DANDY: Your Honor, at this point I believe we're ready to have the NYSEG panel take the stand and be sworn in.

MR. BROWN: Your Honor, we've never had the opportunity to see the credentials of the NYSEG panel. May we ask that they be distributed so that we can do that?

JUDGE EPSTEIN: Are you able to do that?

MS. DANDY: We have --

MR. GIANNASCA: We have one extra copy, your Honor.

MR. VAN RYN: Your Honor, Staff would like a copy at some point also.

JUDGE EPSTEIN: All right. If you could just stand and raise your right hands.

* * *

P A T R I C I A C L U N E,
H E N R Y H O S T - S T E E N,
and C A R L K I N G,
having each been first duly sworn by the Administrative Law Judge, were examined as a panel and testified as follows:

MS. DANDY: Your Honor, I'd like to present the NYSEG panel supporting the Joint Proposal. To my left is Ms. Patricia Clune; to her left is Mr. Henry Host-Steen and to his left is Mr. Carl King. Let me ask the witnesses to identify themselves and each just state their position.

MS. CLUNE: I'm Patricia Clune. Currently I'm a Principal Analyst in the Rates and Regulatory Economics Department, NYSEG.

MR. HOST-STEEN: My name is Henry Host-Steen. I'm a Regulatory Consultant employed by Manpower Professionals, Binghamton, New York.

MR. KING: My name is Carl King. I'm also a Principal Analyst with the Rates and Regulatory Economics Department.

MS. DANDY: Mr. Host-Steen, I will ask you to speak for the panel as we introduce

the panel in support of the Joint Proposal. It's now going to be handed to the court reporter.

DIRECT EXAMINATION

BY MS. DANDY:

Q Have you reviewed the document consisting of 17 pages, outlining NYSEG's statement in support of Joint Proposal?

A (Host-Steen) Yes, I have.

Q Do you adopt the statement in support as the statement in support of New York State Electric & Gas' proposal?

A (Host-Steen) Yes, I do.

MS. DANDY: May we have the 17-page statement copied into the record as if given orally?

JUDGE EPSTEIN: Yes.

(The statement of New York State Electric & Gas Corporation in support of Joint Proposal is as follows:)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

----------X

Proceeding on Motion of the Commission as to New York State Electric & Gas Corporation Electric Tariff Filing to Establish a New Standby Service in Accordance with Commission Order Issued October 26, 2001 in Case 99-E-1470	:	Case 02-E-0779

----------X

STATEMENT OF
NEW YORK STATE ELECTRIC & GAS CORPORATION
IN SUPPORT OF JOINT PROPOSAL

HUBER LAWRENCE & ABELL
605 Third Avenue
New York, NY 10158
(212) 682-6200

Attorneys for NEW YORK STATE
ELECTRIC & GAS CORPORATION

Nicholas A. Giannasca
Katherine W. Dandy
Of Counsel

April 21, 2003

TABLE OF CONTENTS

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

----------X

Proceeding on Motion of the Commission as to New York State Electric & Gas Corporation Electric Tariff Filing to Establish a New Standby Service in Accordance with Commission Order Issued October 26, 2001 in Case 99-E-1470	:	Case 02-E-0779

----------X

STATEMENT OF
NEW YORK STATE ELECTRIC & GAS CORPORATION
IN SUPPORT OF JOINT PROPOSAL

This Statement in Support of Joint Proposal is submitted by New York State Electric & Gas Corporation ("NYSEG" or the "Company") in support of the Joint Proposal filed with the State of New York Public Service Commission (the "Commission") in this proceeding on April 7, 2003 (the "Joint Proposal"). The Joint Proposal represents a settlement reached among the Company, Staff of the New York State Department of Public Service ("Staff"), Multiple Intervenors, AES Eastern Energy, L.P. ("AES"), Lockport Energy Associates, L.P. ("Lockport"), and Indeck Energy Services of Silver Springs, Inc. ("Indeck")[1] (collectively, the "Settling Parties")[2] in connection with the Company's proposed rate design for standby electric service. As set forth below, the Joint Proposal represents a comprehensive resolution of the issues raised in this proceeding in a manner that is consistent with the guidelines and principles set

---

1 AES, Lockport, and Indeck were represented as Independent Power Producers of New York, Inc. ("IPPNY") during the settlement negotiations.

2 In addition, Nucor Steel Auburn, Inc. ("Nucor") has represented to the parties that it does not oppose the Joint Proposal.

forth by the Commission in Opinion No. 01-4.[3] The Joint Proposal satisfies applicable Commission settlement guidelines and thus merits Commission approval.

I. BACKGROUND

A. Commission Guidelines for Standby Service

The Commission's Case 99-E-1470 was commenced in January 2000 to formulate general guiding principles and policies for developing standby tariffs.[4] The proceeding was instituted jointly with an investigation of the costs and benefits of distributed generation ("DG").[5] The two proceedings were initially conducted as a coordinated collaborative process in which numerous parties participated. Subsequently, the collaborative process followed two tracks, one for consideration of DG issues and the other for consideration of standby rate issues. In Opinion 01-4, which addresses the standby rate issues, the Commission adopted "Guidelines for the Design of Standby Service Rates" (the "Guidelines"), and directed utilities to file standby service delivery tariffs in compliance with the Guidelines.

1. Fundamental Principles

The Guidelines provide that standby service rates shall apply to (1) customers with on-site generation ("OSG") serving load that is not isolated from the grid, and (2) wholesale generators that rely on the electric utility to service electric loads that would otherwise be served by the generator. Guidelines, at I.A.1. Under the Guidelines,

---

3 Case 99-E-1470 – Proceeding on Motion of the Commission as to the Reasonableness of the Rates, Terms and Conditions for the Provision of Electric Standby Service, Opinion and Order Approving Guidelines for the Design of Standby Services Rates (issued October 26, 2001) ("Opinion 01-4").

4 Cases 99-E-1470 and 00-E-0005, Order Instituting Proceedings (issued January 10, 2000).

5 Case 00-E-0005, Costs, Benefits and Rates Regarding Distributed Generation.

standby rates shall not apply to self-supplied power where a wholesale generator, when operating, supplies all of its electric energy needs from "behind the meter." Id. at I.A.2. The Guidelines also exempt from standby service rates those customers with OSG used principally as a source of emergency backup when utility service is interrupted. Opinion 01-4, at 5. Since such customers rely on utility service for the vast majority of their electricity needs, all service to these customers should be provided under the otherwise applicable full service tariff. Id.

To the extent that a utility has stranded production costs for which the Commission allows recovery from the utility's delivery service customers, the Guidelines state that standby service customers should also contribute to the recovery of stranded costs. Guidelines, at I.B.1. Such contribution should be established through a uniform percentage mark up of the applicable rate components established for standby service such that standby customers contribute to stranded cost recovery in the same proportion of their delivery rates as customers in the otherwise applicable service classification. Id. at I.B.2.

The Guidelines reflect fundamental cost-based rate design principles that, in most cases, avoid reliance on volumetric ($/kWh) charges for delivery service, and recommend implementation of such principles for standby service as a specialized form of retail delivery service. Opinion 01-4, at 5. These principles recognize that the cost of owning and operating a utility delivery system is essentially fixed and does not vary by usage. The Guidelines also suggest that additional charges or credits may apply to properly designed standby rates. Id. at 6. These might include surcharges imposed under otherwise applicable service classifications that would appropriately be applied to standby

rates, or certain credits or surcharges (such as interconnection charges) directly attributable to individual standby customers. Id.

2. Rate Design Principles for Standby Delivery Service

Under the Guidelines, costs now allocated to each standard service classification will serve as the basis for the design of class specific, revenue-neutral, standby service delivery charges. Guidelines, at II.A. That is, the standby rates for each service classification, if applied to all customers in the class, should produce the same revenues as the standard rates, using the class billing determinants. Id. In addition, because it is a delivery service, standby rates should be established exclusive of electricity supply prices. Id. at II.C.1.

The Guidelines provide that the cost of any additional interconnection facilities and equipment unique to the provision of standby service should be recovered directly from customers that install OSG through separate up-front interconnection charges. Id. at II.B. A fixed monthly access charge (the "Customer Charge") should also be established to recover fully all customer-related costs, to the extent not recovered through interconnection charges. Id. at II.D. To develop the Customer Charge, the utility could use the customer components of the distribution system identified in a fully allocated embedded cost of service study. Opinion 01-4, at 9, n. 8.

To the extent that costs are not recovered in the Customer Charge, the Guidelines recommend that distribution delivery costs should be recovered through a combination of class-specific contract (fixed) demand charges ("Contract Demand Charges") and daily as-used demand charges ("As-Used Demand Charges"). Id. at II.E.2. Costs associated with "local" facilities, i.e., those that are closer to a customer's site, and

are built to meet customer demands regardless of their coincidence with the system peak, should be recovered through the Contract Demand Charge, which should apply to the customer's maximum potential annual metered demand or connected load. Guidelines, at II.E.3. Costs associated with shared facilities, i.e., those located further from the customer's site that are built to meet the system peak, should be recovered through the As-Used Demand Charge, which should apply only to the customer's daily maximum metered demand that occurs during the utility's system peak periods. Guidelines, at II.E.4. The allocation of costs between the Contract Demand Charge and the As-Used Demand Charge should be based on delivery system design and cost causation. Opinion 01-4, at 15.

The Guidelines also provide that interval metering necessary to implement rates for standby service will be required of all standby customers with contract demands in excess of 50 kW. Guidelines, at II.G.1. A standby customer with a contract demand below 50 kW, but nevertheless subject to demand metering under the otherwise applicable service classification, will have the option of taking service at either (1) the monthly demand rate for the otherwise applicable full-service classification, or (2) the interval meter rate that is mandatory for customers at or above 50 kW. Opinion 01-4, at 9.

B. NYSEG Standby Service Rates

In accordance with Opinion 01-4 and the Guidelines, on June 7, 2002, NYSEG filed tariff amendments to its electric tariff schedule (the "June 7 Filing") establishing electric standby service. The parties held a technical conference on August 5, 2002 to discuss the June 7 Filing.

By order dated August 29, 2002, the Commission suspended the proposed tariff revisions through January 3, 2003, and by order dated December 31, 2002, the Commission further suspended the proposed revisions through July 3, 2003. On January 10, 2003, in a procedural conference before Administrative Law Judge Rafael A. Epstein, NYSEG agreed to a further suspension of the proposed tariff leaves through August 3, 2003.[6]

On February 7, 2003, NYSEG submitted draft tariff leaf revisions (the "February 7 Filing"), updated to reflect NYSEG's new delivery rates, which became effective on January 1, 2003 in accordance with NYSEG's Electric Rate Plan.[7] Following a technical conference on February 13, 2003 to discuss the February 7 Filing, interested parties began confidential settlement negotiations in accordance with 16 N.Y.C.R.R. § 3.9. Settlement conferences were held on March 10, 2003, March 18, 2003, March 26, 2003, and April 2, 2003. These settlement discussions have culminated in the Joint Proposal, which is designed to resolve issues that were raised by various parties over the June 7 Filing and the February 7 Filing. The Settling Parties agree in the Joint Proposal that it settles and resolves all issues regarding electric standby service rates for NYSEG service to customers with OSG, including wholesale generators.

II. THE JOINT PROPOSAL

The provisions of the Joint Proposal are summarized below. As a review of these provisions will show, the Joint Proposal comports with the policies and

---

6 By letter dated April 10, 2003, NYSEG formally consented to an August 3, 2003 suspension date.

7 Order Adopting Provisions of the Joint Proposal with Modifications, Cases 01-E-0359 and 01-M-0404, issued February 27, 2002 (the "Electric Rate Plan"), and Order Directing Rate Design and Revenue Allocation, Case 01-E-0359, issued November 22, 2002.

principles enunciated by the Commission in Opinion 01-4 and the Guidelines. Furthermore, the Joint Proposal satisfies applicable Commission settlement guidelines, and should therefore be approved in its entirety.

A. The Joint Proposal is Consistent with the Guidelines and Principles Set Forth By the Commission in Opinion 01-4

In developing the Joint Proposal, NYSEG has tried diligently to accommodate the concerns of the other parties in the proceeding while adhering to Opinion 01-4 and the Guidelines, and also recognizing its responsibility to its shareholders and its other customers. Like the Guidelines themselves, the Joint Proposal represents a compromise of the conflicting views and positions of the parties.

In accordance with Opinion 01-4 and the Guidelines, the Company's proposed standby rates place comparatively less reliance on volumetric ($/kWh) charges for delivery service, and comparatively more reliance on fixed charges (i.e., the Customer Charge and the Contract Demand Charge). The proposed rates are revenue-neutral, class-specific, and reflective of the existing allocations of costs to the various service classifications. The proposed class-specific standby service Customer Charge, Contract Demand Charge and As-Used Demand Charge recover an appropriate allocation of "local" and "shared" facilities costs incurred by the Company in providing standby service. Other than the phase-in provision provided therein, the Joint Proposal assures that customers in non-demand classes, and customers in demand classes without interval metering, will receive standby service rates more reflective of fixed cost recovery. The proposed standby rates provide neither a barrier nor an unwarranted incentive to customers contemplating the installation of economically efficient OSG, and, in this

respect, further the Commission's articulated policy of not impeding the development of alternative sources of energy.

1. Rate Design

In accordance with the Guidelines, the Joint Proposal sets forth, by service classification, cost-based rates comprised of three basic components: a Contract Demand Charge, an As-Used Demand Charge, and a monthly Customer Charge that is based on the Company's full embedded cost of service. The Joint Proposal includes a matrix containing the percentage allocation of costs between the As-Used Demand Charge and the Contract Demand Charge, at the various voltage levels. Joint Proposal, at ¶2. The allocation matrix reflects a consensus of views on the appropriate distribution of costs, and follows the principle enunciated in Opinion 01-4 that allocations between Contract Demand and As-Used Demand Charges "should be based on delivery system design and cost causation." Opinion 01-4, at 15.

Under the Joint Proposal, a customer will have the option of accepting a contract demand established by NYSEG or of establishing its own contract demand in accordance with the provisions of the Joint Proposal and NYSEG's Service Classification 11 standby tariff. Joint Proposal, at ¶6. Regardless of which party sets the customer's contract demand, upon the occurrence of an exceedence, the contract demand will be ratcheted up by the amount of the exceedence. Id.

Where a customer elects to have NYSEG establish its contract demand, the customer will not incur a surcharge if that contract demand is exceeded. Joint Proposal, at ¶8. However, such customer must inform NYSEG in writing prior to the installation or removal of equipment, or any change in operation, that may change in a

material fashion the capacity required to deliver electricity to the customer. Id. If a customer fails to provide such notice, and the customer exceeds the NYSEG-established contract demand, then NYSEG will have the right to include a surcharge in the customer's bill equal to the product of the applicable Contract Demand Change, the amount of the exceedence, and the number of billing periods from and including the period in which the customer first began taking service at the understated contract demand. Id. If the customer fails to demonstrate in writing when it installed such equipment or changed such operation, then NYSEG is permitted to apply the surcharge from the first billing period in which the customer began taking standby service from NYSEG. Id.

Where a customer elects to establish its own contract demand and then subsequently exceeds that level, the customer will be liable for a surcharge. Joint Proposal, at ¶9. Where there is an exceedence of less than ten percent (10%), a surcharge of twelve times the sum of the monthly contract demand charges calculated for the excess demand will apply to the customer's current monthly bill. Id. An exceedence of ten percent (10%) or more, but less than twenty percent (20%) will result in a surcharge of eighteen times the sum of the monthly contract demand charges calculated for the excess demand, and an exceedence of twenty percent (20%) or more will result in a surcharge of twenty-four times the sum of the monthly contract demand charges calculated for the excess demand. Id. With respect to a new customer installing OSG, or an existing customer with new OSG installed after the date of the Joint Proposal, during the two years after NYSEG's new standby rates become effective, one exceedence in the first year

of OSG operation of less than ten percent (10%) in magnitude will be excused from any surcharge. Id.

With respect to metering, in accordance with the Guidelines, the Joint Proposal makes interval metering mandatory for demand billed customers with a contract demand greater than or equal to 50 kW, and optional for those with a contract demand less than 50 kW. Joint Proposal, at ¶15.

2. Phase-in of Standby Rates

To mitigate the rate impact of the proposed standby rates, the parties agreed to a significant concession by NYSEG in allowing for a phase-in of the new standby service rates for certain categories of customers. See Joint Proposal, at ¶3. Phase-in of rates is available for "existing" customers, which are defined broadly to include customers: (a) operating OSG, including a renewable generator[8] and a wholesale generator, as of January 31, 2003; (b) taking standby service from NYSEG as of January 31, 2003; or (c) who had, as of January 31, 2003: (i) commenced construction of an OSG facility (including a renewable generator); (ii) been named by the New York State Research and Development Authority ("NYSERDA") as an OSG project grant recipient; (iii) been named by NYSERDA as an OSG feasibility study grant recipient; or (iv) received a binding, written financial commitment from a lending institution for the construction and installation of an OSG. Id. In addition, renewable generators installed after the date of the Joint Proposal are eligible for a five-year phase-in of NYSEG's new rates for standby service.

---

[8] The Joint Proposal defines renewable generators as generators that use certain technologies and/or fuels (e.g., solar power) as the exclusive technology/fuel for generating electricity. See Joint

The phase-in provisions were included despite the Commission's statements in Opinion 01-4 that standby delivery rates should not provide "an unwarranted incentive to customers contemplating the installation of DG or OSG,"[9] but "should be based on delivery system design and cost causation."[10] The Joint Proposal provides for a gradual imposition of any increased, cost-based financial impact of the standby rates on customers who have already invested or made a commitment to OSG and those customers exploiting renewable technologies, in furtherance of Commission goals.

3. Exemptions From Standby Rates

The Joint Proposal exempts certain customer groups from application of NYSEG's standby rates, including customers supplying fifteen percent (15%) or less of their load from OSG,[11] and, in accordance with the Guidelines, customers with emergency generators (even if they participate in the New York Independent System Operator Special Case Resource program or the Emergency Demand Response program). Joint Proposal, at ¶18.

4. Individually Negotiated Agreements

The Joint Proposal authorizes NYSEG to offer individually negotiated agreements for standby service to customers that may install back-up generation and disconnect their premises from the NYSEG system in lieu of taking tariff standby service. Joint Proposal, at ¶12. The negotiated rate must, at a minimum, provide for recovery of

---

Proposal, at ¶3(b).

9 Opinion 01-4, at 11.

10 Id., at 15.

NYSEG's marginal costs plus a reasonable contribution to NYSEG's recovery of its fixed costs. Id. Additionally, NYSEG may offer individually negotiated agreements for standby service to large (greater than 50 MW) customers that sell into the market, or to a third party, no less than ninety percent (90%) of their site's energy output. Joint Proposal, at ¶13. The rates and charges negotiated will reflect the unique characteristics of the generator. Id. Such individually negotiated rates are consistent with Opinion 01-4 and the Guidelines.

5. Customer Charge Credits

The Joint Proposal also provides that demand billed customers taking service under NYSEG's new standby service rates who have fully paid for their meter and instrument transformation costs will receive a credit on the currently applicable monthly Customer Charge, which includes the Non-Bypasssable Wires Charge ("NBWC") proportional allocation. Joint Proposal, at ¶17. Such credits were contemplated by the Commission in Opinion 01-4.

6. Effective Date of Standby Rates

The effective date of NYSEG's new rates for standby service will be six months after the Commission's order approving the Joint Proposal. Joint Proposal, at ¶10. This delay is necessary to permit the installation of any necessary interval metering and to develop, establish and test an enhanced "off system" billing system for such rates in advance of the effective date. However, a customer may take service under the new

[11] Joint Proposal, at ¶5.

rates immediately if it can demonstrate that it is already being billed off-system as of the date of the Joint Proposal and that it has interval metering. Id.

7. Lost Revenue Recovery

In contrast to the Company's "Load Factor Assessment" proposal, set forth to preclude unintended delivery revenue requirement loss, the Joint Proposal only allows NYSEG to track annually the net revenue gains or losses for all customers that are or would be subject to its standby service rates. Importantly, NYSEG may petition the Commission to recover from the Asset Sale Gain Account ("ASGA"), or for deferral recovery if the ASGA is depleted, any net annual revenue loss over $500,000. Joint Proposal, at ¶ 21. Likewise, any net annual revenue gain over $500,000 will be refunded to the ASGA. Id. NYSEG asks that the Commission approve the Joint Proposal with the understanding that this lost revenue recovery provision permits NYSEG to implement deferred accounting for any lost revenue monies it seeks to recover from either the ASGA or some other deferral mechanism. Including this provision was a pivotal consideration for NYSEG in agreeing to the rates and other terms and conditions of the Joint Proposal.

In sum, underlying the Joint Proposal are the basic principles and policies laid out by the Commission in Opinion 01-4 and the Guidelines. The Commission should therefore approve the Joint Proposal in all respects.

B. The Joint Proposal Satisfies Applicable Commission Settlement Guidelines and Thus Merits Commission Approval

Under the Commission's long-standing settlement guidelines,[12] a number of factors must be considered as part of the Commission's decision whether to approve a

[12] Cases 90-M-0255 et al., Opinion, Order and Resolution Adopting Settlement Procedures and

filed settlement. The relevant questions are whether the proposed settlement is consistent with law and public policy, and compares favorably with the probable outcome of litigation; whether the proposed settlement strikes a fair balance among the interests of ratepayers and investors and the long-term soundness of the utility; whether a rational basis and adequate record exist to support a favorable Commission decision; and whether the proposed settlement is supported by normally adversarial parties.

NYSEG believes that all of these questions can and should be answered in the affirmative.

1. The Joint Proposal is consistent with law and public policy, and compares favorably with the probable outcome of litigation.

The Joint Proposal is fully consistent with the Commission's policies. As discussed in Point A above, the Joint Proposal comports with the Guidelines and the principles and policies established in Opinion 01-4. Moreover, the Joint Proposal also furthers the interests in facilitating DG and supporting wholesale generation as well as renewable generation.

In addition, the Joint Proposal compares quite favorably to any probable litigated outcome. Compared with the Company's litigation position, contained in the June 7 Filing and the February 7 Filing, many of the provisions of the Joint Proposal represent considerable compromise and movement by NYSEG towards many of the positions advocated by Staff and other parties. As was the case with the Guidelines, the Joint Proposal strikes a balance among these opposing points of view. At the same time, the settlement discussions in this proceeding have produced an outcome that could be

---

Guidelines, Opinion No. 92-2 (issued Mar. 24, 1991).

expected from a litigated proceeding, as evidenced by the assent of important stakeholders to the Joint Proposal. For example, the phase-in provisions for renewable generators (¶ 3(b)) and certain existing customers (¶ 3(a)), and the Customer Charge Credit provision (¶ 17) of the Joint Proposal were not contained in the June 7 Filing and the February 7 Filing.

The Joint Proposal also differs from NYSEG's litigated position in that the Joint Proposal provides for a larger proportion of delivery cost recovery through the daily As-Used Demand Charge. Also, the NBWC will now be established based on the fixed NBWC calculated by NYSEG on April 1, 2003 under its Bundled Rate Option, and will be revisited every six months until the end of NYSEG's Electric Rate Plan. Joint Proposal, at ¶ 19. Moreover, unlike the June 7 Filing and the February 7 Filing, the Joint Proposal allows standby service customers to set their own contract demand, as an alternative to having NYSEG establish contract demand. Id. at ¶6. In order to address shared concerns for the possible understatement of contract demand, the Settling Parties agreed to surcharges that would apply if a customer exceeded its nominated demand. Id. at ¶ 9. Customers can avoid such surcharges by electing to have NYSEG establish contract demand; a retroactive surcharge will apply only where a customer fails to notify NYSEG that a material change in its equipment or operation has caused it to exceed its NYSEG-established contract demand. Id. at ¶ 8. This surcharge provision protects NYSEG from gaming by customers.

All of these provisions demonstrate how the Joint Proposal represents a negotiated agreement that is in the public interest, as well as within the range of likely

results of a fully litigated proceeding. Taken as a whole, they demonstrate why the Commission should adopt the Joint Proposal in its entirety.

2. The Joint Proposal strikes a fair balance among the interests of ratepayers and investors and the long-term soundness of the Company, and is supported by normally adverse parties.

The Joint Proposal balances the interests of customers and NYSEG and is supported by a range of stakeholders of adverse interests. The variety of interests represented by the signatories assures that the Joint Proposal is balanced, fair, and reasonable. Also, as noted above, Nucor has represented to the parties that it does not oppose the Joint Proposal.

3. A rational basis and adequate record exist to support a favorable Commission decision.

Finally, a record exists in this case to support approval of the Joint Proposal by the Commission on a rational and reasonable basis. The confidential settlement discussions leading to the Joint Proposal were conducted on a principled basis, on notice to all interested parties, and consistent with the Commission's Rules and Regulations. The Joint Proposal is the culmination of an extensive collaborative process, involving two technical conferences, four settlement conferences, and a discovery period. All parties to the proceeding have had the opportunity to have their voices heard, and to have input into the development of the Joint Proposal. The rational basis for the Joint Proposal is set forth clearly in the document itself, its attachment containing the proposed rates, and in this Statement in Support.

Because the Joint Proposal satisfies the Commission's settlement guidelines, it should be approved in its entirety.

III. CONCLUSION

For all of the foregoing reasons, the Joint Proposal reasonably resolves the various issues presented during this proceeding, and it should be promptly approved in all respects. If it is not approved in its entirety, NYSEG respectfully requests that the Commission remand the Joint Proposal to the parties to enable them to pursue their respective positions and remedies.

Respectfully submitted,

Huber Lawrence & Abell
605 Third Avenue
New York, N.Y. 10158
(212) 682-6200

Attorneys for NEW YORK STATE
ELECTRIC & GAS CORPORATION

Nicholas A. Giannasca
Katherine W. Dandy
Of Counsel

April 21, 2003

BY MS. DANDY:

Q Mr. Host-Steen, I'm going to ask you to again speak for the panel in support of reply comments in support of the proposal. Have you reviewed the document of 25 pages outlining NYSEG's reply comments in further support of the proposal?

A (Host-Steen) I have.

Q Do you adopt these reply comments in support of the proposal as the reply comments of New York State Electric & Gas Corporation?

A (Host-Steen) I do.

MS. DANDY: May we have this 25-page statement copied into the record as if given orally?

JUDGE EPSTEIN: Yes.

(The reply comments of New York State Electric & Gas Corporation in support of the Joint Proposal are as follows:)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

----------X

Proceeding on Motion of the Commission as to New York State Electric & Gas Corporation Electric Tariff Filing to Establish a New Standby Service in Accordance with Commission Order Issued October 26, 2001 in Case 99-E-1470	:	Case 02-E-0779

----------X

REPLY COMMENTS OF
NEW YORK STATE ELECTRIC & GAS CORPORATION
IN FURTHER SUPPORT OF JOINT PROPOSAL

HUBER LAWRENCE & ABELL
605 Third Avenue
New York, NY 10158
(212) 682-6200

Attorneys for NEW YORK STATE
ELECTRIC & GAS CORPORATION

Nicholas A. Giannasca
Katherine W. Dandy
Of Counsel

May 8, 2003

TABLE OF CONTENTS

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

----------X

Proceeding on Motion of the Commission as to New York State Electric & Gas Corporation Electric Tariff Filing to Establish a New Standby Service in Accordance with Commission Order Issued October 26, 2001 in Case 99-E-1470	:	Case 02-E-0779

----------X

REPLY COMMENTS OF
NEW YORK STATE ELECTRIC & GAS CORPORATION
IN FURTHER SUPPORT OF JOINT PROPOSAL

On April 7, 2003, Staff of the New York State Department of Public Service ("Staff") filed with the State of New York Public Service Commission (the "Commission") a Joint Proposal in this proceeding (the "Joint Proposal"). The Joint Proposal reflects a settlement reached among New York State Electric & Gas Corporation ("NYSEG" or the "Company"), Staff, Multiple Intervenors ("MI"), AES Eastern Energy, L.P. ("AES"), Lockport Energy Associates, L.P. ("Lockport"), and Indeck Energy Services of Silver Springs, Inc. ("Indeck")[1] (collectively, the "Settling Parties")[2] in connection with the Company's proposed rate design for standby electric service. The Joint Proposal complies with the Commission's Opinion No. 01-4, issued and effective October 26, 2001 in Case 99-E-1470 ("Opinion 01-4").

On April 21, 2003, NYSEG and other parties to this proceeding filed initial comments or testimony in support of, or in opposition to, the Joint Proposal. NYSEG has received initial comments or testimony from the following parties: Staff,

---

[1] AES, Lockport, and Indeck are represented by Independent Power Producers of New York, Inc. ("IPPNY") in this proceeding.

[2] In addition, Nucor Steel Auburn, Inc. ("Nucor") has represented to the parties that it does not

MI, Lockport and Indeck, National Fuel Gas Distribution Corporation ("NFG"), Joint Supporters and Other Interested Parties (together, "Joint Supporters"), and Wyoming County Community Health System ("Wyoming"). NYSEG is now submitting these Reply Comments in response to various issues raised in opposition to the Joint Proposal.

I. PRELIMINARY STATEMENT

The Joint Proposal represents the culmination of an extensive collaborative process that has taken place over the course of ten months and was intended to address whether NYSEG's new standby rates comply with Opinion 01-4. Two technical conferences and four settlement conferences were held, and detailed discovery was conducted. The Company certainly appreciates the participation of all parties in this process. It is evident from the Joint Proposal that even those parties that did not ultimately sign the Joint Proposal had a significant impact on its development and content. Like the Commission's standby Guidelines (as defined below), the Joint Proposal represents a compromise of the conflicting views and positions of numerous parties.

In evaluating the Joint Proposal and the opposition that has been submitted to that filing, it is critical to recognize the purpose of this proceeding, and of the Joint Proposal. The Commission instituted this proceeding so that NYSEG could establish new, cost-based rates for standby delivery service in accordance with Opinion 01-4. Such rates are now reflected in the Joint Proposal. This proceeding was not instituted to permit parties to revisit and relitigate issues that were resolved in the Commission's generic proceeding on standby rates, Case 99-E-1470. That generic proceeding, which began

---

oppose the Joint Proposal.

over three years ago in January of 2000, was conducted as a collaborative process involving numerous parties, and resulted in Opinion 01-4 and the Commission's Guidelines for the Design of Standby Service Rates (the "Guidelines"). The Opinion and the Guidelines clearly define the applicability of standby rates, and set forth specific rate design principles for standby delivery service. These principles recognize the fixed cost nature of a utility delivery system. Nor was this proceeding intended to be a forum for investigating the costs and benefits of distributed generation ("DG"), or for discussing the development of DG in the context of the State's draft energy plan. The Commission had undertaken an examination of DG in Case 00-E-0005. That proceeding, which was commenced jointly with the generic standby case in January of 2000, was also conducted as a collaborative process involving many parties and resulted in Opinion 01-5.[3] Indeed, NYSEG and other utilities have been actively seeking responses to requests for proposals issued in connection with the pilot program developed pursuant to Opinion 01-5, in order to ascertain the costs and benefits of DG.

The parties that have filed opposition to the Joint Proposal appear to have lost sight of the purpose of this proceeding. Instead, they are attempting to use this proceeding as a forum in which to relitigate issues that have already been settled in prior proceedings, and to raise issues that are not relevant to this proceeding. For example, this proceeding is simply not the appropriate forum in which to litigate the potential impact of standby rates on the development of DG. Nor is it appropriate here to consider promoting a rate structure that permits customers with DG to arbitrage between historically

---

[3] Case 00-E-0005 – Proceeding on Motion of the Commission to Examine Costs, Benefits and Rates Regarding Distributed Generation, Opinion and Order Approving Pilot Program for use of Distributed Generation in the Utility Distribution System Planning Process (issued October 26, 2001).

developed standard rates and standby rates, thereby increasing the potential for windfall gains for DG customers at the expense of windfall losses for other customers. Whether DG constitutes an economic alternative to a customer's use of the utility delivery system and procurement of supply from a competitive market continues to be debated in other, more appropriate, forums. Meanwhile, the parties here should remain focused on the central task of this proceeding, i.e., the design of cost-based standby service delivery rates without regard to whether those rates encourage or discourage DG.

As discussed in more detail below, many, if not all, of the issues raised in opposition to the Joint Proposal should be deferred to the applicable current or future Commission proceeding.[4] As discussed below, any remaining issues should be rejected as contrary to Opinion 01-4 and the Guidelines.

II. SUMMARY OF OPPOSITION TO JOINT PROPOSAL

Joint Supporters, NFG, and Wyoming were the only parties to submit opposition to the Joint Proposal. The crux of these parties' opposition is that NYSEG's proposed standby rates will somehow harm the DG industry.

A. Joint Supporters

Joint Supporters submitted initial comments, plus the testimony of three witnesses,[5] in opposition to the Joint Proposal. Joint Supporters claim that the Joint Proposal, as well as NYSEG's original filing of proposed tariff amendments relating to

[4] There are two newly instituted proceedings that would be among the more appropriate forums in which to address the concerns raised by the opposing parties. On May 2, 2003, the Commission issued an Order Instituting Proceeding, commencing Case 03-E-0640 – Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation. In addition, on April 30, 2003, the Commission issued a Notice Requesting Comments in Case 03-E-0641 – Proceeding on Motion of the Commission Regarding Expedited Implementation of Mandatory Hourly Pricing for Commodity Service.

standby service (the "June 7 Filing"), violate Opinion 01-4 by "failing tests of cost basis and revenue neutrality" and by creating an unwarranted disincentive to on-site generation ("OSG"). Initial Comments of Joint Supporters and Other Interested Parties and Statement in Opposition to Joint Proposal Filed April 7, 2003 (hereinafter, "JS Comments"), at 2. Citing various hospitals and schools as examples, Joint Supporters argue that the proposed rate structure will have a "chilling effect" on the way that OSG projects are engineered and optimized. Id. at 3. In Joint Supporters' view, the imposition of a separate rate structure for customers who choose OSG would create an intrinsically anti-competitive environment for OSG. Id.

Joint Supporters propose a number of revisions and structural changes to the Joint Proposal, including the following:

- The allocation matrix[6] should be revised, as described in the testimony of Mr. Lively ("Lively Testimony");
- Additional special provisions should be considered, including a longer phase-in period for the new standby rates, a supplemental rate structure, dynamic delivery pricing, and special treatment for combined heat and power ("CHP") technologies; and
- The threshold date for existing projects should be extended from January 31, 2003, to the effective date of the Company's new standby service tariff.

Joint Supporters ask the Commission to either stay the instant proceeding until "proper cost data" becomes available, or to amend the rates to "mitigate the harm that [the rates] would otherwise cause to the developing OSG industry." Id. at 21.

---

[5] Mark B. Lively, L. Keith O'Neal, and William Cristofaro, P.E.

[6] The allocation matrix is contained in paragraph 2 of the Joint Proposal.

B. NFG

Claiming that a benefit of the Joint Proposal should be that it will improve the opportunity for installation of DG, NFG also seeks revisions to the Joint Proposal. Comments of National Fuel Gas Distribution Corporation in Opposition to the Joint Proposal (hereinafter, "NFG Comments"), at 3. Specifically, like Joint Supporters, NFG objects to the allocation matrix contained in the Joint Proposal on the basis that it allocates too much cost recovery to the contract demand charge, and requests that additional costs be allocated to the "shared" component of costs and, hence, recovered through the "as-used" demand charge. Id. at 4, 6.

NFG also takes issue with the Joint Proposal's phase-in provision for existing customers, and, like Joint Supporters, argues that the eight-year phase-in provided in the Con Edison Joint Proposal should be applied in this proceeding. Id. at 5, 7. Lastly, NFG requests that NYSEG be required to modify the provision in the Joint Proposal allowing for negotiated rates for projects that can economically isolate from the grid[7] to require only that the customer contribute to the utility's non-bypassable wire's charge ("NBWC"). Id. at 6, 7.

C. Wyoming

On behalf of Wyoming, Leon N. Kuczmarski offers testimony ("Kuczmarski Testimony") concerning the effect of the proposed standby rates on a small rural healthcare facility presently operating OSG. Kuczmarski Testimony, at 2. Mr. Kuczmarski claims that under the proposed tariffs, operators of existing cogeneration equipment would pay an unfair share of distribution costs, and that, as a result, the rates

[7] Joint Proposal, at ¶ 12.

are cost-prohibitive. Id.

III. REPLY COMMENTS

It is evident from their comments and testimony that Joint Supporters, NFG, and Wyoming are attempting to relitigate issues that were settled long ago in the Commission's generic standby proceeding, Case 99-E-1470. Additionally, the opposing parties are seeking to introduce issues that do not belong in this proceeding. Even if the proposals offered were relevant, the opposing parties have failed to provide adequate support to justify their proposals.

A. Many of Joint Supporters' and NFG's Proposals are Inconsistent with Opinion 01-4 and the Guidelines.

Both Joint Supporters and NFG are trying to revive and rehash issues that were resolved by Opinion 01-4. This should not be countenanced by the Commission. That Opinion, and the Guidelines that accompanied it, resulted from the culmination of a lengthy collaborative process in which many parties – including Joint Supporters and NFG – participated. The Commission's conclusions from that proceeding should not be disturbed in the context of NYSEG's compliance filing. Moreover, consistent with the Commission's stated policies and principles, many of the issues raised by Joint Supporters and NFG in opposition to the Joint Proposal should be deferred for consideration in more appropriate proceedings.

1. This is not the appropriate forum in which to address the potential benefits of DG or the impact of standby rates on the DG industry.

At the heart of the opposition of Joint Supporters, NFG, and Wyoming to the Joint Proposal is the argument that NYSEG's proposed rates will be harmful to the DG industry. Joint Supporters allege that the Joint Proposal will have a "chilling" and

"stifling" effect on the development of DG, while NFG claims that a benefit of the Joint Proposal should be that it will improve the opportunity for installation of DG. Wyoming contends that the Joint Proposal will render its OSG cost-prohibitive. What all of the opposing parties have ignored in making these unsubstantiated claims is the fact that the Commission has already made clear its policies that the possible benefits associated with DG would not be considered in the context of the development of standby delivery rates, and that standby rates were not intended to be developed as a vehicle to encourage DG. This is simply not the time or the place to relitigate the potential benefits of DG or the possible adverse impact of the Joint Proposal on the DG industry.

First, from the beginning of its consideration of new standby delivery rates in Case 99-E-1470, the Commission has addressed DG issues separately from standby rates. Indeed, a separate proceeding, Case 00-E-0005 (the "DG Proceeding") was commenced for the Commission to consider issues related to the costs and benefits of DG. In Opinion 01-4, the Commission stated its policy with respect to the impact of standby rates on the DG industry:

> A number of non-utility parties expressed the view that standby rates should provide an incentive for the development of [DG] and OSG. If by that the non-utility parties mean to suggest that standby rates need not be established on a cost of service basis, we disagree. Cost-based standby delivery rates should provide neither a barrier nor an unwarranted incentive to customers contemplating the installation of DG or OSG.

Opinion 01-4, at 11 (emphasis added).

Additionally, in addressing comments submitted during the generic standby proceeding that there are identifiable benefits associated with DG or OSG installations that should be reflected in standby service rates, the Commission's response was as follows:

> To the extent that such economic benefits are not reflected in the utilities' cost of service, they could be addressed within other proceedings such as the Generic Distributed Generation proceeding or System Benefits Charge (SBC) proceeding.

Id. It is telling that the Commission did not suggest that such comments should be addressed in the utilities' individual standby rate compliance filing proceedings. The Commission concluded Opinion 01-4 by stating that the Guidelines

> do not include extraneous factors sought by various parties, such as public policy values or benefits to utilities from DG, which in our view do not belong in the development of standby delivery rates. Rather, such factors should be considered and applied, if appropriate, in the context of a utility's distribution planning process. These values or benefits do not impact the design of embedded cost-based delivery rates.

Opinion 01-4, at 27 (emphasis added).

The Commission has indicated that the consideration of DG benefits is not even ripe for proceedings directly addressing DG. In the DG Proceeding, for example, the Commission directed the utilities to undertake pilot programs for the use of DG as a component of the utility distribution system planning process. In providing guidance to the utilities as to how proposed DG projects should be evaluated, the Commission expressly indicated that it is premature to assess the benefits of DG. The Commission noted that "[i]n reviewing the RFP pilot results, however, we will consider arguments about the costs and benefits of DG-related system enhancements, and about fair allocation of them among customers." Opinion 01-5. at 35.

Moreover, with respect to the assessment of the environmental benefits supposedly attributable to DG, the Commission declared that "it would not be fruitful, and could be counter-productive at this time, to introduce environmental impacts as an evaluation factor in the [DG] bid analysis." Id. at 27. If the Commission had stated that

the examination of the potential benefits of DG should be delayed in a proceeding that is focused on the development of DG, then it stands to reason that a consideration of such benefits is entirely inappropriate in a proceeding that the Commission expressly characterized as having no bearing on the issue of DG development. Despite these and other clear pronouncements by the Commission, Joint Supporters and NFG raise issues that are directly at odds with Commission policy, irrelevant to this proceeding, and unripe for consideration here.[8]

Lastly, Joint Supporters contend that further studies are necessary to understand and correct what Joint Supporters view as flaws in the Company's proposed standby rates. JS Comments, at 19. Specifically, Joint Supporters argue that studies should be commissioned to examine the proper allocation of costs and the effects of standby rates on OSG deployment. Id. at 19. No further studies are required to examine the allocation of costs. The Commission directed the parties to address that issue in this proceeding, and the Joint Proposal reflects significant Company concessions and a reasonable allocation of costs as between contract demand and as-used demand recovery. With respect to the impact of the proposed rates on OSG, it bears repeating that OSG deployment is not the issue here. This proceeding is about NYSEG's compliance filing and whether NYSEG's proposed cost-based, standby service rates comport with Opinion 01-4.

---

[8] It is worth noting that NFG also invokes the Draft State Energy Plan (the "Plan") to support its position. However, it is premature to draw conclusions from the Plan because it is still only a draft and because its authors have received comments about the need to clarify the vague language broadly supporting the development of DG. Moreover, the Plan pre-dates the Commission order approving standby rates for Niagara Mohawk Power Corporation. Hence, the Commission had the opportunity to address DG development in the context of standby rates in keeping with the supposed goals of the Plan, but it did not do so.

2. Joint Supporters' request to exempt CHP technologies is inconsistent with Opinion 01-4 and Opinion 01-5 and should be rejected.

Again ignoring the Commission's declarations in prior proceedings, Joint Supporters argue that CHP technologies should be exempt from NYSEG's standby rates, or at least be eligible for the phase-in of those rates, as are other environmentally preferred systems. JS Comments, at 16. They claim that whatever policy argumentation may be used to justify the grandfathering of renewables in the Joint Proposal[9] also applies to CHP. Id.

First, Opinion 01-4 does not exempt supposed environmentally-friendly technology from standby delivery rates. Indeed, no such exemptions or subsidies are called for by Opinion 01-4 and the Guidelines. More important, NYSEG's other customers should not be forced to subsidize uneconomic generation. Of all the potentially variable costs of DG, the fact that one type of cost, the rates for standby service, is regulated, does not mean that standby service rates should be designed to ensure that otherwise uneconomic projects could be made marginally economic. Such an approach also fails to consider the recovery of utility costs to serve these customers. The fact that there are some technologies and/or operating strategies that would be uneconomic for small customers under the Joint Proposal's rate designs does not justify subsidies for DG in the form of non-cost-based delivery service. Such subsidies would encourage uneconomic bypass, promote inefficient technologies, harm the other customers who would then have to bear the burden of those uneconomic subsidies, increase the economic development problems of the State of New York, and benefit only the manufacturers and distributors of the uneconomic technology, and the customers who

buy their equipment.

Despite the above, the Joint Proposal has addressed many of Joint Supporters' concerns by providing for phase-ins of the bill impacts for existing customers,[10] a category that is broadly defined, and for customers with renewable generation resources,[11] and exempting completely from standby service rates customers whose OSG meets fifteen percent (15%) or less of the customer's load. The Commission's goal was that standby service should be provided at cost-based rates. No further exemptions or special treatment should be accorded.[12]

Lastly, the rationale that was used to justify the Joint Proposal's grandfathering of certain renewable technologies does not apply to CHP. There is nothing "new" about this technology; for many years, it was simply referred to as co-generation. Nor does traditional CHP qualify as a "renewable." See Executive Order 111. Joint Supporters' request for special treatment for CHP must therefore be denied.

3. The Commission rejected a separate rate for supplemental service in Opinion 01-4.

Based on their claim that a proposal to bill all of a customer's delivery on the standby tariff will stifle DG, Joint Supporters argue that there should be separate billing procedures for supplemental power delivery services, as opposed to backup/standby power delivery services. JS Comments, at 12-13. As Joint Supporters

---

9 Joint Proposal, at ¶ 3(b).

10 Given that the Joint Proposal's opponents actively participated in the generic standby proceeding, and have been aware of the move toward more cost-based rates related to fixed costs since before Opinion 01-4 was issued, the phase-in provision is very liberal.

11 The Joint Proposal even expands the definition of renewables to include a fossil-fueled technology.

12 As noted by a Con Edison witness during that company's hearing on standby rates, CHP projects are already encouraged by various programs administered by the New York State Energy Research and Development Authority ("NYSERDA")(Transcript, at 93).

see it, the absence of a split rate creates harmful uncertainty for customers considering the installation of DG, and a split rate structure would mitigate the discomfort DG customers would feel from being forced onto a new tariff when they install DG for part of their loads. Under Joint Supporters' split rate proposal, the electrical needs of a customer in excess of the maximum capacity of the DG should be considered to be supplemental to the capability of the generator, and billed at the standard "parent" rates. Id. Joint Supporters claim that this structural bifurcation is needed until all customers in a rate class are billed according to the same rate structure and principles. Id.

As an initial matter, the "harmful uncertainty" for DG developers that Joint Supporters allege will result from the Joint Proposal is really nothing more than what exists for most businesses decisions. There is always some risk and uncertainty, and this is neither "harmful" nor "good." Future fuel prices are just one other example of the uncertainty facing developers of DG.

More important, this proposal is at odds with Opinion 01-4. In responding to an argument that a standby customer should be able to purchase the balance of its load not served by OSG at the standard delivery service rates, the Commission stated that "the Guidelines provide cost-based delivery service rates that apply to the entire delivery service taken by a customer with an OSG regardless of whether the OSG serves all or only a portion of that customer's load." Opinion 01-4, at 21-22 (emphasis added). Opinion 01-4 and the Guidelines do not distinguish between supplemental service and backup service. Moreover, while a split rate approach was allowed by the Commission in Opinion 82-10,[13] the generic standby proceeding was intended to remedy concerns

[13] Case 27574, Consolidated Edison Company of New York, Inc. – Electric Service to Customers With On-Site Generation, Opinion No. 82-10 (issued May 12, 1982).

regarding the rate design approach taken in Opinion 82-10, including the split rate concept.[14]

4. Joint Supporters' request for a separate standby rate is inappropriate and unsupported.

The Commission concluded in Opinion 01-4 that "not enough valid cost data exists for OSGs to justify creation of a separate service classification or classifications for standby service." Opinion 01-4, at 6. Despite this clear statement, Joint Supporters now advocate a separate rate. They request that "a unique standby rate, without reference to parent rate classes" be established as soon as possible. JS Comments, at 20.

To support their request for a separate rate class for standby customers, Joint Supporters argue that creating a structure for standby rates which differs from the structure used for other members of the same class may violate PURPA. JS Comments, at 11. Here, Joint Supporters are attempting to relitigate an issue that was resolved in Opinion 01-4, where the Commission stated that the "rate design proposed in the Guidelines complies with [PURPA's] regulatory requirements" and is "otherwise consistent with the anti-discrimination principles underlying the PURPA regulations. OSG customers are included in the same rate classifications as other customers, and the rates for the OSG customers are based on consistent system-wide costing principles, as PURPA requires." Opinion 01-4, at 24. Furthermore, as the Commission concluded, "PURPA does not require a separate service classification for OSG customers and the rate design properly recognizes diversity of OSG customer use of delivery facilities." Id.

It is inappropriate for Joint Supporters to challenge the Guidelines and

[14] Joint Supporters may raise this issue in connection with the recently instituted Case 03-E-0640.

principles set forth in Opinion 01-4 in this proceeding. Such a challenge is also counterproductive to the Company's and the Settling Parties' efforts to submit a filing in compliance with those Guidelines and principles. Moreover, even if the Commission were to view Joint Supporters' request as an appropriate one for this proceeding, Joint Supporters have failed to produce the necessary supporting evidence[15] required by the Commission in Opinion 01-4:

> [U]ntil such time that significant data exists on the operation and cost causation of various standby service customers to justify the creation of a separate standby delivery service rate classification, the Guidelines provide that standby delivery service will be provided as part of the otherwise applicable full-requirements class tariff.

Opinion 01-4, at 7.

5. The proposed rates reflect an appropriate allocation between local and shared facilities, and cost segregation is not required by Opinion 01-4.

Joint Supporters criticize the allocation matrix contained in the Joint Proposal, arguing that it was developed "incorrectly," and that its sponsors have failed to justify the proposed allocation on a cost causation basis. See JS Comments, at 3-6. Specifically, Joint Supporters contend that the Joint Proposal's approach ignores distribution costs that are shared between distribution customers, and allocates too much cost to contract demand. Id. at 4. The resulting rates comprise "disproportionately higher" contract demand levels in service classifications where smaller OSG facilities (such as those found at hospitals and schools) tend to appear, e.g., PSC 115, SC 7-1 (Secondary) and SC 7-2 (Primary). Id. As discussed in the Lively Testimony, Joint Supporters propose revising the levels in the allocation matrix. Id. at 6. Like Joint

[15] Joint Supporters did not even submit a data request on this issue.

Supporters, NFG objects to the allocation matrix on the basis that it allocates too much cost to contract demand, and requests that additional costs be included in the shared component. NFG Comments, at 4, 6.

First, it is important to note that the shared and local facilities revenue requirements in the Joint Proposal do not reflect any single Settling Party's view of the appropriate shared and local facilities revenue requirements for standby service. Rather, it reflects a consensus view for settlement purposes among parties whose interests are diverse and normally adverse to each other.

Additionally, NYSEG has provided justification for the proposed allocation reflected in the Joint Proposal. The June 7 Filing, as well as NYSEG's February 7, 2003 filing of revised tariffs, demonstrate the development of an appropriate allocation in compliance with Opinion 01-4 and the Guidelines. In those filings, and consistent with Opinion 01-4 and the Guidelines, NYSEG based the as-used demand charges on the Company's FERC OATT revenue requirement. The facilities whose cost is recovered under the OATT were designed to service the coincident peak of NYSEG's system and, hence, they are shared costs under Opinion 01-4. NYSEG did not determine that additional non-customer costs were properly allocable to the shared component consistent with Opinion 01-4. Once NYSEG determined that only the FERC OATT-based system costs were "shared," then it followed that the balance of NYSEG's non-customer delivery system costs should be deemed local and recovered through the contract demand charge.

The matrix set forth in the Joint Proposal, while not the allocation proposed by NYSEG in its earlier filings, reasonably represents NYSEG's system design

and calls for the recovery of costs through as-used demand charges that well exceeds the recovery initially proposed by NYSEG. In its earlier filings, NYSEG proposed recovery of approximately $75 million in delivery system costs through the as-used demand charge. That amount represents NYSEG's OATT revenue requirement. The Joint Proposal matrix exhibits a proposed recovery of approximately $107 million of costs through the as-used demand charge. Clearly, NYSEG has moved significantly toward a greater recovery of dollars through this more volumetric charge.

With respect to Mr. Lively's alternative matrix, adding levels to the matrix for substation service – a level that is not provided in NYSEG's existing rate structure – should not be addressed here in the context of a compliance filing intended to reflect cost-based rates that were designed using NYSEG's existing rate structure to achieve revenue neutrality for each applicable service class.

Joint Supporters also argue that cost segregation should be added to the proposed allocation matrix, both in the June 7 Filing and in the Joint Proposal, to account more accurately for cost causation. JS Comments, at 5. This could be accomplished, Joint Supporters suggest, either by expanding the matrix to include individual cost components or by allocating the components and setting the matrix percentages to the resulting composites. Id. However, Opinion 01-4 does not provide for the cost segregation Joint Supporters seek.

6. Opinion 01-4 did not provide for dynamic pricing.

Based on their claim that DG is driven by economics that change throughout the day and across NYSEG's distribution grid, Joint Supporters argue that the wires charge for backup/standby power should be determined dynamically using the

estimated marginal line losses between the customer and the location associated with the New York Independent System Operator ("NYISO") price. JS Comments, at 15.

Clearly, the Commission did not envision dynamic pricing in Opinion 01-4. As such, it is inappropriate for Joint Supporters to advocate an entirely different pricing scheme in connection with NYSEG's compliance filing.[16]

In addition, a dynamic pricing model would require the development of customer-specific rates that fluctuate with the time when service is used. Lively Testimony, at 1. The implementation of a rate design that varied by customer, taking into account location and time of day, would be extraordinarily burdensome and most likely impracticable.

Finally, as was demonstrated by the cross-examination of Mr. Lively during Con Edison's standby hearing, Joint Supporters' dynamic pricing proposal has not evolved beyond the broadest theoretical levels. See Transcript, at 264-266. Mr. Lively has presented no specific formulas, and has given no consideration to the costs of implementing this proposal and whether the purported benefits of such proposal would justify these costs. Clearly, Mr. Lively's proposal, as currently structured, is simply unworkable and should be rejected.

B. Joint Supporters and NFG have failed to justify any of their other proposals.

1. Joint Supporters and NFG have offered no support for their proposal for a longer phase-in period for new standby rates.

In their comments, Joint Supporters emphasize the importance of including special provisions in the rate structure for standby service to "keep the playing

[16] Joint Supporters' concerns may be addressed in connection with the Commission's April 30, 2003 Notice Requesting Comments in Case 03-E-0641 – Proceeding on Motion of the Commission

field level." Id. at 7. Special provisions are needed, according to Joint Supporters, as long as utilities have two distinctly different rate structures, one of which applies only to customers with OSG and the other "standard tariff" that applies to everyone else. Id.

As Joint Supporters acknowledge, the Joint Proposal contains a number of special provisions, including a phase-in of the new standby rates for certain categories of customers, and customer charge credits for standby rate customers who have paid for meter and instrument transformation costs. Joint Proposal, at ¶¶ 3, 17. However, Joint Supporters demand additional special provisions. As discussed previously, Joint Supporters advocate a supplemental rate structure, dynamic pricing, and special treatment for CHP technologies. In addition, they suggest that there should be a longer phase-in period than that contained in the Joint Proposal. JS Comments, at 7.

First, Opinion 01-4 does not require standby delivery rates to include any special provisions to "level the playing field." In the Commission's view, the cost-based rates provide a level playing field. That the Joint Proposal includes some special provisions demonstrates only that its development was truly a collaborative process, involving concessions by the Company and by other parties. The only basis Joint Supporters and NFG offer to support their request for a longer phase-in is the fact that the Joint Proposal in the Con Edison standby proceeding contained an eight-year phase-in provision. However, Con Edison has a different service territory in a different location in the State, with different needs, and even Joint Supporters recognize the non-precedential nature of the Con Edison Joint Proposal. Clearly, the opposing parties have failed to justify this proposal.

Regarding Expedited Implementation of Mandatory Hourly Pricing for Commodity Service.

2. There is no basis for further broadening the definition of "existing customers" contained in the Joint Proposal.

Joint Supporters suggest that the threshold date for existing projects should be the effective date of NYSEG's new standby service tariff, rather than January 31, 2003, as stated in the Joint Proposal. Id. at 8. To support their claim, Joint Supporters argue that the proceeding was not well publicized among affected parties, so it is unreasonable to expect potential OSG customers in NYSEG's service territory to have anticipated the effect of the proposed standby rates by January 31, 2003. Id. Joint Supporters also contend that because the effective date of tariffs and/or the date of the Commission Order approving the tariffs are "familiar and acceptable" transition deadlines for the Commission, it would be reasonable to extend the definition of "existing" projects to the effective date of the tariff, which, pursuant to the Joint Proposal,[17] is six months after the Commission Order. JS Comments, at 8. Finally, Joint Supporters also request that the definition of "existing customers" be expanded to include projects approved by "an appropriate authorizing body," such as a School District Superintendent. Id. at 9.

Based on the lack of evidence to support it, the Commission should reject the proposal of Joint Supporters to broaden the definition of existing customers by extending the threshold date for projects. NYSEG made its initial filing in June of 2002, and the case was noticed under the State Administrative Procedures Act on July 3, 2002. Moreover, the Joint Proposal is the result of a long and involved process, including several technical and settlement conferences over the course of nearly a year. Therefore, the argument that the proceeding was not well publicized[18] has no merit, particularly in

---

[17] Joint Proposal, at ¶ 10.

[18] Additional awareness within the DG community in general may have been prompted by NYSEG's writing to customers individually taking standby service under not only NYSEG's

light of the fact that Joint Supporters and at least one of its witnesses were aware of the impending change in cost-based rates even before the issuance of Opinion 01-4. Further, the Joint Proposal has already expanded the definition of existing customers. See Joint Proposal, at ¶ 4. The approach taken by the Settling Parties to more broadly define existing customers was more than reasonable, and should not be disturbed.

3. Joint Supporters have failed to justify their proposal to eliminate surcharges where a customer exceeds the contract demand it sets.

Joint Supporters take issue with the provision in the Joint Proposal that permits the Company to collect a surcharge where a customer has set its own contract demand, and then exceeded it. Joint Proposal, at ¶ 9. Joint Supporters claim that there is no authority for imposing such a surcharge, or "penalty," as Joint Supporters inappropriately characterize it, that Opinion 01-4 does not mention the word "penalty," and that such a penalty would have a chilling effect on OSG development and investment. JS Comments, at 10-11. Furthermore, Joint Supporters contend that to avoid the imposition of a surcharge, it is likely that customers will overstate their contract demand, resulting in NYSEG systematically over-collecting revenues. Id.

Joint Supporters quote selectively from the Joint Proposal in order to justify the elimination of the surcharge provision. First, Joint Supporters ignore the fact that if a customer wants to minimize the risk of a surcharge, it can request that NYSEG set its contract demand, instead of setting its own. Joint Proposal, at ¶ 6. Where NYSEG has set the customer's demand, there is a lessened degree of risk[19] that a surcharge will be

---

Service Classification 11 tariff, but also the otherwise applicable service classification, summarizing this proceeding to date, and advising them of the next procedural steps and how to participate.

[19] Absent changes in equipment without giving NYSEG the required notification, there is no risk of

imposed.

The Joint Proposal also provides a one-time forgiveness for new OSG installations for exceedences of less than ten percent (10%). Id. at ¶ 9. Consistent with Commission precedent, customers can also install load limiting equipment to manage exceedences. Moreover, the new contract demand level set after the exceedence is not permanent; it may be reduced if equipment is removed, or once a year upon written notice to NYSEG. Id.

In addition, while Opinion 01-4 did not provide for such a surcharge, Joint Supporters do not mention the fact that Opinion 01-4 did not provide for a contract demand other than the anticipated full demand of the facility. To the extent flexibility has been negotiated, i.e., allowing customers to set their own contract demand, which was a concession to Joint Supporters and others, including a surcharge provision is reasonable and compensatory, and should be upheld.

4. The Joint Proposal provision concerning individually-negotiated rates properly permits NYSEG to recover its marginal costs plus a reasonable contribution to its fixed costs.

NFG requests that NYSEG be required to modify the provision in the Joint Proposal allowing for negotiated rates for projects that can economically isolate from the grid[20] to require only a contribution to its NBWC. NFG Comments, at 6. This request is inconsistent with Commission precedent, and should therefore be rejected.

In its Order Clarifying Prior Order and Directing Tariff Modifications, issued on January 13, 2003 in Case 01-E-1847 (the "January 13 Order"), the Commission stated that in negotiating flex rate contracts for standby service customers that can

---

a surcharge where NYSEG has set the customer's contract demand.

economically opt to isolate from the grid, the utility "shall employ the same principles it would in addressing other competitive options amenable to flex rate treatment." January 13 Order, at n.7. As the Commission then indicated, those principles are embodied in Opinion 94-15,[21] which provides for a marginal cost floor price to be included in flex rate contracts. Specifically, the Commission states that "[a] floor price for flexible rates will be calculated by each utility, and will generally be set at no lower than the marginal cost of service to the customer plus 1¢/kWh." Opinion 94-15, at 32. Further, the Commission concludes that "retention of a contribution from each [flex rate] customer toward common costs is an important policy goal." Id. at 24. Therefore, NFG's proposal does not comply with the Commission's contribution requirement embodied in its guidelines regarding individually-negotiated rates and, hence, it should be rejected.

5. Wyoming has failed to justify exemption from the new standby delivery rates.

According to Mr. Kuczmarski, the present cogeneration system at Wyoming was designed to provide ninety percent (90%) of the facility's required power, and that an additional ten percent (10%) of electric power is purchased from NYSEG pursuant to an agreement (the "Agreement"). Id. at 3. Mr. Kuczmarski requests that the Commission order NYSEG to grandfather the Agreement on its current terms.

Wyoming's request for grandfathering stems from its misinterpretation of the Agreement and the Joint Proposal. The Agreement expressly calls for Wyoming to purchase standby service from NYSEG in accordance with NYSEG's applicable tariff: "Hospital shall be obligated to accept back-up, maintenance, and supplemental electrical

---

[20] Joint Proposal, at ¶ 12.

[21] Case 93-M-0229, Competitive Opportunities Available to Electric and Gas Customers, Opinion

service (together, "Standby Service") from NYSEG in accordance with the terms of NYSEG's applicable tariff on file with the [Commission]." Kuczmarski Testimony, at 3. The Agreement will not be impacted by the Joint Proposal,[22] and there is no authority for the Commission to disrupt the Agreement. Therefore, there is no reason to grandfather the Agreement. While the Agreement will not change as a result of the Joint Proposal, the applicable Commission tariff will be revised, and Wyoming's rates may change. This is clearly provided for in the Agreement, which refers to NYSEG's applicable tariff on file with the Commission.

Lastly, Wyoming claims that the Joint Proposal will render its OSG cost-prohibitive. Id. at 2. However, the cost of OSG will not change due to the Joint Proposal; rather the availability of economically-inefficient rate savings may have changed as a result of the Joint Proposal. While the rate savings may have improved for some customers – indeed some customers with OSG have embraced the new rate structure – the point is that the Joint Proposal provides a better system of price signals for economically-efficient OSG.

---

and Order Regarding Flexible Rates (issued July 11, 1994).

[22] Paragraph 14 of the Joint Proposal provides that nothing in the Joint Proposal "shall be construed as affecting in any way any existing contractual arrangement for the provision of standby services to which NYSEG is a party."

IV. CONCLUSION

For the foregoing reasons, NYSEG respectfully requests that the Joint Proposal be adopted as written.

Respectfully submitted,

Huber Lawrence & Abell

Huber Lawrence & Abell
605 Third Avenue
New York, N.Y. 10158
(212) 682-6200

Attorneys for NEW YORK STATE
ELECTRIC & GAS CORPORATION

Nicholas A. Giannasca
Katherine W. Dandy
Of Counsel

May 8, 2003

MS. DANDY: A copy is being tendered to the court reporter and, your Honor, at this time I would proffer the NYSEG panel for cross-examination.

JUDGE EPSTEIN: Cross of these witnesses?

MR. BROWN: The Joint Supporters, Ruben Brown first, and others.

I want to explain our procedure which I've cleared with Company's counsel and the counsel for the Staff and MI. We have our own panel here today and they have unique areas of expertise, and so we are going to offer questions led by the "E" Cubed Company staff with additional questions by others present.

They respect your request to keep the issues focused on NYSEG matters and on general matters and if, at any point, any of the questions turn into comments, they are prepared to respond immediately to any requests to stop by you or any other party in the room.

Mr. Young will proceed.

MR. YOUNG: Thank you.

CROSS-EXAMINATION

BY MR. YOUNG:

Q I'd like to start asking a question about the Joint Proposal Section 18, which is the NYSEG exemption, and that section essentially says that customers taking NYPA power will pay for standby service only for that portion of the load that's not covered by NYPA power. So, first of all, is that a correct understanding of that provision?

A (Host-Steen) Yes, Mr. Young.

Q Thank you. And how will that be billed?

A (Host-Steen) How will that be billed?

Q Yes. Well, I mean was it --

MR. GIANNASCA: Mr. Young, what is the "that" in your question?

MR. YOUNG: How will that portion, the NYPA portion of the --

A (Host-Steen) The NYPA portion of supply?

Q Yes.

A (Host-Steen) That will be billed under the appropriate tariff provisions, the Economic Development Power, Power for Jobs or the expansion power.

Q And so will the customer receive two bills, one

for the public standby power and one for the NYPA portion or will that all be in one bill?

A (Host-Steen) Both items would appear on the one bill and are identified as the NYPA portion of it and the non-NYPA portion of it.

Q Okay. And so NYSEG will have some methodology to determine which portion of the delivery is attributed to NYPA power and which portion of the delivery is applicable to bundled power?

A (Host-Steen) We currently bill NYPA power and non-NYPA power on the same bill and there's an allocation process that assigns a portion of it to NYPA-delivered power, NYPA power, and NYSEG-delivered or provided power, and there is a ratio that's used on current bills, and customers -- NYPA customers are familiar with that methodology as currently used. Although we haven't gotten that far, we do have a period of time built into the Joint Proposal for setting up a table. I would envision at this time that this would continue.

Q And just to clarify a little bit further that since you tend to know in advance how much power will require delivery service, is one portion -- is the NYPA portion fixed with the other

applicable standby portion delivery service to vary, or how -- I'm just curious how that's going to work.

A (Host-Steen) It's based -- most of the NYPA allocations are based on a kw assigned per month per customer, and we use that table and use that in relation to the meter capability that appears on the meter.

Q And how is that different from a billing system in which supplementary service is segregated from standby service?

MR. GIANNASCA: Your Honor, I have an objection. This was covered in the comment period. It is not part of this proceeding. The Commission has ruled on this issue and we're supposed to be sticking to the material that enhances the record. Testimony on other issues will not be supported. You can have the witnesses answer, but they'll simply tell Mr. Young that this is not part of the proceeding.

JUDGE EPSTEIN: I think, in all fairness, it's better to allow the question to go forward because I don't want us to get whipsawed by issues here. You know, something

happened in the Con Ed hearing, and then parties might argue about whether or not it was -- might argue about its relevance here, and I'm not sure whether it's generic or not, so just to be on the safe side, let's have the question answered.

MR. GIANNASCA: You want the question repeated, Mr. Host-Steen?

MR. HOST-STEEN: Yes. Would the reporter please repeat the question?

(The pending question was read by the reporter.)

A (Host-Steen) The NYPA power would not be supplementary unless the -- unless the OSG decides to cover all of the additional load other than NYPA load. I would envision that while we're speaking about OSG provides a certain level of load, there is an additional load delivered by NYSEG that's not associated with NYPA. I think NYSEG agreed to this provision and in recognition and in support of the NYPA programs, and not to address whether they're supplemental or not.

JUDGE EPSTEIN: Mr. Giannasca, you said the Commission reached a decision on that

matter. Were you referring to what Mr. Host-Steen just mentioned?

MR. GIANNASCA: No. Actually, I was referring to Opinion 01-4, in which the Commission ruled as to whether or not standby rates should apply to the entirety of the customer's load, and I believe the Commission answered that question in the affirmative, thereby eliminating the possibility for this type of split billing that Mr. Young is questioning my witnesses about.

JUDGE EPSTEIN: Oh.

MR. MAGER: Your Honor, I believe the passage being referred to is on the bottom of page 21, going on to 22, of Opinion 01-4.

MR. YOUNG: Well, is it the position of the Company then that it's not -- I just want to double check that it's not the position of the Company that splitting out the NYPA portion of the bill violates Commission Opinion 01-4.

MR. HOST-STEEN: I would ask counsel to address something of what that violates.

MR. GIANNASCA: Your Honor, I believe that that's an inappropriate question

for the witnesses. Basically, Mr. Young is asking the panel to reach a legal conclusion.

JUDGE EPSTEIN: That's true. I'm also not a big enthusiast for having a legal argument on the hearing record when we could do it off line, but I was looking for a little guidance as to what's generic and what's not, and I think I have a better sense for it now.

MR. YOUNG: I was just trying to understand the methodology, and would it be possible for the witness to provide an example using numbers, in answer to that earlier question? I'm happy to get off of this legal stuff.

MR. HOST-STEEN: Unless --

MR. GIANNASCA: Your Honor, excuse my late objection to this, but I think that asking the panel at this time to use valuable resource time to calculate what Mr. Young wants them to would be ill-advised. I think we need to move forward with other questions perhaps on the same subject matter, but I don't think that the panel is in a position right now to perform calculations.

MR. HOST-STEEN: We don't have a

copy of a sample readily available to us. I don't know whether we're able to replicate one here or not.

MR. YOUNG: Well, in the interest of time, I'm happy to move on for now. We might want to -- I'm sorry.

BY MR. YOUNG:

Q We would ask how many NYPA customers currently are served by NSYEG and how many of those have on-site generation? Ballpark is fine.

A (Host-Steen) We have several hundred PFJ customers. I think we have approximately between five and ten EDP customers -- Economic Development customers, and I think there's half a dozen-plus expansion customers, and I'm trying to just think about it. I don't know of any that specifically have on-site generation at this time, but I'm not that familiar with all of the PFJ provisions, the historic provisions, and I don't know of any that have on-site generation.

Q And in any event, all of the customers will have the rates split between NYPA and standard standby. All of NYSEG's significant customers using -- or I guess all of the customers in the

categories you mentioned, the EDP and other programs, will have their bills split between standby and the other service?

A (Host-Steen) Again, presently it is split, and we have a six-month period to determine how we want to reflect these rates. My expectation is we have some kind of a commitment to NYPA to exclude that from -- from standard rate billing at NYSEG when the standard rate comes in from the Commission and as a convenience or a courtesy, there will be information to be included on the same bill.

Q Thank you, and I'd like to turn back to the Joint Proposal, to Section 5, and the language in that towards the end of the section says that a customer can be --

MR. GIANNASCA: Mr. Young, can you please tell the witness exactly where you are?

MR. YOUNG: I'm looking at Section 5 of the Joint Proposal on page 6. Well, the version I have says page 6, but it may be page 5 in somebody else's version and it's Section (b) of the last sentence of that section.

MR. GIANNASCA: Thank you.

MR. YOUNG: I'll read it for you: "***has not operated or is not operating that OSG in a material manner in order to serve the customers' load," and we would like more information about how the term "material manner" will be defined and applied by the Company.

A (Host-Steen) I think that will be fleshed out further when we make our compliance filing -- billing compliance, in compliance with this Joint Proposal when the Commission decides. "Material manner" in the first instance would mean that the installation is not simply put in place at a threshold just above what is here, 15 percent threshold, in such a manner as to affect billing in the proposed service classification of the standby rates which are beneficial to higher load customers.

Q In order to make that determination, do you envision that the output of the generator would need to be metered?

A (Host-Steen) I would think so, but I'm not -- I'm not sure that that would be necessary, depending on the size of the installation, and there may be other ways to ascertain that

situation.

Q And I just have a couple of more areas of questioning. Changing the subject completely, do you have any information what the average line losses are in your distribution system?

A (Host-Steen) I'm not prepared to discuss that.

MR. GIANNASCA: Your Honor, I also want to object. I don't see the relevancy of the material that Mr. Young is questioning about here to this proceeding.

JUDGE EPSTEIN: It could be. It sounds to me like it's preliminary to something that might have a bearing on the cost of service.

MR. YOUNG: Well, the question I was going to go for is to understand how the line losses are billed, who pays for line losses.

MR. HOST-STEEN: I don't think that that's -- I don't think that that's material here. We were required under the Decision 01-4 to provide rates by service classification based on the revenue requirement as already determined by the Commission in our distribution delivery rate case.

MR. YOUNG: Even as a general cost category?

MR. GIANNASCA: Your Honor, I have no idea what that means. Was that a question?

BY MR. YOUNG:

Q If you were creating very broad buckets for apportioning costs, presumably line losses would be part of a different bucket. I'm thinking language that is different than the unbundling proceeding. I don't know what language is commonly used for defining the cost of theft. I think that there's an understandable meaning to the question.

MR. GIANNASCA: Mr. Young, I just want to apologize. I did not mean to interrupt you.

Your Honor, I object to where this is going. Is this going to some subject matter that is a part of this proceeding, and I think it's appropriate to ask Mr. Young that, if this is going to dynamic pricing, let's get there so that I can object because that's not relevant to this proceeding, but if we're not going to dynamic pricing, why are we talking about line losses?

JUDGE EPSTEIN: Okay. Why are we talking about line losses?

MR. YOUNG: We were going to dynamic pricing, so if you want to object, the last question that you can choose to object to or not, and that is simply this, that in order to meet peak demands are NYSEG distribution facilities currently designed to accommodate that peak demand plus the associated line losses on peak?

MR. HOST-STEEN: I'm not -- I do not work on system designs for NYSEG.

MR. YOUNG: Okay. Thank you. I have a couple of questions about the real time pricing language. Oh, actually that is a good question. Is it possible to get the answer to that question at some point if the panel today is not -- is not expert to answer that?

MR. GIANNASCA: Is that a --

MR. YOUNG: My previous question.

MR. GIANNASCA: Is that a formal interrogatory in this proceeding?

MR. YOUNG: It can be.

MR. GIANNASCA: Your Honor, we have no objection to reviewing the interrogatory

and once we see the transcript, then we'll do our best to answer it within a reasonable time period.

JUDGE EPSTEIN: Okay. Is everybody satisfied that the information that Mr. Young is looking for was described specifically enough to be provided? Everybody understands?

MR. GIANNASCA: Your Honor, let me make this clear. I said that we will attempt to respond to the interrogatory within a reasonable time frame. I didn't say we would provide the information. If, upon reading the transcript at that point, we deem the request that has been made to be irrelevant to this proceeding, we will object.

JUDGE EPSTEIN: Okay. But I'm just trying to get at whether we understand what information is being requested.

MR. HOST-STEEN: Could Mr. Young just submit it quickly as a written interrogatory so we could respond to a question that way?

MR. YOUNG: If it's preferable for that to happen, we can handle it that way, and now I have some questions about the

implementation of real time pricing.

MR. GIANNASCA: Mr. Young, what section of the Joint Proposal?

MR. YOUNG: I believe it's Section 11, page 8, on the copy that I have.

BY MR. YOUNG:

Q And first, I'm -- with the implementation of real time pricing, presumably all energy costs will be -- will need to be recovered from customers. One component of energy costs is the ICAP payment for reliability purposes. It goes to the ISO, and could the Company explain on what basis ICAP will be billed in real time?

A (Host-Steen) Mr. King will answer that question.

A (King) Currently, with our real time pricing program, we pass the UCAP through. It does not change by hour. We calculate the UCAP based on the monthly UCAP auction of the ISO, and that number is passed through as a fixed number, so that would not change hourly.

Q So to clarify, when you say is "fixed," is that "fixed" volumetric or fixed by demand?

A (King) It would be a part of the energy charge which would be a volumetric charge.

Q Okay. And so then that would -- and it will be the same whatever happens? I know it varies by ability period and other periods.

A (King) No, I'm sorry.

Q You were probably answering my question. That's fine.

A (King) Currently it would change each month based on the New York ISO auction, which is -- that's our agreement.

Q And then each month it would be a volumetric energy portion of the total?

A (King) Correct.

Q And that's how it would be billed?

A (King) That's correct.

Q And that would be the same on peak and off peak?

A (King) It is now, yes.

Q And a different billing question: Are there currently some on-site generation customers who pay -- who pay a bill that may vary between months depending upon what the load factor is of that customer?

A (Host-Steen) I don't get the drift of that question.

Q Well, I'm not sure that I do either. I understand that there are some customers who can

switch between Service Class 7 or 11 depending upon whether or not their 12-month rolling average load factor is above or below a particular threshold.

A (Clune) Well, they can't switch between 7 or 11; if they're on SC 11 and their load factor exceeds ten percent, then they automatically get billed at supplemental rates, which is SC 7, the excess rate.

Q And can you tell me something about how that calculation is computed?

A (Clune) It's based on a 12-month rolling average. It compares 12 months of contract demand to the 12 months of what they have paid in demand.

Q And is that use 24 hours in the day or only on peak periods?

A (Clune) On peak periods. Well, I'm -- the ten percent load factor calculation is based on peak or off peak.

Q Okay. And I'm not sure I completely understood the calculation. Just for my benefit, what do you divide by?

A (Clune) Are you asking the ten percent load factor?

Q Yes, I'm asking the ten percent load factor calculation. I'm sorry if I wasn't clear.
A (Clune) That one takes -- let me think, the number of on-peak hours in the year and the number of off-peak hours in the year and it looks at the energy on peak or the total energy on peak or -- I'm sorry, on maintenance backup factored in there, and there's a calculation based on that.
Q So in the bigger picture then, if the result of that calculation shows that the customer has greater than ten percent load factor, it pays based upon which rate class?
A (Clune) Whatever their otherwise service classification.
Q And if they're lower than that, then they pay?
A (Clune) If it's lower than ten percent, then they continue to pay at 11 percent. If it's greater than ten percent, then we do an average of the last 12 months.
Q And would you say that gives an incentive to the OSG operator to operate their equipment in a particular way?
A (Clune) I don't think so. I think how they use it depends on if they take a look at the load

factor and if they take a lot of usage from the Company, we would probably attempt to deal with that.

Q Is there a big price differential between the supplemental rate and the otherwise billed rate, any ballpark?

A (Host-Steen) Mr. Young, the existing SC 11 rates -- the existing SC 11 rates are what the Company has been operating under since 1992, '93 -- '94 is the last time they were changed. They have been consistent with the EDP community. That was a negotiated protocol that was developed in 1993-94 that allowed our customers to take service if they were at or below the SC 11 level. If the customer chose SC 11, there was a load requirement, a maximum for standby service, and the ten percent threshold I think has been in effect since the original 1992 compliance filing, so I don't know. We bill it, we take a look at it. We take a look at the multiple components of the SC 11 rate, the demand component, and then based on that component average we add them up and take credit for that. The load factors of the standby use, that's the backup or the maintenance. If it

exceeds ten percent, the customer then goes to Service Classification 7, 2 or 3, which in some cases may be more advantageous or less advantageous as a service classification, so I don't know what you --

Q Knowing that that's the way many electric customers have been billed for a long time, I presume that many of those customers will be eligible for the -- for the phase-in for existing customers, and I'm curious, since they may pay one of two different rates currently, I'm curious how or whether the Company has figured out what the phase-in -- the percentage phase-in would be based upon.

MR. GIANNASCA: Your Honor, I have to object. I don't understand the question. Perhaps Mr. Young can rephrase it, particularly the presumption that he's making as to whether or not the OSG customer would be defined as an eligible customer and entitled to a phase-in.

(Pause.)

JUDGE EPSTEIN: Does the panel understand the question?

MS. CLUNE: I believe so. If I

understand it correctly, I think what you're asking is that if the customer right now, if they receive the ten percent load factor, they're being otherwise billed for the service, that's what it would be compared to when the phase-in takes effect. If they're billed at SC 11, that particular method right now, that's what it would be compared to.

MR. HOST-STEEN: And if they go over the ten percent during the phase-in period, it would be whatever level is used right now.

MS. CLUNE: Right, whatever they're billed at this point.

BY MR. YOUNG:

Q That doesn't answer my question because currently the determination, as I understand it, is based on a 12-month rolling average. I didn't know whether you were proposing to set one threshold for the determination, if the rate were to apply for any existing customers, and I'm not making a hypothesis about whether or not that would be the case but, if so, I'm curious whether the calculation would be based upon the rate that they would pay each month based on the 12-month rolling average or if it would be fixed

one time.

MR. GIANNASCA: Your Honor --

A (Host-Steen) We would bill each meter reading on the rate that would be in effect absent the result of this proceeding. We would take a look at that amount and if that was over the ten percent threshold for SC 11 that had been chosen for billing -- we would take the appropriate billing on the old protocol, we would compare that amount with the billing under the new Service Classification 11 as it's developed and coming out of here, and we would use that SC 11 and phase it in as it's developed.

MR. YOUNG: Thank you, Mr. Host-Steen.

MR. BROWN: No questions at this time. Turning to Mr. Geartz, who is the manager of customer relations for Siemens Building Technology and manages the relations with a group of schools in NYSEG territory that have on-site generation, including three schools in Binghamton and other communities, Garry, do you want to raise a question or two at this point?

MR. GEARTZ: I think I just -- I

just have one question. I'm just -- I don't have the actual quote --

MR. BROWN: I'm sorry. That quote actually was a quote from the Staff. We'll come back to that. Why don't you ask the general question as to the -- the sense of operation of schedules, the nighttime purchase from the grid and the daytime generation, and see how this panel would respond. Is that an appropriate expectation on your part?

MR. GEARTZ: Well, I'll get there.

JUDGE EPSTEIN: You folks want to consult?

MR. BROWN: Yes, can we have a brief time?

MR. CRISTOFARO: Bill Cristofaro. I have a question ready.

MR. BROWN: Okay, Bill Cristofaro.

MR. CRISTOFARO: The question I have -- can you hear me okay? The question I have has to do with the contract demand rates and the analysis of revenue neutrality between the standby tariff, and I note that in our analysis of impact on customers, the proposed standby tariff contract demand rate, depending

upon the type of electric service, is in the range of 7.50 to perhaps $5 per kilowatt for contract demand. In addition to this rate, the standby customer must pay the daily as-used demand. We note that with the new NYSEG tariffs to take effect in January 2003, the parent tariffs, the new NYSEG parent tariffs, the contract demand rate -- or excuse me, the regular demand rate and the current tariffs ranged between $7 and $8 a kilowatt. The point I'm making is that the contract demand rates and in the standby tariff, that you combined with the daily as-used demand appears to be greater in the standby tariff than in the current so-called NYSEG parent tariffs for the same customers. So my question -- that's the foundation of my thought. My following question is involving revenue neutrality analysis between the two-year rate classes, between the standby tariff and the parent tariffs --

MR. GIANNASCA: Mr. Cristofaro, is that a question?

MR. CRISTOFARO: I'm coming to the question. It's kind of a foundation here.

MR. MAGER: I guess, if I may interrupt, I'm not understanding the foundation. It sounds like a comparison of apples to oranges. The standby contract demand rate and the as-used daily demand rate which may not get charged depending on the performance of the OSG and how it's designed, is really not the same thing as the demand component of full requirement service. So --

MR. CRISTOFARO: I understand that.

MR. MAGER: I'm concerned that this question may make the record unclear.

BY MR. CRISTOFARO:

Q I would ask the question then. The question has to do with the -- of course, the basis of standby tariffs is that for the ability that they be revenue neutral in relation to the comparison of the current tariffs, is that correct?

A (Host-Steen) Revenue neutral by service classification?

Q Is that correct?

A (Host-Steen) Yes.

Q Okay, fine. My first question is this: Did the revenue neutrality model reflect substantial

cost effects of on-site generation sites moving from secondary distribution authority to primary distribution because that changes the cost allocation between the rate classes?

A (Host-Steen) I don't think the Commission's concept of revenue neutrality as set forth in the 01-4, specifically at page 7 of the Opinion, is dynamic of what the changes are going to be. We've established a rate design and revenue allocation in the compliance filing of the distribution delivery case and all we were charged to do is to match those using the ultimate customer charge contract demands and the demand for the appropriate size customer for the individual meter.

Q So what you're stating is that in the revenue neutrality analysis there is no -- there is no consideration for OSG sites that may move from a secondary distribution to a permanent distribution? That's just a yes or a no.

A (Host-Steen) We did not make such an assessment.

Q Okay. The second question I have is also related to the revenue neutrality analysis. Did the analysis reflect a potential decrease in the

cost of maintaining utility's distribution and support systems due to reduction in maintenance or reduction upgrades to subsequent load relief due to on-site generators?

A (Host-Steen) We simply designed compliance rates to meet the approved delivery revenue requirements set forth in the $75.5 million and did not dynamically look at what's going to happen to the customers' loadings on our system over the three, four or five years.

Q You understand why I asked the question is because one of the engineering issues that I'd be familiar with is that on-site generators installed in certain areas actually can result in cost reductions to the utility, leaving the load --

MR. GIANNASCA: Your Honor, I object. That may be his opinion, but that's not even a question, so if he would like to ask the panel a question, he's free to do that.

JUDGE EPSTEIN: You want to reframe that as a --

MR. CRISTOFARO: No, I think I'll just go on to the next question.

JUDGE EPSTEIN: Okay.

Q Another question has to do with revenue neutrality as well. Does the revenue neutrality model reflect potential decreases in the kilowatt-hour costs in the summer due to the ability of OSG plants to supplement the grid during periods of peak demand and thereby reduce --

A (Host-Steen) There is no revenue neutrality model.

MR. GIANNASCA: Your Honor, I object to the question. It's been asked and answered. The panel has already testified as to what went into the revenue neutrality analysis and they did testify as to the inclusion or exclusion of a specific revenue consideration as to costs; so Mr. Cristofaro is giving us a completely different revenue cost than has been considered and we're just wasting a lot of time.

MR. CRISTOFARO: I think this is a clarifying question and I submit I only have one more question.

JUDGE EPSTEIN: Yes. The objection is overruled because if the panel testifies as

to the general approach that they took, let's call it a nondynamic approach, it might be useful to establish what variables were excluded by that -- by the panel or by the Company taking that approach.

MR. CRISTOFARO: I just have one more question, and this one talks about revenue neutrality for the utility for standby versus current as well.

Q In those calculations for revenue neutrality, was a comparison considered of increased revenue to the utility due to additional gas distribution revenue as a part of the analysis?

A (Host-Steen) I repeat, the Company designed standby rates in accordance with 01-4 targeting the revenue requirement established for the electric delivery business in our most recent rate case, 575.5. It did not look at any -- did not assess nor were we required to assess any change in natural gas delivery in any way.

MR. CRISTOFARO: Okay. I have no further questions.

MR. BROWN: I'm going to turn to Ron Krawiec, the Chief Operating Officer of TLC Health Care and Lake Shore Hospital, who has a

couple of questions.

BY MR. KRAWIEC:

Q I'm a consumer affected by these rates and a novice to these proceedings, so if I'm out of line, for the record, please correct me. I don't have the technical expertise that a lot of people in this room have. My understanding from NYSEG and some of the people that met with us is that our rates will be set on the highest rate we've had in the last two years, the highest demand rate we've had in the last two years, which was last August when we shut down our co-gen for service and haven't been running the air-conditioning through the hospital and nursing home, is that true?

A (Host-Steen) If NYSEG were to establish a contract demand on the new rate, we would take a look at the highest demand taken from NYSEG in the previous 12 months, including consideration of the operation after the on-site generation.

MR. BROWN: But at what point would that demand be looked back to; is it August of 2001?

MR. HOST-STEEN: I would expect with these tariffs, Mr. Brown, I would expect them

to be effective on or about January 1st, 2004, so we basically would be looking at -- and again we do have six months for the implementation -- I would think we would be looking substantially at the year 2003 if NYSEG were to establish what the contract on demand service would be.

MR. BROWN: Excuse me for interrupting, Mr. Krawiec.

BY MR. KRAWIEC:

Q That rate, once a contract demand is set, is not renegotiated; it continues on forever?

A (Host-Steen) I think there is a provision in the Joint Proposal that, if there is a change in the operation of the customer or if there is equipment removed such that that peak would not be achieved again, that upon a written request -- I think a 90-day written request -- that you could lower that threshold at that time. For example, if this peak were caused by electrically operated air-conditioning and you switched to gas-fired air-conditioning, something of that nature that would take that load off would then modify the contract demand.

Q Would it go up automatically for additional

demand level in a subsequent month without a request?

A (Host-Steen) I'm sorry?

Q Let's say it's set for August and say the use is 800 kilowatts and our normal usage is in the 400 range. You said we could lower it with a 90-day notice of removing equipment. If that particular demand hits 900 in a subsequent year because our co-gen gets in service at the wrong time, would that automatically become a 900 demand level for the future?

A (Host-Steen) That would remain 900 for one year or until the Commission attempted to lower the change in operation.

Q So it will always go up by the highest peak we will ever hit?

A (Host-Steen) The meaning of the contract demand would be, under the 01-4, to set the contract demand at the maximum anticipated load for the facility, and that load is provided by delivery system or that load is provided by the on-site generation, so in all actuality if your peak demand on the system in August due to air-conditioning is 800 or 900, whatever it might be, if NYSEG were to establish the contract

demand it would be established in that area.
Q But in November or in September and October when we only have 300, we'll be paying for 900 when there's no air-conditioning or heat loss.
A (Host-Steen) That is a monthly charge, an annual cost that will be paid each month. The concern you are raising will be addressed by the Commission providing an as-used demand charge versus a contract demand charge which is to compensate us for having the facilities in place to deliver the power to your facility regardless of temperature, regardless of the time.
Q There is a --
MR. BROWN: Excuse me. You may resume, Mr. Krawiec. You may resume questioning.
Q There is a definition for backup power that exempts facilities from the break. Being that we're a rural hospital, is that status of change of definition of backup power as it stands right now?
A (Host-Steen) Rural or urban hospital makes no difference as far as I'm concerned.
Q Except in the emergent --
MR. GIANNASCA: Your Honor, could we

please instruct Mr. Krawiec to stick to questions?

MR. KRAWIEC: I will. The fact that we are a hospital and hospital's nature is taking care of a patient and the patient could be in ICU, could be in surgery, and there are a lot of things you cannot postpone, we built the co-gen with the situation that if there was ever an emergency even though we have emergency generators that will keep the lights on and keep some outlets going and not perform all the services that you need to perform in a hospital to take care of patients, has there been consideration that in a hospital emergent setting that a co-gen could be considered backup in case of terrorist attack or any other kind of failure of the NYSEG system to maintain the emergent nature of our services?

MR. HOST-STEEN: I would venture to say that our concept of an emergency generator is a generator which would operate only during occurrences when utility delivery is not available. To the extent that an emergency generator is run substantially 20, 30, 40 percent of the time, it would no longer meet

the requirement for emergency consideration. I think you indicated you do have an emergency -- an emergency generator, and that the way you operate that is with the intent of the emergency waiver of applicability of NYSEG rates.

MR. KRAWIEC: Does NYSEG have any provisions within the state to supply, in case there was an outage for a length of time, any backup power to the hospital as far as portable -- a portable generator, something like that if you had an outage of more than five to seven days? Does NYSEG have any backup power that's been brought to a rural hospital?

MR. GIANNASCA: Your Honor, I object. I don't think the panel is capable of answering that question. If they don't know --

JUDGE EPSTEIN: Well, that's always true. Either they know or they don't.

MR. HOST-STEEN: I -- I don't know whether in times of like an ice storm this winter south of Rochester or something, I don't know what the situation was as far as

generation. I would only -- I think it's our understanding that when there is an emergency, customers on life support at the hospital have the highest priority for us to restore the delivery system.

MR. BROWN: If someone in the Company knows, we could submit an interrogatory and ask for an answer to the question.

MR. GIANNASCA: That's fine.

BY MR. KRAWIEC:

Q On Provision 12, NYSEG has authorized individual negotiated agreements for customers. In a situation of Lake Shore Hospital, the fact that I think my understanding is with individual contracts are negotiated so people would not leave the service area because of particular changes in rates. The hospital can't leave a service area. Is there a potential that the hospital would be able to individually negotiate their rate structure with NYSEG?

A (Host-Steen) Mr. Krawiec, I think you have a bit of a misunderstanding about the purpose of Paragraph 12. It's -- it's not that you would physically leave the service territory; it's

that if you were to take a look at your OSG and determine that you could fill the patient emergency generation under a facility such that you would no longer need to be interconnected with our delivery system, if that were a viable choice for you and your facility, NYSEG would then be authorized to negotiate a change in the standby rates to the extent that additional emergency installation would not be economic for NYSEG and its other customers.

Q Under these conditions, could you negotiate an individual rate with us if we came back and said we're going to build additional capacity?

MR. GIANNASCA: Your Honor, I object. I have no idea what "under these conditions" refers to.

MR. KRAWIEC: Under the rate structures that are being set that we haven't implemented yet.

MR. BROWN: You mean under Joint Proposal 12, Section 12?

MR. KRAWIEC: Yes.

MR. HOST-STEEN: If the hospital meets the requirements of Section 12 of the Joint Proposal and rates are implemented that

are unfair to the customer, the customer has a viable alternative economically, environmentally, then NYSEG would be authorized to negotiate a rate that would be different than the SC 11 otherwise applied to that situation.

MR. BROWN: Thank you, Mr. Kraweic.

I'm going to ask Mr. Lively to ask a question or two.

BY MR. LIVELY:

Q At various times you described the rate level as being revenue neutral. At various times you described it as being cost-based. Which is it?

MR. GIANNASCA: Your Honor, I object. I don't believe that the panel testified that the rate level is revenue neutral. I believe they testified that they have designed -- that they designed the rates under the concept of revenue neutrality.

Q Under -- concerning counsel's question that seems to say that the revenue level of these rates is not revenue neutral. Was that the case?

MR. GIANNASCA: Your Honor, I don't know whether that question is directed at me

or at the panel, but Mr. Lively is asking questions of the panel.

Q Are the revenue levels specified in the standby rates revenue neutral?

A (Host-Steen) Yes.

Q Are they cost-based?

A (King) Yes.

A (Host-Steen) Yes.

Q And under these rates, a customer who is on your system, will NYSEG recover from that customer its total costs?

A (Host-Steen) The recovery of NYSEG's revenue based on these rates is not an issue relative to the development of the process. The concern that I have about recovery and the subject of recovery is covered in the Joint Proposal in Paragraph 21.

Q But the question that I'm asking here is for a specific customer. You say that it is cost-based rates.

MR. GIANNASCA: Which specific customer?

JUDGE EPSTEIN: Mr. Lively, are you asking whether it would be fair to say on a customer-by-customer basis the proposed rates

are cost-based?

MR. LIVELY: Yes.

MR. HOST-STEEN: I would say by definition the rates are cost-based as required by the Commission.

Q So that for a customer, the utility will recover its costs based upon these rates?

A (Host-Steen) The -- whether the old rates or the new rates, on a customer-by-customer basis, the -- there may not be a perfect match. I would venture to say that under the proposed service classification rates, there would be a closer match to the fixed costs, recovering the fixed costs of having a delivery system available for each customer.

Q You say that there's a closer match, I believe are the words you used; I'm not sure exactly what the words you used, for under the new service classification. Why do you want to disqualify customers from using that rate if it's a cost-based rate?

MR. GIANNASCA: Your Honor, I don't understand the question. What type of disqualification? I don't understand the characterization.

Q In Paragraph 5 of the Joint Proposal, there is provision in Item (b) that allows NYSEG to disqualify customers from receiving the standby -- service under the standby rate and, if the rate is cost-based, why should we be interested in disqualifying customers?

A (Host-Steen) The new Service Classification 11 rates are applicable solely to customers at NYSEG generation interconnected with the Company. Being more cost-cased, in effect, the fixed cost of the delivery system, customers with higher delivery load factor would see a benefit from these rates. Customers with a lower delivery load factor would see increases as a result of those rates and what you're not going to be able to expect with this particular set of protocols available to customers whether the Joint Proposal includes a threshold of 15 percent lower fee installation and requires that that installation be done in the appropriate manner so as not to take advantage of the arbitrage discounts where arbitrage is taking place as a result of this OSG, and otherwise the existing SC 11 or other rates there for consideration.

Q Now, you've already testified that this rate is more cost-based, more nearly cost-based than the current rate, and shouldn't there be some provision to kick out customers from the current rate who operate in a manner such as described in (b)? I mean if considering that this rate is supposed to be more cost-based, shouldn't -- shouldn't you be encouraging customers to get under this rate?

MR. GIANNASCA: Your Honor, I think that that's the same question that has already been posed regarding disqualification.

JUDGE EPSTEIN: I think it is the same question. The answer, as I understood it, was that you don't want the customers gaming the system on the basis that -- of what their load factor is or -- well, I'll leave it at that, that I mean I -- I think there's an underlying question here that wasn't expressly answered, which is shouldn't the company be economically indifferent to how many customers avail themselves of a cost-based rate if it is cost-based. The answer, as I understand it, was there might be some gaming based on those load factors. Whether that's a satisfactory

answer to you, you have to decide. Do you want to go -- subject to --

Q Subject to getting an objection again: So it's objectionable to the Company for the customers to, quote, game the system when the system that they're gaming is cost-based?

A (King) I just want to mention that these rates were designed -- they were designed as if all the customers went over to the SC 11 rate in compliance with the 01-4, just as customers have an option for going on our normal rates when we designed the rates for all customers going -- all customers were on a rate, so that's the difference here.

Q You're saying the customers have an option that they -- once they install OSG, that they have an option as to whether to take this rate or not?

A (Host-Steen) I think Mr. King is saying an option whether to install OSG or not given the rates that they are faced with. Hence the OSG industry has -- has grown. In fact, OSG takes a look at the electricity rates available to them for various standby services and then makes an economic decision as to whether to go to OSG or not. Going forward, the OSG industry would take

a look at NYSEG's SC 11, make a determination as to what size, what fuel, what type of OSG, how it will be sized to meet the load, what is the heat load, make a determination as to how it operates and make a determination whether to sever from the system by installing emergency backup, and the only set of dynamics are set up by these more cost-based facilities providing delivery of service, designed to provide delivery of service to the entire population of our customers but applying initially to customers with on-site generation.

Q So again -- I guess again -- it's a cost-based rate. You object to customers trying to use that cost-based rate?

A (Host-Steen) That's correct. I think that the Paragraph 5 of the Joint Proposal speaks for itself and -- Section 5 speaks for itself and we will certainly flesh that out when we get to the compliance tariffs.

Q Shouldn't that have been part of the Joint Proposal to flesh that out?

MR. GIANNASCA: Your Honor, I have a general objection to questions of the nature shouldn't the Joint Proposal have contained

this, shouldn't it have contained that. It's the result of fairly lengthy and involved settlement negotiations where numerous concessions were made by the parties. It doesn't contain every possible provision that one can concoct and that's true, so we can ask a number of questions about why doesn't it contain "A" or "B," but again I don't see the relevancy of that.

JUDGE EPSTEIN: Well, okay. We're not going to insinuate anything as to whether the parties did do a complete job when they drafted the Joint Proposal, but the question that I think is before the Commission is whether the Joint Proposal as it stands is worthy of being adopted or are there additional terms that somebody such as the Commission needs to specify before we go further.

I don't know if you want to restate the question. I mean the proper way for the witnesses to couch the answer would be if they want to address whether they think Paragraph 5 as currently written provides an adequate basis for the Commission to decide whether

it's going to be setting just and reasonable rates when it adopts this paragraph or -- and is that because this is as specific as anybody can get right now, or is there some other -- I guess I'd be interested in knowing whether the panel has a reaction to the premise that it could be fleshed out more and whether it should have been or not is beside the point.

MR. BROWN: Thank you, Mr. Lively.

MR. GIANNASCA: Your Honor, I wanted to ask a question. Could have been fleshed out in what circumstance, sir?

JUDGE EPSTEIN: That is, I think Mr. Lively's question goes to whether there is a lack of specificity, that if the Commission -- whether there's a lack of specificity such that the Commission can't properly go forward and adopt Paragraph 5 the way it reads now.

MR. HOST-STEEN: Your Honor, if I recall correctly, the predecessor company had adopted a threshold for operation under the standby rates and the Commission did make a determination about this, so I don't know if it's presumptuous for me to say whether the Commission made a determination based on this

or not, but it's already been approved in another case.

MR. BROWN: Thank you, Mr. Lively.

I'm going to ask a few questions and they will be few, and then we'll look toward the folks from Wyoming Community Hospital if they have any questions.

Garry -- I'm sorry, get back to Garry. You want to go ahead, Garry?

MR. GEARTZ: You go ahead.

BY MR. BROWN:

Q In the Provision 7 or Section 7 of the Joint Proposal, there is a term introduced twice. It appears with respect to an existing customer and it appears with respect to a new customer. This is the issue of establishing contract demand when the Company does it. The terms are "coincidence" and "diversity."

The reference in the middle of the paragraph deals with the Company taking into consideration a variety of factors including the coincidence and diversity of the customers' load. That's for an existing customer. With a new customer, the same provision would be taken. The first instance with an existing customer

involves revenue of 12 months of bills. The new customer, it involves some engineering analysis. Could you please explain what you consider the terms "coincidence" and "diversity" to mean, if anyone on the panel is competent to do so.

A (Host-Steen) Sure. Competent again, Mr. Brown?

Q Considers themselves competent.

A (Host-Steen) Thank you. In particular, I think it was an issue of looking at the nameplate of the installation. It would be -- it would not be appropriate for us to consider the nameplate of air-conditioning equipment that would be used during the summertime and electric heating supplemental in someone's home in the wintertime, as bearing on the peak demand because it is unlikely they would both be operating at the same time. That's one way that it is a factor definition we're looking at here, giving the customer that recognition.

Q And so the contract demand that you would set would not be simply the setting of the customer's highest peak in a period and the nameplate rating of their generator?

A (Host-Steen) No. The Company would start with the meter demand of -- if the Company were to

set or establish the contract demand, we would look at the meter demands for the past 12 months and then assess on what the situation was with the on-site generator at that point in time. If the highest demand was at -- in August and the highest demand was 600 but the generator was providing 400, then the contract demand would be 1,200.

Q Then how would you use it?

A (Host-Steen) To the best of my knowledge, Mr. Brown, contractwise, combining those we do have meterings on the generator in part to ascertain whether the generator -- how that contract impacts on the provision of power.

Q And that would be true for schools as well?

A (Host-Steen) I'm not familiar with any particular school, but I think it's probable that we do have that.

Q The next question goes to the issue of Section 21 which has to do with the tracking of net revenue gains or losses for all customers that are or would be subject to the standby service rates, including phase-in customers. The -- this section is intended to compare the customer's revenue contribution under the

standby rates and the revenue contribution under the lower existing SC 11 rates or the otherwise applicable standard classification, and the netting puts the money into -- if there is any, into something called the NYSEG gain account, so losses go there and looks like revenue gains go there. Could you speak to this account and describe what it is briefly, and then I'll ask another question.

MR. GIANNASCA: Now, your Honor, I object. I don't think that Mr. Brown is clear about how the system works. I believe he indicated that the monies, once the comparison was done, would flow into and out of the Asset Sale and Gain account. I don't believe that's, in fact, correct. If there are net revenue losses and that -- if that would be above a certain threshold, I believe the Company has the right to petition the Commission to recover from this account those lost revenues. If the Company has net incremental revenues, those are to be disposed of in a manner to be determined by the Commission, so there is no automatic entry or removal from the ASGA.

JUDGE EPSTEIN: Okay. If that is true does that answer the question that you have? Does that answer the question that you have asked about the ASGA, or did you have some other questions?

MR. BROWN: Well, I think he correctly answered part of it, and I would appreciate the panelists to respond, because I have a follow-on question to the panel. The specific question is leading to negotiated agreements. Do the gains and losses go to this account?

MR. GIANNASCA: Gains and losses from?

Q The negotiated agreement result. In other words, let's assume we negotiated an agreement such as the one Mr. Kraweic asked you about, and are there -- are there gains and losses in the negotiated agreement and do they have to go to this account?

A (Host-Steen) I had not anticipated that, Mr. Brown.

MR. BROWN: Thank you.

Garry Geartz has reminded me I overlooked him. So, Garry, would you please

come forward?

MR. GEARTZ: Just a couple questions of clarification.

BY MR. GEARTZ:

Q You had stated earlier that as the tariffs come into effect, the proposed Joint Proposal comes into effect, that those customers looking to possibly install on-site generation are going to have to look at the economic benefits and/or downfalls of doing so with respect to the rate. I guess from the standpoint of customer base that I'm attached to or responsible for, does that not -- and a lot of times these customers are tied into a long-term commitment. Does that not, I guess, unfairly penalize those customers who have already made that economic decision maybe two or three years ago, have already made an economic decision that fit their situation or their particular business needs and now that is going to, I guess, put a different twist on that economic decision-making process, but it's something that they've already expended monies for. Doesn't that, I guess, kind of put an unfair burden on those customers?

A (Host-Steen) I don't think so.

Q But I mean they could potentially -- and I guess I want to just use an example to something you were touching on that I'm not quite clear, an example of the demand where the Company would set the contract demand. I just thought I'd have an example.

Let's say, I mean I'm familiar -- I'm familiar with hospitals and how they operate and at times maybe a hospital would pull up an MRI truck, okay, and that tends to be a large consumer of heavy demand, so if a hospital in this type of a situation were to pull this truck up for a two-month period and let's say that they were operating on a -- their existing contract demand was set at 1000 kw or whatever it was, and they pull up an MRI truck and now all of a sudden it adds another 200 kw to their load. Now, would the contract demand then be re-established at 1200 kw by the Company, and then once that truck leaves, they would be paying that for how long?

A (Host-Steen) If the contract demand of the hospital is 1000 kw and they add 200 kw additional load, I think that there is a requirement that you notify the Company of any

substantial changes. I think it's a 12.5 percent as a threshold, a threshold where we would have to be notified of the equipment. You would be required under this tariff to notify us that you were going to add an MRI unit to the hospital and we would adjust your contract by 200 kw because that would be the potential overage you would have to make. After 12 months, after the truck was removed, you would be able to petition us for a change in contract demand to reflect the fact that now that the truck has been completely disconnected from the facility, that NYSEG would have to provide electricity service to.

Q But the customer would have to still pay that for the 12-month period even if it was there only for a month?

A (Host-Steen) There is an annual carrying charge for having that electricity available to you. The contract demand is over the 12-month period, correct.

MR. GEARTZ: Thank you.

MR. BROWN: A follow-on to the question of that.

BY MR. BROWN:

Q You mention the 12 months, and then you have a 90-day period in which to respond to the request for a reduction. Does that mean you're waiting 15 months?

A (Host-Steen) I would think that, if the 12 months, you make that request and if that request were granted that would be based upon the completion of a 12-month period.

Q So that would effectively preclude seasonal loads being brought into a site, summer seasonal loads, for example?

A (Host-Steen) That would be the assessment the EDP community makes to the Company.

MR. BROWN: Okay. That concludes the Joint Supporters' questions.

Wyoming, do you have questions of your own that you desire to make?

MR. KUCZMARSKI: No.

MR. BROWN: They don't. Thank you.

From our point of view, the Company panel has sufficed its term. Thank you.

JUDGE EPSTEIN: Thank you.

Mr. Host-Steen, you were talking with the questioner about the timing of the

request to have the demand charge reduced again after an increase, and this may be self-evident but just in case it isn't, can a customer come in any time and say, okay, I think that at the expiration of 12 months, I will be in a position to have you reduce the demand charge, or do they have to wait 12 months and then come in?

MR. HOST-STEEN: It would be my intention, your Honor, to have a 12-month period, that the contract demand would be in place for 12 months before they request it.

JUDGE EPSTEIN: Before they request it?

MR. HOST-STEEN: Right.

JUDGE EPSTEIN: Can the customer come in any time?

MR. HOST-STEEN: I -- I would say after a 12-month period. Whether the customer would want to, as a courtesy, give us a heads up to make sure we know it's a temporary truck coming in, such that there wouldn't be billing for the three-month period or 90 days, I'm not sure. We could work that out, but the intent would be that once a contract demand is

increased, once a contract demand is increased based on additional load, that there be a 12-month period that that contract demand would be paid prior to a reduction. Whether the truck being pulled on or off the premises, I mean that's pretty clear, it's not cut and dried.

BY MR. BROWN:

Q Let me ask a follow-up. Seasonal business like ski resorts or agricultural activities, recognizing that we do have separate operations on farms with waste-based generation. There may be many farms with site generation without waste. Would you consider for seasonal loads some flexibility in implementation of these provisions because 12 months essentially kills the next summer too, or winter.

A (Host-Steen) The 12 months is 12 months. A seasonal customer, the customer has the alternative either not using OSG or using OSG and backing that up with additional emergency equipment and not being connected with the delivery. If that was a choice, it would be -- we would be required to negotiate the alternative price.

MR. BROWN: Thank you.

MR. GEARTZ: Can I ask one more question?

JUDGE EPSTEIN: Yeah.

BY MR. GEARTZ:

Q Just going back to my example, just taking that same hospital that, let's say, they have brought on or decided to build an on-site generation facility and they were able to reduce their load by, just to use arbitrary numbers, 200 kw, and then I understand the situation now, if they're bringing the MRI in, how would that play out under this specific tariff?

Now, if we take the same hospital and let's say they were able to reduce their load by 200 kw through other means, whatever, doing internal distribution, but let's say they went from 1000 kw to 800 kw and it was a permanent reduction, okay, same as the on-site generator was doing and they brought in the same MRI machine, okay? Now, would they in that event, whatever their existing tariff was, I'm not just familiar with the numbers but whatever their standard tariff would be, would they also then pay for a 12-month window or would that be the

traditional one month?

A (Host-Steen) I think there's a timing requirement for the reduction assuming that the reduction from the 1000 to 800, if that were to take place, okay, because a demonstration of the permanent demand that the Company would have to provide for a facility, a delivery facility has been reduced from 1000 to 800, once that's in place then if the MRI truck is brought on board or the MRI is brought on board with another 200, you would be required to advise us of that and that would make the demand go back to 1000. If you notified us of the reduction from 1000 to 800, it wouldn't go from 1000 to 1200, is my under-standing.

MR. GEARTZ: Okay. Thank you.

JUDGE EPSTEIN: There is one area where I'm having difficulty, I think, understanding the intent of the Joint Proposal's provisions, and that's Paragraph 21 about the ASGA. We had some discussion here today about revenue neutrality and if I'm not misunderstanding Mr. Host-Steen, you said, well, you go to Paragraph 21 to assure cost recovery of whatever may be happening

dynamically, and then we had Mr. Brown was asking what, if someone negotiates a demand charge, would that be reflected in the ASGA account, and I think the meaning of the question was if you looked at that customer's demand charge comparing it with either SC 11 or the otherwise applicable service classification, would that differential go to the ASGA? I think your question -- your answer was you did not anticipate that it would. That's one piece of it.

What I was wondering was not what Mr. Brown was asking about, but why -- it seems to me that part of what the Joint Proposal is trying to address is the customer that isolates itself or doesn't, and I'm wondering whether the differential between the revenues from that customer which was zero and the SC 11 revenue or the otherwise applicable service classification would be reflected in the ASGA, and furthermore I see just one more element here. I thought in Paragraph 12, it says if -- in case of isolation, NYSEG will go to SC 14 to recover contribution.

So with all that as background, I

guess I don't quite understand what exactly -- what exactly type of revenue change or revenue differential the ASGA is intending to capture and if it doesn't capture all the things that might happen such as isolation or a negotiated demand contract, why is that?

MR. GIANNASCA: Your Honor, a point of clarification. I think Mr. Host-Steen testified to the fact, "I did not anticipate that," and he was referring to the question and not the disposition of the differential in the case.

JUDGE EPSTEIN: Oh, big difference!

MR. HOST-STEEN: That's correct.

JUDGE EPSTEIN: Big difference. Okay. So what that means in the case of the individually negotiated contract, does that differential fit the description that we get in Paragraph 21? Does it count?

MR. HOST-STEEN: I would say that as a result of the change in protocols -- as a result of the change in protocols under the new Service Classification 11 rate, if their availability causes any significant -- if you get additional revenues or lower revenues

under any aspect of this tariff, that would go into the plus or minus or the Paragraph 21 consideration. So upon further consideration, I would say that, if we had a special contract that caused customers to pay less than SC 11 or an increase in rates, that would be the calculation and we would calculate the bill based on the protocols in place. Today you would calculate the bill based upon the available protocols or the alternate applicable classification SC 11, and take a look at whether the Company gains or loses money as a result of this change.

JUDGE EPSTEIN: As a result of those negotiated terms with the individual customer?

MR. HOST-STEEN: Yes.

JUDGE EPSTEIN: Okay. And what if the customer isolates, what does SC 14 do? In a general sense, how -- how is that recovery calculated?

MR. HOST-STEEN: There is a section of the Service Classification 14 which was established in approximately 1995 that allows the Company to negotiate with customers who have installed on-site generation or who have

isolated from the system and get them back on a delivery system based on their paying marginal costs and a contribution toward fixed costs, specifically one penny toward fixed costs pursuant to Opinion 94-15, I think.

JUDGE EPSTEIN: Okay. And does the SC 14 contribution show up in the ASGA?

MR. HOST-STEEN: If the SC 14 contribution was a result of the customer severing under these new SC 11 protocols, I would say yes, your Honor. In other words, it would -- if it was an historic severing that had been in place for some period of time, I would say that would be incorporated under the overall revenue requirement concept. We would only be looking at Paragraph 21 as it related to the change in the SC 11 protocol going forward.

JUDGE EPSTEIN: So are you saying that you think the SC 14 contribution would -- would show up as a gain or loss in the ASGA relative to what that customer would be paying under SC 11 or otherwise applicable tariffs, or are we comparing it with -- is the SC 14 contribution a gain because, if the customer

walked out the door, the revenue would be zero?

MR. HOST-STEEN: Your Honor, I think the -- the defining point is whether the severing took place after, let us assume, January 1, 2004. If the severing took place after January 1st, 2004, such that the new SC 11 protocols are in place at the time of severing, then to retain or to bring it back, if you bring it back under SC 14 that would allow those revenues to go in as a contribution at that time. Paragraph 21, in my view, is only to address the changes in revenue requirements that occur as a result of us changing the service classification SC 11 protocols.

JUDGE EPSTEIN: Okay. So if the termination occurred after -- after this entire plan was in effect, then the loss or gain in the ASGA would be relative to the new SC 11.

MR. HOST-STEEN: That's correct. That would be my interpretation, as Mr. Brown phrased the issue.

JUDGE EPSTEIN: Okay. So that the

premise of my question wasn't correct when I said that there is a possible gain as compared with zero because that would be an incorrect way of looking at it because SC 14 ensures that the revenue from a customer in that situation is greater than zero anyway. There's no -- there's no potential loss of all revenue.

MR. HOST-STEEN: Under S -- excuse me. Under SC 14 we are required by our tariff established by 94-15 to negotiate a price that is marginal cost with distribution of a penny towards fixed costs, so that you wouldn't -- the delivery price would be calculated at zero and it would be at least a penny, a penny for whatever the cost.

JUDGE EPSTEIN: Okay. Okay. Thank you.

Do other parties have cross for this panel? Mr. Mager?

MR. MAGER: I do have some follow-up on the last line of questioning, your Honor.

BY MR. MAGER:

Q SC 14 doesn't guarantee or require that a customer will not disconnect from a system,

correct?

A (Host-Steen) SC 14 is applicable after a customer has taken action. SC 14 is applicable after a customer has taken action relative to on-site generation whether it's the installation of it or the installation of it and severing from the delivery system.

Q Okay. And right now notwithstanding anything in this case, if a customer installs on-site generation and disconnects from NYSEG, it is allowed to disconnect from NYSEG's service territory in which case it would not pay any standby rates, correct?

A (Host-Steen) Today if a customer severs from our system by installing on-site generation and suitable backup, to the best of my knowledge, there is no recovery -- there is no billing to that customer under the current situation.

Q So NYSEG revenues from that customer would be zero, correct?

A (Host-Steen) Yes, I think so.

Q Okay, and the Joint Proposal provides NYSEG with additional authority to negotiate a standby rate to keep that customer on the system, correct?

A (Host-Steen) Yes, because in order to negotiate

to keep a customer on the system under existing protocols, the customer needs to meet minimum thresholds depending upon the revenue class of that customer, the smallest threshold being 1000 kw for industrial customers who would install on-site generation. We are broadening -- you know, the Joint Proposal broadens our authority to negotiate with institutional customers not relative to the installation of on-site generation, relative to the installation of backup for the on-site generation which would allow for the disconnection of the facility from the utility system.

Q So is it fair to characterize the existing situation that customers have the right to install on-site generation and disconnect from the system in which case NYSEG's revenues would be zero, but the joint proposal gives NYSEG additional flexibility to retain those customers through negotiated contract?

A (Host-Steen) We can retain those customers through negotiated contracts if the viable alternative is the installation of backup generation that would allow them to put in the

OSG and sever from the delivery system. It's a very targeted requirement or a very targeted eligibility criteria for getting a negotiated contract with NYSEG.

Q And doesn't that additional flexibility permit NYSEG to retain revenues that it might otherwise lose entirely?

A (Host-Steen) Might, yes.

Q So isn't a proper comparison of the revenue impact of that provision the comparison of the revenues that NYSEG is able to retain as compared to zero, the revenues that NYSEG would have, had the customer disconnected from the system?

A (Host-Steen) Mr. Mager, could you rephrase that? I --

Q For purposes of -- I will rephrase it. For purposes of tracking revenue neutrality, in the case where a customer has the capability to install on-site generation with sufficient redundancy to isolate entirely from the system, isn't the proper comparison the revenues NYSEG is able to retain by negotiating standby rates with that customer versus zero, the revenues that NYSEG would have had the customer

disconnected entirely from the system which it is now permitted to do?

A (Host-Steen) I'm not sure that would be the case. I'm trying to -- I'm trying to consider what the situation has been and absent the new SC 11 protocols. Under the old protocols, the customer wouldn't be severing and now you're saying the customer under the new protocols would consider severing and we would negotiate a rate and actually, in fact, as a rate we would receive zero. Is that what you're saying?

Q I'm saying that a customer five years ago, today and going into the future has the right to install on-site generation and disconnect from the utility system, in which case that customer's standby costs would be zero to NYSEG?

A (Host-Steen) I think that's correct.

Q I want to go back and touch upon a couple of things that you were cross-examined on. First, I'd like to draw your attention to Paragraph 5 of the Joint Proposal. Can you just explain so the record is clear what the purpose of Paragraph 5 is?

A (Host-Steen) The purpose of Paragraph 5 is to set a threshold of 15 percent as to the size of

an on-site generator that would be installed at a facility prior to their qualification to take service under a certain classification level.

Q And the purpose of the threshold is to prevent gaming, correct?

A (Host-Steen) The purpose of the threshold is to require customers to make a real commitment to on-site generation and not a pseudo commitment to get the benefits of a service classification that benefits customers with higher load factors for delivery service.

Q Now, in the normal situation if a customer installs on-site generation under the Joint Proposal, the customer's entire rate would be filled under the standby rates, correct?

A (Host-Steen) Absent the NYPA intrustion?

Q Yes.

A (Host-Steen) Yes.

Q Okay. I'd like to just give a simple hypothetical. Let's say there's a 10 mw customer. If that 10 mw customer goes to Home Depot and buys a 50 kw generator and installs it, how would that customer be billed under the Joint Proposal?

A (Host-Steen) Ten megawatts, 50 kw generator.

Under the SC 11 service classification.
Q Under Paragraph 5, is that correct, because the customer -- that customer would be under the 15 percent threshold?
A (Host-Steen) That's correct.
Q And absent Paragraph 5(a), that customer might be billed under the standby rates, correct?
A (Host-Steen) Yes.
Q And if there was a revenue loss to NYSEG as a result of such an occurrence, other customers would have to bear that also under the revenue neutrality provision, is that correct?
A (Host-Steen) Ultimately, it would be reflected in the future, yes.
Q So is that the purpose of the 15 percent threshold, to avoid gaming situations such as that?
A (Host-Steen) Yes, that -- that would be part of it, yes.
Q And can you give me an example of what the purpose of Subparagraph (b) is with respect to preventing gaming?
A (Host-Steen) The purpose of Subparagraph (b) is to provide what -- is to prevent what I think years ago was called a "cardboard generator," a

generator put in place with no intent to operate that, simply to gain the advantage of the standby rates at that present time.

Q And to the extent that the Joint Proposal has revenue neutrality provisions, these anti-gaming provisions in Paragraph 5 are essentially to protect other customers, is that correct?

A (Host-Steen) Ultimately, yes.

Q I just have two brief questions again just to make sure the record is clear. You were asked a number of questions concerning revenue neutrality. Can you just explain what -- what this standard of revenue neutrality is with respect to this case and the Joint Proposal?

A (Host-Steen) The Opinion 01-4 basically requires the Company to take its existing revenue requirement by service classification and establish new rates under a new structure that includes contract demand and daily as-used demand for customers over 50 kw that would be covered based upon the operations in place when the revenue requirement was determined under the same amount of dollars as is recovered in the otherwise applicable service classification rates presently in place.

MR. MAGER: Thank you. I have no further questions.

MR. VAN RYN: Your Honor, I have a couple.

JUDGE EPSTEIN: Yeah, but let me just jump in here while we're on the theme. I'm sorry to belabor this, but I just want to confirm that we have eliminated the hypothetical with the customer who produces zero revenue because they have isolated. In other words, going back as far as 1994, are you saying that it's the case that SC 14 would require a negotiating process where the parties would arrive at a revenue agreement that would produce marginal costs plus a contribution?

MR. HOST-STEEN: If the Company and the customer could not negotiate a contrat that would provide that, then the alternative would be for the customer to take its action of remaining -- remaining with the generator, with the customer to remain with the generator operating, where the customer generated and severed from the Company's system.

JUDGE EPSTEIN: Okay. And in the

latter scenario then, that is a zero revenue producer.

MR. HOST-STEEN: If it was isolated, yes, it would be, but if that occurred -- if that occurred prior to this -- to this point in time, that would only be reflected in the revenue requirements. If that customer were brought back on the system as a result of the new SC 11, then the revenue again would go towards the ASGA or offsetting of the customer's costs.

JUDGE EPSTEIN: Okay. And what Mr. Mager, I guess, was getting at was there was a scenario of a zero cost customer because they're isolated, is that right?

MR. HOST-STEEN: If we have a -- well, if we have a customer that's isolated, we don't have a customer so there's zero revenues coming in.

JUDGE EPSTEIN: All right. Okay. Thank you.

Mr. VanRyn?

BY MR. VAN RYN:

Q Continuing along that line, if you negotiate an SC 14 contract with a customer who would thereby

agree to not install an OSG generator, is there a loss to your revenues currently?

A (Host-Steen) Mr. VanRyn, I agree that scenario would be addressed by Service Classification 14 for retention. SC 14 would apply only to customers who have already installed the on-site generation before the act of on-site generation or before the act of potential severing from the system. That would be addressed by the flexibility of the potential contract, the different eligibility criteria, different eligibility criteria than SC 14 offers, but I think we would have to make a distinction as to when the customer took a particular action whether SC 13 would apply, SC 14 would apply. SC 14 allows us to incent a customer to come back onto the delivery system presently if the customer has already installed on-site generation, and avoiding some of the local costs going back by arbitrage. Going forward SC 14 would allow us to buy back that customer who had severed entirely at a threshold other than currently available under SC 13.

Q Then, let's turn to SC 13 and ask a question about it. If you prevented a customer from

leaving the system and negotiated an SC 13 contract with them so they did not install an OSG system, would you recover any lost revenues?

A (Host-Steen) To the extent that an SC 13 contract took place prior to SC 11 being implemented, say in January 2004, that's already addressed in the way we designed our delivery revenue requirement rates that became effective in January of 2003, so it would have no impact on that.

Q A question on another topic. We discussed EP power -- EDP power deliveries from NYPA. Those deliveries are allocated in a set amount to each customer, is that correct?

A (Host-Steen) I would say yes.

Q And that amount doesn't vary month by month, is that correct?

A (Host-Steen) The kw allocation is the same allocation each month, yes.

MR. VAN RYN: Thank you.

JUDGE EPSTEIN: Other cross?

(There was no response.)

JUDGE EPSTEIN: Let's go off the record for a scheduling discussion.

(Discussion off the record.)

JUDGE EPSTEIN: Back on the record.

We discussed scheduling. We're back, and we are in recess for 45 minutes.

(Whereupon, at 12:15 p.m. a recess was taken until 1 p.m.)

AFTERNOON SESSION

JUDGE EPSTEIN: O.K. Panelists, you're still under oath.

MR. GIANNASCA: Your Honor, I have two short questions on redirect, in the hope that they'll clarify the record.

REDIRECT EXAMINATION BY MR. GIANNASCA:

Q. NYSEG panel, I'd like you to turn your attention to paragraph 21 of the Joint Proposal. Please clarify for the record disposition of net annual revenue gains.

A. (Host-Steen) Yes, Mr. Giannasca. The last sentence of paragraph 21 of the Joint Proposal states that any net annual revenue gain over $500,000 will be refunded to the ASGA. I think the clarification is that there is no petitioning required for funding under that proposal.

Q. Thank you. I'm going to give you a hypothetical. Assuming that we're in the time period subsequent to January 1st, 2004. Assuming that you have a hospital informs you that it wants to install a second back-up generator and thereby isolate from your system. You then utilize your authority under paragraph 12 to reach an initial

negotiated contract with that customer.

A. (Host-Steen) Under SC 11.

Q. Under SC 11, correct. Under paragraph 21, what would be the appropriate revenue comparison to determine whether there's net revenue gain or net revenue loss.

A. (Host-Steen) If such a hypothetical hospital were to have additional generation post the effective date of the implementation of the new service classification rates the comparison you would make is between the billing under the current SC 11 protocol, whether that customer is billed under Service Classification 11, or whether that customer is billed under the otherwise applicable service classification, that bill versus the bill that ultimately results under the new Service Classification 11 protocols that become effective on January 1st of 2004.

Q. Is it safe to say, when you say the SC 11 protocols, that includes individually negotiated contracts?

A. (Host-Steen) Under SC 11, yes, sir.

MR. GIANNASCA: Your Honor, I have no further questions.

JUDGE EPSTEIN: Thank you. Anything further for the panel? Mr. Mager?

MR. MAGER: I just have a question on the hypothetical.

RECROSS-EXAMINATION BY MR. MAGER:

Q. Let's -- let's assume that the customer is paying $1 million in revenues under SC 11 to NYSEG under their standby service and that customer indicates that it intends to install back-up generation and disconnect from the grid, under which case NYSEG's revenues would be zero, and NYSEG negotiates a contract with that customer which will result in $500,000 in annual revenues. Under that example, are you saying that NYSEG would realize $500,000 in lost revenues under paragraph 21 or $500,000 of revenue gain under paragraph 21?

A. (Host-Steen) I would say that we take -- we would be having a $500,000 revenue loss in paragraph 21, because that contract was negotiated solely as a result of the new protocols available to that customer under the new Service Classification 11. The severing option would have been available to that customer in both protocols and the customer did

not act upon that. It's our position that it's the availability of negotiated SC 11 contract that causes the revenue loss to NYSEG.

Q. Just so we're clear, prior to these -- prior to the Joint Proposal, the customer could always disconnect from the NYSEG system and pay nothing for standby service, correct?

A. (Host-Steen) Yes.

Q. So by "new protocols," you're talking about NYSEG's ability to offer a contract to serve that customer?

A. (Host-Steen) It's the protocols including the economics of those new protocols. It might not have been economic for them to sever under the old service classification and it becomes so under the new service classification. However, because it is now economic to do so, that is a change in the company's ability to recover its approved delivery revenue requirement, then I think it's important to be neutralized by paragraph 21 of the Joint Proposal.

Q. So it's your assumption that the customer would not install back-up generation but for the new standby rates, or the proposed standby rates?

A. (Host-Steen) That's one of the items that we're

looking at in paragraph 21, yes, sir, Mr. Mager.

Q. That's not necessarily the case, isn't that true? Isn't it possible the customer could find it economic to disconnect from the grid regardless of what NYSEG's standby rates are?

A. (Host-Steen) if it were economic for them to have done so, I would think that they would have done so already.

Q. But you don't know that for a fact with respect to individual customers, do you?

A. (Host-Steen) No, I do not. It's a presumption I'm making.

Q. Now, under the current situation, I just want to go over this with you. Let's say a customer has on-site generation and indicates an intention to disconnect from the grid. I believe you testified earlier that NYSEG could offer that customer a contract under SC 13.

A. (Host-Steen) No, Mr. Mager, it's doubtful that a hospital would meet the threshold of, I think it's 10 megawatts for a public authority, a public authority hospital or 5 megawatts for a -- for other commercial or non-residential entity. There is a threshold there. I think most hospitals are below that threshold for

retention.

Q. Mr. Host-Steen, let me just interrupt you to clarify that. None of my questions have been limited to hospitals. Just let me be clear --

A. (Host-Steen) O.K.

Q. -- in my questions.

A. (Host-Steen) Oh, I'm sorry.

Q. Let me -- with your clarification, let me just rephrase the question. Let's say today a qualified 12-megawatt customer has on-site generation. That customer can elect to disconnect from the grid entirely, in which case they would pay no standby rates to NYSEG, correct?

A. (Host-Steen) Correct.

Q. And NYSEG has the ability to offer that customer a contract under SC 13.

A. (Host-Steen) That's correct.

Q. And the customer is under no requirement to enter into such contract.

A. (Host-Steen) That's correct.

Q. And if -- if a customer does enter into such a contract, what would be the impact, the revenue impact on NYSEG?

A. (Host-Steen) Under the terms of the electric

rate plan currently in place, there would be a reduction in delivery revenue for NYSEG.

Q. Which NYSEG would bear?

A. (Host-Steen) Which NYSEG would bear subject to -- there are a certain caps in the electric delivery case as well. As far as earnings caps, there's a ceiling on those, a threshold at the bottom of that.

Q. So at least with respect to customers above 10 megawatts, customers currently have the right to disconnect from the system; NYSEG currently has the right to offer them a flex rate contract and NYSEG currently bears any loss in revenues should they enter into such a contract?

A. (Host-Steen) That's correct, under the -- under the protocols in place on the electric plan at the moment.

Q. And if NYSEG bears such revenue loss, why would it, in fact, offer a negotiated contract to such customer?

A. (Host-Steen) In order to maximize the recovery of delivery revenues from that customer.

Q. Right, because under the contract, revenues would be zero?

A. (Host-Steen) Possibility, yes.

MR. MAGER: Thank you. Nothing further.

MR. VAN RYN: Your Honor, I have one question.

BY MR. VAN RYN:

Q. Does the panel interpret the provision of the Joint Proposal we've been discussing as providing for a recovery of all lost revenues if a customer leaves the system and isolates entirely?

MR. GIANNASCA: Your Honor, just for clarification, the provision itself doesn't require -- doesn't provide for the recovery of all lost revenue to begin with, so there is a threshold that has to be met, but Mr. Van Ryn, if you can restate the question.

MR. VAN RYN: I believe that all lost revenues refers to the revenues associated with that particular customer, not the threshold. With that particular clarification, go ahead.

A. (Host-Steen) I would say if they sever from the system, they are not a customer, so I don't see how we could say that there's a -- that we could calculate that difference because there are no

-- once they sever, they're not a customer any more.

MR. VAN RYN: Thank you. Nothing further, your Honor.

JUDGE EPSTEIN: You can't calculate what difference is this?

MR. HOST-STEEN: In response to Mr. Van Ryn's question, he indicated if the customer severed from the system under any protocols --

JUDGE EPSTEIN: O.K.

MR. HOST-STEEN: -- would we include that customer in the calculation of lost or gained revenues and I've indicated once the customer severs from the system, the customer is no longer a customer, so we cannot include that as a revenue loss or a revenue gain.

JUDGE EPSTEIN: So you're not going to attempt to recognize it to be what the customer would have been paying under SC 11?

MR. HOST-STEEN: Once they leave the system, I would certainly like to, but I don't think we can.

JUDGE EPSTEIN: All right. O.K. I see, and all you were saying earlier today was

that, if they stay on the system presumably for the negotiated contract, then presumably you would retain the account.

MR. HOST-STEEN: My intention -- my understanding of paragraph 21 is we would take a look at what the revenues were -- the revenues that were anticipated under the electric rate plan versus the revenues we get as a result of the change in the rules under the new classification service level and capture the gains and losses associated with that and that is to the extent there's over or under a half a million dollars in each direction.

JUDGE EPSTEIN: Mr. Giannasca, do you have anything further?

MR. GIANNASCA: I do not.

MR. BROWN: I have a follow-up question.

JUDGE EPSTEIN: I'm sorry.

BY MR. BROWN:

Q. You've raised in my mind a question regarding the third paragraph of section 13 which reads: "In the event of a conflict between any provision of an agreement negotiated pursuant to this authority and any inconsistent provision of

this Joint Proposal or the standby rates provisions of NYSEG's tariff on the same subject, the provision of the negotiated agreement shall take precedence and control."

In line with the recent discussion, can you envision any circumstance where the terms of the individual agreement would affect the treatment of the revenue gains or losses one way or another under 21?

A. (Host-Steen) I don't --

Q. Let me try --

A. (Host-Steen) I understand the provision. The provision, I guess, is sort of a legal provision, if you will. The intent is that if it is a dispute as to what -- how the customer should be treated, the special contracts would override any other concept.

Q. O.K. And it's your opinion then, when you negotiated this, that the precedence of this over the net revenue loss and recovery provisions of 21 would not occur?

MR. MAGER: Your Honor, I don't know if it's our place, I guess I'm going to object to the question. I don't think legally it would be permissible for NYSEG to enter into

an individual contract with a customer that would somehow bind other customers in terms of the revenue treatment, so I think from the outset, the question is based on a -- on something that it is not legal to begin with.

MR. VAN RYN: I agree, your Honor. It's a fundamental principle of administrative law that parties to a contract cannot bargain away the state powers.

MR. BROWN: I have no further questions.

JUDGE EPSTEIN: O.K. Thank you. Panel, you're excused.

(The panel was excused.)

MS. CURTISS: Your Honor, I was wondering if I might bring forward an affidavit to be marked for identification as Exhibit 4.

JUDGE EPSTEIN: Well, you -- off the record.

(Remarks off the record.)

JUDGE EPSTEIN: On the record, we'll take Mr. Eck's testimony by means of an affidavit which will be marked as Exhibit 4 and we'll reserve number 4 for that exhibit, and that will be -- that affidavit will be provided

to me. I'm not going to direct that it be provided to the other parties unless somebody here specifically requests it. Can you provide that to me?

MS. CURTISS: I will.

JUDGE EPSTEIN: The unsigned affidavit to all parties, and is there any exhibit associated with the statement?

MS. CURTISS: There are a set of comments, his testimony and two associated attachments, so there's four documents that are 4 through -- 4, 5, 6 and 7.

MR. VAN RYN: Your Honor, if you're going to follow the same process that you followed, then the testimony and the statements of NFG would be copied into the record as if given orally, and then the original exhibit and a revised exhibit, there's original exhibits and revised exhibits here, so you can address that as well.

MR. GIANNASCA: I think maybe you would want to ask if there are any objections to the reading in of those parts of testimony as part of the record?

JUDGE EPSTEIN: Thank you. Is

there?

MR. GIANNASCA: Yes.

JUDGE EPSTEIN: We don't require Mr. Eck's presence for this?

MR. GIANNASCA: No.

JUDGE EPSTEIN: I'm sorry. Let me -- let me hear what the objection is because in case it involves excising portions of the statement.

MS. DANDY: Your Honor, NYSEG would like to note for the record its general objection to the admission of the comments of NFG and the testimony of Robert Eck, on the grounds that they contain material that is irrelevant to this proceeding. We are not making the motion now to strike portions of the testimony. We would reserve our right to detail this objection at the briefing stage.

MR. GIANNASCA: Your Honor, we wanted the record to reflect the objection with the reservation of right to address the probative value of Mr. Eck's testimony at the briefing stage, but we wanted to have the record indicate that our general objection is based, as my associate stated, on the fact that certain

portions of the testimony on specific matters like the encouragement of DG technologies are not germane to this proceeding and are best addressed at a later stage in a different proceeding if at all.

JUDGE EPSTEIN: So we are inserting these, the NFG comments, into the record subject to a motion to strike.

MR. GIANNASCA: No, subject to that general objection, the reservation of right to address the probative value of that testimony at the briefing stage.

MS. CURTISS: Just for the record, I do think we would disagree with that assertion. There is a statement in the standby order which suggests that standby charges cannot either be encouraging or in the business of DG. That is the issue which Mr. Eck's testimony addresses.

JUDGE EPSTEIN: All right. I understand. With that commentary, the statements will be incorporated in the record as if they were testimony given by Mr. Eck orally, and Exhibit 4, as I said, will be the affidavit.

(The Testimony of Robert D. Eck and the Comments of National Fuel Gas Distribution Corporation in Opposition to the Joint Proposal are as Follows:)

TESTIMONY OF
ROBERT D. ECK
ON BEHALF OF
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

NEW YORK STATE ELECTRIC & GAS CORPORATION
v.
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
CASE NO. 01-E-0779

April 21, 2003

Q. Please state your name and business address.

A. My name is Robert D. Eck, and my business address is 10 Lafayette Square, Buffalo, New York 14203.

Q. By whom are you employed and in what capacity?

A. I am employed by National Fuel Gas Distribution Corporation ("Distribution") as an Area Manager in the Energy Services Department.

Q. Please summarize your educational background and experience.

A. I received a Bachelor of Science degree in Mechanical Engineering from the University of Vermont in 1982. I also received a Master of Business Administration Degree from the State University of New York at Buffalo in 1990.

I have been employed in the energy industry for 21 years. I began my career in 1982 with Bechtel Power Corporation as a Construction Field Engineer at the Midland Nuclear Generating Station in Midland, Michigan. In 1984 I joined Distribution as a Junior Engineer in Technical Sales Support. Since that time I have held various managerial positions associated with marketing, market research, technology development and sales. I am currently responsible for the commercial/industrial sales, technology development and residential marketing activities in the New York Division of Distribution.

Q. What is the purpose of your testimony?

A. My testimony will review the importance of Distributed Generation ("DG") to Distribution's customers and the overall economic health of Western New York and New York State. I will also discuss the market potential of DG within Distribution's service territory and the types of customers best suited to take advantage of DG. I will then review the current economics for customers interested in installing DG for two (2) different levels of standby charges:

- No standby charges.
- NYSEG's proposed standby charges

Lastly, I will provide some conclusions on the impact of several key variables, including the above standby charges, on the likelihood of customers installing DG in Distribution's service territory.

Q. Why is DG important to Distribution's customers in Western New York?

A. NYSEG's electric rates are, and have been, among the highest in the United States, well above the national average. This high cost power has been shown to be a major deterrent to economic growth in Western New York, as well as relocation of new businesses to the area. DG has the potential to significantly lower electric rates in Western New York as well as increase the reliability of electric supply to the region.

Q. What is Distribution's interest in DG and the NYSEG Standby Proceeding?

A. Distribution is the primary gas utility serving NYSEG customers in Western New York. We have worked with many businesses and have been able to show them energy savings of 30 – 50% using DG with simple paybacks on their investment of 4 – 7 years, absent any standby charges. These paybacks can vary somewhat for each customer depending on variables such as the DG equipment installed cost, the customer's burnertip gas cost and the amount of heat recovery utilized. With paybacks in the 4 – 7 years' range, DG can be somewhat attractive to certain customer types. However, any increased costs, such as excessive standby service charges from the electric utility, can push the paybacks to the point where customers cannot justify installing DG at their facility. Our primary interest in the proceeding is to ensure that a truly cost-based standby charge is adopted by NYSEG that allows our customers a fair and reasonable opportunity to install DG.

Q. Does DG have a role in the 2002 New York State Energy Plan?

A. Yes. The 2002 Draft New York State Energy Plan ("Draft Energy Plan") issued December 2001, prominently features DG as a very important piece of the overall State energy strategy. The Draft Energy Plan discusses DG in a number of sections throughout the document. The general tone of the DG discussions can be encapsulated in Section 1, page 33, Item B.

The State should encourage the development and use of DG and combined heat and power ("CHP") technologies at customer sites, with the goal of becoming a national leader in the deployment of DG technology. (Emphasis added.) Primary focus should be on applications where such technologies can be shown to reduce energy costs, improve electricity system reliability, and reduce harmful pollutant emissions.

1. The State should continue its research and development support for DG and CHP technologies and applications, supporting, in particular, clean and renewable energy-based DG and CHP technologies.

2. The State should coordinate agencies' efforts to facilitate the interconnection of DG and CHP resources into the electricity system and increase the use of DG and CHP resources in the State.

3. The State should consider offering investment tax credits to spur private sector investment in environmentally sound and cost-effective DG and CHP technologies.

Later in the Draft Energy Plan, more specifically Section 2, page 100, it is stated:

- Emerging distributed power (DG) technologies offer the potential to self-generate electric power at efficiencies and with lower emissions than central station generators. When heat is recovered for useful purposes (i.e., cogeneration or CHP), these options can provide the consumer with a highly efficient and reliable energy supply option at prices competitive with the grid while reducing emissions. The DG/CHP systems can exceed 80% fuel-use efficiency and can significantly reduce NOx and other air pollutant emissions.

- New York's deregulated electricity market furthers the potential for DG/CHP growth in the long term, but faces hurdles, such as utility interconnections, exit fees, and the standby/backup charges in the near term. Use of DG/CHP offers a means to enhance a customer's power quality and reliability, alleviate load pocket constraints, and provide customers with an option for load shedding, in addition to energy-efficiency and air quality benefits. Therefore, DG/CHP represents an opportunity to improve energy efficiency and to reduce environmental impacts associated with power generation and use.

Q. Did Distribution submit comments pertaining to the DG sections of the Draft Energy Plan?

A. Yes. In our comments Distribution expressed our strong agreement with the DG language from the Draft Energy Plan. However, we also expressed our concern that the near-term hurdles identified in the Plan (utility interconnections, exit fees and standby/backup charges) have the real potential to retard not only the near term, but also the long-term growth and potential benefits of DG. Consequently, we stated that we would prefer that the Final Energy Plan not only identify the near-term hurdles, but offer some sort of mitigation, if not the elimination, of those near-term hurdles. We expressed our strong feelings that where such hurdles are in place, that they be flexible enough to allow for the efficient development of DG applications. Distribution also expressed our concern that the standby proceeding now being undertaken by the State's utilities may make DG marginally possible, if at all. The proceedings may result in charges that make very few DG projects possible if such projects envision a connection with the grid.

Q. What is the market potential for DG in Distribution's service territory?

A. Given reasonable standby charges, the total achievable market potential for DG is very large. One estimate of this was developed by Energy Nexus Group and Pace Energy Project, in a report they prepared in October 2001 for NYSERDA and Oak Ridge National Lab, entitled "Combined Heat and Power Market Potential for New York State". The report estimates the market potential for DG in New York to be 26,181 customers and 12,824 Mw of installed capacity. Of this total, approximately 5% lies in NYSEG's service territory (1,492 customers and 765 Mw of installed capacity). Exhibit ___ RDE-1 contains a more detailed summary table of this market potential estimate.

Q. What are the best candidates for DG?

A. Distribution has evaluated the economic feasibility for various residential, commercial and industrial customers utilizing fuel cells, microturbines, engines and turbines, in both power generation and cogeneration/CHP applications. The best baseloading candidates tend to be customers with higher electric and gas load factors, in combination with use for the thermal energy (hot water, hot air or steam) available from the DG equipment.

The best peak-shaving candidates tend to be the poorer load factor customers, especially those in time of use (on peak/off peak) electric rates, again with the ability to utilize the waste heat from the equipment. Among the best DG candidates are hospitals, nursing homes, hotels, office buildings, schools and industrial manufacturers. We chose certain customers in these segments to illustrate the affect of differing levels of standby charges in our payback analysis.

Q. What NYSEG standby service rates were used in your payback analysis?

A. We used the standby charges as proposed by NYSEG in the April 7, 2003 Joint Proposal Settlement document.

Q. What financial criteria did Distribution use to evaluate DG projects in your payback analysis?

A. Distribution used the simple payback as the measure of the DG project's financial merit. This is the easiest to calculate and simplest to understand of all financial measures and tends to be the one most often utilized by the majority of our customers to look at the preliminary economics of a project. We did not include the financial effect of such factors as project financing (interest charges), income taxes, depreciation or the time value of money (discount rate). We also did not factor in any Gross Receipts Tax ("GRT") or sales tax on either the electric or gas use of the customer. Our goal was to keep the analysis as straightforward and understandable as possible. By not including the negative effects of project financing, income taxes and discount rates on project cash flow, our estimates of paybacks are therefore optimistic and would be longer if these elements were factored in. The revised customer paybacks after factoring in these effects would likely look even less attractive to the customer.

Q. How did Distribution calculate the as-used demand charge costs in your payback analysis?

A. The filed as-used demand charge is a daily demand charge assessed to any energy used from NYSEG during on-peak hours only. Because we did not have 365 days of daily on-

peak demand levels available to us for the six (6) customer types we evaluated, we calculated an effective monthly demand charge based on the daily demand charge. We did this by dividing 365 days/year by 12 months/year to get an average of 30.42 days/month. We then multiplied 30.42 days/month by 5/7 (5 on-peak days, Monday – Friday, per 7-day week) to get 21.73 on-peak days per month. We then multiplied the daily as-used demand charge by 21.73 to get an effective monthly as-used demand charge. This effective monthly as-used demand charge was then multiplied by the difference between the average monthly peak demand and the DG equipment size, for a period of 12 months.

Q. Briefly explain how Distribution calculated the paybacks for DG customers in its payback analysis.

A. For our examples in this testimony, Distribution looked at electric baseloaded cogeneration/CHP applications, which included heat recovery, utilizing gas engines. The DG system was then sized to meet the estimated baseload monthly electric demand. We used electric and gas energy consumption data for actual customers of ours in each of the six (6) top market segments mentioned earlier. These customers served as representative examples of "typical customers" for each segment. All customers were SC-2 or SC-7 customers (secondary or primary voltage) and we used NYSEG's most current retail rates for the analysis. Assumptions were made regarding variables such as:

- Equipment installed cost (varied depending on DG size).
- Electric efficiency (varied depending on DG size).
- Heat recovery efficiency (54%).
- Maintenance cost ($0.01/kwh).
- Electric commodity energy charge ($0.04/kwh).
- Contract demand nomination level (variable).
- Marketer citygate gas price ($5.00/Mcf).
- Distribution transportation charge (varied by customer size).

- Percent full load operating hours (varied by customer).
- Percent heat recovery utilized (varied by customer).

The process then consisted of five (5) steps:

1. Calculate the current total energy costs for the customer (electric and gas) without DG.

2. Calculate the electric and boiler gas usage the DG unit would displace, and the corresponding increase in gas usage of the DG unit.

3. Calculate the new total energy costs for the customer (electric and gas) with DG, including all standby charges and DG maintenance costs.

4. Calculate the equipment installed cost, annual energy savings and simple payback using DG.

   - A sensitivity analysis was then done to illustrate how the payback changed for different combinations of two (2) key variables: contract demand level and marketer gas price.

5. As a baseline reference, calculate the same simple payback for the customer without any standby charges.

Q. What is the reason for calculating the economics of DG without any standby charges?

A. Even though it is not realistic to expect customers to be able to install DG without any standby charge, it does provide a good reference point or baseline to compare against the impacts of different levels of standby service. It represents a "best case" scenario to contrast against NYSEG's legitimate right to address its need to recover the costs associated with having the electric infrastructure ready to go in the event of an outage of the DG equipment.

Q What are the current economics of DG without any standby charges?

A. Presently, without any standby charges, the customer paybacks for the six (6) best customer types we looked at ranged from 4.1 to14.3 years. These paybacks are not at the typical three-year hurdle rate required by many businesses, but are certainly close enough for customers to seriously consider DG. Furthermore, some customers such as schools

are not under as much competitive pressure as industrial manufacturing or hospitals for short-term results, so they may make investments resulting in longer payback periods, which make these installations more attractive.

Q. How did Distribution evaluate the effect of a customer-nominated contract demand on the economics of DG with standby charges?

A. Distribution calculated the paybacks for each customer type at different levels of contract demand. At one extreme, we looked at the payback if a customer elected to nominate their maximum contract demand, which is equal to their annual peak demand of the entire facility. This represents NYSEG's "default" level of contract demand as proposed in their compliance filing. This level of contract demand represents the ultimate insurance policy for the customer, in that by choosing this level, they reduce their risk of potential contract demand penalties to zero if their DG has an outage at any time during the year. At the other extreme, we looked at the payback if a customer elected to nominate their minimum contract demand, which is equal to their annual peak demand minus the demand displaced by the DG unit. This level of contract demand represents the total lack of an insurance policy for the customer. At this level the customer assumes all of the risk of potential contract demand penalties if the DG unit has an outage. To avoid these penalties, the customer must either have redundant backup generation to use during a partial or total outage, or have the capability to instantaneously shed electric load to reduce their demand on NYSEG's system during an outage to avoid penalties. By calculating paybacks at these two (2) levels of contract demand, we can see what the economics of DG are at two (2) opposite extremes of customer risk, zero and 100%.

Q. What are the current economics of DG using NYSEG's proposed standby charges at the two (2) different contract demand levels?

A. At the maximum contract demand levels the paybacks were very poor. They ranged from 11.7 years to no payback at all. At this contract demand level we do not see DG as being a viable economic option for any of our best customer candidates. At the minimum contract demand level the paybacks become marginally attractive in the range of 5.4 to 20.8 years. However, these paybacks do not factor in the likely added costs of redundant backup generation or load shedding control systems to avoid any contract demand penalties during a DG outage. These added costs would likely push the paybacks even higher. It is our feeling that even at the minimum contract demand levels, the economics and added risks will not be very attractive to most of our best customer candidates and adoption of DG will be minimal at best.

Q. Have you provided workpapers to backup this payback analysis?

A. Yes. Exhibit __ RDE-2 contains a summary of the estimated paybacks for the six (6) customer types evaluated, for the two (2) different options without standby charges and with NYSEG's proposed standby charges. For the standby service option, the Exhibit also provides the minimum and maximum contract demand levels for each customer type and the associated paybacks. Finally, the Exhibit also includes each customer type's electric and gas annual load factors and the customer's annual peak demand. In addition, the DG size selected for each customer is provided along with the DG unit's estimated installed cost ($/Kw), electric efficiency, percent equivalent annual full load hours of run time and the percent effective annual heat recovery utilized by the customer.

Q. What conclusions do you draw from your payback analysis?

A. The first conclusion is that paybacks are sensitive to a handful of key input variables. These variables are:

- Equipment installed cost ($/kw).
- Electric efficiency.
- Marketer citygate gas cost ($/Mcf).
- Contract demand charge ($/kw).
- Contract demand level (kw).
- Percent equivalent annual full load operating hours.
- Percent equivalent annual heat recovery utilized.

A. All of these above factors are customer/site-specific, except for the contract demand charge. However, based on Distribution's experience with DG projects, Distribution is comfortable that the assumptions we used for these variables are reasonable. With the adoption of NYSEG's proposed standby charges, the use of DG by the best customer candidates will be limited, at best. Without any change to any of the customer/site-specific variables mentioned above, the only way for DG to be a cost effective option for the customer is to make even further reductions in the contract demand charges than what is proposed by NYSEG in its Joint Proposal. Therefore, based on our analysis, the ability of DG in the short term to meet the stated goals of the Draft New York State Energy Plan and reach its market potential will be very limited with the current standby charges proposed by NYSEG.

Q. Does this conclude your direct testimony?

A. Yes, it does at this time.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to New York State Electric & Gas Corporation Electric Tariff Filing to Establish a New Standby Service — **Case 02-E-0779**

COMMENTS OF NATIONAL FUEL GAS DISTRIBUTION CORPORATION IN OPPOSITION TO THE JOINT PROPOSAL

APRIL 21, 2003

BY: Alice A. Curtiss
Senior Regulatory Attorney
National Fuel Gas Distribution Corp.
10 Lafayette Square
Buffalo, NY 14203
(716) 857-7951

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to New York State Electric & Gas Corporation Electric Tariff Filing to Establish a New Standby Service	))))	Case No. 02 E-0779

NATIONAL FUEL GAS DISTRIBUTION CORPORATION'S
STATEMENT IN OPPOSITION TO THE JOINT PROPOSAL

On April 7, 2003, New York State Electric and Gas ("NYSEG" or "Petitioners") filed with the State of New York Public Service Commission ("Commission") in the above captioned proceeding a Joint Proposal by which it seeks to resolve the issues in this proceeding. ("Joint Proposal"). National Fuel Gas Distribution Corporation ("Distribution") filed as an intervenor in this proceeding and will be directly affected by the resolution of the issues in this case. Distribution attended and participated in the settlement discussions in this proceeding.

Petitioners, supported by various other parties to the proceeding filed the Joint Proposal in purported compliance with the Commission's Standby Guidelines, issued in connection with Case No. 99-E-1470, Proceeding on Motion of the Commission as to the Reasonableness of the Rates, Terms and Conditions for the Provision of Electric Standby Service. ("The Standby Order"). The Joint Proposal is designed to resolve the issues raised by various parties in the settlement negotiations in this proceeding. Presiding Administrative Law Raphael Epstein has directed that statements in response be filed by April 21, 2003. Distribution files this Statement in Opposition to the Joint Proposal and respectfully requests that the Presiding Administrative Law Judge recommend that the Commission modify the Joint Proposal to assure fair, non-

discriminatory and complete development of distribution generation in NYSEG's service territory as described more fully in this statement.

SUMMARY OF REASONS FOR OPPOSITION

Distribution is the principal supplier of natural gas in a portion of NYSEG's service territory in western New York. Distribution has also worked diligently to install distributed generation projects in western New York. Distribution's interest in this proceeding is to ensure that its customers and potential customers in western New York have a fair and reasonable opportunity to install distributed generation.[1]

Distribution opposes portions of the Joint Proposal. One benefit of the Joint Proposal should be that it will improve the opportunity for installation of distributed generation. Distributed generation (or "DG") has the potential to not only create savings in electricity costs for individual customers and groups of customers, but also to serve as a critical tool in economic development activities in western New York. This would benefit the entire region, including NYSEG and all of its customers. DG also can assist NYSEG's electric customers as a means of providing a least cost solution to needs for generating capacity and to relieve transmission and distribution constraints. For the reasons summarized below, the Joint Proposal does not adequately or fully extend to all customers the potential benefits of distributed generation. Therefore, the Joint Proposal should either be revised or rejected. Distribution opposes the Joint Proposal in the following specific respects:

---

[1] While distributed generation may be fired by natural gas provided by Distribution, other suppliers and other fuels may be used. Therefore, Distribution must compete to provide this service to customers in its service territory.

1. Provision 2 at Table – 1 of the Joint Proposal sets out the percentage of the Contract and As-Used (or "Local" and "Shared") allocation of non-customer costs revenue requirement. These allocations are purportedly in compliance with the Standby Order. However, the Standby Order states,

> Fixed, "local" costs, those that can be attributed exclusively or nearly exclusively to the customer involved, would be recovered through a fixed contract demand charge. Variable and shared facility costs, the incurring of which cannot be singularly attributed to the individual customer, would be recovered through an as-used demand charge.

Standby Order, mimeo at 13.

However, for secondary service NYSEG here proposes that there is no shared service. See Joint Proposal, Provision 3. Similarly, the costs for primary and secondary voltage customers using the primary system facilities are allocated nearly entirely to local costs (75/25); meaning nearly entirely on a contract demand basis. No cost-of-service information, by account, was made available to demonstrate that these levels of service do not use (or rarely use) shared facilities. Further, based on common sense, it would seem illogical that whole classes of customers have no facilities which are shared. This premise further does not appear consistent with the above noted portion of the Standby Order.

Distribution asserts that this provision of the Joint Proposal will be an impediment to development of DG alternatives and therefore is inconsistent with the Commission's goals in the Standby Order. See Standby Order mimeo at 27. As seen in the attached Exhibit A, Testimony of Robert D. Eck,

the proposed NYSEG rates under the Joint Proposal will result in little, if any, new DG. Therefore, revisions to these rates is appropriate.

2. The Joint Proposal at Provision 3 sets out a phase-in of standby service rates, for current customers of three years with jumps of thirty-three percent each year. It is Distribution's understanding that in the Consolidated Edison Case at Case No. 02-E-0780/0781, the phase-in of standby rates is accomplished over an eight-year period. The Niagara Mohawk case allowed indefinite grandfathering of pre-existing DG installations. See Niagara Mohawk Power Corporation Tariff SC-7, Section 4.D.

   Installation of DG is a cost-intensive endeavor, requiring a payback of a number of years for the equipment, without regard to the utility costs or rates associated with the service. DG owners, who have put significant investment into DG facilities with NYSEG's pre-existing rates in place, should be able to achieve a return after investing millions of dollars of investment. These customers should at the very least receive the same treatment as was received in the ConEd case of an eight year period with the last four years as a phase-in; otherwise NYSEG will receive a windfall at these customers' expense. These customers should not be penalized for their forward thinking and investment in DG, consistent with the Commission's stated goal of achieving more DG. Otherwise, the customers may in fact be forced to simply return to standard electric service.

3. Pursuant to the Joint Proposal at Provision 12 NYSEG responds somewhat to the Commission's "Order Clarifying Prior Order and Directing Tariff

Modifications" of January 13, 2003, where the Commission modified the Standby Order ("Modifying Order"). The Commission there required that NiMo offer negotiated rates for customers that "... can economically isolate from the grid." Modifying Order at 13. The Commission required that NiMo's rates should be reduced as necessary in response to such a customer, as long as NiMo received a contribution toward its stranded costs. Modifying Order at 13-14.

NYSEG proposes in the Joint Proposal that instead it requires recovery of its "marginal costs" plus a reasonable contribution to its "fixed costs." NYSEG has not made clear to any party what "marginal costs" are, nor what are its "fixed costs." In any case, neither of these complies with the Modifying Order. Therefore, NYSEG should be required to modify its rates to require simply a contribution to its non-bypassable wire's charge, which is its stranded charge.

CONCLUSION

For the reasons explained in these Comments Distribution respectfully requests that the Administrative Law Judge recommend revisions to the Joint Proposal as provided below to ensure that DG opportunities are indeed not foreclosed in NYSEG's service territory.

1. Provision 2 of the Joint Proposal should be revised to include additional costs in the shared component to reflect the common sense conclusion that all or virtually all of these costs are not local for the lower level customers.

2. Provision 3 of the Joint Proposal should be modified to allow existing DG customers to have a longer phase-in of the Standby rates, similar to that allowed in the ConEd case, and
3. Provision 12 should be modified to comply with the Commission's Modifying Order of January 13, 2003, and require only some contribution toward stranded costs for projects that can economically cut from the grid.

Respectfully submitted,

Alice A. Curtiss
Senior Regulatory Attorney
National Fuel Gas Distribution Corporation
10 Lafayette Square
Buffalo, NY 14203
Telephone: 716/857-7951
Fax: 716/857-7687
Email: curtissa@natfuel.com

Dated: April 21, 2003
Buffalo, New York

JUDGE EPSTEIN: Exhibit 5 will be what formerly was known as RDE-2 and Exhibit 6 will be revised RDE-2.

MS. CURTISS: There is also RDE-1.

JUDGE EPSTEIN: Oh, I'm sorry. Let's start over. Exhibit 5 will be RDE-1; Exhibit 6 will be RDE-2, and Exhibit 7 will be revised RDE-2. Thank you.

MS. CURTISS: Thank you very much, sir.

JUDGE EPSTEIN: Would the next order of business be to call the Staff panel?

MR. VAN RYN: Yes, your Honor.

EDITH ALLEN. STEPHEN A. BERGER, MICHAEL J. RIEDER and COLONEL DICKENS

each having been first duly sworn by the Administrative Law Judge, were examined as a Panel, and testified as follows:

MR. VAN RYN: Your Honor, Staff has a panel consisting of Edith Allen, Stephen Berger, Michael Rieder and Colonel Dickens, and I offer as an exhibit their qualifications. I ask it be marked for identification.

JUDGE EPSTEIN: All right.

Number 8.

(Exhibit Number 8 was marked for identification, this date.)

DIRECT EXAMINATION BY MR. VAN RYN:

Q. I show the panel the Staff Statement in Support of Joint Proposal, and I ask you if you assisted in its preparation and are familiar with its contents.

MR. DICKENS: Yes, I did.

MR. BERGER: Yes, we did.

Q. I show you the Staff's Reply in Support of the Joint Proposal, and ask the same question.

MS. ALLEN: Yes.

MR. DICKENS: Yes.

MR. VAN RYN: Your Honor, I ask that these documents be copied into the record as if given orally.

JUDGE EPSTEIN: Yes.

(The Staff Statement in Support of Joint Proposal and the Staff Reply in Support of Joint Proposal are as follows:)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 02-E-0779 - In the Matter of the Compliance Filing of New York State Electric & Gas Corporation in Response to Opinion No. 01-4 on Standby Service Rates.

STAFF STATEMENT IN SUPPORT OF JOINT PROPOSAL

LEONARD VAN RYN
Assistant Counsel
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350
(518) 473-7136

Dated: Albany, New York
April 21, 2003

TABLE OF CONTENTS

Case 02-E-0779 - In the Matter of the Compliance Filing of New York State Electric & Gas Corporation in Response to Opinion No. 01-4 on Standby Service Rates.

STAFF STATEMENT IN SUPPORT OF JOINT PROPOSAL

PRELIMINARY STATEMENT

In Opinion No. 01-4, the Commission adopted guidelines for the design of standby service rates. A standby service customer obtains some of its electric usage from a source other than deliveries through the utility's transmission and distribution grid. These customers generally fall into two categories: 1) customers that install on-site generators (OSG) that produce energy primarily to serve a portion or all of the customer's load; and, 2) wholesale generators that produce electricity primarily for sale into the wholesale market. Standby rates apply to the service both types of customers purchase from the utility in either supplementing their electricity supply or replacing the electricity they would otherwise supply themselves.[1]

[1] Case 99-E-1470, Proceeding on the Provision of Electric Standby Service, Opinion No. 01-4 (issued October 26, 2001).

On June 10, 2002, New York State Electric & Gas Corporation (NYSEG) issued proposed tariff leaves for electric standby service in compliance with the Opinion No. 01-4 standby guidelines. Negotiations thereafter commenced on March 10, 2003 and culminated in a Joint Proposal (JP) that was filed on April 7, 2003.

The Joint Proposal should be adopted because it satisfies the criteria the Commission has established for judging the reasonableness of utility rate settlements. In considering recent joint proposals setting forth agreement among parties, the Commission has generally evaluated each joint proposal on its own merits against a standard of reasonableness. It has also reviewed the adequacy of joint proposals in furthering the progress of implementing retail competition. These reviews have been conducted in conformance with the guidelines the Commission established in Opinion No. 92-2 for consideration of a settlement.[2] Indeed, the Commission has adopted with modifications a Joint Proposal establishing standby rates for Niagara Mohawk Power Corporation (Niagara Mohawk).[3]

---

[2] Case 90-M-0255, Proceeding on Settlement Procedures and Guidelines, Opinion No. 92-2 (issued March 24, 1992).

[3] Case 01-E-1847, Niagara Mohawk Power Corporation - Standby Rates, Order Approving Joint Proposal (issued June 21, 2002).

Opinion No. 92-2 identifies a number of criteria for judging whether a joint proposal setting forth a settlement is in the public interest. In considering a joint proposal, the Commission reviews the extent to which it is supported by generally adverse parties and determines that the record for decision is adequate. In order to win approval, a joint proposal should be consistent with law and public policy, have a rational basis, balance the interest of customers and the utility, and compare favorably with the probable outcome of litigation. The Joint Proposal here satisfies these criteria.

There is wide support for the Joint Proposal. Multiple Intervenors (MI), a consumer group adverse to the interests of the utility, has joined in the Joint Proposal. Several wholesale generators also signed the Joint Proposal.[4] While the settlement is not unanimous, there is support for it among a range of parties representing customer interests.

The record is adequate to justify adoption of the Joint Proposal. NYSEG has made available supporting workpapers justifying the proposed rates, and parties conducted detailed discovery into the bases for the proposed standby tariffs. This

[4] These generators are: AES Eastern Energy, L.P., Lockport Energy Associates, L.P. and Indeck Energy Services of Silver Springs.

evidence is sufficient to justify approval of a tariff compliance filing such as NYSEG has submitted.

The remaining Commission criteria for judging the reasonableness of a joint proposal are directed towards ascertaining whether the proposed terms are in the public interest. For the reasons discussed below, the Joint Proposal meets that standard.

DISCUSSION

The standby rates proposed in the Joint Proposal satisfy the standby rate guidelines that were promulgated in Opinion No. 01-4. As a result, the Joint Proposal's provisions on standby service tariffing and rates should be adopted.

The Standby Rate Calculation

As discussed in Opinion No. 01-4, the cost of delivery facilities dedicated to service of a particular customer are recovered in a contract demand charge while the cost of delivery facilities shared more broadly among customers are recovered through an as-used demand charge. Initially, parties opposed NYSEG's allocation of cost for recovery between the two charges. Under the Joint Proposal, substantial costs are shifted from the contract demand charge to the as-used demand charge (JP at 2), resulting in the proposed rates set forth at JP Appendix A.

This reallocation of costs reduces the fixed charge burden on OSGs while still enabling the utility to recover the

costs of serving these customers. It substantially ameliorates the bill impacts for the majority of existing standby customers. It will enable new customers, who can design their facilities to take advantage of these rates, to economically obtain standby service.

As a result, the standby rates arrived at in this proceeding are just and reasonable. They should be adopted.

Existing Customers

Notwithstanding the proper allocation of costs, some existing NYSEG customers will still see substantial bill increases when the new standby rates take effect. To reduce the rate change impacts that would adversely affect this group of customers, the Joint Proposal provides for a phase-in of the new rates (JP at 3).

For the first year of the phase-in, existing customers would be billed at NYSEG's otherwise applicable non-standby service rates. Beginning on January 1, 2005, these customers would be billed by adding to the non-standby rate a percentage of the difference between that rate and the otherwise applicable standby service rate. In 2005, the first year of movement, the adder would be set at 33% of the difference, and in 2006, the second year of movement, the adder would be increased a 67% increment. This gradual movement towards the full standby rates, which would take effect as of January 1, 2007, will

alleviate adverse impacts on those customers who would otherwise experience significant bill increases if the new rates were imposed immediately.

Many existing customers, however, will benefit from the new standby rates, in that their bills will be lower under the standby rates than under the standard service rates. Those customers may opt to move to the full standby rates upon providing 30 days notice to the utility at any time.

In order to ensure that entities who had made a commitment to installing OSG while this proceeding was underway, the definition of "existing customers" is broadly drafted (JP at 4-5). It includes, as well as operational OSG facilities, entities that had commenced construction of an OSG facility, executed binding financial commitments to construct an OSG facility, or had been named by the New York State Research and Development Authority (NYSERDA) as an OSG project grant recipient or feasibility study funding recipient as of January 31, 2003. These provisions preserve the viability of investment commitments made in reasonable reliance on prior rate structures.

The definition of "existing customer" is also drafted carefully, to avoid opening standby rates exemptions to new customers who should make investments in response to the new standby rates. Limitations prevent over-expansion of the

category. The commitment to OSG must have been made as of January 31, 2003, and, for those commitments that consist of a NYSERDA feasibility study grant or a binding financial obligation, the OSG facility must commence operation within two years from the date of the grant or obligation.

With these limitations, the approach to the definition of customers entitled to the standby rate phase-in is appropriate. Customers who should have had notice of the impending change in standby rates will be governed by those rates once they take effect. Those customers that made financial commitments prior to the time it became apparent the existing rates would be replaced will avoid disruption of their financial expectations.

The 15% Proportion

NYSEG customers installing OSG sized at 15% or less of their load will be entitled to serve all of their load at the standard service tariff (JP at 5). This provision encourages customers to install smaller-sized units to meet peaking or other purposes without moving all of their load to standby rate billing. Moreover, the provision prevents the exploitation of the differential between standby rates and standard service rates by a non-OSG customer who might find the standby rate advantageous, and install a small OSG facility only for the purpose of switching its load to the standby service. Because

it properly demarcates the dividing line between shifting all load to the standby rate and retaining all load on the standard service rate, the 15% limitation is appropriate.

Environmentally Beneficial
Technologies and Small Facilities

NYSEG customers installing environmentally-beneficial technologies are also encouraged under the Joint Proposal. These customers may take standby service under the new standby rates at the time they take effect or opt to participate in a five-year phase-in of the new rates, with bills moving towards the full standby rate in yearly increments. The customer could elect to join the phase-in at its then-effective level at any time.

During the five-year period, the bill for a customer installing an environmentally-beneficial technology would move from the standard tariff rate towards the standby rate via an adder to the standard service rate reflecting the differential between that rate and the otherwise-applicable standby rate. During the initial period of the phase-in, commencing with the effective date of the new standby rates and ending December 31, 2004, the customer would be charged the otherwise-applicable tariff rate. Movement towards the full standby rate would commence on January 1, 2005 with an adder of 25% of the bill difference, and grow at 25% increments over the subsequent

period, until the full standby rate is reached on January 1, 2008 (JP at 3).

To obtain the benefit of the phase-in without benefiting the environment, some customers might plan to install some environmentally beneficial generation along with a larger generator that does not meet that standard. To forestall this unintended consequence, customers seeking to qualify for the phase-in must restrict their OSG equipment to the environmentally beneficial category without interconnecting under the same account OSG equipment does not qualify under the definition.

Another exemption will further benefit customers interested in environmentally beneficial technologies. Small customers in NYSEG's non-demand service classifications will be billed at the standard tariff rates instead of a standby rate (JP at 10-11). These customers can explore environmentally beneficial technologies without incurring the added cost of calculating the difference between various rate designs. For these non-demand customers, reducing costs will also reduce barriers to entry by environmentally beneficial technologies.

The approach to this exemption is balanced. To prevent rate erosion and concomitant potential for shifting of costs to other customers, this exemption will expire if more than 200 customers located east of the Total East transmission

constraint or 250 customers located west of the constraint.[5] It is also scheduled for expiration at the end of NYSEG's current Rate Plan, on December 31, 2006.

These provisions favoring environmentally beneficial technologies are appropriate, within the constraints of this proceeding. If additional measures are needed to promote these technologies, proposals can be made in proceedings on renewable generation policy.[6]

Standby Rate Contracts

NYSEG is authorized to enter into flexible rate contracts to address particular circumstances that might not fit well within the new standby rate structure. Both wholesale generators and customers contemplating isolation from the utility grid, by installing their own back-up generation, may avail themselves of the individual contract opportunity (JP at 7-9).

Interconnection arrangements between wholesale generators and utilities can be complex. The generators may own all or substantial portions of their interconnection equipment,

---

[5] This allocation is reasonable even though the bulk of NYSEG's customers are located west of the constraint. Since capacity is in shorter supply to the East, OSG installations are more useful there.

[6] See, e.g., Case 03-E-0188, Retail Renewables Portfolio Standards, Order Instituting Proceeding (issued February 19, 2003).

and might find that application of the new standby rates over-collects costs from them. As discussed in Opinion No. 01-4, customers should not be charged for delivery equipment when they have already paid for that equipment elsewhere. Allowing wholesale generators to enter into individualized contracts will enable them and the utility to avoid double-collection of costs. It will also recognize the unique characteristics of each particular interconnection.

This authorization to enter into individualized contracts is circumscribed to prevent participation by unqualified customers. It is restricted to generators that devote the bulk of their production to wholesale markets, making only incidental retail sales of less than 10% of their production. A generator also must be sized at 50 MW or more. This ensures that only those large generators capable of owning interconnection equipment where a double-collection of costs is a realistic possibility can avail themselves of the individual contract opportunity.

NYSEG is also authorized to offer individualized contracts to avoid bypass of the standby rates. As discussed in the Niagara Mohawk Order,[7] utilities might lose revenues if OSG customers decide to isolate from the utility system and furnish

[7] Case 01-E-1847, supra, Order Clarifying Prior Order and Directing Tariff Modifications (issued January 13, 2003).

their own back-up through installing additional generation. Often times, this back-up generation may take the form of diesel generators that are more environmentally disadvantageous than utility sources of generation. To avoid these adverse impacts, the utility is authorized to enter into a contract at a rate below that set in the standby tariff to retain the customer on the utility system.

This contract opportunity is circumscribed to avoid adverse and unintended consequences. To qualify, a customer must demonstrate that it can isolate from the system. This prevents gaming by customers who might seek an individual contract premised upon the possibility they could install generation that partially backs up their load without isolating. Such claims would be difficult to evaluate.

Setting Contract Demand

The Joint Proposal sets forth detailed provisions for the setting of the contract demand level that will establish the basis for billing the contract demand charge (JP at 5-7). This fixed charge that an OSG customer must pay monthly, is important to both NYSEG and the customer, and the appropriate figure for any particular customer must be arrived at accurately.

Under the contract demand provisions of the Joint Proposal, customers may elect to set their own contract demand. This avoids disputes with the utility over setting the proper

level. Affording the customer this freedom, however, raises the potential for manipulation, in that a customer might set the contract demand artificially low to avoid paying the full contract demand charge.

To discourage this sort of behavior, the Joint Proposal provides for surcharges in the event a customer-set contract demand is exceeded. The surcharges, modeled on those adopted for Niagara Mohawk after no party opposed them,[8] are reasonable. They compel the customer to pay based on the amount of the exceedence, with the size of the surcharge tied to that amount. The customer is also afforded a reasonable opportunity to avoid surcharges. It is forgiven one exceedence of less than 10% in magnitude, and it may raise its contract demand at any time.

To afford further flexibility, the customer may reduce its contract demand in two ways. First, it may drop the level to the size of greatest demand it has experienced in the previous twelve months. It also may demonstrate, in writing, to NYSEG that its circumstances have changed upon the removal or disabling of equipment. Subject to the utility's reasonable satisfaction, and to its right to inspect the premises, the customer's demand level would then be reduced below its

[8] Case 01-E-1847, Joint Proposal, Exh. 10 (Draft Revised Leaf 106-C).

historical experience, with the contract demand charges falling to the appropriate level.

Moreover, the customer may allow NYSEG to set the contract demand. If it acquiesces to the utility's determination, the customer will not be surcharged if the demand is exceeded, unless the customer fails to notify the utility of an equipment addition that raises its demand by more than 12.5%. In that event, a reasonable surcharge would adhere. Again, the customer may increase its demand at any time, or apply to the utility to reduce the demand under proper circumstances.

These provisions ensure that the contract demand will be set accurately. It also affords the customers flexibility in arriving at the contract demand level that best suits their load, while ensuring that the utility is properly paid for the capacity it actually supplies to meet demand.

The NBWC

Like NYSEG's other customers, standby customers will be subject to the non-bypassable wires charge (NBWC), a recovery mechanism for certain stranded and sunk costs under the utility's existing Rate Plan.[9] The NBWC charge will be allocated proportionately to the customer charge, the contract demand

[9] Case 01-E-0351, New York State Electric & Gas Corporation - Electric Rates, Order Adopting Provisions of Joint Proposal With Modifications (issued February 27, 2002).

charge, and the as-used demand charge. The amount of the NBWC will be set initially at the level NYSEG calculated as of April 1, 2003, and will be updated each six months thereafter at the time scheduled for NBWC recalculation in the Rate Plan.

This method of stranded cost recovery conforms to Opinion No. 01-4, which requires that standby customers bear the same responsibility for stranded costs as other customers, and that stranded cost charges should be assigned proportionately to the standby rate components.[10] Since it appropriately recovers stranded and other sunk costs from the standby customers, the NBWC mechanism should be approved.

Revenue Variances

Under the Joint Proposal, NYSEG will track annually the net revenue gains and losses annually, by comparing each standby customer's revenue contribution under the rates it is charged to the revenue contribution it would have made under the lower of either the existing S.C. 11 rate or the otherwise applicable standard service classification. NYSEG may petition for recovery or deferral of an overall net annual revenue loss of more than $500,000 (JP at 11). Any net annual revenue gain over that amount will be deferred for future disposition by the Commission.

[10] Opinion No. 01-4, pp. 22-23.

This provision appropriately balances utility interests in avoiding revenue erosion and ratepayer interests in avoiding utility revenue over-collection. It should be adopted.

Other Issues

Some NYSEG customers previously funded the costs of metering and instrument transformation equipment dedicated to serving their locations. If these customers were charged the full standby rate, which subsumes metering and transformation costs, they might be double-billed for some costs. As a result, a credit has been developed that will be subtracted from the customer charge otherwise applicable to these customers (JP at 9-10). This approach appropriately avoids double-billing.

The Joint Proposal affords those standby customers that elect to purchase their energy from NYSEG the option of hourly integrated energy pricing (JP at 7). This more accurate form of energy pricing furthers the development of competitive markets and encourages customers to properly plan their electricity usage by avoiding or reducing peak period consumption. The provision should be adopted.

Under the Joint Proposal, NYSEG may postpone implementation of the new standby rates until six months after issuance of the Commission's Order (JP at 7). This will enable them to install metering where necessary and update billing systems to accommodate the new rate design. Affording NYSEG

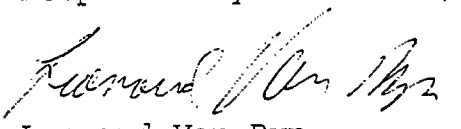
sufficient time to properly implement this substantial change in rate design is appropriate, and will avoid errors that could accompany a too-rapid introduction of the new rate.

Other provisions of the Joint Proposal address the procedures for its consideration and implementation (JP at 11-12). These provisions resemble provisions set forth in many other joint proposals, and should be accepted.

CONCLUSION

For the forgoing reasons, Staff requests that the Administrative Law Judge and the Commission approve the Joint Proposal, because it provides for standby rates that comply with the standby guidelines the Commission established in Opinion No. 01-4, and because those rates are non-discriminatory, further the Commission's policy objectives, balance the interests of all the parties, and constitute a fair resolution of the issues in these proceedings.

Respectfully submitted,



Leonard Van Ryn
Staff Counsel

Dated: April 21, 2003
Albany, New York

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 02-E-0779 - In the Matter of the Compliance Filing of New York State Electric & Gas Corporation in Response to Opinion No. 01-4 on Standby Service Rates.

STAFF REPLY IN SUPPORT OF JOINT PROPOSAL

LEONARD VAN RYN
Assistant Counsel
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350
(518) 473-7136

Dated: Albany, New York
May 8, 2003

TABLE OF CONTENTS

Case 02-E-0779 - In the Matter of the Compliance Filing of New York State Electric & Gas Corporation in Response to Opinion No. 01-4 on Standby Service Rates.

STAFF REPLY IN SUPPORT OF JOINT PROPOSAL

PRELIMINARY STATEMENT

On April 21, 2003, Staff received filings in this proceeding supporting the Joint Proposal from Indeck Energy Services of Silver Springs, Inc. and Lockport Energy Associates, L.P., Multiple Intervenors (MI), and New York State Electric & Gas Corporation (NYSEG). Filings opposing adoption of the Joint Proposal were received from the Joint Supporters, National Fuel Gas Distribution Corporation (NFG), and Wyoming County Community Health System (WCCHS).

Opponents of the Joint Proposal present positions ranging from disagreement with the premises underlying the standby rate design embodied in the Joint Proposal to objections directed against its discrete provisions. Some parties argue that the new standby rates do not accord with public policy promoting on-site generation (OSG), and propose a variety of exemptions from the application of the new rates.

These arguments lack merit. This proceeding is limited to the issue of implementing the rate design adopted in Opinion No. 01-4. Many of the arguments the opponents raise are

well beyond the scope of that Opinion, and equate to either a request for its reconsideration or a collateral attack on its provisions. As to the discrete criticisms leveled against the specific provisions of the Joint Proposal, they would disturb the balancing of interests essential to the success of any settlement. They should be rejected.

Compliance With Public Policy

The parties opposing the Joint Proposal argue that the rate design here conflicts with public policy, and maintain that the approach undermines Executive Order 111. Under the Joint Proposal, however, where the rate design might discourage OSG development, the adverse impacts are ameliorated through rate phase-ins. To the extent amelioration of impacts via a phase-in is insufficient, these parties are making their argument in the wrong proceeding.

A. The Scope of OSG Incentive Proposals

Joint Supporters, NFG and WCCHS argue that public policies justify the development of incentives that favor OSG development in this proceeding. Indeed, Joint Supporters calls for an expansion of the scope of this proceeding to encompass what amounts to a resource planning effort, addressing broad issues like competitive markets, energy independence and a cleaner environment.

This approach cannot be squared with the restricted ambit of Opinion No. 01-4, which provides that standby delivery rates "should provide neither a barrier nor an unwarranted incentive to customers contemplating the installation of DG or OSG" (Opinion No. 01-4, p. 11). If rates that properly recover costs are a barrier to the growth of desirable OSG, remedies should be adopted in another proceeding where a better record can be developed on the appropriate approaches and their costs.

Incentives promoting OSG installation are beyond the scope of this proceeding, which is limited to the preparation of tariff schedules, not the evaluation of environmental or societal benefits. Opinion No. 01-4 expressly prescribed that the tariff revisions at issue here were Type 2 actions exempt from State Environmental Quality Review Act (SEQRA) review. As a result, no SEQRA analysis has been prepared in this proceeding,[1] and expanding its scope to reach the resource planning issues Joint Supporters raises would be improper.

B. The Customer Impact Evidence

WCCHS and NFG argue that the impact of the Joint Proposal rates justifies exemption of OSG projects from their application, with WCCHS presenting an analysis of the costs it

[1] Opinion No. 01-4, pp. 25-26.

believes it faces as a result of the new standby rates. Their presentations, however, are flawed.

According to WCCHS, it will experience a 54% increase in S.C.-11 standby rates and a 29% increase in S.C. 7-2 standard tariff rates when the new rate design takes effect. Since it was actually charged only the S.C. 7-2 rates under the prior rate design, only that comparison is meaningful. And that comparison is overstated.

In matching its 2002 bills to a forecast of standby rates, WCCHS includes energy rates in both figures. Those rates rose by about 10% on January 1, 2003 for S.C. 7-2 customers. Reflecting that factor, which is not attributable to the standby rate design, reduces the actual rate increase WCCHS will experience below 20%, and below $20,000 per year. Moreover, as eligible for the phase-in, WCCHS will avoid any increase attributable to new standby rates for both this year and the first year the rates are in effect.

WCCHS projected it would realize annual savings of $215,000 from the operation of its OSG facility. An increase of less than $20,000 per year in costs, while significant, is less than 10% of the savings it expected. Moreover, any reasonable OSG developer would understand that electric utility rates change over time, and would have factored the possibility of rate increases into its overall savings assumptions.

Consequently, WCCHS' evidence does not justify exempting it from the standby rates.

NFG details what it describes as the impact of standby rates on OSG project development. As NFG concedes, however, even if standby service were free, many OSG projects would be uneconomic. Moreover, NFG fails to compare the actual cost of standby service to the cost of other OSG inputs, such as fuel, maintenance and financing. It therefore fails to demonstrate that standby rates are the most serious obstacle to OSG development.

NFG attempts to support its exemption approach with an analysis of changes in OSG penetration levels that would allegedly occur if the new standby rates were implemented. Forecasts of penetration, however, can be unreliable. For example, in 1988, the growth of independent power production penetration was forecast to reach about 2,000 MW in-service by 1996.[2] By 1992, that forecast had more than doubled to 5,000 MW.[3] Actual penetration in 1996 was closer to 5,600 MW.[4] There is nothing to indicate that NFG penetration estimates are

---

[2] Case 28962, Long-Run Avoided Cost Estimates, Opinion No. 88-13 (issued May 10, 1988), p. 22.

[3] Case 91-E-0237, Long-Run Avoided Cost Estimates, Opinion No. 92-16 (issued June 26, 1992), p. 7.

[4] Case 93-E-0912, Long-Run Avoided Costs, Exh. 85.

substantially more accurate than the penetration estimates developed for independent power production.

The parties' evidence does not support the contention that the introduction of new standby rates will be accompanied by unacceptably severe rate impacts. Accordingly, consideration of the means for promoting OSG penetration should be taken in an appropriate proceeding where a better record can be compiled.

C. The Joint Proposal
Impact Amelioration Measures

The opponents of the Joint Proposal have not demonstrated that its measures to promote public policy are inadequate. Under the Joint Proposal, existing customers may elect to participate in a phase-in to the full standby rate. Because many existing OSG customers will benefit from the new rates, a phase-in rather than exemption is the proper approach to the impacts the remainder could face.

Included among the existing customers qualified for participation in the phase-in are OSG projects that have been awarded grants by the New York State Energy Research and Development Authority (NYSERDA). Undermining the financial commitments OSG developers have made in partnership with NYSERDA is therefore avoided, and the growth of OSG is promoted. Moreover, a separate phase-in will ameliorate potential rate impacts that might affect environmentally beneficial OSG

projects, which may operate at disadvantageous load factors and fall among the customers facing more significant rate impacts from the new standby rates.

In comparison to these phase-ins and limited exemptions, the incentives and broad exemptions proposed by opponents of the Joint Proposal could prove costly to implement, and utilities or their non-OSG ratepayers could experience adverse financial impacts. Since these parties' proposals create a cost risk without constraining that risk through appropriate limitations, their exemptions should be rejected, without prejudice to raising them in another proceeding where a more complete evaluation can be conducted.

D. The Definition of Existing Customer

Joint Supporters would expand the definition of existing customer, by extending the deadline for qualifying to join the rate phase-in afforded those customers. The phase-in, however, is appropriate only for those customers that had made their investment decisions, or had substantially planned their projects, or had been selected by NYSERDA, before the impact of the standby rates became widely disseminated. The Joint Proposal is already generous on this point, establishing a cut-off date of January 31, 2003 for making such a commitment.

This date is retrospective and arrives at a definition of existing customer that is limited to customers previously

committed to OSG installations. It rewards customers who diligently developed their projects but experienced a change in circumstances, and balances that benefit to OSGs against the impact of the costs attending the benefit on the utility and other ratepayers. Accordingly, the use of a later cut-off date should be rejected.

E. Promoting CHP

Contrary to the arguments of Joint Supporters, expanding the scope of the phase-in to include CHP projects as an environmentally beneficial technology is not appropriate on the record here. CHP is already encouraged, because many of the NYSERDA projects qualifying as existing customers are CHP installations. The development of those projects should yield the benefits of experience to guide future CHP installations and the molding of future CHP policy.

Moreover, if CHP projects are well designed, they can be expected to operate at advantageous capacity factors, and are less likely to experience disparities between the standard and new standby rates. It also appears feasible for CHP developers to design real-time metering and operational flexibility into their projects, enabling them to avoid expensive peak period purchases from the grid while relying on it during cheap off-peak periods. A more definitive showing of need should be required before additional benefits are awarded to CHP projects.

Another difficulty attending proposals for the exemption of CHP projects is encountered in properly defining the types of CHP that should be exempt. From Joint Supporters' presentation, it can be seen that CHP projects vary widely in their characteristics. Teasing out the characteristics that define a CHP project as advantageous could be a complex endeavor. Moreover, Joint Supporters proposes that clean air impact criteria be incorporated in the definition of beneficial CHP, but those criteria are beyond the confines of the rate design issues that Opinion No. 01-4 prescribed for consideration in this proceeding.

The appropriate characteristics for defining beneficial CHP installations are best considered in a proceeding devoted to that purpose where environmental criteria can be fully considered, rather than addressed here on a scanty record. Case 03-E-0188,[5] or a similar proceeding, would be a more appropriate venue.

F. Further Proceedings on Public Policy

Joint Supporters continues to argue that incentives are needed to promote renewable and other beneficial forms of OSG. Those proposals are beyond the scope of this proceeding,

[5] Case 03-E-0188, Renewable Portfolio Standards, Order Initiating Proceeding (issued February 19, 2003).

and are better addressed in Case 03-E-0188.[6] If incentives are needed, but cannot be adequately considered there, another alternative would be to open a new proceeding.

In assessing the effect of rates on public policy, the Commission begins with establishing the appropriate cost-based rates. Clearly, the standby rates proposed here are the correctly designed cost-based rates that properly charge the true cost of standby service to the customers taking it. Where cost-based rates obstruct public policy, the Commission has taken appropriate action to alleviate adverse impacts. It has devised low-income customer programs, economic development programs, and retail access programs to promote desirable public policies. It has also instituted a Systems Benefit Charge (SBC) to collect funding for programs that achieve public policy goals.[7] In all those instances, it began by charging the correct cost-based rate. Only with that rate in place is it possible to accurately and properly evaluate the incentives that are needed for public policy purposes.

Once cost-based standby rates are in place at NYSEG, many OSG customers may find them satisfactory. If, however, OSG

---

[6] Case 03-E-0188, Renewable Portfolio Standards, Order Instituting Proceeding (issued February 19, 2003).

[7] Case 94-E-0952, System Benefit Charge Issues, Opinion No. 98-3 (issued January 30, 1998).

advocates can demonstrate that the standby rates adopted here are obstructing beneficial or renewable OSG development, and that consideration of incentives cannot be accomplished in Case 03-E-0188, a review of incentive proposals could take place in a new proceeding instituted for that purpose. The costs and benefits of appropriate incentives could be calculated and evaluated in such a proceeding.

Absent accurate cost-based rates as a guide, however, an overstated incentive could shift unreasonable costs to other ratepayers. Rising electricity costs could compel businesses to reduce employment or leave the State, thereby retarding economic development, or could overburden already economically-distressed low-income customers. On the other hand, too small of an incentive, if one is needed, would fail to bring forth the desired OSG penetration. These complex issues could be considered in a new proceeding.

The Opinion No. 01-4 Ratemaking Principles

Joint Supporters proposes segregating standby service into supplemental and back-up components and to price the back-up component "dynamically." It also argues that the new standby rates do not properly reflect coincidence factors. These positions conflict with decisions reached in Opinion No. 01-04.

The Opinion expressly rejects separating supplemental service from other standby services. It states that standby

rates should "apply to the entire delivery service taken by a customer with an OSG regardless of whether the OSG serves all or only a portion of that customer's load" (Opinion No. 01-4, pp. 21-22).

Joint Supporters proposes "dynamic" pricing for back-up service that would fluctuate with volumetric usage. The Opinion provides:

> Using volumetric rates as the basis for recovering delivery service costs for standby customers is not appropriate because the local costs of providing delivery service correlate with the size of the facilities needed to meet the generating customers' maximum demand for delivery service. This varies, not with the volume of electricity delivered, but with the peak load that must be delivered (Opinion No. 01-4, p. 12).

Dynamic pricing is a volumetric approach that cannot be squared with the Opinion.

Joint Supporters argues that the standby rates developed in the Joint Proposal do not properly recognize OSG coincidence factors. The Opinion provides that "the use of daily, as-used demand charges for stand-by service is a direct reflection of the lower cost responsibility of standby customers for service classification coincident peak load" (Opinion No. 01-4, p. 11). Since it conforms to the Opinion, the Joint Proposal rate design properly reflects the potential for coincidence benefits.

Joint Supporters' Other
Rate Design Arguments

Joint Supporters' proposal to segregate rates into supplemental and back-up components is not properly structured. Joint Supporters has not demonstrated that its division of an overall rate into the two components applies equally well in bundled rate or unbundled rate circumstances. While its rate segregation proposal was developed in a bundled rate context, NYSEG offers rates unbundled into energy and delivery, with a volumetric component as a feature of each rate option. Joint Supporters has not shown that a "supplemental" rate providing for such variable charges can be calculated or billed on a cost-effective basis when combined with a "back-up" rate consisting entirely of customer and demand charges.

Joint Supporters defines supplemental service incorrectly. It would treat as "supplemental" any generation the utility furnishes to an OSG customer in addition to an amount that would be calculated based upon the OSG's historic operation pattern. To the extent that historic operations reflect less than the full generating capacity of the unit, the utility is asked to supply service that compensates for deficiencies the generator could have produced, but did not.

Back-up service is the appropriate charge for electricity supplied to replace generator production

deficiencies, not supplemental service. As defined in the Public Utility Policy Act of 1978 (PURPA) regulations, back-up power is supplied by an electric utility to replace OSG production during "an unscheduled outage of the facility," while supplemental power is supplied in addition to that the OSG could generate itself.[8] Joint Supporters' approach fails to comport with these definitions.

Joint Supporters proposes that back-up service be priced "dynamically." This approach, however, is premised upon analysis of line losses and allocation of responsibility for the cost of those losses to customers. Joint Supporters has failed to demonstrate that its approach is used elsewhere or that it can be practicably implemented.

Joint Supporters argues that OSG installations will reduce coincident peak loads, and that the cost benefits of that load reduction should be directed to OSG customers. Joint Supporters has failed to submit any data showing the actual cost impact such a coincident peak effect would have, because that data does not yet exist. Assuming the existence of a speculative coincidence benefit risks rate under-recovery of costs by the utility, improper rate shifting of costs to non-OSG

---

[8] 18 C.F.R. §§292.101(a)(8)-(9). See also, Case 27574, Electric Service to On-Site Generation Customers, Opinion No. 82-10 (issued May 12, 1982).

customers, and raises the potential for reliability impairments. For example, if the delivery system is designed based on coincident peak assumptions that prove understated, the needed delivery capacity will not be available when called upon.

Joint Supporters' proposals to substitute its rate design for the Opinion No. 01-4 rate design lack merit. They should be rejected.

The Allocation Matrix

Joint Supporters protests the allocation of costs between the contract and as-used demand charges, at the varying voltage service levels (JP 2). Joint Supporters argues that assuming 100% of secondary distribution system costs and 75% of primary distribution costs are local and attributable to specific customers is unwarranted. NFG submits a similar analysis of the allocation matrix.

As discussed in the Opinion, the allocation between contract and as-used charges is premised upon cost recovery of local facilities (i.e., those costs allocated on a non-coincident peak basis) through the contract demand charge and cost recovery of shared facilities (i.e., those costs allocated on a coincident peak basis) through the as-used demand charge.[9] The allocation matrix for NYSEG conforms to the Opinion,

[9] Opinion No. 01-4, p. 15.

recognizing that, in NYSEG's widely-dispersed and lightly urbanized service territory, transformer and other costs are local to customers connected at the secondary and primary levels where the transformation equipment is installed. Moreover, even some primary costs are attributable as local to secondary customers, because the primary system is sometimes designed to satisfy purely local needs. Recovering those local costs through the contract demand charge is appropriate.

Joint Supporters would modify the secondary and primary allocations by creating a new category for "transformer" costs. Since the Opinion permits utilities to rely on existing voltage and rate classifications in designing standby rates, Joint Supporter's new categorization is suspect at its inception.

Moreover, Joint Supporters, at its Exh.___ (MBL-3) Table 3, allocates "secondary transformer" costs all to the as-used charge. But in NYSEG's service territory, secondary transformer costs are all local, because they are incurred to meet non-coincident peaks at locations serving secondary customers. Those costs are therefore properly allocated all to contract demand, and none to as-used. Joint Supporters' primary level allocations to primary customers at Table 3 are premised upon a similar misanalysis of transformer costs for primary customers in NYSEG's territory, and are similarly flawed.

Joint Supporter's other Table 3 adjustments are not adequately justified. Table 3 should be rejected in favor of the Joint Proposal allocations.

The Length of the Phase-In

NFG contends that the phase-in period should be extended. The four-year phase-in, however, begins with a year of no rate increase at all, and then proceeds to move towards the full standby rate level in 33% increments. NFG has failed to present any evidence that this phase-in period is inadequate, given the rate impacts existing customers face. The rate increase confronted by the one customer that did submit evidence, WCCHS, shows that such a phase-in is adequate, because customer impacts, while significant, are not severe as would be needed to justify a lengthier phase-in period. NFG's argument should be rejected.

Selection of Contract Demand

Under the Joint Proposal, OSG customers are allowed to select their own contract demand. Normally, evaluating the demand a customer draws is a utility function. To afford OSG customers more flexibility in arriving at the contract demand that best meets their needs, however, the Joint Proposal grants them the privilege of establishing their own contract demand. Accompanying this privilege is an obligation for customers to

act responsibly when setting their demand. The obligation is enforced through a reasonable surcharge mechanism (JP at 5-8).

The surcharge mechanism provides, for exceedences of between 0% and 10%, a surcharge of twelve times the amount of the exceedence. That is the price the customer would have paid if it had properly set the contract demand for the prior year. For an exceedence of between 10% and 20%, the surcharge is 18 times the amount of the exceedence, and for an exceedence of more than 20%, the surcharge is a multiple of 24.

The surcharge mechanism was arrived at after substantial effort to balance the interests of NYSEG with the interests of its customers and is reasonable. Joint Supporters opposes the surcharge mechanism. Its criticism lacks merit.

Joint Supporters argues that the surcharge mechanism conflicts with the requirements of Opinion No. 01-4, and that there is no precedent for it. This analysis is unsustainable. Opinion No. 01-4 does not establish procedures for the setting of contract demand by customers, and this privilege is a benefit granted to OSG developers in addition to those addressed in the Opinion. As an additional benefit, it goes well beyond the requirements of the Opinion. Joint Supporters should not be heard to complain that one component of the privilege, the surcharge mechanism, is in conflict with the Opinion, while the beneficial components are not.

Moreover, contrary to Joint Supporters contention, similar surcharges are imposed on customers under similar circumstances. For example, natural gas customers can access lower gas rates if they promise to switch to alternative fuels during periods of high gas demand, such as when temperatures fall. Customers that fail to switch, however, must pay surcharges. Similarly, electric customers have been permitted to pay interruptible rates if they promise to reduce electric demand or disconnect from the utility system when properly notified by the utility. Again, if that promise is not kept, surcharges are applied.

Joint Supporters maintains that the surcharge mechanism discriminates against OSG customers, because other customers are not subject to a similar mechanism. But other customers are not allowed to select a contract demand for their operations. To treat OSG customers like other customers would require that the entire customer demand selection feature be excised from the Joint Proposal. This benefit to OSG customers should not be lost because some customers would prefer to reap the benefits of contract demand self-selection while declining to accept the concomitant obligations and consequences.

Flex Rate Contracts

NFG objects to NYSEG's cost standard for negotiating flex rate contracts with customers that can economically isolate

from the grid. NFG describes NYSEG's standard as requiring recovery of marginal cost and a reasonable contribution to fixed costs. NFG would modify the standard to require a contribution towards meeting the utility's non-bypassable wires charge (NBWC), which NFG believes represents NYSEG's stranded costs.

The marginal cost standard, however, may be more beneficial to customers seeking to negotiate flex rate contracts. The NBWC is not a marginal cost, and additional non-marginal costs may be subtracted from the otherwise-applicable delivery rate, thereby enabling NYSEG to make a lower offer under its standard to a customer than the utility could under NFG's standard. The Joint Proposal standard is superior and should be retained.

CONCLUSION

For the forgoing reasons, Staff requests that the Administrative Law Judge recommend to the Commission that it adopt the provisions of the Joint Proposal on standby service rates at New York State Electric & Gas Corporation.

Respectfully submitted,

Leonard Van Ryn
Staff Counsel

Dated: May 8, 2003
Albany, New York

MR. VAN RYN: The panel is available for cross-examination.

CROSS-EXAMINATION BY MR. YOUNG:

Q. I just want to start with just a general double check that the Staff's view is that the standby rates assume that they -- assuming that they are cost based, provide the proper, in some definition of that word "proper", incentives for development of OSG in NYSEG territory; is that a fair statement?

A. (Berger) Proper incentives?

Q. In NYSEG territory, yeah, in some definition of that, under the proposal.

A. (Rieder) Standby rates designed in this proceeding?

Q. Yeah, in this proceeding.

A. (Rieder) They are designed neither to present a barrier or act as an encouragement for on-site generation.

Q. And in the view of Staff, does the rate as proposed in the Joint Proposal provide some sort of economic signals to potential OSG developers concerning what kind of OSG to install in both?

A. (Rieder) The standby delivery rates show or present a proper price signal for the cost of

delivery service to be realized by each developer.

Q. And does that price signal encourage or allow developments with a certain type of load factors to be built?

A. (Rieder) There's a lot of characteristics, both operating and financing, that has to be considered by each developer. The standby rates present the proper price signal for the costs of standby service for the electric delivery.

Q. Turning to that issue that we talked about when examining NYSEG with the 15 percent threshold, first, is that an agreement in your view that deals with the purpose of the provision that those installations in which OSG is less than 15 percent do not go on standby rates, is that in agreement with the view that that is to prevent gaming and provide or ensure that the proper economic signals are sent?

A. (Rieder) The reasons that Staff felt the 15 percent was -- should be included in the Joint Proposal was to prohibit gaming in certain areas.

Q. Does the Staff have any information, conducted any studies, attempting to understand what are

the site characteristics that cause certain types of OSG to be in a certain size or on a certain percentage basis of total load?

A. (Rieder) Staff doesn't perform those things.

Q. I'd like to ask a hypothetical. If a small CHP installation were sized to meet the thermal load, the potential thermal load to (a) achieve, and environmental efficiency to optimally use fuel burned and it turned out that that size of load were 16 percent, would Staff view that as economically efficient for the engineers to reduce the installation size by 1.5 percent in order to get the effect of that production cheaper?

A. (Rieder) Again there's a lot of factors that have to be considered when sizing and operating an on-site generation in the standby rates and as incorporated in the Joint Proposal, the 15 percent threshold, it would be appropriate to have an analysis done of impacts of that.

Q. I'm sorry. An analysis done of impacts of what?

A. (Rieder) Of the standby rates and the 15 percent threshold; whether or not it's more economic for the developer would be his determination.

Q. Well, as a general matter then, is there any

evidence that 15 percent is the right number?
A. (Rieder) No, there's no evidence. It was a number that was reached after extensive discussion and negotiation.
Q. And another issue regarding maybe root principle is that there's been a lot of discussion in the case about a particular passage of 01-4 something along the line -- I'm not quoting exactly, but something along the line that NYSEG standby rates provide neither a warranted nor unwarranted barrier to OSG development. I would stand to be corrected on the exact quote, but I am curious whether Staff has a view about what percentage of bill reduction would constitute an unwarranted subsidy. Would 10 percent bill reduction be an unwarranted incentive to OSG?
A. (Rieder) Would a 10 percent reduction -- would you repeat that.
Q. Would a 10 percent bill reduction constitute an unwarranted incentive to the construction of OSG?
A. (Berger) Are you saying a 10 percent reduction to an individual customer or a 10 percent reduction in the overall rate to all customers?
Q. I'm thinking in terms of a specific customer.

A. (Berger) Well, the way the rates are designed being they've revenue neutral, one customer may see a 15 percent increase and one may see a 10 percent decrease.

Q. Right.

A. (Berger) So, therefore, I think it has to be individual to the customer as to what works for them economically; I think what we've been saying is that the rates are based on costs developed by the Commission in 0-14 and whether they provide an incentive for an individual customer would depend on what that customer's costs were, in construction, maintenance, fuel costs, many other inputs, so I -- it's hard for me to say, would there be an unwarranted incentive. The rates weren't designed to set up an incentive at all per se one way or the other and, therefore, on a classwide basis there should be hopefully no unwarranted incentive or disincentive but, on an individual customer basis, depending on their particular economics.

Q. I think we can take it for granted that the rates were intended to not provide an unwarranted incentive or disincentive, and I would like to ask a question in a different

way. If, across the board, the rates were hypothetically incorrectly constructed and the bill impact to the OSG customers on an average basis were 10 percent less --

MR. VAN RYN: Your Honor, I would object to that question. We do not hypothetically -- you do not come up with a hypothetical whereby the Commission sets incorrect rates. That's not an acceptable hypothetical.

MR. YOUNG: I'm trying to determine Staff's definition of unwarranted incentive.

MR. VAN RYN: Your Honor, that question was answered in great detail, very precisely and very eloquently, I might add, by Mr. Berger. I think you've got the answer and we should move on to a different area.

JUDGE EPSTEIN: Are we still on whether -- you're presuming that the rates are designed not to provide unwarranted incentives or disincentives and yet they have a certain bill impact for particular people affected; is that right?

MR. YOUNG: Well, I think it's been well established that certain individual

customers will have a bill impact up or down, and on the whole I think there's been a rather disputed contention that it's revenue neutral. Be that as it may, there's still this language that's hanging out there that is talking about an unwarranted incentive or barrier and not that that has been well defined or quantified, and I think it's worthwhile to do that.

MR. VAN RYN: Well, your Honor --

JUDGE EPSTEIN: I'm asking are you asking whether the individual customer's individual impacts have to be reviewed against that general standard of no unwarranted incentive or disincentive?

MR. YOUNG: No, I think I agree with you that it would be unreasonable to do it for the individual customer disincentives and I'm not suggesting that.

JUDGE EPSTEIN: Are you asking him whether --

MR. YOUNG: I'm asking him -- I just don't know what an unwarranted incentive is.

MR. MAGER: Your Honor, I guess part of the confusion is that language or

whatever was used was done by the Commission in Opinion 01-4. I don't think it's necessarily the job of the Staff panel or any party to the agreement to interpret the Commission's, you know, language.

JUDGE EPSTEIN: Well, all right.

MR. VAN RYN: I don't think they really want to argue. The panel has said what it has said.

JUDGE EPSTEIN: I don't think they've said it's inconsistent. If there's an impact for an individual customer, they don't think that's inconsistent with the Commission's language in 01-4. Now, we have that much. Can we go on from there?

MR. LIVELY: You described that you put in -- that the company has proposed cost-based rates and that it's consistent with the Commission order. How does a customer going onto those cost-based rates, how is that game playing if the Commission says this is an appropriate rate design and the customer says, "O.K., I'll take advantage, I'll use this appropriate rate design." How do you define "game playing" under section 5 of the Joint

Proposal?

A. (Berger) As a foundation, I think what you're saying is how do we define game playing? A situation where a customer may choose between more than one rate and can get a lower overall cost based on their choice that allowed them to, I think the word is arbitrage the company's revenues. They can then choose a rate that will contribute less to the overall cost of the system, and I believe the section you're pointing to is the 15 percent threshold area and if a customer -- the threshold is to set a situation whereby there isn't that kind of switching available for a nominal fee, for instance, I believe and one -- one way to look at it would be to say that, if you would like standby rates and for some reason you thought they would be advantageous to you, you could install, I believe, something called a Honda generator which is just a negligible amount of generation, not run it but actually have it physically installed and connected and without this provision could basically have chosen a rate for a small entry fee that is advantageous to it and, yes, disadvantageous to the rest of

the customers. So when we talk about gaming, we're not talking about choosing between two different cost-based rates which may be appropriate for the different kinds of service being provided. What we're talking about is someone who is being provided specific types of service like standby, being able to choose different methods to serve and different costs, different costs to be recovered by the company. So in this particular threshold, this is -- this -- the gaming would not be necessarily going from one -- from a non-cost based rate to a cost-based rate or vice versa. It would be going to two different rates, both of which are cost-based but apply to different types of service.

MR. LIVELY: But if this customer puts in on-site generation and there is an on-site generation rate, standby rate as we call it here, he has no option as to whether he should be taking that rate or not and he should be, according to the dictates of the order, he now has to go under that rate, but here the 15 percent seems to kick him out. How is that game playing on his part?

A. (Berger) Game playing is with his taking service at an advantageous rate. If he feels that -- this customer thinks that he can get a lower overall bill by being serviced under standby service putting in on-site generation, he will do so and then receive the benefit of a lower standby rate, but if he's only installing generation equipment that he doesn't expect to use that that would be the game that we would try to prevent with this 15 percent threshold.

MR. LIVELY: But, again, he's still following the rules, so how does following the rules constitute game playing?

MR. VAN RYN: Your Honor, following what rules? He's totally lost me.

A. (Berger) the 15 percent is the rule that we're discussing.

JUDGE EPSTEIN: Is there a -- is there an economic rationale that enables you to say, O.K., well, the person who puts in a minuscule generator with no intent to go on it particularly is affecting the system differently from the person who puts in a larger generator with some real intent? I mean does the intent matter, or is it -- should the dispositive thing

be that the customer has installed some generation? I think that -- I think that's what Mr. Lively is getting at. At least that's what I'm wondering.

A. (Rieder) Yes, your Honor, that is the issue, installed generation means that he intends on using. It is not that he -- he should not install a piece of equipment which he has no intent of using in order to get a better rate.

JUDGE EPSTEIN: The installation is what has the impact on the system, I mean the installation is why we start looking at the rates. You're saying, O.K., this is an appropriate situation for a standby rate, isn't it?

A. (Rieder) That's correct, your Honor.

MR. BERGER: It's the usage.

MR. RIEDER: (Rieder) It's the installation and usage of that, intended usage of the installation. What we're trying to get away from is installation of a very cheap nominal piece of equipment and calling it on-site generation when you have no intention of using it whatsoever and the only -- the only

reason why you would do that was to -- was to get a more advantageous rate for him, thereby gaming the system.

JUDGE EPSTEIN: O.K.

MR. LIVELY: How do you determine the intent when he installs it?

MR. DICKENS: I think that is rather obvious; he installs it and you assume it's installed to run and then he does play games by not running it.

MR. RIEDER: And the 15 percent threshold is in order to protect all the other customers in the company from the situation where a certain customer would game the system by installing it to that effect.

MR. LIVELY: So he installs a 16 percent -- his intent is not to run it, but the utility has no knowledge of what that intent is, other than that the customer has installed that 16 percent generator. How -- how does that paragraph (b) -- how do you play out paragraph (b) to disqualify that customer?

MR. RIEDER: If he installs a 16 -- installs a generator that's more than 16 percent, 16 percent or more of his load, but

does operate it, then he would still fall under that paragraph, under section 5. Draw your attention to that paragraph (b) of that section.

MR. LIVELY: Which is what I pointed out to you, but how do you determine that? When do you determine that he doesn't qualify under section (b)? How do you make that determination?

MR. RIEDER: At this point, that hasn't been fully -- fully drawn out or specified, and it will be a matter of the company's compliance filing in this case.

MR. LIVELY: I thought that this case was a compliance filing with regard to 01-4.

MR. RIEDER: That's -- you're correct.

MR. VAN RYN: Your Honor, it's well known that you could have a string of compliance filings for all sorts of reasons that can go on for a substantial period of time.

JUDGE EPSTEIN: O.K. Well, Mr. Lively, I think if I'm not mistaken you have your answer in that what you're asking is not

spelled out.

MR. LIVELY: O.K. Thank you, your Honor.

MR. YOUNG: I think this is related, so I'll turn to it now. On page 7 of, I believe it's Staff's reply comments, I believe there's a sentence that runs over from page 6 to page 7.

MR. MAGER: You just want to hold on a second.

MR. RIEDER: Thank you. What page?

BY MR. YOUNG:

Q. The top of page 7. The sentence actually begins on the bottom of page 6. I'll read it. It says, "Moreover, a separate phase-in will ameliorate potential rate impacts that might affect environmentally beneficial OSG projects, which may operate at disadvantageous load factors and fall among the customers facing more significant rate impacts from the new standby rates."

What I would like to understand is what -- what Staff means by the word "disadvantageous"?

A. (Rieder) When the rates are designed on a revenue neutral basis, you have some winners and losers based on a number of differing characteristics. Those with disadvantageous effects and those who would see a rate effect are below the percentage generation.

MS. ALLEN: For example, windmills may be generating in the middle of the night when the customer doesn't really need that power and not generating in the lull of a very hot still summer day and that would be disadvantageous for the generator.

Q. So we're getting back to the point now of the winners and losers, one of the factors that might cause a particular winner as opposed to a loser is load factor and I thought we were talking about before whether in Staff's view these rates provide the right incentives for OSG to be built and focusing specifically on this issue of load factor --

MR. VAN RYN: Objection, your Honor. What we established --

JUDGE EPSTEIN: Well, let's hear the question.

Q. (Continuing) By the inclusion of the idea of

advantageous or disadvantageous load factors, does that indicate that, in Staff's view, that the rates properly provide incentives for certain kinds of load factor installations to be constructed?

JUDGE EPSTEIN: Mr. Van Ryn.

MR. VAN RYN: The objection I had, your Honor, was that we did not establish that the rate set was an incentive. The facts we have established were just the opposite. The rates were not designed to establish that. In fact, we established that the rates were cost-based.

JUDGE EPSTEIN: That's correct.

MR. VAN RYN: Or designed to be cost-based.

BY MR. YOUNG:

Q. And part of the purported cost basis of the rates is that some sites may gain or lose with respect to the bills that they pay for, among other reasons, because of the load factor; is that much true?

A. (Rieder) yes.

Q. And is it the view of staff that that is an appropriate outcome of these rates?

A. (Rieder) It's an outcome of these rates.
Q. And if the rates are -- if the rates are properly cost-based, then presumably that means it's an appropriate outcome?
A. (Rieder) No, I wouldn't make that jump.
Q. If it turned out that the fact that some sites win or lose depending on their load factor is not an appropriate outcome, would it be appropriate to mitigate that impact through some measure?
A. (Rieder) No, it's just an outcome. There's outcomes -- we've designed the rates. Along with that, there are outcomes. Some are good; some are bad. They're not designed with that intent. What we have is cost-based rates that are designed on a revenue basis and some customers will win, some customers will lose. Those are outcomes.
Q. It's not just those with different load factors?
A. (Rieder) Has a lot to do with operating characteristics. There's a host of issues that go along with this matter.

MR. YOUNG: I think that's it for me. Thank you.

EXAMINATION BY MR. O'NEAL:

Q. I just have a couple questions to follow up on where we were just now, Joint Supporters. I think I heard the staff panel say there will be winners and losers.

Do we have any idea --I am actually going to qualify that a little bit. Winners and losers, and some will kind of break even; is that safe to say?

A. (Rieder) Yes.

Q. Do we have any idea how many or what proportion is going to stack up in the winning column, the break even column, and the losing column here for NYSEG specifically?

A. (Rieder) Because the rates are designed on a class average revenue neutral basis you can assume about half will win and half will lose, whoever had a bandwidth around zero, a draw.

Bandwidth around zero will be those who won't change.

Q. So, half will be above or will win, half will lose, some --it's not strictly half, I mean some will break even?

A. (Rieder) Depending what your bandwidth you draw around zero.

Q. Those who win, there is an intent of those that win

will equal those that sort of lose and balance out average?

A. (Rieder) That's just the outcome of design and revenue neutral rate on class average.

(Berger) That is for the entire class including sales customers, not necessarily just the existing OSG customers.

The Commission in 01-4 determined that there would be --would not be a separate class created for OSG or DG or generators of any type, but said they would keep them within the parent class and that rates should be designed based for the entire class.

If for some reason only people with advantageous load factors went to DG, or ones with disadvantageous load factors, that would obviously make a difference as far as the actual results that you would see.

Is that clear?

Q. No.

A. (Rieder) When we designed the rates, assuming all the customers from the parent class would be taking service under the standby rate.

Q. I understand that, but I wasn't--

A. (Rieder) That clarifies what you just said.

Q. I will take that on face value.

A. (Berger) All right.

Q. Just a couple general questions in terms of the scope of what we are talking about.

Does staff know how many OSG customers that exist today in NYSEG?

A. (Dickens) Not offhand, no.

Q. So we don't know, then, roughly half will be winners and half -- when I say half winners, is there another way to say this, because there are going to be some in the bandwidth of zero being neutral. On balance, half winners, half losers, so there is some revenue neutrality projected, correct?

A. (Rieder) No. If you are talking existing customers that outside generation can't make the same correlation the way we designed the rates. We designed the rates assuming all the customers and service classes took service under the standby rate service class.

Q. So then you don't know specifically --for the set of OSG customers you don't know how many are going to be winners out of them? They could all be winners or they could all be losers but the whole class itself will remain revenue neutral?

A. (Rieder) The whole class will remain revenue neutral if they are all served under standby rates.

Q. Let me ask the question again.

A. (Rieder) Yes, but the existing customers we're not going to know. Going to be a range. Maybe all winners or all losers.

Q. This gets back to my original question, which is really I guess maybe my original question was misunderstood.

How many OSG customers that exist right now --and I suppose because you don't know how many exist you wouldn't know the answer to this.

MR. MAGER: Objection. I think the record is again getting muddled. Two points.

First of all, the rates were designed, as the staff panel said, for the rate class as a whole, but also based on historic determinants. It doesn't make a difference how many standby customers there are.

It's impossible to say with certainty how many may be winners or losers going forward, no matter how you define winners or losers, because you don't know how often the plants are going to be out, how often you need as used daily demand or not.

I think the line of questioning needs to be more specific or precise, otherwise the record is really going to be confusing.

Q. What Mr. Mager just said, is that the opinion of

the panel?

A. (Dickens) I think some of the confusion, the current SC-11 class, they have --they weren't --it wasn't that they were designed revenue neutral to that class. The rates were designed revenue neutral to all the parent classes, all the voltage levels. SC-7, SC-2s. All of those were used as a basis.

Now, people that are currently on SC-11 have to go to these rates. The impacts may or may not be, depends on the relationship of that class.

These existing rates were designed revenue neutral that the entire class, not from the existing SC-11 class, got two parameters, people coming --new customers coming from --who have been on SC-7 rates going there, and customers already on the SC-11 rates going there. There is two different situations going.

Q. But I guess my simple question was: We don't really have an idea of how many of these OSG existing customers, no matter what class they hail from originally, when they move to SC-11 we don't have an idea of how many are actually going to be hurt versus how many are going to be--

A. (Dickens) When you say go from the current to the parent to the proposed?

Q. To the proposed SC-11, yes.

A. (Dickens) We haven't seen impacts.

(Rieder) During the course of settlement negotiation discussions with the company regarding bill impacts for existing customers with on site generation, I do not have the results.

With any customer impact issue we to try to alleviate the bill impacts associated with the going on to different rates. Staff and the parties in the Joint Proposal agreed to a phase-in of the standby rates in order to ameliorate any negative rate impacts.

Q. There was no assumption on the part of staff --in signing onto the NYSEG Joint Proposal there was no assumption that OSG customers, roughly half would benefit, roughly half would be losers?

A. (Rieder) No.

(Allen) There was a reliance on the part of Opinion 01-4 that addressed the concerns for I believe benefits associated with DG or OSG. To the extent such economic benefits are not reflected in the utility cost of service they could be addressed within other proceedings; however, the main point is that the rate design reflects the benefits.

Daily as used demand charges for standby services is a direct reflection of the lower cost responsibility of standby customers for service

classification coincident to peak load.

Q. Thanks for that clarification. I guess what I am having trouble with rectifying in my mind, and I will pose this as a question to staff and see where you come out on it, is 01-4 of the original Order does make it clear, and we said that in testimony today that new rates really shouldn't be a barrier and they shouldn't be designed as any sort of incentive, so there is a neutral thing going on, but is it correct that what you have neutralized is the average revenues but not the impact on on site generation?

MR. VAN RYN: Your Honor, I don't understand what he means by the impact on on site generation.

Q. We have covered the fact that staff doesn't know how many are going to be winners of the existing set of OSG folks and how many losers, so we cannot gage the impact as a barrier to going on these rates to either existing OSG or new OSG?

A. (Berger) I am not sure you actually are interpreting the word "barrier incentive" correctly, or at least the way I would say it was being used.

You seem to be looking at the rates as being a barrier or an incentive to DG or OSG. I think when the Commission said they shouldn't be a barrier it was referring to the idea they are cost based, not

incentive or barrier based.

We are not designing them to be an incentive or a barrier. Not that cost based rates might not be a barrier to certain technologies or certain growth. That would be impossible. That would be asking far too much of a raise that applies to an across the board to all customers.

In fact, in the opinion the Commission said the rate design principles, not surprisingly, would result generally in greater cost responsibility for standby customers than if these retail delivery service costs were recovered strictly on the basis of metered consumption of energy, kilowatt hours.

The bottom line is the rates were intended to reflect the demand on the system and the cost underlying serving that load, or demand or potential load and demand in the case of OSG, and designing those based on the costs of protecting a system that can meet those demands or loads is how the rates were designed to be realized by the Commission in 01-4, not by providing an incentive, not by providing a barrier.

It did not state that the rates themselves wouldn't have an impact on customers. In fact, it recognized it in the statement I just read it would have an effect, and it was a desired effect, that costs

would be recovered by the customers who would have on site generation.

Q. By or from the customers?

A. (Berger) Sorry?

MR. BROWN: By the customers is what you said. Did you mean from the customers?

MR. BERGER: Right. By the customers' rates would be more accurate.

Q. Can you --that was not clear to me in my reading of 01-4. I mean basically there was --my understanding of the case, though I was not involved in it, there was some discussion about incentives, and clearly they didn't want people to be incented to go on to these rates.

And I guess I am just asking --I mean let me ask it a different way. I think we have already answered it, so I will move on, but just to be clear about what you just said, Mr. Berger, still you are interpreting 01-4 I think differently than maybe other people have, that it's an average over all the rate classes that is going to be neutral and not--

A. (Berger) No.

Q. --And not a specific impact on OSG customers?

A. (Berger) You have quoted me incorrectly. First off, I did not say average over rate classes. It would

be an average over a single rate class.

These revenue neutral standards that the Commission adopted in 01-4 and have been employed in the case were by parent rate class, not by all the rate classes combined.

I want to make sure we are clear on that. I don't think I am doing anything radical in that determination.

On page 11 of the Order where we were talking about the cost based should provide neither a barrier nor an unwarranted incentive, it was preceded by the sentence that if --by a whole section, basically, where parties were talking about how these rates should be constructed.

And a number of non-utility parties here expressed the view that standby rates should provide an incentive, and the Commission was responding to that argument by saying if by that the non-utility parties mean to suggest the standby rates need not be established on a cost of service basis, we disagree.

And then to explain their rationale they went on and said cost based standby delivery rates should provide neither a barrier nor an unwarranted incentive to customers contemplating the installation of DG or OSG.

The sentence of the cost based rates not providing a barrier is in relationship to the Commission's earlier discussion. It decided rates constructed on a cost basis, not on an incentive or barrier basis.

Q. Fine. You know, I am reading the same part right here. Your cost based rates, which you indicate in your interpretation of what the Commission said, are not to provided an incentive.

I think that you have already answered, staff as a panel has, that we don't know the impact specifically on the OSG community within NYSEG of moving to SC-11 at this point.

You have a feeling or a belief, anyway, and others may disagree, but you have a belief that the rates will be cost based and meets 01-4.

My concern, if we were to implement this rate, then, there is a possibility, not withstanding our previous conversation, if I am hearing you correctly, now a possibility a lot of people could be harmed or helped of the existing OSG community.

A. (Berger) Are you referring to the existing --

Q. In other words, it doesn't have to be balanced, I think you I heard you say?

A. (Berger) The OSG commodity is the people who are

already taking service from--

Q. Existing OSG that would have to go on to the SC-11 rates.

A. (Berger) Is what I am referring to. We don't have an impact specifically studied on that set of customers.

(Allen) But we have a phase-in that was negotiated.

Q. You have a phase-in itself?

A. (Berger) It's more than that. Some customers who are winners obviously can opt to go on the phased-in, the actual rate itself.

Those who perceive themselves as losers can stay on the other rates and then be phased-in slowly, or if they come up with the conclusion they can operate their systems effectively to take advantage of the rates, can migrate over quickly with a 30 day notice to the company under the JP.

Q. But still a lot more could be affected of these customers negatively than positively. I mean that's a possible outcome. And is that through--

A. (Rieder) I think we answered the question. We don't know of the existing customers. We answered that question.

Q. Now, hypothetically, if a lot of people are going

to be harmed by this new rate, that does provide a barrier to them, not withstanding what 01-4 says?

MR. VAN RYN: Objection, Your Honor. He's gotten a full explanation of staff's analysis of the opinion of the word "barrier". I think we fully addressed that matter. If he wants to rephrase that question to go somewhere else, that's fine. I don't think in that form it's acceptable anymore.

JUDGE EPSTEIN: It's pretty clear what they are saying.

MR. O'NEAL: Your Honor, I will go on.

JUDGE EPSTEIN: Okay.

BY MR. O'NEAL:

Q. There was --let me just explore another proceeding because you mentioned that DG, if there is this harmful effect of SC-11, you mentioned, staff did in comments in support of the JP and in reply comments as well, there might be another proceeding, another avenue for relief, if you will.

Can staff specifically point the DG commodity to some other proceeding at this point or is this something we have to convene ourselves?

A. (Berger) Depends on the particular group we are talking about. Obviously there is the RPS proceeding that is ongoing that might address some concerns of

renewable or other environmentally benign technologies or not.

There is a recently enacted Commission notice for a new proceeding on rates. I don't have the notice with me but I know it was just a week or two ago, that may or may not address the concerns you are raising.

There is the opinion 01-5 in the DG case that was the --I guess almost you call its sister rates to the standby rates case, and that had avenues for certain kinds of DG to pursue I think it was pilot programs related to expansion of distribution systems.

Those are three existing rate cases or proceedings, I should say, not rate cases, that can be used. It is possible, obviously, to hypothesize a different proceeding that is not yet begun, but that is always the case.

Q. In these proceedings that you just mentioned, are they designed to provide any relief to DG CHP interests? Are they designed for any kind of incentive or--

A. (Rieder) I think the question was asked, if we could point you to the direction of other proceedings that were ongoing that may address this. I think we answered that question.

We are not, as a staff panel, in the

proceeding involved in those. It would be up to the involvement in that proceeding to determine whether or not the issue you are looking for is being addressed.

Q. You are just not going to characterize these other proceedings?

A. (Rieder) That's right. We are not going to characterize.

Q. It's hard for us, too.

Turning to another topic. There is a revenue tracking provision. It's paragraph 21. I think it got a lot of consideration so far when the company panel was up.

I am sure staff is familiar with the revenue tracking provision of the Joint Proposal?

A. (Rieder) We are.

Q. If I am to understand that provision from the earlier discussions, I don't want to mischaracterize it because we have already pretty much accurately defined that provision, but it places funds in an account, if there is an overage or underage, if you will, if that's a word, designed to determine after the fact, after SC-11 has been implemented, what the revenue impact was to the company, if I understand it correctly?

A. (Rieder) Yes.

Q. And it's not a done deal. I heard this morning

that if there is revenues that accrue to the company that they go directly back to the company, or if there is revenues that accrue to the rate classes it goes directly back to the rate classes. It really would still be up to the Commission to decide on that?

A. (Dickens) Just goes to the fund. Current ASGA fund out there.

Q. What does that fund ultimately do?

A. (Dickens) Decided by the Commission as to how --at the end of the rates agreement dispensation will be discussed then.

Q. It's got almost like a safety net, if the standby rate itself did not have the impact that I believe staff is forecasting?

In other words, you are forecasting revenue neutrality and cost based, and therefore the fund really shouldn't have debits or credits to it. It should be pretty much zero neutral, but if it's not then it's a safety net for that.

A. (Rieder) Staff is not making that forecast or any other forecast in the proceeding. The rates are designed --again, the rates were designed on a class average revenue neutral basis.

So, if all the customers taking service moved to the standby service there would be no net revenue

gain or losses.

Q. That's correct, but what if there is a revenue gain or loss? That's what this account in clause 21 is for, right?

A. (Dickens) It's to collect --within the threshold is to collect over- and underages, yes.

Q. Now, again, that clause is an after the fact clause, and if I understood the conversation this morning correctly it's actually done on an individual customer basis, but then averaged over all customers, so there is analysis of each customer's impact? Or am I --did I mishear this morning?

A. (Dickens) I guess I am confused. The impacts are customer by customer. How are they related to the fund is an aggregate, I guess.

Q. I was getting at the point the company --and with staff's review would be analyzing the impact customer by customer and then adding that up over a customer class to determine what the harm or--

A. (Dickens) I think the impacts would come on a class basis.

Q. Right, the impacts would be on a class basis, but in order to get that you almost have to do this OSG customer by OSG customer?

MR. VAN RYN: If he could reference us to the

Joint Proposal where he's deriving his analysis from I think that would be helpful.

MR. O'NEAL: I am not referring to any analysis. It's that the Joint Proposal is supported by staff and in clause 21, and I am getting at the issue of overages and underages and whether or not we measure that on a customer basis or not.

MR. VAN RYN: If you could point to the language in 21 that would be helpful.

JUDGE EPSTEIN: 21 does appear to say that it's each customer's as to what their revenue contribution is versus what it would have been.

MR. O'NEAL: Okay. I was just trying to have them say that. That's fine.

BY MR. O'NEAL:

Q. Is it possible -- let me back up and ask a generic question for staff. In your experience, being rate staff, have you undertaken rate impact analyses in the past before and prior to implementing a rate structure when there has been changes?

In other words, if the company comes in for a rate increase, do you either routinely or on occasion determine what the impact analysis or impact would be on the various customer classes?

A. (Dickens) We do them generically on a class basis,

and we look within those maybe different levels of usage by customer, but we --basically that's what we do.

You see impact tables that have by class and then by usage characteristics, but a specific customer would have to know what category it falls in to see when his increase would begin.

Q. You do that analysis during the rate proceedings and before the rates are put into place; is that correct?

A. (Dickens) Yes.

Q. In this proceeding we don't really have a subclass within --I guess we do, it's the OSG customers, but it's not an official class of customers. There is some in various customer classes.

So, in the case of this rate structure proposal we are not really analyzing the impact on this subclass of rate customers that SC-11 would have on them, like you would during a normal rate case, you would say SC-7, SC whatever the number is, this is the impact on them actually prior to implementing the rate structure, but in this case we are not doing that?

A. (Rieder) In this case we are exactly doing that. What Mr. Dickens referred to, what we are not doing is on an individual customer basis we are not doing.

Q. I don't think you understand the question. The question isn't are we measuring SC-7 or are we measuring all the classes which we are doing. You have testified to that earlier.

I am saying we are not doing that for a subclass of customer called OSG existing customers?

A. (Rieder) We are not doing them for individual customers. We are doing them on a class basis.

Q. But you are not doing it for the entire class of OSG customers?

A. (Rieder) There is no entire class of OSG customers.

Q. Exactly, thank you.

A. (Berger) We are addressing any possible negative impacts on customers the same way we would do not on a rate case, which is using a phase-in.

MR. O'NEAL: That's all I have right now.

EXAMINATION BY MR. GEARTZ:

Q. I would like to actually just expand upon your last question about the phase-in. Was there something specific that the staff used to determine what that length of time is?

A. (Rieder) That length of time was an issue of discussion throughout the settlement negotiations for the Joint Proposal.

Q. But was there any historical data, any existing OSG customer who looked at to see what the impacts would be on those existing customers from a phased-in approach?

Not to say that it's not a good approach, but what was the basis of it? Was there any specific data utilized or was it just a number that was tossed out there?

A. (Rieder) Can I have a moment with my counsel.

(Recess taken.)

MR. RIEDER: Clarification. Repeat the question.

BY MR. GEARTZ:

Q. For the phase-in, the certain numbers of years that was used as a phase-in, was there any type of analysis done of existing OSG customers to say, all right, what would the potentially negative impact to the customers be even though it was a phased-in approach?

Was it just a number tossed out there or was there actual data that was used to determine a means to minimize the impact to the existing customers?

MR. GIANNASCA: I would like to observe before answering the questions the parties may want to consider whether or not answering the question will divulge settlement discussion.

MR. VAN RYN: Your Honor, I would like to

discuss that point with the panel. They seem to still be struggling with it, if I could.

MR. RIEDER: I can't divulge what transpired during the settlement negotiations. Based on my experience and the experience of the staff panel, the outcome of the phase-in period, the phase-in term, is reasonable.

BY MR. GEARTZ:

Q. What determines reasonable? The reason for my question is: During the proceedings was the Municipal Law taken into account at all?

A. (Rieder) I can't divulge what took place during the settlement negotiations.

What I consider is reasonable in this is contained in the Joint Proposal and has been signed by numerous parties. So, it was considered reasonable by those signatory to the Joint Proposal.

Q. I guess I can assume, then, there was no specific data that it was drawn from, it was just a reasonable conclusion?

JUDGE EPSTEIN: The problem here is that if there was they are not at liberty to go into it.

The reason we have this type of hearing is that this type of hearing is sort of after everybody leaves the room you or another party can come in and

say this number of years is not reasonable and here's my evidence why.

You can't go back into the negotiating room and bring out material that parties may have been looking at that was offered to one another for negotiating purposes. Unfortunately, oftentimes, such as this, it would be interesting to try to do that, but to protect the negotiating process in future cases we have to close the door on that.

If you have facts that you can present as to why the jointly proposed phase-in doesn't do the job, that's fine. If you don't have --if you have arguments separate and apart from cold hard facts you are welcome to make your arguments, but you can't go back and ask the parties what did you look at when you were in the room.

MR. GEARTZ: Can I ask was it consistent with Municipal Law? Is that a reasonable question?

MR. VAN RYN: He's got to pull out sections, give us a citation, and explain what he believes the inconsistency would be. Just saying consistent with Municipal Law is far too vague and general. Once he does that we will decide whether the panel has the legal expertise.

JUDGE EPSTEIN: You can ask whether they have

some understanding what Municipal Law has to say about rates.

BY MR. GEARTZ:

Q. Doesn't have anything specific to say about rates, but what it does have to say --and the reason I ask this question is because, again, with my experience with this industry many of the customers are municipal customers.

By Municipal Law they are required --the projects that they do under specific guidelines, such as performance contracts, they are required to be budgeted annually. So, for the term of the contract, for example.

If it's a ten year program they have to have a zero or positive net cash flow for each of those years.

The reason I ask the question there in a situation like this for existing customers that may be in year one, two, of say a ten year contract and are now put in a position to switch to SC-11, that in --I am just going to take a situation in their particular case, kind of going back to one of the scenarios I utilized earlier of where the contract demand would be bumped up due to whatever reason, that it now under the circumstances puts a significant financial burden on the municipal customer and puts them in violation of

Municipal Law because they are no longer budget neutral.

MR. VAN RYN: That I believe that would be argument because the counter argument would be they should have taken it into account in the budgeting, like they do increases in maintenance costs and fuel prices and otherwise should have been--

JUDGE EPSTEIN: We have the rate people here, so to the extent there is a question here legitimately addressed to the panel, would be whether the panel was familiar with that kind of approach that Mr. Geartz has just described and whether you took that into consideration in signing on to this proposal.

MR. GIANNASCA: Taking it into consideration is inappropriate and whether or not they do so is not an appropriate question. If they are familiar with the process, I think that's appropriate.

JUDGE EPSTEIN: Do you have a reaction to whether it's pertinent here? Do you have any reaction as to the appropriateness of the kind of approach that Mr. Geartz has just described? Have you ever heard of it?

MS. ALLEN: I think it's a legal question.

MR. BERGER: It is a legal question.

MR. RIEDER: The staff panel is not aware of

what the gentleman is speaking towards, neither one of us on the panel.

BY MR. GEARTZ:

Q. Actually I would like to just address Mr. Van Ryn's last comment about the rates. If I look actually at the comments from staff on page four.

A. (Berger) The initial or reply comments?

Q. These are the reply comments dated May 8th.

A. (Berger) Thank you.

Q. At the last paragraph, down near about midway through starts, "Moreover, any reasonable OSG developer would understand utility rates change over time and would factor the possibility of rate increases into its overall savings assumptions".

My question would be: Does staff view a totally new tariff as a rate increase? I mean I would agree to the comment to an extent that typically when a project is developed that is taken into account, normal rate increases due to inflation, what have you, obviously we all know fuel costs go up and things change and those types things are taken into account.

How does --or is it feasible for a customer or developer to fully I guess expect a total rework or totally new tariff like this for a project that would have been done four years ago prior to any discussion

of standby rates?

Is that a reasonable assumption or expectation of a developer?

A. (Rieder) Is it reasonable that developer should have known that standby rates were being considered, is that your question?

Q. Yes. Going back, say, five years, prior to discussions of standby rates, within NYSEG territory that would it be --not withstanding knowing that rates are going to change, but is it a reasonable expectation that in a time frame five years ago someone could anticipate this type of a change in cost impact to a customer?

A. (Rieder) I would say yes, it would be reasonable considering the fact that the Commission's original Opinion 01-4, was as part of a case that was started in 1999, so, that's four years ago.

NYSEG does have an existing standby tariff. From anybody that's developing a project of this magnitude for its customers I would think it would be reasonable for them to be aware of what's coming down the line.

Q. Being aware of what's coming down the line, but you reference four years ago. If I were to step back five years ago, which is very reasonable in my world, in

that time frame, is that still a reasonable expectation and to what extent?

If there were no specific discussions or talks as to how this would play out or what it may look like, is that still a reasonable expectation five years ago, if it hadn't begun yet?

A. (Rieder) I would say four definitely. Five, I don't know.

(Berger) You also seem to be assuming that all these would negatively impact. As we described, this could have positively impacted and one might ask should they be able to take advantage of newly revised improvement.

May have been marginal and going to lose the contractibility and all of a sudden found it safer in the standby rates. Standby rates themselves were created to be cost based and reimburse the utility for what it does.

If you are asking whether or not the developer should have been aware of the possibility being a shifting of rates to adjust to match up with the costs being imposed on the system by their clients or potential clients, I think we would still have to say, yes, they should have been aware that perhaps rates might be shifted.

(Rieder) Again, we draw you to the point of the phase-in. We understand that operating and cost characteristics prior to the effect of the tariff gave the developer different economic scenario going forward. We do provide a phase-in to ameliorate impacts to a customer.

Q. We established we can't go there to even know what that was based on. I don't know if that's a valid point without knowing what it's based on.

MR. VAN RYN: The reverse is also true. If he believes it's insufficient he had more than adequate evidence to introduce it was. The only evidence on the record shows, according to the Commission, the phase-in is of an appropriate length.

No one has shown here they are going to receive a 75 or 80 percent increase. Less than 20 percent and not charge them the full rates until January 1st.

MR. BROWN: We object to counsel's testimony.

MR. GEARTZ: I have no further questions at this point.

EXAMINATION BY MR. KRAWIEC:

Q. Good afternoon. On paragraph four of existing customers, either under A, B, C, NYSERDA feasibility studies, or D, having a binding financial commitment, I

see a list of maybe 18, 15 NYSEG customers who operate OSG.

Lakeshore Hospital is not on there. We have had one for awhile. NYSERDA funds. We have a contract and financing and it's existing.

MR. VAN RYN: Object to the question. I don't know what he means by Lakeshore Hospital is not on there.

MR. KRAWIEC: It's not on the list.

MR. VAN RYN: You are saying it's not a NYSERDA project?

MR. BROWN: It received NYSERDA funding is his statement.

MR. VAN RYN: And it's not on the list.

MR. KRAWIEC: We have a binding financial contract. Under the categories our hospital is not on this list.

MR. VAN RYN: First off, that list applies only to one category, not to all three. It applies just to the list of projects that receive NYSERDA funding. The list was received from NYSERDA itself.

I would imagine that if, in fact, you did receive such funding and can demonstrate that, it would be incumbent on you to do it as soon as possible.

The fact it's not on the list does not

disqualify you from the other two categories if you can prove you could be included in those, that you are existing or have--

MR. KRAWIEC: We do.

BY MR. KRAWIEC:

Q. My question would be: If Lakeshore Hospital is not on the list how many here are not? How complete is the list that has been presented as to affected customers?

A. (Rieder) To the best of our understanding this was a complete list. It was given to us by NYSERDA.

Q. There is two customers in the room and one of them is not on the list, so then if we go by the rule of averages 50 percent of the people aren't on the list.

MR. MAGER: Objection.

MS. ALLEN: If you are an existing--

JUDGE EPSTEIN: Are you familiar with how the list was developed?

MR. VAN RYN: Yes, Your Honor.

JUDGE EPSTEIN: Do we need or do we have a process for unlisted parties coming in and saying we meet these exact criteria, we should be treated the same way?

MR. VAN RYN: First off, there again, if he's not on the list and he received NYSERDA funding he should be --as soon as possible he should be writing

NYSERDA and phoning them and asking them why he's not on their list, and he should be certainly informing the record here as to the evidence.

He should have shown up today with the evidence demonstrating he, in fact, received NYSERDA funding and should be on the list.

We won't be able to address that today. As soon as possible contact NYSERDA, asking them to inform us he should be on the list and submitting to all parties for review his evidence he is, in fact, on the list because he received the funding.

MR. GIANNASCA: I think we have a question about this. I don't understand why we are discussing whether or not his entity is on the list as a NYSERDA project. I thought I heard him say he's an existing customer.

MS. ALLEN: Are you operating?

MR. KRAWIEC: Yes.

MS. ALLEN: Then you would not be on the list.

JUDGE EPSTEIN: Off the record.

(Discussion held off the record.)

JUDGE EPSTEIN: Back on the record. We did have discussion of how you determine whether somebody should have been on this list. I think we would all agree that it's not a question on which we should have

an evidentiary hearing like this with a panel of witnesses who really aren't here to address possible omissions in the listing.

And I wonder whether we could stipulate that if the Commission were to adopt this paragraph four they would do so with the understanding there may be errors in the list, and it's something that would be the customer's responsibility to bring to the attention of staff at the appropriate time, which I assume would be in the compliance filing.

MR. GIANNASCA: Perhaps it's not necessary to make any assumption there are errors. Maybe it's more appropriate to say if a customer believes there are errors it's incumbent for the customer to bring that to the appropriate parties.

JUDGE EPSTEIN: And I would add that that would be with the understanding that this proceeding has been the subject of ample public notice.

So, putting those elements together, does any party think that's objectionable to say it's incumbent on the party, on an adversely affected party, to bring the concern to the staff's attention and that it doesn't go to the adequacy of the public notice up to this point?

MR. BROWN: Including the unfunded customers

that aren't here.

MR. MAGER: What are you talking about?

MR. GIANNASCA: What is an unfunded customer not here?

JUDGE EPSTEIN: Couldn't afford to participate.

MR. GIANNASCA: They are funded or unfunded?

MR. BROWN: They can't afford to. Intervenors' funding. People that aren't in the room.

MR. CRISTOFARO: I thought I heard Hank say if a customer was existing for the January 31st date, 2003, whether or not they are listed on the list they are eligible for the phasing in period; is that correct?

MR. HOST-STEEN: That is correct.

MR. CRISTOFARO: Any customer existing before January 31, 2003, whether or not they are listed here, is eligible for the phase-in?

MR. HOST-STEEN: That is correct.

MR. CRISTOFARO: This list is maintained to address customers who don't have an existing system yet but received and applied for NYSERDA funding, also included in the phase-in period, and by experiencing many NYSERDA contracts and awards.

The NYSERDA documentation is quite extensive.

It's impossible for any client to fake not receiving NYSERDA funding before the period. If somebody isn't listed here that has received NYSERDA funding it can easily be able to prove they received the document before January 31, 2003.

If we are clear, this list does not need to list all the customers who are existing before 2003 and they can prove they are existing or not, the utility should also be able to conclude if a customer is not listed here but later on can prove he got NYSERDA funding, the documentation should be clear and viable enough because it's a contract signed and dated by NYSERDA.

Any customer can easily prove to anybody in the room, even if not listed here, if he received NYSERDA funding before January 31, 2003; is that okay?

MR. BROWN: Moving on.

MR. GIANNASCA: One clarification. I think that's correct, only to add that that particular customer has to otherwise comply with the sections in paragraph four, and there is a commencement of construction milestones that need to be satisfied for certain NYSERDA customers.

I don't mean to omit that.

MR. CRISTOFARO: That's fine, I understand.

JUDGE EPSTEIN: The point was that the listing requirements are only to clause B or clause C and not to clause A, which is pre-existing customers.

To sum up the situation, is what we typically find that if a customer is eligible for a certain type of treatment they should be able to come to staff and demonstrate that.

And nothing in the Joint Proposal is intended to shut --nothing about these lists in the Joint Proposal is intended to preclude customers from doing that.

BY MR. BROWN:

Q. Turning to the staff's reply comment, page eight, bottom paragraph. I am going to address the first two sentences of this paragraph and ask the staff to clarify its understanding of what some of the terms mean.

"Moreover, if CHP projects are well designed they can be expected to operate at advantageous capacity factors and are less likely to experience disparity between the standard and new standby rates. It also appears feasible for CHP developers to design real time metering and operational flexibility into their projects, enabling them to avoid expensive peak period purchases from the grid while relying on it

during chief off peak periods".

I would like to ask staff to explain what an advantageous factor is that ameliorates the standard between the standards and the new rate.

MR. VAN RYN: I am going to object. Mr. Young started off the discussion with the panel on the exact same topic.

While I have not objected to the unusual procedure of switching back and forth between examiners, I don't believe it should be used to disadvantage staff. I don't believe it's appropriate to have one cross-examiner ask a series of questions and have the second come back to it.

JUDGE EPSTEIN: It doesn't ring a bell with me as far as Mr. Young's cross is concerned.

MR. VAN RYN: He talked about disadvantageous and advantageous load factors in the first series of questions.

MR. BROWN: That raises the issue, sir.

There is a difference between the capacity factor and a load factor and I would like to ask the staff to clarify that.

MR. VAN RYN: That sounds more specific and more pointed. I won't object to it.

BY MR. BROWN:

Q. Capacity factor of CHP plant is one load factor. During peak hours is another.

A. (Rieder) What we say in the document is that if the CHP is designed to --if the CHP -- to be optimally designed for the CHP would have to be on when the cost to purchase power is high and it can be turned off when the cost to purchase power is low.

Q. So the definition of good design under the new standby tariff is one that's on when the power is expensive from the grid and off when it's not so expensive?

A. (Rieder) That's what we were referring to.

Q. That's your general understanding and specific recommendation.

In the second sentence where real time, if the developer, presumably Mr. Geartz is a reasonable developer, you are a reasonable developer, were to design real time metering and operational application flexibility into the projects then they would routinely avoid the expensive peak period purchases; is that your understanding?

A. (Rieder) That would appear to be optimal from his operational point of view.

Q. I am going to ask you about the peak periods of NYSEG. When are the peak periods of NYSEG?

A. (Rieder) NYSEG's distribution peak I believe is from 8:00 a.m. to 10:00 p.m, give or take an hour.

Q. Would you accept, subject to check, it's 7:00 a.m. to 10:00 p.m.?

A. (Rieder) Subject to check, yes.

Q. In that period the CHP project is operating to its fullest capacity factor possible. Could you explain what its full capacity factor would be or what would be the best capacity factor it could run at during the peak hours?

A. (Rieder) During those peak hours and during the peak hours of the ISO, where the purchase of electricity would be more expensive, as long as the DG developer can provide its unit at a cost lower than what it could purchase the power from, both the energy supply and from NYSEG should be on.

Q. Theoretically, if the 300 kilowatt machine, let's say it's a school with a 500 kilowatt load, is operating flat out 300 kilowatt for the 15 hours from 7:00 a.m. to 10:00 p.m, what would be the capacity factor in that period?

A. (Rieder) It would be a hundred percent during that period.

Q. If there were no additional purchases from the grid or via the wires what would be the load factor for the

purchases?

A. (Rieder) Would you repeat the question.

Q. Surely. I am generating my entire load on site. I have a hundred percent capacity factor. I am running through 100 kilowatt all the time.

I am sorry. My example I had 500 kilowatt peak. I am just trying to --if I am meeting my entire load with the on site generation what's the load factor of my purchase from the utility in the same time period?

A. (Berger) You have no load. Zero?

Q. The load factor of my purchase is zero, I agree with you.

Then you introduce a peak load of 500 kilowatt and I only have a 300 kilowatt machine and my load goes up above 300 kilowatt during the course of the day, so I am buying during the peak hours.

What is your estimation of what happens to the relationship between the capacity factor, which we said a moment ago was a hundred percent, and the load factor, which was zero, on the purchases?

What happens? The more I buy does the load factor go up significantly somewhat?

A. (Berger) It would depend how flat your load was. If you were demanding 500 constantly and generating 300

constantly both would be a hundred percent.

Q. Okay.

A. (Berger) Because your load would remain constant and so would the capacity factor unless you count the total load as being minus your capacity.

If you were going to say your only capacity would be 200 kilowatt hours what you are buying over the total of five would be 2/5ths or 40 percent.

Q. Let's assume the latter instance is occurring, in which there is an incremental purchase beyond what I can generate. I have got a hundred percent capacity factor on my generator throughout this whole period and before 7:00 a.m. I don't have it on and after 10:00 p.m. I don't have it on.

What I have got is the load that goes up and comes down during the day, which is typical to a school. What happens --I guess I am still --I am dancing around the question about the ideal capacity factor that would let the standby rates and the standard rates harmonize, and if you could give us any guidelines or insights that would be helpful.

A. (Berger) I think the capacity factor we are talking about, as you indicated, is different than the load factor. It's the machine itself. How reliable is it. It's a measurement of that.

If your machine is extremely reliable I think the benefits you gain that are affected in the paragraph, you can count on it during peak hours and therefore you can turn it off for maintenance, which would be your -- primarily your only outages. If you have got a hundred percent capacity factor you only need to bring it down occasionally for your own economic benefits.

Q. Would it be acceptable to you to accept, I guess, without an exhibit to lead you to, that the load factor for the purchases in that 15 hour period might actually be relatively low compared to the class average load factor?

After all, we have shaved the base off with the big machine.

A. (Allen) You are not demanding 500?

Q. I am sort of going past 140 at 7:00 a.m. and down past it at 10:00 p.m, so my 300 kilowatt machine got the big bulk of the production and the purchase is a hump.

A. (Berger) Depends. It's not as easy a question to answer as it may appear on the surface because we don't know what the load is between 10:00 p.m. and 7:00 a.m.

Granted, it's going to be lower. As far as what the load factor would look like without DG, might

have hundred I assume kilowatt maximum some period during the day and drop much lower during the night.

Q. Assume it drops to 100 or 140.

MR. VAN RYN: If he would let the witness finish.

A. (Berger) If during the day it never gets higher than 200, draw on the utility because you are generating the load factor. As far as the utility is concerned, how flat you have been over the day would be between the 200 maximum during the day and the 140 at night, as opposed to what would have been something more along the lines of 500 and 140. You would be flattening the curve somewhat.

Q. When you flatten the curve does the load factor go up or down?

A. (Berger) I think I mentioned earlier it depends how you are looking at load factor. If you are looking at overall load factor you could impose on the system, which is the 500, that's a different measurement than, say, the actual load that you are imposing over the 24 hour period.

Q. The example, the 500, would that be the number for the contract demand number?

A. (Berger) Depends. If it was set by NYSEG I assume it would be. If it's set by the customer maybe,

depending how much reliance on the system, or if they install load limiters.

Q. Assume for a fact it's a NYSEG determined number and it would be that. I am still trying to clarify your perception of whether or not the shaped portion that is purchased from the utility might have a load factor lower than the class average load factor or higher than it.

A. (Berger) I think the answer to that is yes. It may have either way depending on what your characteristics are.

Chances are good that what the utility is facing is going to be a flatter load curve. We are mixing a lot of apples and oranges.

Q. I appreciate your courtesy. I think you are absolutely correct. It would be a lower load factor. It would be below the class average?

A. (Berger) I did not say that. I said the curve would become flatter, which would be a higher perceived load factor by the company.

They would be seeing you as not range as high as 500 as far as perceived load. They would be reserving the ability to serve you at 500 but not receive that as a load, and therefore your actual load on the system would become flatter and higher load

factor, if you will, based on what you are actually taking.

We are mixing what you are actually taking with what you are asking the utility to reserve for. I am not sure if we are--

Q. I appreciate your discussion on it. I want to go back to the reasonable CHP developer installing real time metering and operational flexibility.

Can you think of any other conditions under which they might just turn off from the grid --excuse me --turn off their generator and buy entirely from the grid than the examples you provided in the written reply, the off peak times?

A. (Rieder) There is going to be other times when the developer would turn off its generation. For maintenance, for any number of reasons.

MR. BROWN: I think that's all I wanted to pursue on that except that you made -- no. I will drop that at this point. That was helpful because obviously we had not had a chance to discuss a specific installation in the record so far.

Is there anyone else on our group that has a question or comment to this?

EXAMINATION BY MR. LIVELY:

Q. Earlier staff is talking about how the rates are

revenue neutral on a class basis. And when this gentleman down at the end of the table asked about how what the planner or developer would expect that asked about rate level changes, that's to be expected, and staff responded yes.

And sometimes rate design changes should be expected, but those would overall be neutral. And that sometimes there would be a rate increase for a group of customers. Sometimes a rate decrease because of the tilt of the rates.

And do you remember that discussion with the gentleman at the-- with Mr. Geartz?

A. (Rieder) I remember answering questions for Mr. Geartz, yes.

Q. And said that there was a potential for the customers to be advantaged or disadvantaged by the rate design change.

Earlier discussions with me staff said, well, if the customer saw a rate decrease that's gaming and we wouldn't allow the customer to enjoy that rate decrease.

A. (Rieder) Staff did not say that.

MR. VAN RYN: Objection. Asked and answered, number one. And number two, argumentative.

If he wants to argue this point in brief he

can have as many pages as he likes.

MR. LIVELY: May I ask my question?

MR. VAN RYN: I am not done with my objection.

MR. LIVELY: You are objecting even though I didn't ask a question?

MR. VAN RYN: If you are going to go back to the same ground, yes. If you want to move on to something else, fine.

JUDGE EPSTEIN: Fair enough. If you were to ask a repetitive question that had already been answered it would be objectionable, okay. We have agreed on that much.

But I assume --

MR. LIVELY: I am trying to understand how this applies to revenue neutrality. There is supposed to be --these rates are supposed to be revenue neutral, yet if there is a revenue increase the company gets to charge that revenue increase, but if there would be a revenue decrease that's gamesmanship and the customer doesn't get to enjoy that revenue decrease, so how is there revenue neutrality in that case?

MR. VAN RYN: I think he's mixing two concepts.

JUDGE EPSTEIN: I think he's assuming an answer that is different from what actually was said,

according to my recollection, anyway. The objection to gamesmanship was not, if I recall correctly, the revenue impact. It was the people would be taking advantage of rate design features that weren't designed for their benefit.

Now, I don't know. You want to just start fresh as if they never said anything about gamesmanship and its revenue impact, you can ask them if gaming has a revenue impact that they are trying to avert.

BY MR. LIVELY:

Q. Under the rate design there is going to be some revenue increase, some revenue decrease; is that correct?

A. (Dickens) No, that's not correct. Revenue neutral is revenue neutral.

Q. But when the rates are only applied to certain customers?

A. (Dickens) That wasn't your question.

Q. But under the application the new rates are only applied to certain OSG customers?

A. (Dickens) Say that again?

Q. Under the rate proposal the new rate design is only applied to certain customers, OSG customers?

A. (Rieder) On the standby rates, yes.

Q. The standby rates will only be applied to OSG

customers?

A. (Rieder) Yes.

Q. And the way that paragraph five is written it will only result in revenue increases because for those customers who would get a revenue decrease you say it's not allowed because that's gamesmanship, so doesn't that mean that the new rate design overall will increase the rates, increase the revenue?

A. (Rieder) No.

(Berger) You are aware that the section five is only about the threshold and is not necessarily about increasing or decreasing rates at all.

Q. It's also in paragraph B says customers who game a system, as we have been using that terminology in this proceeding, will be disallowed from being qualified from the rates?

A. (Berger) Says if the customer has over 15 percent is over the threshold and yet did not use the OSG in any material manner to serve the load, that it would be considered to be like the same as underneath the threshold of 15 percent.

So, it doesn't say the word "gaming". Doesn't say anything like what you are saying. You are implying an application of it that we haven't stated and I don't know why you would be asserting that or

positing it.

(Berger) Doesn't say if you are not using it. It didn't say whether or not you are using it. Increases or decreases revenues; therefore, it is not --paragraph B or section B of paragraph five does not address whether or not you are creating more or less revenues.

Q. So a customer who under paragraph B installs generation but ends up not using it and as a result gets charged higher rates, then under paragraph B they should be eliminated from the --they should be disqualified from receiving rates under this standby rates.

MR. MAGER: Objection. I think the question is really misconstruing the entire provision and it doesn't say anything about higher rates or not. It may well be that the parent class rates are lower, not necessarily higher, but the provision that's being questioned says that if the customer has not operated or is not operating the on site generation then he's priced out at the full --at the regular parent class rates. It doesn't go to higher or lower or anything.

And these questions are really just, A, making the record unclear and, B, misconstruing the Joint Proposal.

MR. VAN RYN: What you have here in this 15

percent provision is simply the case of customers who have an election. It was not intended that customers should have such an election. It was intended that all OSG customers go to the standby rates and all non-OSG customers stay on the standard rates, but someone figured out the systems could be engaged to create an election, whereby a customer who should be on the standard rates should opt for the standby rates.

And in order to forestall uneconomic gaming exercise of that option, which undermine rate design, remember rate design is aimed at broad customer classes. The idea, if you have certain characteristics that's going to be assigned to that class no matter what.

It's not going to say you are not going to have these elections and giving elections undermines fundamental principles of rate design. Just maintained to cut off an unintended election option that the new rate design created and that's all it was designed to do.

Has very little revenue impact whatever other than if a whole bunch of customers were to figure out they could game the system this way.

MR. BROWN: Thank you, Your Honor. We are through.

JUDGE EPSTEIN: I am glad I could clarify it for you.

Is there other cross for this panel?

MR. MAGER: Brief, Your Honor.

CROSS EXAMINATION

BY MR. MAGER:

Q. I want to go back and clarify certain things so the record is clear. Do you recall being questioned with respect to the meaning of revenue neutrality and how it might apply to individual customers?

A. (Rieder) Yes.

Q. Could you please read into the record footnote six on page seven of Opinion 01-4.

A. (Rieder) "Revenue neutral here means that the full service class, not any individual customer, would contribute the same revenues if the full class were priced under either the standard service class rates or the standby rates given the historic usage patterns of the customers in that class".

Q. Thank you. I would like to now also ask a clarifying question concerning paragraph 21. Could you just define for the record what is the ASGA.

A. (Rieder) The asset sale gain account.

Q. That account has been in existence prior to the settlement negotiations in this project, correct?

A. (Dickens) Yes. Stemmed from the sale of the plants.

Q. I believe there was some testimony in terms of whether any revenue gains or losses would be automatically credited or debited from that account. Do you recall that general questioning?

A. (Dickens) Yes.

Q. Turning your attention to the actual language in paragraph 21, I have two questions. One, with respect to revenue gains, does the Joint Proposal provide that any revenue gain over $500,000 would just be returned to customers from the ASGA?

A. (Dickens) It says any net revenue gain over this fund would be refunded to the ASGA.

Q. There is no requirement the Commission be petitioned in that instance, correct?

A. (Dickens) No.

Q. With respect to revenue losses, revenue losses would be recovered? Excuse me. Revenue losses over $500,000 would be recovered from customers through the ASGA by NYSEG upon petition to the Commission, correct?

A. (Dickens) That's what it says.

Q. Now, I would like to draw the panel's attention to paragraph nine of the Joint Proposal. Was at least some of the panel present during the cross-examination

of NYSEG's panel?

A. (Rieder) Yes.

Q. Now, do you recall certain questions about in terms of how a customer contract demand would be set? And specifically I believe there were a series of questions with respect to a hospital and an MRI truck. Do you recall that topic?

A. (Rieder) Yes.

Q. I don't want to focus on an MRI truck, but I would like to back it out and talk about customers in general or say hypothetically an industrial customer.

Let us suppose an industrial customer has NYSEG set the contract demand at five megawatts, okay, and at some point the customer exceeds that contract demand and has a demand of 5.1 megawatts.

Are you with me so far?

A. (Rieder) Yes.

Q. Now, turning to the first sentence of the second full paragraph, where towards the bottom of page six of the Joint Proposal it states, "A customer that sets its own contract demand may revise its contract demand downward by written notice to NYSEG once every 12 months"; do you see that?

A. (Dickens) Yes.

Q. I would like you to assume from my hypothetical

that the industrial customer with the 5.1 megawatts demand has not made such a request in the past 12 months.

Let us suppose that this customer takes out equipment away off site or disables it. Under that situation, turning to the next sentence of the Joint Proposal it states, "The new contract demand level cannot be set at a level lower than the highest demand achieved in the previous 12 months unless the customer demonstrates in writing to NYSEG's reasonable satisfaction that electricity consuming equipment is removed or disabled in place".

Do you see that?

A. (Rieder) Yes.

Q. If the customer in my hypothetical removes equipment from the site and can only demonstrate that to NYSEG, would you agree that the customer may lower its contract demand to a level below 5.1 to take into account the removal of the equipment?

A. (Berger) Yes.

MR. MAGER: Thank you. I have no further questions.

MR. BROWN: I need to follow up because I thought Mr. Mager was going to address his question on paragraph 21, question that he asked the NYSEG staff,

and I now want to posit it to this staff.

BY MR. BROWN:

Q. This was the customer has a million dollar account or service and individually negotiated contract reduces that to $500,000. Is this a gain or loss in terms of the number section 21 account? He could have gone to zero.

MR. GIANNASCA: Can you repeat the question, please.

Q. Surely. Actually, unfortunately, the other reporter is already gone or we could have her read back Mr. Mager's question directly.

'It was assumed the customer has a one million dollar service annually. It threatens to leave, effectively demonstrates it, negotiates something with the utility, and a $500,000 continuing contract annually is put in place. And I am asking the staff panel: Is that $500,000 a gain or a loss in terms of the ASGA? It could have been zero.

A. (Dickens) It's neither. As far as the ASGA, it's neither.

Q. So it doesn't go in as a revenue loss or a revenue gain?

A. (Dickens) No.

MR. BROWN: That's all I have, sir.

MR. DICKENS: I assume --maybe I should have made this clear. I think the --I thought the discussion centered around someone signing a flex contract to negotiate $500,000.

My understanding is flex contracts are not borne by ratepayers. The losses are not borne by ratepayers.

MR. GIANNASCA: I think the assumption in that question was that the parties negotiated a special contract under paragraph 13 of the Joint Proposal.

MR. BROWN: Mike, that was your original SC-13?

MR. GIANNASCA: Paragraph 12.

MR. MAGER: I didn't ask that question to this panel.

MR. BROWN: I appreciate that.

MR. MAGER: It's your question, Mr. Brown.

MR. O'NEAL: I think what you wanted to assume and have the panel assume is that the customer in the hypothetical entered into a negotiated contract with the utility under paragraph 12, not under the flex rate service classification, 13 or 14.

MR. BROWN: He's talking about SC-13. I was referring to paragraph 12, you are correct.

BY MR. BROWN:

Q. So, my question still stands, Mr. Dickens. Is it a gain or a loss? Your position was, no, it's neither.

If that's your position I will leave it there.

A. (Rieder) No. We clarified. That was under a different assumption.

Q. Under this assumption now.

A. (Dickens) For one thing, it would be in context with any other losses or gains because there is a $500,000 window. If that's it, my answer still stands. Doesn't affect it.

Q. It would be aggregated with other things?

A. (Dickens) Yes.

MR. VAN RYN: Your Honor, if we could have a break at this moment.

JUDGE EPSTEIN: On that question?

MR. VAN RYN: Not only that. First off, is there any other cross for the panel based on that question or any other?

JUDGE EPSTEIN: I just want it clear to me whether the panel completed their answers. Are you still working or are you done?

MR. RIEDER: We are finished.

JUDGE EPSTEIN: Did you want to add something to that?

MR. RIEDER: No. We are finished.

JUDGE EPSTEIN: Is there any other cross for the panel?

MR. MAGER: I might, Your Honor. I might need the answer read back. It would be a follow up to that answer which I am not --I don't fully understand.

Maybe during a break I could have the reporter read back the answer and determine whether I need to follow up or not. I am not sure. Or we could do it now. I didn't catch the answer.

(Answer read by reporter.)

MR. MAGER: I think I am set, Your Honor.

JUDGE EPSTEIN: Okay. Redirect.

MR. VAN RYN: Yes, Your Honor.

REDIRECT EXAMINATION

BY MR. VAN RYN:

Q. I ask the panel if it recalls a series of questions about the flex rate provision under the Joint Proposal for customers that can economically isolate from the system?

A. (Dickens) Yes.

Q. Do you believe the usual flex rate contract principles should apply to those flex rate contracts?

A. (Dickens) Yes.

Q. And that is including the principle that the utility bears the revenue loss?

A. (Dickens) Yes.

Q. And except to the extent the Joint Proposal might provide for other conditions?

A. (Dickens) That's true.

MR. VAN RYN: That's all, Your Honor.

JUDGE EPSTEIN: Anything further?

Okay, thank you, panel. You are excused.

(Panel excused.)

At this point I think the next order of business before we talk about scheduling any other RG&E hearing there are-- we will be back in ten minutes.

(Recess taken.)

JUDGE EPSTEIN: On the record briefly just to have Mr. Brown --Mr. Brown has presented these three witnesses, each of whom submitted prefiled testimony, and in addition Joint Supporters filed initial comments.

And, Mr. Brown, are you going to--

MR. BROWN: And reply comments, sir, and an exhibit.

JUDGE EPSTEIN: That was remarks by William Flynn. I read it this morning and didn't know it was your exhibit.

MR. BROWN: Didn't have a mark. I apologize.

JUDGE EPSTEIN: Mr. Brown, do you want to

confirm with these witnesses that they are --if you would get the witnesses to confirm they were adopting these three pieces of testimony and the two comments.

MR. BROWN: The additional comments are the initial comments, the reply comments, and the exhibit of Mr. Flynn's remarks of the meeting on May 1st. So, you are swearing to that?

MR. LIVELY: Yes.

JUDGE EPSTEIN: And so the initial and reply comments and the testimony of the three witnesses will be incorporated in the transcript as if given orally.

(The following is the Initial Comments of Joint Supporters, Reply Comments of Joint Supporters, Direct Testimony of L. Keith O'Neal and William Cristofaro:)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 02-E-0779 - New York State Electric & Gas, Inc. – Proceeding on Motion of the Commission as to an Electric Tariff Filing to Establish a New Standby Service in Accordance With Commission Order.

Initial Comments of Joint Supporters and Other Interested Parties and Statement in Opposition to Joint Proposal Filed April 7, 2003

April 21, 2003

Introduction

Opinion No. 01-4, Opinion and Order Approving Guidelines for the Design of Standby Service Rates (Issued and Effective October 26, 2001), launched a process to which New York State Electric & Gas, Inc. (the "Company") responded with a set of proposed tariffs filed on June 7, 2002. A series of technical conferences and settlement meetings were held among interested parties. The Joint Supporters and other interested parties[1] mobilized by The E Cubed Company, LLC, participated in the conferences and meetings among all the active parties. A submission dated February 7, 2003 (the "February 7 Submission") contained updated, draft tariff leaves reflecting delivery rates that took effect on January 1, 2003 reflecting decisions of the Commission on the "Electric Rate Plan" in Cases 01-E-0359 and 01-M-0404 (February 27, 2002) and on Rate Design and Revenue Allocation in Case 01-E-0359 (November 22, 2002). After a technical conference and a series of Settlement Conferences a Joint Proposal ("JP") for settlement of issues was filed by several other parties on April 7, 2003.

Joint Supporters hereby oppose the original June 7th filing and the proposed April 7th Joint Proposal in the above-referenced proceeding, both in

[1] Joint Supporters is a thirteen-year-old voluntary association of entities advocating robust competitive energy services, including electricity, natural gas, and new technologies and services. Its associated entities participating in this proceeding include: Siemens Building Technology Inc., District One, Gerster Trane Energy Services, Energy Concepts Engineering, P.C., Custom Energy, LLC., All-Systems Cogeneration, Inc., Capstone Turbines, Inc., Clifton Springs Hospital & Clinic, Finger Lakes Health (Geneva Hospital) , Hess Microgen, Ingersoll-Rand Energy Systems, Invensys, Inc., KeySpan Technology Inc., RealEnergy Inc., , TLC Health (Lakeshore Hospital) and The E Cubed Company, LLC. Additional institutions and groups endorsing all or part of these comments and testimony include: Wyoming County Community Hospital, the on site generating projects, for the following schools (Binghamton -High School, East Middle School, West Middle School, Peru School, DePugh High /Middle/Lower School complex, Corning Painted Post – two High Schools, Owego-Appalachia-High School, Middle School, Alden Central - High School/Middle School, altPower, Inc. and the New York Solar Energy Industry Association.

terms of their broad structures and in several of the specific details. Both documents violate Opinion 01-4 by failing tests of cost basis and revenue neutrality. Both documents also violate Opinion 01-4's policy goal of creating neither incentives nor barriers to OSG: the June 7th Filing and Joint Proposal would establish unwarranted disincentives to OSG.

The Joint Proposal ("JP") submitted with signature pages and distributed by Trial Staff on April 7, 2003 comprises twenty-seven paragraphs and an Appendix A comprising nine pages. Paragraph 1[2] declares that the "Settling Parties" settle and that the JP resolves "all issues regarding electric standby service rates for NYSEG service to customers with on-site generation ('OSG'), including wholesale generators."

Unfortunately, there are a number of open issues that severely jeopardize a number of customers who have already built, operate or have committed to purchase OSG system that have not been adequately dealt with by the Joint Proposal. A simple example is provided by hospitals, such as TLC Health's Lakeshore Hospital, Wyoming County Community Hospital, where the OSG facilities were generally built to meet the thermal load and the electric load except for summer air conditioning. Another example is provided by hospitals such as Clifton Springs Hospital and Clinic and Finger Lakes Health's Geneva Hospital where the OSG facilities were built to meet the thermal load and the electric load including absorption chillers for summer air conditioning. Both situations are impacted adversely by the proposed rate structure.

A further example is provided by schools, such as those listed in footnote 1, where the OSG facilities were built to meet the peak electrical loads of June

[2] Hereinafter referenced in footnotes as JP, ¶1.

and September. The current tariff proposal undermines such investments. One overarching issue to keep in mind is that forcing customers who install OSG onto a new and unfamiliar rate structure, while customers who chose not to install OSG retain an entirely different structure, institutionalizes a profound "chilling effect" on the OSG industry. If all customers were to face a similar contract demand rate structure, then the competition between OSG and full service would occur on transparent grounds.

Witness William Cristofaro of Energy Concepts Engineering, P.C. speaks tellingly about the chilling effects of the proposed rate structure on the way OSG projects are engineered and optimized.

Witness L. Keith O'Neal of The E Cubed Company, LLC also addresses the substantial harm to end-users of OSG and the DG/CHP industry from the implementation of the standby rates as conceived in the Joint Proposal.

The proposed imposition of a separate rate structure for customers who choose OSG would create an intrinsically anticompetitive environment for OSG. Therefore, and for a vast array of legal and policy considerations, certain measures are called for to protect OSG from the potential distortions of the proposed standby rates. These measures may be either structural, or prophylactic within the proposed rate structure.

The "Allocation Matrix" Requires a New Rate Level

The Joint Supporters believe that the Joint Proposal developed its allocation matrix incorrectly.[3] The Joint Proposal implies that the sponsors believe that 75 percent of the Company's primary distribution system costs and 100 percent its secondary distribution system costs are incurred to serve an individual customer connected at the secondary level of the system. The sponsors

provide no evidence to support this assertion. The Joint Proposal makes a similar unsupported assertion with respect to the costs of the primary distribution system. The sponsors of the Joint Proposal fail to identify the cost components that comprise the local elements here and they therefore are unable to provide any explanation of how those cost components comply with the Guideline's criteria for being "local" costs.

The JP and the Company's approach seriously misallocates its costs and results in allocating too much cost to the contract demand[4]. Specifically, the Company ignores distribution costs that are shared between distribution customers. Metering and service drop costs are customer specific and should be allocated by contract demand. Distribution wires other than service drops as well as transformers, capacitors, poles, and other equipment as well as operating and maintenance cost are more related to coincident diversified demand than a specific customer's installed capacity. Therefore, the rates that result, appearing in JP, Appendix A comprise disproportionately higher Contract Demand levels than warranted, especially in the PSC 115, SC 7-1 (Secondary) and SC 7-2 (Primary) services where smaller OSG facilities tend to appear. This is particularly characteristic of hospitals, schools and other commercial accounts which may be on either service.

Witness Mark B. Lively addresses these issues.

Proper cost allocation would allocate each of these items as a separate cost category. Service drops and meter costs should be allocated 100% to contract

---

[3] JP ¶2.

demand but all other components were designed to serve the aggregated demand and would more properly be allocated to as used demand. The proper matrix percentage allocated to contract would be the sum of all customer specific costs divided by the total secondary distribution system cost.

The same principles would hold true for customers served at higher voltage segments of the distribution system. There is no justification for recovering any cost of the primary system by contract demand charges in the secondary. The individual secondary customer demand does not impact primary system design all primary system costs are incurred to serve primary customers and the aggregated demand of secondary customers. As such the Primary costs for secondary customers are shared costs that should be allocated 100% by as used demand. Again the same principle would apply when stepping from primary to subtransmission and subtransmission to transmission.

The Company ignores the distinction between customer specific costs and shared costs. Cost segregation should be added to the proposed allocation matrix, both in NYSEG's proposal and in the Joint Proposal, to account more accurately for cost causation. This could be accomplished either by expanding the matrix to include individual cost components or by allocating the components and setting the matrix percentages to the resulting composites. In either case any cost recovered from service charges should be removed from the cost attributable to contract demand.

---

[4] JP, ¶2, (Table 1 Percentage of Contract (Local) and As-Used (Shared) Allocations of Non-Customer Costs Revenue Requirement). Compare with Joint Supporters alternative matrix below at Table 1 and in Witness Lively's Testimony Exhibit _(MBL-2?)

Given the lack of justification for the proposed allocation, the allocation matrix should be revised to the following levels that are justified in the testimony of Witness Mark Lively:

Table 1

Delivery Voltage Level

Distribution Delivery Costs	Secondary Customers		Primary Customers		Transmission Customers	
	% Contract	% As-Used	% Contract	% As-Used	% Contract	% As-Used
Secondary Distribution	50%	50%				
Transformers	25%	75%				
Primary Distribution	0%	100%	50%	50%	100%	0%
Substation	0%	100%	25%	75%	100%	0%
Transmission	0%	100%	0%	100%	50%	50%

Special Provisions Are Deemed Essential In the JP, But Additional Special Provisions Are Warranted. The Pain of Comparison to Existing Rates Is Dramatic.

In concluding Opinion No. 01-4, the Commission indicated that it will monitor implementation of the principles "... in order to balance our interest in assuring the recovery of prudent, unavoidable utility costs with our goal of not impeding the development of alternative sources of energy."[5]

Unfortunately, the rates that the Company proposed as amended in the Joint Proposal that has been filed, do not provide a level playing field but rather tilt it, and associated distribution revenues and rate base, toward the utility. Witnesses Leon Kuzmarski, et.al. from Wyoming County Community Hospital directly confront the dramatic impact on the prospect that they can continue to

[5] Opinion No. 01-4, Pg. 27.

operate their OSG. They essentially say "No, we cannot continue in the face of the proposed rates."

Placing the proposed rates in the context of the alternative rates that Customers may face, it should be observed that as long as the utility has two distinctly different rate structures, one of which applies only to customers with OSG and the other "Standard Tariff" that applies to everyone else, special provisions are required to keep the playing field level. Some of these provisions appear in the JP.[6] They include definitions of "Existing Customers" that warrant special transition provisions over the period to January 1, 2007 in a number of cases[7] and January 1, 2008 in the case of a class called "renewable generator.[8]" Other special provisions appear in paragraphs 6-22 of the JP.

The Joint Supporters argue that, if our other proposals are not accepted, then additional special provisions are appropriate. These would include a longer phase-in period than that proposed in the JP.[9] more closely tracking the non-precedential eight year phase-in advanced in the Joint Proposal of March 7, 2003 in Cases 02-E-0781/0780 for Consolidated Edison Company of New York, Inc. and Orange & Rockland Company. Appropriate additional Special Provisions include: Supplemental Rate Structure, Dynamic Pricing, and treatment for highly efficient environmentally advantageous CHP. These will be addressed below.

---

[6] JP ¶3-4.
[7] These are triggered by events that occurred as of January 31, 2003.
[8] (b) Customers with OSG that constitutes a "renewable generator" (defined as a generator that uses any of the following technologies and/or fuels as the exclusive technology/fuel for generating electricity: fuel cell; wind; solar thermal; photovoltaics; sustainably-managed biomass; tidal; geothermal; or methane waste) that is installed after the date of this Joint Proposal (a "Renewable Customer"),...(JP, ¶4 (b).
[9] JP, ¶4 –5.

The Threshold Date for Existing Projects Should be the Effective Date Of the Tariff, Not January 31, 2003

It is unreasonable to expect potential OSG customers throughout NYSEG's service territory to have anticipated the effect of the proposed standby tariffs by the date proposed. As noted above, the Company's updated rate proposals were not even circulated until February 7, 2003. Representatives of OSG site-owners and developers continued to make new direct or indirect appearances in the case until the very end of settlement negotiations, for example the TLC Health (Lakeshore Hospital), Clifton Springs Hospital & Clinic, Finger Lakes Health (Geneva Hospital), Wyoming County Community Hospital,, Custom Energy, and a series of schools with OSG projects, providing evidence that the proceeding was not well publicized among affected parties. And even NYSERDA and School Boards in conjunction with the State Education Department has funded a series of projects, based on available rate assumptions.

One possible argument for the use of the January 31, 2003 date was to deter a "land rush" against a potential future date, including extensive applications to NYSERDA for funding in the CHP solicitation that closed on April 16, 2003. It is not plausible to expect that a land rush number of project funding applications were urgently prepared between April 7th and April 16th, 2003. In any event, that date is passed.

The effective date of tariffs and/or the date of the Commission Order are familiar and acceptable transition deadlines for the Commission. For these reasons it would be imminently reasonable to extend the definition of "existing" projects to the effective date of the tariff which is six months after the Order.[10]

[10] JP, ¶10..

Given the amount of time and effort involved in analyzing and developing an economically viable OSG installation, using the effective date of the tariff for projects selected by NYSERDA to qualify for a multi-year "grandfathering" or "transition" treatment is imminently reasonable.[11]

However the following provision, JP paragraph 4 (d) should be modified to allow for the circumstance in which an appropriate authorizing body has approved the project and initial contracts to engineer, procure and build projects. A specific example is approval by a District School Superintendent. In the instance, further authorizations to release funds by the State Education Department may take considerable time, while the engineering work has already been launched under binding commitments by the School District.

The Provision on Applicable Tariff Service When OSG is 15% or Less Of Maximum Potential Demand Being Served

The Joint Proposal in this NYSEG proceeding highlights the need to have a split rate which the Joint Supporters advocate below in its reference to prohibiting OSG customers from buying electricity under the backup rate. Paragraph 5 of the Joint Proposal states:

> NYSEG has the right to petition the Commission to disqualify a customer from these standby rates if NYSEG can demonstrate that the customer (a) has installed OSG with a total nameplate rating greater than fifteen percent (15%) of its load, but (b) has not operated or is not

[11] JP, ¶4 (b) and (c)

operating that OSG in a material manner in order to serve the customer's load.

Elsewhere NYSEG generally is trying to force OSG on to the backup rate, but here, NYSEG is trying to establish its right to prevent an OSG customer from using the backup rate. As Witness Lively observed in the O&R/Con Edison proceeding (Tr. 263), there is a potential for revenue erosion due to the existence of two tariffs on which a customer may be served. Mr. Lively refers to an appropriate solution to this problem in the form of establishing the concept of normal generation level in his Exhibit___(MBL-2).

Contract Demand Penalties of JP Paragraph 9 Neither are Justified Nor Supported in Opinion No. 01-4

There is no basis, precedent, or authority for the penalties proposed to be imposed on NYSEG customers who exceed their contract demand levels.[12] Opinion No. 01-4 does not even mention the word "penalty."

No rate class currently carries any comparable penalty. It would be wholly inequitable to subject some customers to the risk of penalties merely because they have made a decision to self-supply some electricity—particularly customers who are ostensibly in the same rate class.

Furthermore, the chilling effect of penalties is palpable. Industry participants tell us that they would likely set their contract demand significantly higher than expected peak demand (assuming that customers have the right to set their own contract demand) just to avoid any risk of penalties. It is not just that people are naturally risk-averse: investment decisions are made according to

[12] JP, ¶9

predictable risk profiles, and the uncertainty of potentially onerous penalties may not be acceptable to many investors.

Thus, not only might the threat of penalties cause some otherwise beneficial OSG investments not to occur, the likelihood that contract demand would be systematically overstated would result in NYSEG systematically over collecting revenues. And because of the nature of contract demand, this is a one-way ratchet upwards for NYSEG's potential revenue. The letter of Opinion No. 01-4, which does not allow for any penalty or surcharge structure that does not exist in other tariffs, must be respected.

It is important in the context of this proceeding to recognize that Order 01-4 does not create a NEW rate class because of the absence of cost data for that class, but is, instead, sets rates for a subsection of an existing class.

For this reason, the Joint Supporters express particular concern with the application of the "revenue neutrality" standard in the matter, because the rate structures for regular customers in this class and standby customers differ substantially in structure and concept. This rate structure differs dramatically from the rate structure for the rest of the class, which does not have to pay for T&D changes based on a maximum potential demand, but rather on a modified monthly peak usage basis, in which lesser penalties are incorporated.

Customers in the standard rate design face a much lower degree of rate risk.

Creating a structure for standby rates which differs from the structure used for other members of the same class may not only violate PURPA which still is

on the books, but also have a strong tendency to shift recoverable cost burdens from the standard rate customers to standby rate customers. This occurs primarily by charging the standby customers a rate which is based on maximum potential demand and charging non-standby customers off of a modified peak demand formula.

The Company should force all customers in a class to this design before a subclass moves.

Proposed Structural Changes:

Supplemental Delivery Service Should Not be Paid Through Standby Rates

The Joint Supporters believe that there should be separate billing procedures for supplemental power delivery services as opposed to backup/standby power delivery services. The billing procedure for supplemental service should follow the rate in the standard delivery or retail access (RA) tariff. A simple procedure for separating interval energy consumption between supplemental delivery service and backup/standby delivery service is presented in testimony by witness Mark Lively.[13] This is the most direct and elegant way to address the structural anti-competitiveness briefly noted above. This Supplemental Rate proposal both (1) remains closer to the intent of that Order than other apparently acceptable proposals (i.e., penalties and real time energy pricing) and more importantly, (2) solves a number of pressing problems with the rate proposed.

[13] Exhibit ___(MBL-2)

Application Only to OSG Customers Impugns Revenue Neutrality

The JP would change the structure of the distribution tariff for those customers who have distributed generation. The new tariff would be revenue neutral compared to the existing tariff, if the new tariff were applied to *all* of the Company's commercial and industrial customers. The proposed new tariff structure applies only to distributed generation customers and therefore, is not revenue neutral.

Stifling Effect on Distributed Generation

The proposal to bill all of a customer's delivery on the new standby tariff will stifle distributed generation. Distributed generation developers attempt to compete against the economics that consumers experience by remaining "on the grid" as full service customers. The Company's insistence that all electricity through the meter be billed under the new standby tariff sets a new and unfamiliar price for the supplemental part of the consumer's load—that is, the part of the consumer's load that is still served by the Company. Forcing the consumer to face a new price for its entire load, including the supplemental part of its load, increases the uncertainty that the consumer faces, and the perceived risk that investing in OSG will be economically harmful. Whether or not the perception of risk is justified, this increased uncertainty will reduce the likelihood that the consumer will utilize distributed generation.

Some customers would benefit from the change to the new tariff whether or not they install distributed generation. The Joint Supporters estimate that the Company will be exposed to a potential revenue erosion of 7 % of the Company's distribution services revenue. This revenue erosion would occur when select existing customers, with or without distributed generation, switch to the proposed Company standby rate. (This ramification is part of the rationale for the proposed

15% of load exemption.) Under the Company's proposal, such customers could qualify for the proposed Company standby rate by installing an inconsequential generating unit, even if that unit never operated. The split rate concept would limit the effect of such revenue erosion to customers who installed and substantially operated distributed generation and would not effect the portion of a customer's load not impacted by the distributed generation.

The absence of a split rate creates harmful uncertainty for customers considering the installation of distributed generation. Further, for those customers who have already installed distributed generation, the new tariff could dramatically and artificially increase the amount that they are paying to the Company. The split tariff structure would buffer the Company from revenue erosion and also mitigate the discomfort distributed generation customers would feel from being forced onto a new tariff when they installed distributed generation for part of their loads.

Standby service should apply to load when the distributed generator operates at less than its normal capacity. Electrical needs of the customer in excess of the maximum capacity of the distributed generator should be considered to be supplemental to the capability of the generator, and billed at the standard "parent" rates. This structural bifurcation would cease at such time as all customers in a rate class are billed according to the same rate structure and principles. The Joint Supporters propose a method to split electricity between standby electricity and supplemental electricity that treats supplemental power as the first energy through the meter.

Dynamic Pricing of Backup/Standby Delivery Service

Background

The Company proposes a fixed rate tariff for pricing the use of its distribution system by distributed generation customers. The Joint Supporters note that distributed generation is driven by economics that change throughout the day and across the Company's distribution grid. The Company and Staff implicitly acknowledge that the cost of using the distribution grid varies throughout the day. The existing Company tariff provides support for the concept that the cost of using the distribution system varies by time of day in that usage charges only accrue during defined on-peak hours during each weekday, not during the night and not during the weekend.

To address this reality, the wires charges for backup/standby power should be determined dynamically using the estimated marginal line losses between the customer and the location associated with the NYISO price. The estimated marginal line losses should be evaluated financially at the NYISO price. The estimated marginal line losses initially should be assumed to be proportional to the loading on the company's substation providing power to the distribution grid serving the customer and the distance that the customer is from the substation. The estimated marginal line losses should also reflect the non-linearity associated with periods of congestion on the distribution grid.

The Joint Supporters also note that the Company and the other utilities in the state have embarked on bidding programs to locate distributed generation in specific areas of the Company distribution grid. To the extent that the Company is using a bidding program to encourage distributed generation to be located in

specific areas, the Company should change its pricing mechanism for distributed generation to provide that same encouragement. The experience with the bidding programs to date has been spotty at best because the design militates against multiple benefit streams to the OSG. Adding benefits in the form proposed here could help the Company meet projected capacity shortfalls during the coming summer and future years.

Highly Efficient CHP

Despite assertions that ratemaking should not be a tool for public policy making, the JP includes Special Provisions for existing and certain environmentally beneficial technologies and not others. It should consider leveling the playing field for the most environmentally beneficial and most economically efficient technology, Combined Heat and Power (CHP).

For reasons of equity, competitive neutrality, and to support established New York public policy objectives, highly efficient Combined Heat and Power systems (CHP) should be exempt from this ratemaking process or at least be eligible for the phase-in of the standby rate, as are other environmentally preferred systems. Support for this view can be found in many quarters, and for a wide variety of reasons.

Whatever policy argumentation may be used to justify the renewable grandfathering treatment in Joint Proposal[14] also applies to highly efficient CHP. The technologies and expertise that facilitates exceptional heat recovery are not nearly so well established that they can be considered a "mature industry;" if it is true that justification for the special treatment afforded fuel cells, solar panels and

geothermal energy derives from their "infant industry" status, the same is also true for leading edge CHP development. If energy savings are the key, using existing energy not once but twice, both for heat use and electricity generation, meets the same standard. If the treatment is justified by support for new technologies, development of New York industry, or the creation of jobs, the manufacture, design, installation and maintenance of highly efficient CHP systems certainly qualifies as well. And if synchronization with other State polices is the rationale, then the Commission should note the New York State Energy Plan and the strong initiatives of NYSERDA to support the best examples of CHP.

Joint Supporters agree that the bar delineating "highly efficient" in terms of total fuel use for both electricity generation and heat recovery should be set high enough that only CHP projects that meet or exceed a specific efficiency level should be included in the provision.

Highly efficient CHP systems offer significant reductions in emissions of both greenhouse gases and improvements in the efficiency of utilization of non-renewable energy resources relative to conventional separate heat and power systems. As the State Energy Planning Board has indicated in its state energy plan, these factors benefit the state by providing improvements in environmentally emission and resource utilization efficiency while addressing the expanding need for energy to fuel growth in the state.

Three criteria were identified by Witness R. Neal Elliott in unrefuted testimony in Case 02-E-0781/0780 that build upon the definitions of efficient

---

[14] JP ¶3 (b)

CHP developed by the U.S. Combined Heat and Power Association and emissions criteria that emerged by the Regulatory Assistance Project's (RAP) model emission rule discussions.[15] To qualify for environmentally advantaged status a CHP system should:

1. Have a total system design efficiency, adjusted for seasonal thermal demand factors, of at least 55% for systems with a power output of less than 500kW and 60 % for systems of 500 kW or greater.
2. Produce at least 15% of the total usable energy output in the form of electrical power and at least 20% of the total usable energy output in the form of thermal power.
3. Achieve an emissions rate for NOx equal to or less than 0.35 pounds per kWh based on the total usable system output converted into kWh.

Any system that is added to an existing thermal facility that recovers waste heat to produce usable power should be excluded from the above criteria. This exclusion is added for such instances as the application of a heat engine such as a Stirling engine or the replacement of a steam pressure-reducing valve when a backpressure turbine is added to an existing system. In these cases power is produced directly from reducing wasted energy, and no addition fuel consumption or emissions result from the modification.

[15] Tr. 365-387

Further Studies are Required to Understand and Correct Known and Potential Flaws of the Standby Rates

A Study of the cost allocations needed to properly allocate costs between contract and as used capacity for Standby Rates Should Be Commissioned as Part of This Proceeding

Allocation of individual costs directly from the books and records of the company should be used to identify the costs directly related to customers. These costs should be used to determine how much of the total distribution cost should be recovered from the service and contract demand components of the standby rates. All remaining costs are for shared system that was installed and is maintained and operated to serve aggregated rather than customer specific loads.

A Study of the Effects on OSG Deployment Generally by Standby Rates Should Be Commissioned as Part of This Proceeding

Standby tariffs certainly will change the incentives facing potential OSG installation. Some sites and projects will become relatively more or less attractive from a business and developer perspective. These new incentives may or may not comport with other New York State energy policies: it should be the business of this Commission to make that determination, and amend the rates if it becomes know with greater certainty that these rates do not optimize the potential benefits of OSG to New York State. Thus, the Commission should order NYSEG to conduct such a study in its service territory.

A Unique Standby Rate, Without Reference to Parent Rate Classes, Should be Established As Soon As Possible

The current rate is not truly cost based because it assumes the diversity of the parent service classes. This flaw must be corrected as soon as possible as data become available.

Utility-caused trips

Customers who set a new contract demand if their OSG fails due to power quality failures of NYSEG's grid should not be subject to any penalty or surcharge. Joint Supporters consent that any new peak may establish a new contract demand level, however if such new peak is caused by the utility, rules should clarify that, even if penalties endure in the final order, no penalty would apply in this case.

Perverse Incentives Should Never be Turned Against the OSG Industry

Another incentive effect is that only economic OSG to be installed. In a secondary effect, DG that compares favorably on the rate will likely be built, and OSG that compares unfavorably will not. Joint Supporters fears that in the medium term, NYSEG will identify revenue erosion "due to OSG," but that actually may be caused by the incentives implicit in these standby rates. Under no circumstances should any claim of "revenue erosion" that results from the unfavorable incentives arising from NYSEG's already unfavorable rates be used to justify further forays into irrational ratemaking.

Conclusion

The rates proposed are not adequately justified on a cost basis and should not be accepted. Furthermore, the rates violate Opinion 01-4 by creating an unwarranted disincentive to OSG. Since the rates are not properly justified, there is, thankfully, a reasonable opportunity for the Commission to either stay the proceeding until proper cost data become available, or amend the rates to mitigate the harm that they would otherwise cause to the developing OSG industry.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 02-E-0779 - New York State Electric & Gas, Inc. – Proceeding on Motion of the Commission as to an Electric Tariff Filing to Establish a New Standby Service in Accordance With Commission Order.

Reply Comments of Joint Supporters and Other Interested Parties and Statement in Opposition to Joint Proposal

May 8, 2003

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 02-E-0779 - New York State Electric & Gas, Inc. – Proceeding on Motion of the Commission as to an Electric Tariff Filing to Establish a New Standby Service in Accordance With Commission Order.

Reply Comments of Joint Supporters

Introduction and Summary of Reply Issues

The Joint Supporters and other interested parties[1] mobilized by The E Cubed Company, LLC, participated in the conferences and meetings among the active parties.

These comments address primarily the comments of Staff and NYSEG in support of the Joint Proposal (JP).[2] Joint Supporters strongly oppose the JP on the basis that it is not in the public interest, the record for decision is inadequate, and it is not generally supported by adverse parties that would be most impacted by

[1] Joint Supporters is a thirteen-year-old voluntary association of entities advocating robust competitive energy services, including electricity, natural gas, and new technologies and services. Its associated entities participating in this proceeding 02-E-0770-9 include: Corning Painted Post – two High Schools, TLC Health (Lakeshore Hospital), Clifton Springs Hospital & Clinic, Finger Lakes Health (Geneva Hospital), Siemens Building Technology Inc., District One, Gerster Trane Energy Services, Energy Concepts Engineering, P.C., Custom Energy, LLC, All-Systems Cogeneration, Inc., Capstone Turbines, Inc., Hess Microgen, Ingersoll-Rand Energy Systems, Invensys, Inc., KeySpan Technology Inc., RealEnergy Inc. and The E Cubed Company, LLC. Additional institutions and groups endorsing all or part of these comments and testimony include: Wyoming County Community Hospital (which files and defends its own independent comments), the on site generating projects for the following schools (Binghamton -High School, East Middle School, West Middle School, Peru School, DePugh High /Middle/Lower School complex, Owego-Appalachia-High School, Middle School, Alden Central - High School/Middle School, altPower, Inc. and the New York Solar Energy Industry Association.

[2] A Joint Proposal ("JP") for settlement of issues filed by several other parties on April 7, 2003.

it—namely most customers that own or are considering installing DG/CHP. We also oppose the settlement because it does not meet the guidelines set forth in Opinion 01-4 as staff and the company contend, it does not establish an appropriate phase-in period for existing and proposed DG/CHP projects, its exemption policies do not promote fair and competitive uses of DG/CHP and, while it takes into account all volumetric lost revenues associated with DG/CHP, it does not take into account any of the cost benefits to the utility of DG/CHP. It therefore does not properly balance the interests of the customer and the utility. These opposing arguments are taken in order.

The JP Does Not Meet Criteria for Settlement

For the reasons enumerated below, the Commission need not JP accept the as a valid settlement of the issues in this case. It violates the public interest, is inequitable, is not properly based on underlying foundations, and not supported by adverse parties.

JP Violates the Public Interest

The comments of Staff and the Company in support of the Joint Proposal (JP) claim that it should be adopted because it is in the public interest. The JP is not in the public interest for the following reasons.

The JP is not consistent with public policy. Public Policy as set forth by the Governor, NYSERDA and the PSC, all of whom are supporters of the DG/CHP industry in NYS, prescribes that NYS will be a national leader in the deployment of DG/CHP. Evidence in this case shows that the JP will cause existing DG/CHP to shut down (Testimony of Leon Kuczmarski, P. 3-4), an outcome clearly contrary to existing public policy and the public interest. Similar conditions exist for Lakeshore Hospital (TLC Health) represented here by The E Cubed Company; the Chief Operating Officer Ronald Krawiec offers to appear in

the hearings on the Joint Supporters panel on May 19 to address this and related issues.

While testimony filed on behalf of Joint Supporters focuses attention on existing public policy, such policy with regard to DG/CHP has been made all the clearer by the comments of NYPSC Chairman William H. Flynn at the recent US Combined Heat and Power Association meeting on May 1, 2003, (Ex. ___JS-1, Attached as Appendix B), the recent PSC Order on gas rate service for distributed generation (Case 02-M-0515) and the Order instituting a proceeding on DG/CHP (Case 03-E-0640).

The NYPSC issued an order on April 24, 2003, "Order Providing for Distributed Generation Gas Service Classifications." This Order was specifically set in motion to "begin the process of developing rates for gas service to DG and removing any impediments to its development." (P. 2) The Commission stated, "Our actions concur with the State Energy Plan which, in addressing distributed generation from an electric perspective, found: 'Distributed generation, including combined heat and power (CHP) applications, offers customers the promise of increased electric reliability, power quality, efficiency, and affordability, while potentially reducing supply and distribution costs.'" "Fostering the development of distributed generation is thus in the public interest." (P. 2) The Commission "duly notes" in this order the need coordinate gas and electric rate issues to foster distributed generation, as was raised by several parties to this proceeding while remanding such action on electric issues to the standby cases. (P. 16)

Chairman Flynn amplified support for DG/CHP in his May 1 address saying, "New York's energy policies are focused on creating jobs and economic development opportunities, as well as adding energy capacity, protecting environmental resources and promoting efficiency." "The work that the New York State Energy Research and Development Authority does exemplifies the Governor's vision in that NYSERDA's efforts focus on supporting the emergence

of new technologies that will lead to new jobs as well as cleaner and more efficient energy production and use." (Ex. ___, JS-1)

Because public policy, and the policies of the NYPSC find that DG/CHP is an industry that can help New York State meet its energy policy goals and is therefore an industry actively supported by the NYPSC and NYSERDA, the damaging affects of the standby rates in the JP, or even the risk of damaging affects of standby rates in the JP on the DG/CHP industry, are not in the public interest.

Finally, there is evidence that excessive standby rates introduced in a rate proceeding can outweigh benefits that DG/CHP are provided through other regulatory and New York State energy policies and institutions. Thus, the suggestion that DG/CHP can find support through the System Benefit Charge or through some other case, while viable and clearly being pursued, will not be sufficient for the industry's survival if standby rates are not properly designed. This is best illustrated by Chairman Flynn's May 1 closing remarks: "There were a number of problems with standby rates assessed by Niagara Mohawk that were brought to our attention by developers and customers. At NYSERDA, I saw first-hand how the standby rates can essentially kill the economics of otherwise sound CHP projects that were proposed to us for funding. Even with financial incentives from NYSERDA, many projects could not be economically justified as a result of standby rates." (Ex __ JS-1)

Equity not Served by JP

The JP is prejudicial favoring one subset of several ratepayer classes over another subset of those same classes. Those customers that can curtail load have the same effect on the utility cost of service as those customers who add OSG. Those customers that can economically deploy load curtailment to avoid volumetric grid costs do so in exactly the same way as OSG is deployed, and yet

the utility will still have to have distribution facilities to serve that customer's entire load. The rate and revenue circumstances for those that deploy OSG and those that deploy load curtailment are the same and yet only those that deploy OSG will be subject to standby rates under the JP. The JP therefore will invoke unequal and unfair treatment of customers in several rate classes.

Basis for Decision Not Adequate

Contrary to the opinion expressed in Staff's comments, the record for decision is inadequate. There has been no quantitative analysis of financial harm to the utility based on the operation of OSG in its territory and therefore no evidence of the need for a new rate structure. There has been no rate impact analysis made of the customers to whom the JP will be applied. A record based on the preceding points is essential in order to avoid implementation of excessive standby rates that would wipe out all of the economic, environmental, reliability and other benefits of the DG/CHP industry.

Neither has there been any analysis of the impact of existing OSG on company revenues in this proceeding, nor have any revenue targets been set. The record has no evidence indicating quantified estimates of lost revenues due to existing OSG or OSG forecast to be installed over the time frame of the JP. The record is therefore not apprised either of the positive or negative impact on utility revenues of OSG.

The Commission does an analysis of the rate impact of nearly all of its decisions where rate impacts can reasonably be estimated. In this case there is no rate impact analysis on the very customers to which the standby rate will be applied. Staff merely points out in its comments in support that some customers will experience significant rate increases and others will experience rate decreases (Staff Statement in Support of Joint Proposal Pg 5-6). Staff does not offer any quantified analysis that might show how many customers will be harmed versus

how many will benefit. On the other hand, the testimony and evidence that is provided by the Joint Supporters and other witnesses in this case weighs heavily toward substantial harm to this subset of several rate classes as a result of implementation of the JP.

There is substantial risk to the DG/CHP industry of implementing the standby rate tariff of the JP. This alone suggests a continuance of this proceeding to study the cost benefit impacts to ensure that these proposed standby rates do not wipe out many DG/CHP projects and to ensure consistency with existing New York State energy policy that supports this industry.

JP not Supported by Adverse Parties

The JP is not supported by generally adverse parties participating in this proceeding as evidenced by the testimony and comments offered. Only one party, MI, that may or may not have members with OSG, has signed onto the JP. All other participants in this case that own or represent those who own or might own OSG stand opposed to this settlement. This does not constitute adequate support by adverse parties.

The JP Does Not Meet the Guidelines of Opinion 01-4

While the Company and Staff contends that the JP meets the guidelines of Opinion 01-4, there are certain critical aspects of those guidelines that are violated by the JP. The Commission should correct them.

JP Violates Revenue Neutrality Requirement

The JP does not meet the revenue neutrality requirement, as Mr. Lively pointed out in his prefiled direct testimony (P. 21-22). The proposed ratchet and penalty for exceedances both create revenue for NYSEG, revenue that is not

reflected in the billing determinants used by NYSEG to design the rates in this proceeding.

If there is an unbalance of winners and losers for those customers that will be forced onto standby rates, then revenue neutrality has not been achieved. The majority of evidence in this proceeding projects significant rate increases for many OSG customers. If this were true then a windfall would accrue to the utility. In any case, there is no evidence that supports a balance of winners and losers and an unbalance violates the revenue neutrality guideline.

Penalties are Contrary to Guidelines

The JP includes severe penalties that are not included in the guidelines; in fact the guidelines do not even contain any discussion of the possible need for penalties. As Mr. Lively points out, the revenue associated with these penalties violates the revenue neutrality principle set out in Opinion 01-4.

Opinion 01-4 guidelines indicate that contract demand be applied to assets that "mostly serve the individual customer" and that as-used charges be applied to "shared" costs. National Fuel Gas (NFG) makes a very reasonable argument on this issue, premised on common sense. (P. 4) Furthermore, NARUC, in their 1992 NARUC Electric Utility cost Allocation Manual (P. 97), states that distribution substations and primary feeders have high load diversity and that customer-class loads (and not individual customer loads) are used for allocation of costs. Logically, this cost allocation is "shared" according to the guidelines and therefore should be recovered 100% by the as-used demand charge. The JP allocates only 25% of these shared costs to as-used and the rest to contract demand charges, a violation of the guidelines.

Opinion 01-4 specifies that standby rates should neither be an incentive to the DG/CHP industry nor impede its development, yet staff advocates in support of the JP position that provides an incentive to customers who would otherwise

isolate from the system. The incentive is the ability to negotiate a separate and lower contract than the standby tariff. This would not be needed if the standby tariff of the JP would not impede development of OSG.

The proposed rate design provides incentives to some customers, incentives that the JP inadequately seeks to prevent by instituting a 15% exemption to the rate. The proposed rate design similarly impedes the development of OSG by causing individuals to incur significantly higher costs just by considering OSG. The split service concept proposed by Mr. Lively, with supplemental service remaining on the parent tariff, removes a substantial amount of these undue incentives and impediments. The Commission recently affirmed the split rate principle affecting distributed generation in the DG Gas Rate Order, when it declared, "The non-DG gas use for a customer should be served under the applicable tariff for the type of service."[3] A similar principle should be implemented in this case.

Entities on Fixed Incomes Need Special Protection

Wyoming County Community Health System (Leon Kuczmarski) testifies that the standby rates will impact the health system's ability to make payments on its CHP system and thus cease operation. (P. 3-4) Some NYSERDA awardees represented by Joint Supporters[4] are also at risk of losing the benefits of NYSERDA investments funded by society at large. Similarly, beneficiaries of school aid capital improvement funds and local development incentives may end up wasting the public monies that have been awarded them. Not only is this an egregious example of one agency wastefully making the investment of another

[3] Case 02-M-0515, Proceeding on Motion of the Commission to Establish Gas Transportation Rates for Distributed Generation Technologies. ORDER PROVIDING FOR DISTRIBUTED GENERATION GAS SERVICE CLASSIFICATIONS (Issued and Effective April 24, 2003) P. 12, Fn 7.

[4] These awardees include TLC Health, also a rural hospital system; Finger Lakes Health System (Geneva Hospital); Clifton Springs Hospital and Clinic; and Corning Painted Post Central School District.

agency moot, it also traps certain institutions that are unable to pass through their costs in an untenable position. The Commission should exempt by grandfathering or extended phase-in such facilities.

Phase-In Provisions are Inadequate and Should be Extended

Staff comments that because of substantial bill increases that would adversely affect existing customers when the new standby rates take effect, the JP provides for a phase-in of the new rates. The phase-in for existing customers of 3 years included in the JP is financially meaningless to OSG that was installed under performance contracts that will last 10 to 15 years, and meaningless to projects with 10 year payback periods. As NFG demonstrated in its initial comments and the testimony of Robert Eck, the rates will cause payback periods for some customers to extend from low single digits to 15 years or longer. The 3 year phase-in does not allow such customers to avoid significant financial consequences to existing contracts. The phase-in period is therefore, too short to "preserve the viability of investment commitments made in reasonable reliance on prior rate structures." (Staff Comments P. 6-7.) Therefore, existing contracts for OSG should be exempt from standby rates or provided a more reasonable phase-in period that accounts for the performance contract period, or the payback period of the facility. Joint Supporters concurs with the filed comments of NFG proposing an eight-year phase-in (NFG Comment, P. 5.)

Likewise, the phase-in for renewables is insufficient given the high capital costs and intermittent operational characteristics of some of these systems. Finally, there is no provision at all for a phase-in for hybrid renewable systems in the JP, and such a provision should be included.

All types of customers suffer from a "one way ratchet" in the phase-in; as written it only applies if the standby rates result in an increase during the billing month, not if it results in a decrease. Thus, to the extent that bill impacts differ

between summer and winter, or month-to-month, there is a bias against the customer. Table 1 illustrates this perverse effect.

Table 1: Ratcheted Phase-In Effects

	Standard SC	Standby SC	Difference	Positive Limit	1/3 Phase-In
Month 1	$500	$400	-$100	$0	$500
Month 2	$500	$600	$100	$100	$533
Total	$1,000	$1,000			$1,033

The "one-way ratchet" provision should be removed.

Definition of Existing Customers

Staff claims that the definition of existing customer properly balances the needs of existing customers. The inclusion of NYSERDA approved projects is an important step in the right direction, but not far enough. Considering the miniscule impact on NYSEG revenues from the small number of projects under consideration and the fact that the customers will be contributing to NYSEG revenue in any case, the definition of existing customer should be extended to the effective date of the tariff. Furthermore, the definition must also include beneficiaries of school aid capital development funds as well as local development incentives, committed by whatever deadline the Commission adopts—which should be the effective date of the tariff, or the Commission Order.

Exemptions and Demand Response

The JP allows emergency OSG an exemption from standby rates, while economic, efficient and environmentally beneficial CHP projects are not. This

will provide incentive for customers to install less clean diesels that operate as emergency backup only at the expense of development of clean CHP and renewable systems that will contribute choices and competitive options to New York State energy markets.

Wholesale market participation of DG/CHP through the Day Ahead Demand Response Program of the NYISO is harmed by the exemption for EDRP and SCR. At a minimum, those OSG facilities participating in DADRP should be exempt as well.

Errata

In Joint Supporters' earlier comments, and Prefiled Testimony of Mark B. Lively, tables filed contained editing mistakes. Parties were previously notified, and emailed corrected tables on April 23. Corrected tables are hereby filed as Appendix A.

Conclusion

For the reasons above and stated in Joint Supporters' initial Comments, the Joint Proposal in this case can and should be amended as indicated.

Signed,

Ruben S. Brown
The E Cubed Company, LLC

Dated: May 8, 2003

Appendix A

NYSEG Allocation Proposal
Table 1

	Secondary		Primary		Subtransmission		Transmission	
	Contract	As-Used	Contract	As-Used	Contract	As-Used	Contract	As-Used
Secondary	100%	0%	0%	0%	0%	0%	0%	0%
Primary	75%	25%	75%	25%	0%	0%	0%	0%
Subtransmission	25%	75%	50%	50%	75%	25%	0%	0%
Transmission	0%	100%	25%	75%	25%	75%	25%	75%

April 7th Joint Proposal
Table 1A

	Secondary		Primary		Subtransmission		Transmission	
	Contract	As-Used	Contract	As-Used	Contract	As-Used	Contract	As-Used
Secondary	100%	0%	0%	0%	0%	0%	0%	0%
Primary	75%	25%	75%	25%	0%	0%	0%	0%
Subtransmission	25%	75%	50%	50%	75%	25%	0%	0%
Transmission	0%	100%	15%	85%	15%	85%	15%	85%

NYSEG Allocation Proposal
Contract Demand Allocation Factor Modified For How Customers Are Served
Table 2

	Secondary		Primary		Subtransmission		
	Wires	Trans.	Wires	Station	Wires	Station	Transmission
Secondary	100%	100%	0%	0%	0%	0%	0%
Primary	75%	75%	75%	75%	0%	0%	0%
Subtransmission	25%	25%	50%	50%	75%	75%	0%
Transmission	0%	0%	25%	25%	25%	25%	25%

Appendix A

April 7th Joint Proposal
Contract Demand Allocation Factor Modified For How Customers Are Served
Table 2A

	Secondary		Primary		Subtransmission		
	Wires	Trans.	Wires	Station	Wires	Station	Transmission
Secondary	100%	100%	0%	0%	0%	0%	0%
Primary	75%	75%	75%	75%	0%	0%	0%
Subtransmission	25%	25%	50%	50%	75%	75%	0%
Transmission	0%	0%	15%	15%	15%	15%	15%

NYSEG Allocation Proposal
Contract Demand Allocation Factor Modified For Costs Associated With How Customers Are Served
Table 3

	Secondary		Primary		Subtransmission		
	Wires	Trans.	Wires	Station	Wires	Station	Transmission
Secondary	75%	0%	0%	0%	0%	0%	0%
Transformer	25%	75%	0%	0%	0%	0%	0%
Primary	0%	25%	75%	0%	0%	0%	0%
Substation	0%	0%	25%	75%	0%	0%	0%
Subtransmission	0%	0%	0%	25%	75%	0%	0%
Substation	0%	0%	0%	0%	25%	75%	0%
Transmission	0%	0%	0%	0%	0%	25%	25%

April 7th Joint Proposal
Contract Demand Allocation Factor Modified For Costs Associated With How Customers Are Served
Table 3A

	Secondary		Primary		Subtransmission		
	Wires	Trans.	Wires	Station	Wires	Station	Transmission
Secondary	75%	0%	0%	0%	0%	0%	0%
Transformer	25%	75%	0%	0%	0%	0%	0%
Primary	0%	25%	75%	0%	0%	0%	0%
Substation	0%	0%	25%	75%	0%	0%	0%
Subtransmission	0%	0%	0%	25%	75%	0%	0%
Substation	0%	0%	0%	0%	25%	75%	0%
Transmission	0%	0%	0%	0%	0%	15%	15%

Appendix B

Appendix B Distributed Electronically
File Named "ApxB-JSrepl.pdf"

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 02-E-0779 - New York State Electric & Gas Corporation – Proceeding on Motion of the Commission as to Electric Tariff Filing to Establish a New Standby Service in Accordance With Commission Order Issued October 26, 2001 in Case 99-E-1470

PREFILED DIRECT TESTIMONY OF

L. KEITH O'NEAL

APRIL 21, 2003

CASE NO. 02-E-0779

DIRECT TESTIMONY OF L. KEITH O'NEAL

INTRODUCTION AND WITNESS QUALIFICATION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is L. Keith O'Neal. I am a Consulting Associate at The E Cubed Company, LLC, a strategic energy services firm with an office at 215 East 79th Street, New York, New York, 10021.

Q. WOULD YOU PLEASE DESCRIBE YOUR QUALIFICATIONS?

A. Yes. I received my B.S.M.E. degree from Clarkson College of Technology, with special courses in Advanced Negotiation, Alternate Dispute Resolution, Advocacy Accounting and Public Administration.

Since beginning with E Cubed more than two years ago, I have conducted extensive negotiations at multiple levels of government and market institutions to open the door so that demand resources, including behind-the-fence On Site Generation (OSG), might interact reliably with grid and markets beyond the fence and the meter. I shall address this further in my testimony.

My career as an Energy Engineer with the New York State Public Service Commission spans over 20 years. During that time, I helped develop a structural framework for electric competition and had technical oversight responsibility for the transition to electric competition in New York, which

included agency interaction with the NYISO, the New York State Reliability Council (NYSRC) and the Federal Energy Regulatory Commission (FERC). I also assessed reliability and market performance of the NYPP, NYISO and NYSRC, assessed the reliability of the bulk electric system including reliability of its supply, analyzed major bulk power operating events, developed and negotiated multi-year rate plans for electric and gas utilities, and prepared testimony in proceedings before the PSC and FERC.

I was a primary negotiator for the PSC in evolving a competitive marketplace in New York State, suggesting the creation of the New York State Reliability Council (NYSRC), and later helping to implement it, and serving as the PSC's representative on the Council. I was also a division, team or project leader in projects that resulted in the development of the NYISO, bulk power reliability standards, a market power mitigation study, multi-year rate cases, distribution reliability standards based on outage statistics, and the implementation of a T&D regulatory function. My work was instrumental to the development of the NYISO and NYSRC, and led to the first development of a broad cost index incentive that measures a company's cost performance against an index of peer companies, efficiency improvements in the power pool, the development of the first set of PSC emergency response procedures, and the development of statewide reliability criteria.

DIRECT TESTIMONY OF L. KEITH O'NEAL

Q. ARE YOU ASSISTING A GROUP OF PARTICIPANTS IN THESE CASES IN PRESENTING THIS TESTIMONY?

A. I am assisting the Joint Supporters, a voluntary association of providers and users of OSG capabilities, and other interested parties, which together include a number of hospitals, schools, providers of the energy services, recent and potential near-term awardees of NYSERDA CHP grants within the territory of the New York State Electric and Gas Company ("NYSEG" OR "Company").

Q. WHAT IS THE PRIMARY PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. My testimony will show:

1. There is significant risk that the existing and future distributed generation and combined heat and power industry (DG/CHP) in New York State will suffer substantial harm from the implementation of standby rates as conceived in the Joint proposal in this and the other standby rate proceedings.
2. The risk of substantial harm to the DG/CHP industry is directly at odds with New York State Policy that, for several years, has heavily promoted development and deployment of DG/CHP.
3. Because of tight capacity supplies in New York State over the last several years and projected into the next several years, the risk of

substantial harm to existing and future DG/CHP supply increases the likelihood of statewide and downstate supply shortfalls reduces the reliability of supply.

4. The importance to reliability of supply across the state and statewide of DG/CHP that run every day based on economics and positive environmental attributes, is equal to and probably greater than the contribution to reliability of supply provided by emergency backup generators.

5. The existence of exemptions from standby rates for some favored OSG supply resources implies that standby rates as proposed might have an onerous impact on OSG development to which they are applied. If standby rates could be designed that do not impede development of OSG then exemptions would not be required for any generating or supply resource.

6. There has not been time to comprehensively analyze the financial, reliability and environmental impact of this Joint Proposal and those of the other utilities on the DG/CHP industry in New York State.

7. Alternatives to traditional ratemaking techniques for standby rates should be explored.

8. California has faced similar issues with regard to implementation of standby rates and its PUC has decided to waive standby rate implementation at least until 2004 while it tracks DG/CHP costs and benefits that would allow for a better design of standby rates.

9. Because of my findings in each of the areas listed above, I recommend that the Joint Proposal on standby rates in this case, and for that matter in other utility cases for precisely the same reasons, be put on hold until a comprehensive analysis of the impact such rate structures would have on the DG/CHP industry in New York State.

10. I also recommend because of the foregoing findings that alternatives to traditional ratemaking for standby rates be explored including an analysis of methods to align utility incentives with other areas of energy policy, possibly by setting utility procurement targets for customer onsite generation and providing a cost savings sharing mechanism that represents the utility's avoided costs due to DG/OSG.

Q. WOULD YOU PLEASE DESCRIBE HOW YOUR DIRECT TESTIMONY IS ORGANIZED IN THIS CASE?

A. My testimony is organized according to the topic areas listed above.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR PREPARED UNDER YOUR DIRECTION?

A. Yes.

I. Standby rates as proposed imperil the DG/CHP industry.

Q. HOW DO STANDBY RATES, AS PROPOSED IN THIS PROCEEDING, IMPERIL THE DG/CHP INDUSTRY IN NEW YORK STATE?

A. The following points illustrate the answer to this question:

1. The direct testimony of Wyoming County Community Health System (Wyoming Hospital) witness Leon N. Kuczmarski indicated that the hospital will shut down its on site generation (OSG) rather than be exposed to the proposed standby rate structure.
2. The direct testimony or affidavits of other witnesses from within the DG/CHP industry in this proceeding.
3. There is a wide perception among hospitals and schools and other customers that are candidates for OSG that standby rates will cut out significant savings that they otherwise would derive from installation and operation of OSG. Therefore, an already difficult sale to entities whose core business is far from energy becomes even more difficult.

Q. PLEASE ELLABORATE ON THESE POINTS FURTHER?

A. The testimony of Wyoming Hospital witness Mr. Kuczmarski provides compelling and conclusive evidence of how the proposed standby rates will shatter its financial structure relative to the installation and operation of a well functioning CHP project. Its closing will induce the loss of future cost savings, the loss of self sufficiency and hospital supply reliability, the loss of CHP's attendant environmental and efficiency benefits, and contribute to a reduction in the reliability of supply to the State (the latter covered later in more detail).

If one entity finds that the new standby rate structure will force a closure of its OSG in order to remain on current standard rates, it is logical to assume that other businesses across the state will likely close the operation of OSG for the same reasons when they make financial analyses themselves. Of course many existing DG/CHP operators have not made this analysis because little is known about what standby rates finally will be adopted, especially to those not involved in the confidential negotiations, and there has been little time to consider proposals made for those involved in the negotiations.

The situation may be even worse for customers who are candidates for new DG/CHP projects and who may be approached or have been actively considering installing OSG. For these customers, the risk, real or perceived, of moving off standard rates to new standby rates if they add OSG makes the

decision to install DG/CHP, a very difficult sale to begin with, even harder. Few institutions want to take the chance that rates will go up, so the new standby rates will induce most potential users to avoid any change that might invoke the new risk.

Without any change to the current rate structure, entry of DG/CHP has been limited, the primary reason being that nearly all candidate customers such as schools, hospitals, hotels and the like, all are expert at their core business pursuit and very reluctant to commit to gaining expertise in the unrelated energy business. With the added threat that standby rates can reduce or even eliminate the benefits to any move to DG/CHP, the limited appeal of these technologies is all but removed. When being sold a bill of goods that will have a significant up-front cost, customers want a guarantee of savings and a known payback period. In short, customers are risk averse and the double risk of spending money on unfamiliar energy technologies that promise savings, and at the same time being forced onto a new rate structure with its own risks will be too great for the large majority of customers.

II. NEW YORK STATE POLICY HEAVILY PROMOTES DG/CHP

Q. HOW DOES NEW YORK STATE POLICY HEAVILY PROMOTE DG/CHP?

A. State agencies and the Governor determine State policy with regard to development and implementation of DG/CHP as evidenced by the following:

1. The New York State Energy Plan (SEP)
2. Executive Order #111 regarding state agency energy policy
3. NYSERDA grants to promote DG/CHP

The current New York State Energy Plan (June 2002) includes the following goals for DG/CHP:

- "Increasing energy diversity in all sectors of the State's economy through the greater use of energy efficiency and technologies and alternative energy resources, including renewable based energy." (SEP page 1-39)
- "...support the development and use of distributed generation and combined heat and power (CHP) technologies at customer sites with the goal of becoming a national leader in deployment of clean distributed generation technology." (SEP page 1-40)

Executive Order #111 was incorporated into the State Energy Plan and includes specific provisions for "Directing State Agencies to Be More Energy

Efficient and Environmentally Aware." The policy goals of EO 111 can be summarized as follows:

1. Environmental protection and economic growth
2. Increase competition
3. Reduce energy costs
4. Recognize and reduce the environmental impacts of electric generation
5. State government should lead by example in promoting the efficient use of energy and natural resources

Relevant to DG/CHP, EO 111 also requires state entities to:

1. Procure ENERGY STAR energy efficient products when replacing or installing new equipment
2. Purchase power from renewable resources
3. For new buildings, follow the guidelines for the operation and construction of "Green Buildings."

For each of these goals and requirements, new and clean DG/CHP technologies can help achieve compliance. Most new DG/CHP technologies are ENERGY STAR rated, some like fuel cells and solar applications are

renewable, and most provide reduced emissions over existing central station technologies.

Finally, NYSERDA currently offers millions of dollars in funding for the development and deployment of new DG/CHP technologies. Program Opportunity Notice (PON) 750-02 alone makes $10 million available for "Power System (PS) Distributed Generation (DG) and Combined Heat and Power (CHP)." Both current NYSERDA funding opportunities and recent past opportunities, have provided grants in one form or another to most existing DG/CHP applications and many currently under development. These actions serve as testimony that NYSERDA values the economic, technological, efficiency and environmental benefits of distributed generation technologies.

From this evidence it can be concluded that the development and deployment of DG/CHP technologies is heavily encouraged by State agencies and the Governor, and that by specific design and planning, are intended to play an important role in providing reliable and environmentally friendly energy supplies to New York State consumers. Therefore, the promotion of new standby rate structures that might harm the existing and future DG/CHP industry is inconsistent with clear State energy policy goals to promote the development and deployment of DG/CHP technologies in New York State.

III. DG/CHP DEPLOYMENT IS CRITICAL TO RELIABLE ENERGY SUPPLIES IN NEW YORK STATE

Q. IS THE RELIABILITY OF ELECTRIC SUPPLY IN JEOPARDY THIS YEAR AND OVER THE NEXT SEVERAL YEARS IN NEW YORK STATE?

A. Yes. Experts agree on this point. William J. Museler, NYISO President and CEO stated in a press release issued February 25, 2003 that "Unless significant generating capacity is added to the system- and soon- demand is going to overwhelm supply and reliability will be at risk." Moreover, the sub-title of the press release on the NYISO electricity forecast is "New York State, Once Again, Has A Thin Margin Between Supply and Demand."

Q. DID THE NYISO PRESS RELEASE ON ITS ELECTICITY FORECAST PROVIDE ANY QUANTIFIED FORECASTS?

A. Yes. The capacity requirement for a reliable supply for this summer is 37,087 MW. New York State resources total just 36,527 MW for a total shortfall of 560 MW. The New York City shortfall is projected to be 67 MW. These numbers do not count generation projected to be added to the system sometime this summer or later (presumably due to projected in-service dates that are typically delayed and to typically unreliable operation of units at initial startup).

Q. DO OTHER DOCUMENTS COOBORATE THE NYISO PRESS RELEASE?

A. Yes. The NYISO Market Operations Department prepared a document entitled "ICAP Generating Unit Maintenance Coordination Survey," dated December 2002, that provides a load and capacity projection for 2003. It projects a slight surplus of 27 MW during the peak load summer weeks. Such a surplus is very narrow considering a projected load of 31,700 MW. This load forecast is for a typically hot summer day. If hotter weather than typical or average occurs or generation outages are greater than average, then the very thin margin evaporates and New York experiences a shortfall of supply posing real reliability risks.

Q. HOW WILL THE NYISO MAKE UP FOR THE PROJECTED SHORTFALL OF ELECTRIC SUPPLY FOR THIS SUMMER?

A. The NYISO will rely on imports from external resources and on OSG that can provide emergency energy.

Q. DOES EXISTING OR FUTURE OSG PROVIDE ADDED RELIABILITY OF SUPPLY?

A. Yes. In fact, without existing supply of OSG, the NYISO projections indicate a statewide shortfall of 560 MW. OSG will continue to be relied upon to meet

reliability requirements for capacity supply over the next several years where tight supply conditions are expected to continue.

Q. CAN OSG MEET CURRENT TIGHT SUPPLY CONDITIONS BETTER THAN CENTRAL STATION GENERATION?

A. Yes. Lead times for installation of central station generation vary but are no less than three years. OSG can be installed and operational in less than one year.

IV. OSG HAS AN IMPORTANT ROLE IN THE RELIABILITY OF SUPPLY

Q. WHAT ROLE DOES OSG PLAY IN THE RELIABILTY OF SUPPLY?

A. It plays a very similar role to central station generation. Economic DG/CHP that runs most of the time serve a specific load similar to base load generation. Emergency OSG such as those facilities that participate in the Emergency Demand Response Program (EDRP) or the Special Case Resource (SCR) program agree to be called upon by the NYISO to activate during times of emergency and can be viewed as contingency supply. Both of these categories of supply are valuable in meeting statewide and locational supply requirements and thereby enhance reliability of supply on an equal basis with central station generation.

Q. DURING TIMES OF TIGHT SUPPLY WOULD THE LOSS OF DG/CHP CAPACITY REDUCE RELIABILITY OF SUPPLY?

A. Yes. The loss of supply in any category of generating or other supply resource will reduce the reliability of supply statewide and in the location where the DG/CHP resource exists.

Q. WHAT MIGHT THE RESULT BE DURING TIMES OF TIGHT SUPPLY IF A SUPPLY SOURCE SUCH AS DG/CHP IS LOST AT LEAST IN PART?

A. To my knowledge the exact amount of DG/CHP that is installed and capable of producing energy across the State is not known. However, DG/CHP that has signed up for EDRP and SCR with the NYISO amounts to more than 1,500 MW for this coming summer period. Moreover, there are numerous other OSG installations across the state that do not participate in these programs and while known to exist by the Transmission owners, are not tracked by the NYISO but do serve as load modifiers. Without these resources or a part of these resources such as the Wyoming Hospital CHP facility, other generating supplies will have to pick up to meet the demand of these loads.

The specific impact of the loss of even just a small percentage of the existing DG/CHP supply could be severe. During periods of tight supply the loss of any, even small, amount of supply will result in the increased use of

emergency operating procedures that include measures such as voltage reduction and load shedding. Therefore, the loss of supply will mean an increased likelihood that voltage reduction and/or involuntary firm disconnection of load will be needed.

V. EXEMPTIONS FROM STANDBY RATES

Q. ISN'T IT TRUE THAT EDRP AND SCR RESOURCES AND OTHER GENERATORS USED, NOT TO ECONOMICALLY SUPPLY LOAD, BUT TO PROVIDE EMERGENCY BACKUP TO THE HOST LOAD OR THE NYISO, ARE EXEMPT FROM STANDBY RATES UNDER THE CURRENT JOINT PROPOSAL?

A. Yes, not only in the NYSEG standby rate proposal but also in the other utility standby rate proposals to date.

Q. CAN YOU EXPLAIN THE RATIONAL FOR EXEMPTING THESE EMERGENCY ON-SITE GENERATORS FROM STANDBY RATES?

A. There are two reasons that I can think of. First, generators used exclusively as emergency backup generators will not have as significant an impact on utility revenues as generators that operate efficiently cleanly, and economically. Second, I believe the utilities and the PSC staff realize that standby rates could have the chilling affect on the DG/CHP community that I describe in this

testimony and that is described in other testimonies in this case. In order to mitigate this chilling impact, the emergency backup sector of DG/CHP, those that have provided emergency backup to the NYISO and that will provide this reliability service, will be shielded from standby rates in order that they continue to provide reliability services that are needed in times of tight supply. Threatened with standby rates, this supply resource may disappear.

Q. DO EMERGENCY GENERATORS AND THOSE ENROLLED IN THE EDRP AND SCR PROGRAMS OF THE NYISO PROVIDE GREATER RELIABILITY SERVICE TO THE STATE THAN DOES ECONOMICAL DG/CHP THAT OPERATES MOST OF THE TIME?

A. No. This would be akin to concluding that base-load or must-run central station generation does not provide as much reliability as gas turbines that typically start up only to respond to emergencies. Resources that run all, or much, of the time that they are available (not on a maintenance outage) are extremely reliable since they are running and certainly their output can be counted on. Units such as gas turbines that start on demand in response to emergencies are less reliable simply because sometimes they do not start when called on. When comparing EDRP on-site units or even SCR on-site units to DG/CHP units that run most of the time, the same analogy can be made. Units that are running are more reliable than those that are not.

Moreover, EDRP units are voluntary meaning that they are not penalized in any way if they do not start and operate when called on by the NYISO. During times of tight capacity, these units are even less reliable than economical on-site units that run most of the time. The NYISO only "counts" on a certain percentage of EDRP units to activate for any given call.

Q. THEN THE SHIELDING OF EMERGENCY GENERATORS FOR THE PURPOSE OF PRESERVING RELIABILITY IS MISPLACED?

A. To some degree it is since it will protect existing and, indeed, attract new emergency on-site generation that will not provide as great a reliability of supply service as economic, efficient and clean DG/CHP that operates most of the time.

Q. ARE OTHER GENERATING RESOURCES SIMILARLY SHIELDED FROM STANDBY RATES?

A. Perhaps. This is to be determined. The specific form of these standby rates, and in particular the NYSEG Joint Proposal, leave the possibility open for specific exemptions for the renewable generation industry at the pleasure of the PSC.

Q. IS IT LIKELY THAT RENEWABLE RESOURCES WILL BE GRANTED AN EXEMPTION FROM STANDBY RATES?

A. While no one can predict with certainty the outcome of a NYPSC proceeding, it seems likely that renewable resources will be granted an exemption from standby rates. First, the Governor has stated a goal that 25% of electric supply must come from renewable resources by 2013. No chilling affect on the development of these resources can be tolerated if the State is to achieve this rather aggressive goal. In addition, the PSC has convened a case to determine an appropriate portfolio or attribute standard that would be designed to help development and expansion of renewable resources in New York State.

Q WHAT DOES THE PRESENCE OF EXEMPTIONS IMPLY?

A. It implies that standby rates as proposed might have an onerous impact on OSG development to which they are applied. If standby rates could be designed that do not impede development of OSG then exemptions would not be required for any generating or supply resource.

VI. ANALYSES OF THE IMPACT OF STANDBY RATES ON THE DG/CHP INDUSTRY

Q. YOU INDICATED EARLIER THAT, TO YOUR KNOWLEDGE, NO ONE SEEMS TO KNOW HOW MUCH AND WHAT KIND OF DG/CHP EXISTS IN THE STATE. HAS ANY PARTY IN THIS CASE OR THE OTHER STANBY CASES ATTEMPTED TO TABULATE THE AMOUNT

AND KIND OF DG/CHP AND THEN DETERMINE THE FINANCIAL IMPACT THAT THE PROPOSED NEW STANDBY RATES MIGHT HAVE ON THE DG/CHP INDUSTRY?

A. No. Not to my knowledge. Since most of these standby rate proposals have been recently derived including the NYSEG proposal (dated April 7, 2003), no party has had sufficient time to perform a comprehensive analysis of the financial impact of these proposed standby rates on the DG/CHP industry. Only a few DG/CHP facility owners have done a projected financial analysis on their own facility. PSC staff and Con Edison staff testified in the Con Edison standby rate proceeding that they had not conducted these types of analyses in the Con Edison service territory.

Q. IS THERE AN INCONSISTENT LOGIC THAT THE IMPACT OF STANDBY RATES HAS NOT BEEN ANALYZED AND YET COULD JEOPARDIZE AN INDUSTRY THAT MULTIPLE STATE AGENCIES EMBRACE INCLUDING THE GOVERNOR?

A. Yes. Implementation of a state policy on standby rates that might imperil the DG/CHP industry in New York State is inconsistent with other stated policies by other state agencies including the Governor through the State Energy Plan, that strongly promote development and deployment of DG/CHP technologies. At the very least, this inconsistency demands that the impact of standby rates

be comprehensively analyzed before they are implemented. It also suggests that alternatives to this more traditional form of determining standby rates be explored.

VII. ALTERNATIVE RATEMAKING

Q. CAN YOU SUGGEST AN ALTERNATIVE RATEMAKING STRUCTURE THAT COULD BE EXPLORED IN LIEU OF THE EXISTING JOINT PROPOSAL?

A. Yes, at least conceptually. Procurement targets for LSEs for DG/CHP that correspond to State energy and policy goals could be set by the PSC in conjunction with attribute portfolio standards being considered in the current Renewable Portfolio Standard proceeding. For economic DG/CHP projects, cost savings below levels the LSE would otherwise have incurred in the procurement of supply, can be shared equitably thereby accounting for utility costs to provide standby service while preserving the financial viability of DG/CHP development.

VIII. CALIFORNIA WAIVES IMPLEMENTATION OF STANDBY RATES THROUGH AT LEAST 2004

Q. HAVE OTHER STATES CONSIDERED IMPLEMENTATION OF STANDBY RATES?

A. Yes. California has gone through extensive analysis and multiple proceedings to determine how to implement standby rates. In a recent order, the California PUC has waived implementation of standby rates through at least 2004 to, among other reasons, allow for "...tracking the actual costs and benefits of distributed generation" so that it "...can ensure that in each utility's rate proceeding, any costs are recovered within the customer class and any net costs or benefits are properly assigned."

IX. RECOMMENDATIONS

Q. IN LIGHT OF YOUR TESTIMONY, WHAT ARE YOUR RECOMMENDATIONS?

A. Because of my findings in each of the areas listed above, I recommend that the Joint Proposal on standby rates in this proceeding, and for that matter in the other standby rate proceedings, be put on hold until a comprehensive financial analysis can be completed to determine the impact these proposed standby rate structures would have on the DG/CHP industry in New York State. These standby rate proposals should not be implemented until we know for certain that these rates will not produce significant harm to this vital and

infant industry. The Commission Order providing guidelines for developing standby rates did not prescribe a time frame for actual implementation of such rates and so a postponement of implementation does not violate existing guidelines established.

The current rate structure, that I recommend continue, can serve as the baseline for analyses of the impact of standby rates on existing DG/CHP facilities. Such facilities can be studied over time under the current rate structure, and as if the standby rate proposals went into effect. The difference can be used to measure the degree of financial impact on existing DG/CHP facilities and the impact this may have on candidate customers that might consider installation of new DG/CHP facilities over the time period of the study. Similar to California, I recommend that the time period for study of these impacts be through the calendar year 2004 which will provide more than a full year of data on existing projects. Anything less than a year might not produce meaningful results.

I also recommend during this stay of implementation of standby rates that alternatives to traditional ratemaking techniques for standby rates be explored as discussed in Section VII of my testimony.

DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 02-E-0779 - New York State Electric & Gas Corporation – Proceeding on Motion of the Commission as to Electric Tariff Filing to Establish a New Standby Service in Accordance With Commission Order Issued October 26, 2001 in Case 99-E-1470

PREFILED DIRECT TESTIMONY OF

WILLIAM CRISTOFARO, P.E..

April 21, 2003

I. INTRODUCTION AND WITNESS QUALIFICATION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is William Cristofaro, PE. I am president of Energy Concepts Engineering PC in Rochester, NY. Energy Concepts performs mechanical and electrical engineering across all New York State and the North East, specializing in on-site power and Combined Heat and Power plants. Our address is Energy Concepts Engineering PC, 3445 Winton Place, Suite 102, Rochester, NY 14623.

Q. WOULD YOU PLEASE DESCRIBE YOUR QUALIFICATIONS?

A. Yes. I received my Bachelor's in Science degree in mechanical and environmental engineering from the University of Miami in Coral Gables Florida.
I am a licensed professional engineer in New York State and Connecticut and have been a practicing engineer in NYS since 1976. I have been actively involved in all forms of mechanical and electrical engineering for buildings and facilities. In particular my major focus has been on energy engineering of both new and retrofit systems for building heating, cooling, industrial process and electrical systems. My experience with on-site power and CHP plants began in 1991 with one of the first fully successful design and implementations of a natural gas fired CHP plant in upstate New York. Since 1991 and to the present the Energy Concepts staff and myself have been involved with the successful implementation

of over 32 CHP plants in the Northeast. I presently serve on the NYS Combined heat and Power task force facilitated by NYSERDA. I have been actively involved with on-site power and alternative energy organizations and in testimony before the NYS assembly energy committee, and with CLEAN a non-profit organization representing on-site power. I am a member of ASHRAE, AFE and ASEE.

Q. ARE YOU EMPLOYED BY A PRIVATE GROUP IN NEW YORK TO PRESENT THIS TESTIMONY?

A. No.

Q. WHAT IS THE PRIMARY PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. I will present testimony related to the engineering design and actual operation of CHP plants and how such operation relates to fundamental assumptions underlying utility standby tariffs. In particular, how high contract demand rates may discourage proper design of base load-following CHP plants and also how high contract demand rates may not reflect true standby utility costs.

Q. WOULD YOU PLEASE DESCRIBE HOW YOUR DIRECT TESTIMONY IS ORGANIZED IN THIS CASE?

A. My testimony is organized into the following sections:

(1) Relevancy to this proceeding.

(2) CHP in a design and operations context.

(3) Fundamental assumptions of standby tariffs that conflict with actual CHP and on-site plant operation.

(4) Disadvantageous effects of standby tariffs on the operation and benefit of CHP.

(5) Specific recommendations for standby tariffs structured to better reflect the technical operations of CHP plants.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR PREPARED UNDER YOUR DIRECTION?

A. Yes. I prepared it.

I. RELEVANCY TO THIS PROCEEDING

Q. WHY IS THE QUESTION OF CHP DESIGN AND OPERATIONS RELEVANT TO THIS PROCEEDING?

A. Under the terms of the Joint Proposal and standby tariff the cost recovery rates for both contract demand and daily as used demand my be incorrectly reflect actual cost impact to the utility for maintaining true standby for the large majority of typical on-site CHP plants. It can be demonstrated that according to the design and operations of most CHP plants actual standby cost will likely be considerably

lower than the proposed rates. Therefore relatively higher contract demand rates discourage proper CHP plant design.

II. CHP IN AN DESIGN AND OPERATIONS CONTEXT

Q. HOW ARE THE MAJORITY OF CHP SYSTEMS DESIGNED AND OPERATED?

A. Most CHP plants are designed to operate very efficiently both from an electrical, thermal and utility-parallel operations perspective. A major design goal with a CHP plant is to design a modular and reliable plant. That is, a plant consisting of several units operating in tandem with electrical and thermal loads. Example, a 500-kilowatt (kw) plant will typically consist of either 7 by 75 kw units or 4 by 120 kw units. The typical units and plant is computer controlled for parallel operation with the utility. Typically the plant will operate at full power until when and if at such a time the remaining parallel power provided to the facility by the utility drops below a desired set point level. At that time the computer controlled CHP plant will ramp back so as to avoid feeding power back to the utility. (Unless there is either a utility power sell back agreement or an NYISO market sell back contract and participation.) Since it is important for cost savings for a CHP plant to run consistently, particularly during peak utility periods, tremendous care is taken to assure cogeneration unit robustness and survivability from either short duration alarm shutdowns or extended down periods. The engine or turbine water-cooling (heat recovery) hydronic systems are designed to operate continuously and in a manor to maximize cogen engine protection. With most designs, there is double redundancy of major components such as pumps, heat exchangers and

control devices to maximize engine system protection. An array of computer alarm and data trending points are used to pre-empt the potential malfunction or failure of critical components.

CHP plant optimum economic design also best matches facility thermal load and profile to the CHP plant size and operation. Often the best CHP plant may address 70 percent of electric load and 90 percent of thermal load. (Example.)

CHP plant maintenance-warranty contracts are usually established as a virtual warranty and maintenance. The purpose and result of such combined maintenance and warranty contracts are immediate, unquestioned 8-hour response time by cogen service personnel to repair cogen units. Often, microprocessor controllers and automatic phone dialers will contact service personnel for immediate service even before the owner is aware a problem has developed. Most often such response is to serve only one in a multiple unit line-up a typical CHP plant. Full CHP plant failures are quite rare due to the modular design, computer controls, remote access ability and service/warranty contract methods.

Q WHAT IS THE EFFECT OF SEVERAL SUCH PLANTS IN A SINGLE UTILITY TERRITORY?

A With several plants in operation the statistical probability of the plants totally failing at the same time is extremely low. While the probability of one of several modules in a plant is greater, each module often represents just 15 to 25 percent of total plant load. *With several plants in the same system the total percentage effect on* ***true utility demand decreases as the number of CHP plants and number of multiple units increases.*** Normally accepted statistical models can demonstrate this with actual operations experience from existing CHP plants.

III. FUNDAMENTAL ASSUMPTIONS OF STANDBY TARIFF THAT IS IN CONFLICT WITH ACTUAL CHP OPERATION

Q. HOW IS THE PROPOSED TARIFF NOT RELECTIVE OF CHP OPERATION?

A. As previously indicated in part II, coincidence of CHP failure and consequently CHP site demand on utility resources is infrequent and in smaller proportions than the proposed standby tariff contract demand and daily as used demand rates attempt to recover. Generally, the combined cost effect of the NYSEG contract demand rate and daily as used demand rates proposed approach as much as 70 to 95 percent of the normal full parent demand rate cost per kw of metered demand. While certain CHP plant reliability rates may differ, the averages of actual operating plants point to a lower percentage of cost recovery allocation for respective CHP plant demands on the utility system. Moreover, when several CHP plants are taken in the aggregate, such effects are made greater in the direction of the consideration of lower contract demand and daily as used rates.

IV. DISADVANTAGEOUS EFFECTS OF STANDBY TARIFFS ON THE OPERATION AND BENEFIT OF CHP PLANTS

Q. WHAT EFFECTS WILL POORLY DESIGNED STANDBY TARIFFS HAVE ON THE DESIGN AND OPERATION OF CHP PLANTS?

A. Poorly designed standby tariffs lead to contorted CHP plant designs and decisions by owners, which ultimately are not in concert with either the utility goals or that of government energy policy.

To work around higher standby demand rates, CHP plant designs may incorporate diesel-fired units to be used only when specific primary cogen units fail in an effort to avoid high demand charges. This results in higher capital cost for equipment that may very infrequently be used. It may also have the unintentional effect of more reliance on diesel unit as an easy alternative to consistent proper cogen unit maintenance.

Standby rates and the confusion and anxiety created by then have prompted some owners and developers to choose to implement "off the grid" CHP plants. This is done to completely avoid all utility tariffs and cost. In fact in the last 3 years of designs and installations performed with Energy Concepts Engineering the quantity of "off grid" plants has increased each year. While effective in avoiding standby tariffs the "off grid plant" actually reduces the potential benefits on-site power CHP plants can offer to the electric grid. With proper controls, a CHP plant and it's associated computer controls can be readily incorporated into a statewide system to participate in several markets to assist in NYISO goals. CHP plants could provide certain portions of demand shedding capability; load reduction and power sell back to the NYISO and/or local utilities.

CHP plants that are most efficient by matching thermal load to CHP heat recovery may be adversely affected. The CHP plant may be designed to address average electric load and maximize heat recovery use. Certain peak demand loads that occur infrequently may set a high contract demand charge. In order to avoid this

the CHP plant-sizing logic may become contorted, establishing units that run infrequently and/or with not much use for their respective heat recovery.

V. SPECIFIC RECOMMENDATIONS FOR STANDBY TARIFFS STRUCTURED TO BETTER REFLECT THE TECHNICAL OPERATIONS OF CHP.

Q. HOW SHOULD THE STANDBY TARIFFS BE MODIFIED?

A. From a design and operations standpoint the overall structure of the proposed standby tariffs seems consistent with actual realities of plant operation. That is the four point overall structure of: 1.) A base connection charge, 2.) A Contract Demand, 3.) Daily as used and 4.) KWH purchase rates from third parties or optionally from the Utility based on average NYISO market conditions. However the **High Rates** of contract demand are out of proportion to proper cost recovery and encouragement of best CHP plant sizing. Owners of CHP plants should be given choices that reflect the actual operating reality of their CHP plant and the effects on utility true local and system standby cost. In general we recommend a scaling back of contract demand and smoothing of daily as used demand rates to more properly reflect these conditions.

Alternately, and possibly of equal recovery value to the utilities, provide choice of an option(s) in the choice of rates for Contract Demand and Daily As Used Demand such that a decrease in one would be linked to an increase in the other. Practically, this would better result in a choice of two (or more) ratios of Contract Demand and As Used in a defined standby tariff.

Another and simpler method would be to maintain the existing owner choice of taking service under the otherwise applicable parent tariff or the applicable standby tariff.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes

JUDGE EPSTEIN: And I believe the only --together with that, we are going to mark for identification four exhibits as follows.

Number 9 will be the biography of Mr. Lively. Number 10 will be MBL-2, number 11 will be MBL-3, and number 12 will be remarks by PSC Chairman Flynn dated May 1, 2003.

(Exhibits 9, 10, 11 and 12 marked for identification.)

MS. DANDY: Can I place NYSEG's objection on the record?

JUDGE EPSTEIN: Does it apply also to Mr. Kuczmarski's testimony for Wyoming?

MS. DANDY: Applies to comments and testimony submitted by Joint Supporters and by Wyoming.

JUDGE EPSTEIN: Let me complete the process with regard to Wyoming. I have here an affidavit of Mr. Kuczmarski, which will be marked as Exhibit 13.

Exhibit 14 for identification is three pages, including a financial analysis that was filed, together with that affidavit.

And Exhibit 15 is an agreement between NYSEG and Wyoming Community Hospital.

(Exhibits 13, 14 and 15 marked for identification.)

And I understand that all the materials that have just been provided for the transcript were numbered for identification are subject to an objection by NYSEG, which is related to the objection that was raised concerning National Fuel Gas's statement.

Do you want to expound on that?

MS. DANDY: That is correct, Your Honor.

We have the same objection and that is that the testimony and comments contain material that is irrelevant to this proceeding, but we do reserve the right to detail our objection at the briefing stage.

JUDGE EPSTEIN: Now, Mr. Mager, this statement of Multiple Intervenors, it's going to be incorporated as if it was --

MR. MAGER: Given orally. I have an affidavit from me.

JUDGE EPSTEIN: That you would testify to this? Are you representing that you would have presented a witness to adopt this statement if there had been any cross for questions?

MR. MAGER: I probably would have been the witness, but yes.

JUDGE EPSTEIN: Number 16 for identification will be an affidavit of Mr. Mager.

(Exhibit 16 marked for identification.)

JUDGE EPSTEIN: And the Initial Statement of Multiple Intervenors will be incorporated in the transcript as if were prefiled testimony adopted by a witness.

(The following is the Initial Statement of Multiple Intervenors:)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Standby Service

Case 02-E-0779

INITIAL STATEMENT OF MULTIPLE INTERVENORS

Dated: April 21, 2003

COUCH WHITE, LLP
540 BROADWAY
P.O. BOX 22222
ALBANY, NEW YORK 12201-2222
(518) 426-4600

TABLE OF CONTENTS

PRELIMINARY STATEMENT

Multiple Intervenors, an unincorporated association of approximately 55 large commercial and industrial energy consumers with manufacturing and other facilities located throughout New York State, including the New York State Electric & Gas Corporation ("NYSEG") service territory, hereby submits its Initial Statement in support of the Joint Proposal filed with the State of New York Public Service Commission ("Commission") on April 7, 2003 in Case 02-E-0779, Proceeding on Motion of the Commission as to New York State Electric & Gas Corporation Electric Tariff Filing to Establish a New Standby Service in Accordance with Commission Order Issued October 26, 2001 in Case 99-E-1470. For the reasons set forth herein, the Commission should adopt the Joint Proposal, without modification, in this proceeding.

PROCEDURAL BACKGROUND

On June 7, 2002, NYSEG filed proposed standby service rates and tariffs in this proceeding ("June 7th Filing"). The June 7th filing purportedly was made in compliance with the Commission's generic policy order governing standby service.[1] The parties subsequently convened a technical conference to discuss NYSEG's June 7th Filing. At the technical conference, the parties agreed that the litigation of and possible settlement

---

[1] See Case 99-E-1470, Proceeding on Motion of the Commission as to the Reasonableness of the Rates, Terms and Conditions for the Provision of Electric Standby Service, Opinion No. 01-4, Opinion and Order Approving Guidelines for the Design of Standby Service Rates (issued October 26, 2001); see also Case 99-E-1470, supra, Order Concerning Petitions for Rehearing (issued March 29, 2002).

negotiations on the June 7th Filing should await the outcome of the then-pending revenue allocation and rate design phase of NYSEG's electric rate proceeding.

Thereafter, the Commission established new electric delivery rates for NYSEG, effective January 1, 2003.[2] On February 7, 2003, NYSEG updated its proposed standby service rates and tariffs based, in part, on the Commission-adopted electric delivery rates for full requirements customers ("February 7th Filing"). The February 7th Filing was the subject of a technical conference, discovery by numerous parties, and multiple settlement meetings. Settlement negotiations between the parties culminated in the filing of the Joint Proposal on April 7, 2003. The Joint Proposal is supported by NYSEG, Department of Public Service Staff, AES Eastern Energy, L.P., Lockport Energy Associates, L.P., Indeck Energy Services of Silver Springs, and Multiple Intervenors.

ARGUMENT

THE JOINT PROPOSAL SHOULD BE ADOPTED

The Joint Proposal should be adopted by the Commission in this proceeding. The Joint Proposal reflects a carefully negotiated compromise by parties with very diverse interests. From Multiple Intervenors' perspective, the Joint Proposal represents a

[2] See Case 01-E-0359, Petition of New York State Electric & Gas Corporation for Approval of its Electric Price Protection Plan, Order Directing Rate Design and Revenue Allocation (issued November 22, 2002); see also Case 01-E-0359, supra, Order Adopting Provisions of Joint Proposal with Modifications (issued February 27, 2002).

considerable improvement over NYSEG's February 7th Filing, and generally is consistent with the Commission's prior orders governing standby service rates and tariffs.[3]

Some of the factors considered traditionally by the Commission in evaluating settlement agreements include: (a) consistency with regulatory policies; (b) how the proposed result compares with the likely outcome of litigation and is within a range of reasonableness; (c) whether the settlement strikes a fair balance among the interests of the utility's customers and shareholders; and (d) the amount of support for the settlement, including by and between parties with adverse interests.[4] Based on these considerations, the Joint Proposal should be adopted by the Commission.

First, the Joint Proposal is in all material respects consistent with the Commission's policies regarding standby service. While the Joint Proposal does break some new ground, those provisions – some of which are beneficial to NYSEG and others which are beneficial to standby customers – are not inconsistent with prior Commission rulings and contribute to the careful balancing of interests reflected in the Joint Proposal. Second, the provisions of the Joint Proposal fall within a range of reasonableness in terms of likely outcomes were this proceeding to be litigated. The agreed upon standby service rates, for instance, are far more attractive than those proposed by NYSEG in its February 7th Filing, yet

[3] This is not to say that the proposed rates are particularly favorable to customers with on-site generation ("OSG"). Rather, Multiple Intervenors continues to be very concerned that some of the Commission's generic policies on standby service rates are detrimental to standby customers and the development of OSG in New York. However, given the policies currently in effect, the Joint Proposal constitutes a reasonable outcome of the issues in dispute.

[4] See Cases 90-M-0255, et al., Proceeding on Motion of the Commission Concerning its Procedures for Settlement and Stipulation Agreements, filed in C 11175, Opinion No. 92-2, Opinion, Order and Resolution Adopting Settlement Procedures and Guidelines (issued March 24, 1992) at 30-31.

still are higher than what Multiple Intervenors and probably others would advocate in litigation. Third, Multiple Intervenors does contend that, given existing Commission policies, the Joint Proposal strikes a reasonable balance between the interests of NYSEG's customers and shareholders. The identity of the settling parties bears out this balance. Finally, the Joint Proposal is supported by a majority of the active parties in the proceeding, and those parties have very diverse interests. Moreover, although a few active parties elected not to support the Joint Proposal, it remains to be seen whether there is any active opposition to the Joint Proposal and the scope of any such opposition.

Accordingly, the Commission should adopt the Joint Proposal as filed. In particular, the Commission should adopt Paragraphs 2, 3, 6-10 and 17-19 without modification. Multiple Intervenors would not have executed the Joint Proposal without these provisions, and any changes to them could alter, if not eliminate altogether, Multiple Intervenors' support of the Joint Proposal.

Paragraph 2 sets forth the allocation between contract demand and daily as-used demand charges, and also incorporates Appendix A, which sets forth the proposed standby service rates for all customer classes. These issues were discussed and debated extensively in settlement negotiations and represent a tenuous compromise involving numerous competing interests. Any increase to the proposed standby rates for customers whose otherwise applicable service classification is S.C. 7 would affect materially Multiple Intervenors' decision to support the Joint Proposal.[5]

---

[5] The proposed allocation between contract demand and daily as-used demand charges is acceptable to Multiple Intervenors in this instance given NYSEG's rate structure and the other provisions in the Joint Proposal. The Commission should accord no precedential significance to that allocation or any other provision of the Joint Proposal.

Paragraph 3 provides that certain customers with OSG will be subject to a phase-in of the new standby rates, while also offering customers with existing OSG a one-time election to take service under the standby rates without the phase-in. This customer choice is critical to Multiple Intervenors' support of the Joint Proposal and should not be disturbed.

Paragraphs 6-9 provide standby service customers with important control over their contract demand levels. Pursuant to these provisions, a customer can opt to accept a NYSEG-calculated contract demand or select its own contract demand level. This option is extremely important to customers, and provides much-needed protection where the utility-calculated contract demand may not be aligned with the customer's operations or expected use of the OSG.

These provisions also provide numerous protections for NYSEG and customers. Paragraph 6 provides that whenever a customer exceeds its contract demand, the contract demand will be ratcheted up by the amount of the exceedence. Paragraph 7 governs how NYSEG will calculate contract demands for customers. These provisions protect customers against the selection of an arbitrary contract demand by the utility. Paragraph 8 provides that where a customer relies on the NYSEG-calculated contract demand, there will be no penalty for exceeding that demand level, except if the customer fails to provide notice of a material change in equipment or operations that would increase its peak demand by more than 12.5%. Finally, Paragraph 9 establishes penalties where a customer exceeds a customer-selected contract demand level. The penalties are intended to prevent gaming by customers without being unduly punitive. Paragraph 9 also provides customers with the opportunity to adjust their customer-selected contract demand subject to certain limitations.

Paragraphs 6-9 constitute a reasonable and acceptable compromise of contract demand issues. Multiple Intervenors considers it absolutely essential that standby service customers be accorded the opportunity to select their own contract demand, and the Joint Proposal's provisions resolve these issues in a fair and balanced manner.

Paragraph 10 permits NYSEG to delay the implementation of new standby service rates to address issues related to interval metering and modifications of its billing system. Importantly, where a customer can demonstrate that it already possesses interval metering and was being billed off-system as of the date of the Joint Proposal, it has the right to move to the new standby rates immediately upon written notice to NYSEG. This option was critical to Multiple Intervenors and the carefully-balanced provisions in Paragraph 10 should not be modified.

Paragraph 17 provides credits to the proposed standby service rates for customers that have paid for their meter and instrument transformation costs. In all likelihood, Multiple Intervenors would not have executed the Joint Proposal absent Paragraph 17. The proposed customer charges for standby service are very high, particularly for customers whose otherwise applicable parent class is S.C. 7, and exceed comparable customer charges for full requirements customers. It would be particularly inappropriate to impose such high customer charges on standby customers that already have paid meter and instrument transformation costs (which underlie the proposed customer charges). Thus, providing a credit to customers already paying these costs avoids an inequitable double recovery from such customers.

Paragraph 18 establishes certain logical exceptions to the proposed standby service rates. For instance, customers with individually-negotiated contracts and that portion

of a customer's delivery service applicable to a New York Power Authority power allocation would not be subject to standby service charges. Additionally, the use of emergency generators is exempt from standby service liability, even where the emergency generator is used to respond to a system emergency through the New York Independent System Operator, Inc.'s Emergency Demand Response Program and Special Case Resources program. The imposition of standby service charges in these instances would be inappropriate and the Joint Proposal avoids such a result.

Finally, Paragraph 19 provides for NYSEG's standby service rates to be adjusted every six months to reflect changes in stranded costs, which are recovered through NYSEG's Non-Bypassable Wires Charge ("NBWC").[6] These provisions represent a reasonable compromise to a contentious issue. As the Commission is aware, customers electing NYSEG's Bundled Rate Option commodity option have a fixed NBWC for as long as two years. However, customers electing NYSEG's Variable Rate Option or ESCO Rate Option commodity options have NBWCs that vary monthly subject to true-up. The six-month update embodied in the Joint Proposal allows the standby rates to be updated periodically to reflect commodity price changes affecting the amount of NYSEG's stranded costs, while still preserving a large measure of stability for standby customers. The six-month update agreed to by the settling parties was the subject of extensive negotiations and should not be modified.

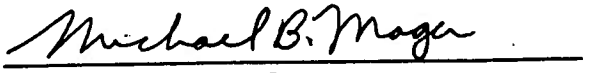
[6] Because NYSEG's NWBC is based in large part on wholesale electricity prices, it is extremely volatile.

CONCLUSION

For the foregoing reasons, Multiple Intervenors urges the Commission to adopt the Joint Proposal, without modification, in this proceeding.

Dated: April 21, 2003
Albany, New York

Respectfully submitted,



Michael B. Mager, Esq.
COUCH WHITE, LLP
540 Broadway
P.O. Box 22222
Albany, New York 12201-2222
(518) 426-4600
mmager@couchwhite.com

J:\DATA\Client2\10947\mbm004.doc

CERTIFICATION OF SERVICE

I hereby certify that on this day a true copy of the above document was served upon the attorney of record for each party by mail/by hand/overnight delivery.

Date: 4/21/03 Valerie L. Faulli

MR. JOHNSON: I also have one, an initial statement on behalf of Lockport Energy Associates, LP and Indeck Energy Services of Silver Springs, Inc. and I have one affidavit on behalf of Lockport. And I would like to reserve a place for an affidavit from Indeck to bring with me tomorrow.

JUDGE EPSTEIN: So, number 17 would be an affidavit of Lockport Energy and number 18 of Indeck Energy.

(Exhibit 17 marked for identification and Exhibit 18 reserved)

MR. JOHNSON: This is the affidavit on behalf of Lockport.

JUDGE EPSTEIN: And the statement just described by Mr. Johnson will be incorporated into the transcript.

(The following is a Letter from Read and Laniado to Secretary Deixler:)

READ AND LANIADO, LLP
ATTORNEYS AT LAW
25 EAGLE STREET
ALBANY, NEW YORK 12207-1901
(518) 465-9313

TELEFAX NO.
(518) 465-9315

KEVIN R. BROCKS
CRAIG M. INDYKE
DAVID B. JOHNSON
SAM M. LANIADO
HOWARD J. READ

ROBERTO C. BARBOSA
JEFFREY B. DUROCHER
STEVEN D. WILSON

Via Hand Delivery

April 21, 2003

Hon. Janet H. Deixler
Secretary
New York State
Public Service Commission
3 Empire State Plaza
Albany, NY 12223-1350

Re: Case 02-E-0779 – New York State Electric & Gas Company – Standby Electric Rates.

Dear Secretary Deixler:

Lockport Energy Associates, L.P. ("LEA") and Indeck Energy Services of Silver Springs, Inc. ("Indeck") hereby wish to file this letter in support of the Joint Proposal on standby rates filed with the New York State Public Service Commission ("Commission") by New York State Electric & Gas Company ("NYSEG") on April 7, 2003, in the above-referenced proceeding.

LEA owns and operates a 200 megawatt ("MW") nominal capacity cogeneration facility located in NYSEG's service territory. Indeck owns a 50 MW nominal capacity cogeneration facility located in NYSEG's service territory. This statement is offered in support of the overall settlement embodied in the Joint Proposal and it should not be construed as LEA's or Indeck's agreement with any particular element or discrete outcome in the Joint Proposal.

The Joint Proposal is the result of extensive negotiations and mutual concessions on a number of conflicting issues and positions that reflect an overall outcome the Commission would likely approve upon a litigated record. LEA and Indeck support the Joint Proposal because it authorizes NYSEG to offer individually negotiated agreements for standby service to customers that are wholesale generators equal to or greater than 50 MW and that sell into the market, or to a third party, no less than 90% of their site's energy output, such as LEA and Indeck. Section 13 of the Joint Proposal provides:

> The rates and charges negotiated will reflect, where applicable, the characteristics of the specific interconnection arrangements, including, but not limited to, the voltage level of the interconnection, whether the interconnection is bi-directional, and the nature of the NYSEG facility where the generator is interconnected with the NYSEG system.

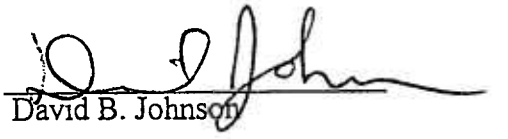
This provision will allow NYSEG to develop standby rates for wholesale generators that more fairly and accurately reflect the costs that individual generators impose on NYSEG's system.

The Joint Proposal also contains elements and outcomes upon which LEA and Indeck made substantial concessions to achieve settlement and to avoid full litigation. Accordingly, it would be wrong to construe LEA's and Indeck's support as an indication that they have agreed to or accepted as appropriate any individual or discrete tariff term or rate design.

The Joint Proposal, which is the result of extensive settlement negotiations on a range of interrelated issues and compromises, warrants Commission approval.

Respectfully submitted,

READ and LANIADO, LLP
Attorneys for Lockport Energy Associates, L.P. and Indeck Energy Services of Silver Springs, Inc.

By: 
David B. Johnson

cc: Hon. Rafael A. Epstein (via hand delivery)
Active parties (via First Class mail and e-mail)

JUDGE EPSTEIN: In discussions among the parties and me we determined that an appropriate briefing schedule for NYSEG would be initial briefs June 5th, replies, which could be very limited in scope, they should --you are free to keep them narrowly responsive to the June 5th briefs and those would be June 12th.

And I would add that in mentioning those dates what I had in mind was that those would be mailing dates for e-mail and hard copy. E-mail it to the parties and me on the 5th or the 12th, as the case may be, and you can mail hard copy at the same time by first class mail, so there is no implicit in hand delivery date in this schedule.

It's just June 5th and June 12th e-mail, but hard copy should follow at least to the people on the active party list that appears on the Commission's website and to the Secretary of the Commission, and do not e-mail the Secretary of the Commission.

I think that completes everything we need to do in NYSEG; am I correct?

MR. VAN RYN: Yes.

MR. GIANNASCA: I believe so.

JUDGE EPSTEIN: Did I mention that I think there was a consensus --I don't know if this binds

everybody --but Mr. Van Ryn suggested that the NYSEG and RG&E briefing could be one and the same. That you could submit a combined document in both cases if the comments are appropriate to each case.

I am not sure that's going to work, but if you find that that's more convenient than doing two separate documents give it a shot, and try to make sure that you have got the hard copy going to the right active parties because those two active parties lists are somewhat different from each other.

Anything else on NYSEG?

MR. BROWN: Your Honor, I presume we could do separate.

JUDGE EPSTEIN: Yes. You know --

MR. VAN RYN: If the parties want to do separate I will withdraw the suggestion. Let's just do separate if everybody thinks it's going to be confusing.

JUDGE EPSTEIN: All right, fine.

MR. BROWN: I don't think we object, but we wanted to reserve the right to do separate because of a concern RG&E counsel had that we may want to get their witnesses on the record on some things.

JUDGE EPSTEIN: So, we are adjourned in NYSEG.

(Hearing adjourned.)

INDEX TO WITNESSES

(5-19-03 - A.M. Session)

NAME	DIRECT	CROSS	REDIRECT	RECROSS
NYSEG PANEL	75	125	202	204
STAFF PANEL	236	279		

INDEX TO EXHIBITS

NUMBER		FOR IDEN.
1	February 2003 Tariff Filing	73
2	Joint Proposal	73
3	Panel Resume	74
4	Affidavit of Mr. Eck	Reserved
5	Exhibit marked RDE-1	236
6	Exhibit marked RDE-2	236
7	Exhibit marked revised RDE-2	236
8	Staff Panel resume	237

INDEX OF EXHIBITS

INDEX OF WITNESSES

ORIGINAL

PUBLIC SERVICE COMMISSION CASE NO. 02-E-0779

NEW YORK STATE ELECTRIC AND GAS CORPORATION

ADDITION TO HEARING TRANSCRIPT May 19, 1993

PREFILED TESTIMONY RECEIVED BY E-MAIL 6-3-03

Pages 449 thru 480

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 02-E-0779 - New York State Electric & Gas Corporation – Proceeding on Motion of the Commission as to Electric Tariff Filing to Establish a New Standby Service in Accordance With Commission Order Issued October 26, 2001 in Case 99-E-1470

PREFILED DIRECT TESTIMONY OF

MARK B. LIVELY

APRIL 21, 2003

CASE NOS. 02-E-0779

DIRECT TESTIMONY OF MARK B. LIVELY

Q. What is your name and address?

A. My name is Mark B. Lively. My address is 19012 High Point Dr., Gaithersburg, Md., 20879. I am an engineering consultant specializing in pricing issues related to natural gas and electricity.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony in this proceeding addresses rate design issues presented by the New York State Electric & Gas Corporation (NYSEG) in its original filings and in the April 7th Joint Proposal. I believe that NYSEG, its customers, and the State of New York are ill served by the NYSEG proposal in regard to standby service to be provided to on-site generators (OSG). The proposed design, especially in regard to the Contract Demand, falls into the trap of the California Debacle Syndrome. I therefore recommend that the Commission adopt:

- A pricing plan for OSG that differentiates between serving supplemental retail load versus providing backup for OSG;
- A pricing plan for providing backup for OSG that dynamically changes the price for such backup based on the conditions being experienced by NYSEG at the time and in the location that the backup is being supplied. The cost of developing this plan should be borne by all NYSEG customers;
- Failing the adoption of dynamic pricing suggested in the previous paragraph, a less harsh approach to the formulation of the Contract Demand, including a

moderation of the ratchet and the elimination of the penalty for exceeding the Contract Demand; and,

- Again failing the adoption of dynamic pricing, a recognition that backup service is relatively inexpensive for NYSEG to supply since OSG outages are unlikely to occur during the weather extremes that drive the peak on NYSEG's distribution system.

Q. What is your educational background and experience?

A. I earned a Bachelor of Science degree in electrical engineering from the Massachusetts Institute of Technology in 1969. I earned a Master of Science degree in management from the Massachusetts Institute of Technology's Sloan School of Management in 1971. I am a registered professional engineer in the District of Columbia.

From 1971 to 1976, I worked for American Electric Power Service Corporation (AEPSC) in New York City, first in the Controller's Office, then in the Rate Department. AEPSC provided engineering and management services to its utility affiliates in Indiana, Michigan, Ohio, West Virginia, Kentucky, Virginia, and Tennessee. While in the rate department of AEPSC, I received on the job training on issues related to pricing electricity, including cost analysis.

From 1976 to 1991, I worked as a consultant in the Washington, D.C., utility office of the accounting firm of Ernst & Ernst, and its successors, first

Ernst & Whinney and then Ernst & Young, which I will collectively refer to as "Ernst". The Washington utility office provided audit, tax, and consulting services to its clients on electric and natural gas matters. My clients at Ernst included utilities, large industrial consumers, independent power producers, and regulators.

Since the beginning of 1992, I have been self-employed as a utility economic engineer specializing in the costing and pricing of electricity and natural gas. My clients since that time have included state commissions, consumer advocates, industrial consumers, gas utilities, and electric utilities. I have professionally interacted with NYSEG twice since 1992, first helping NYSEG with its analysis of FERC's competitive initiative on ancillary services and later helping a NYSEG customer on its billing complaint in regard to the ratchet in NYSEG's retail tariff. For the purpose of this current standby case and other proceedings in the State of New York, I am a consultant to The E Cubed Company, L.L.C. A copy of my CV is provided as Exhibit ___ (MBL-1)

Q. Have you testified in regulatory proceedings?

A. Yes. Most recently I testified in the proceedings of this Commission in Case 02-E-0780 and in Case 02-E-0781, the consolidated Orange & Rockland Utilities, Inc. and Consolidated Edison Company of New York, Inc. (O&R/ConEd) proceeding that parallel this NYSEG proceeding. As I will develop more fully

later, my testimony in that proceeding is applicable in this proceeding. However, I have expanded the issues addressed here versus the testimony originally filed in the O&R/ConEd proceeding.

In regard to other proceedings, while I was with AEPSC I testified for the affiliated Michigan Power Company before the Michigan Public Service Commission on accounting adjustments, cost allocation, and rate design. While with Ernst, I testified before the Arkansas Public Service Commission, the Louisiana Public Service Commission, the Montana Public Service Commission, the Texas Public Utilities Commission, and the New Mexico Public Service Commission. Generally my testimony was on the issue of cost allocation, with some testimony on budgetary forecasts and innovative rate design. Since being self employed, I have testified before the Texas Public Utilities Commission on rate design, before the Public Service Commission of the District of Columbia on behalf of the D.C. Office of People's Counsel on accounting issues in the failed merger between the Baltimore Gas & Electric and Potomac Electric Power, and before this Commission in a proceeding on behalf of St. Lawrence Gas Company, as well as in the O&R/ConEd proceeding that parallels this proceeding. I have also filed comments in various FERC proceedings including RM01-12, FERC's current investigation into a Standard Market Design for Independent System Operators.

Q. Have you written any published papers or articles?

A. Yes. *Public Utilities Fortnightly* published several of my articles, beginning in 1989. The National Regulatory Research Institute (NRRI) has also published several of my articles in its *Quarterly Bulletin*. NRRI is affiliated with the National Association of Regulatory Utility Commissioners. *McGraw-Hill's Electrical World* published an article I wrote in 1991. I have also presented papers to conferences sponsored by the American Society of Mechanical Engineers, the American Nuclear Society, the Institute of Electrical and Electronics Engineers, and the Association of Energy Engineers. I attach my complete resume as Exhibit___(MBL-1), which includes a list of the many articles and speeches I have prepared on the subject of pricing electricity and natural gas.

Q. How is your testimony in the O&R/ConEd proceeding, Case 02-E-0780 and Case 02-E-0781, applicable to this NYSEG proceeding?

A. The issues that I raised in the O&R/ConEd proceeding, Case 02-E-0780 and Case 02-E-0781, relate to rate design, that is, to the structure of the tariff. All three utilities, O&R and ConEd in the other proceeding, and NYSEG in this proceeding, have adopted the same structure for the standby rate. Thus, any structural defect in one tariff has a parallel structural defect in the other tariffs. Very little of my testimony relates to the actual level of any of the rates in these tariffs. My testimony deals almost exclusively with the structure of the tariff. Thus, since the structures are the same, my testimony should be the same, though

supplemented by information and conclusions that arise as these proceedings progress.

Q. What do you mean by having a pricing plan for OSG that differentiates between serving supplemental retail load versus providing backup for OSG?

A. As I said in the O&R/ConEd proceeding, many OSGs are designed to serve part of the electrical load of the utility customer. The rest of the load must be served across the wires of the utility. This load that must be served across the wires of the utility is considered to be supplemental to what the OSG can provide. Since OSGs occasionally are not available, during such times the utility wires must serve more of the electrical load of the customer. The additional load served by the utility wires at these times is called standby or backup. This case is about how to price the wire service being provided by NYSEG, not about the energy service that can be provided by NYSEG or other providers.

Q. Why is it important to have a pricing plan for OSG that differentiates between serving supplemental retail load versus providing backup for OSG?

A. Customers who wish to install small OSG projects generally do not want to see the financial discontinuity associated with a change in the price for the remaining portion of their load. Such a financial discontinuity creates uncertainty and greater risk for the customer and thus creates a barrier to greater penetration by OSG.

Q. Is a pricing plan for OSG that differentiates between serving supplemental retail load versus providing backup for OSG consistent with traditional rate making practices?

A. Yes. Traditional rate making practices includes the creation of customer classes with similar service requirements. A major issue in identifying customer classes is the commonality in their load shapes. For most customer classes for NYSEG in this proceeding, the primary determiner of their load shape is a seasonal weather pattern, whether due to air conditioning during the summer or heating during the winter. NYSEG designs its distribution systems to meet the peak demand caused by seasonal weather patterns. This is true for customers served under the standard tariff and would be true for the supplemental load customers desire NYSEG to serve in excess of what the OSG can provide. I understand from my previous experience with NYSEG that NYSEG has a strong seasonal peak, though generally driven by winter chill instead of by summer heat.

In contrast to the weather driven load faced by standard tariffs, the backup load will be determined by the outage characteristics of the OSG. These outage characteristics will generally be independent of the summer or winter weather patterns. The weather independence of the outage characteristics of OSG suggests that this portion of customer consumption should be treated as a separate class of customers; at least conventional utility ratemaking suggests such treatment as a separate customer class.

The appropriateness of having a separate rate for supplement service versus the rate for backup service was nicely presented by the Commission staff during the O&R/ConEd hearing (TR. 222-226) under cross examination by Mr. Robert Loughney of Couch White, LLP, on behalf of the Standby Customers Coalition. Mr. Loughney posited a customer with a 3 MW load and with a 2 MW. The latter 2 MW load could be electrically isolated and was ideally situated for the combined heat and power (CHP) form of OSG. Staff conceded that the 2 MW load could be treated as a separate customer for purposes of the March 12th O&R/ConEd Joint Proposal and for other aspects of the O&R/ConEd case, if the customer paid the two customer charges that would be appropriate under the tariff, since the utility would indeed be experiencing the cost of dual metering and dual service connections.

Staff's acceptance of Mr. Loughney's example should also be an acceptance of the concept of a split rate for supplemental power versus standby power. Staff's acceptance must be modified for the actuality of a unified customer load. The difference relates to the customer costs. A split rate would require separate metering for the OSG and a procedure for identifying the amount of the utility delivery that should be treated as supplemental power versus that amount that should be treated as standby power. Again I note that standby power should be less expensive for the utility to serve. The customer could own the separate metering for the OSG. Customer ownership of the metering would

reduce the cost that NYSEG would have to incur in serving the customer. Customer ownership would also protect the customer from additional charges associated with the non-bypassable wires charge, some of which NYSEG has classified as being customer related.

Q. How can NYSEG determine how much electricity should be billed as supplemental versus the amount that should be billed as standby?

A. I present a separation procedure in Exhibit___(MBL-2). The separation procedure identifies the amount of electricity metered by the utility that should be billed as supplemental power versus the amount of electricity that should be billed as backup power. The procedure uses a customer owned interval meter to determine the amount of electricity that the customer is receiving from its OSG. The customer owned interval meter would be synchronized with the utility meter with the data from the customer owned meter made available to the utility in the same fashion that the utility obtains data from its own meter. Together, the two meters would determine the maximum monthly consumption by the customer. The normal capability of the OSG would be subtracted from the site load to determine the supplemental demand of the consumer. The supplemental demand is the amount of electricity that the consumer could not supply to itself. This supplemental demand would be the basis for the demand charge under the standard tariff. Any electricity taken up to the supplemental demand during each interval would be considered to be supplemental load, subject to the terms of the

standard tariff. Electricity in excess of the supplemental demand during each interval would be considered to be backup energy subject to the standby charges. A more complete explanation of this procedure is presented in Exhibit__(MBL-2). I note that this separation procedure is identical to what I presented in the O&R/ConEd proceeding.

Q. Is there a difference in this NYSEG proceeding versus the O&R/ConEd proceeding?

A. Yes. The April 7th Joint Proposal in this NYSEG proceeding highlights the need to have a split rate in its reference to prohibiting OSG customers from buying electricity under the backup rate. Section 5 of the April 7th Joint Proposal states

> NYSEG has the right to petition the Commission to disqualify a customer from these standby rates if NYSEG can demonstrate that the customer (a) has installed OSG with a total nameplate rating greater than fifteen percent (15%) of its load, but (b) has not operated or is not operating that OSG in a material manner in order to serve the customer's load.

Elsewhere NYSEG generally is trying to force OSG onto the backup rate, but here, NYSEG is trying to establish its right to keep an OSG customer from using the backup rate. As I observed in the O&R/ConEd proceeding (Tr. 263), there is a potential for revenue erosion due to the existence of two tariffs on which a customer may be served. I referred to an appropriate solution to this problem in the form of establishing the concept of normal generation level in Exhibit___(MBL-2).

Q. How does the concept of normal generation level address NYSEG's concern to be able to disqualify customers from obtaining service under the standby tariff?

A. As I understand the concern expressed in Paragraph 5 of the April 7th Joint Proposal, a customer might install inconsequential equipment that technically meets the definition of OSG capable of meeting 15% of its load. The customer's intent is not to operate the equipment but merely to qualify for the standby tariff since the standby tariff is less expensive for that customer than would be the standard tariff. An operational definition of normal generation level lessens the ability of customers to create revenue erosion for the utility.

Q. What is revenue erosion?

In this proceeding, as in the O&R/ConEd proceeding, I use the term revenue erosion to refer to the decline in revenue that a utility can experience when customers have the option to switch to another, newly introduced rate schedule. The potential for revenue erosion comes from the customer having the option to switch. The expectation is that the customer will choose the less costly of the two rate schedules.

It is expected that customers who stay on the current rate do so because doing so is less costly. From such customers, the utility will receive the same revenue as it has been receiving. Conversely, it is expected that customers who voluntarily change from the current rate to the proposed rate would only do so if

the proposed rate is less costly. From such customers, the utility will receive less revenue than it has been receiving. Thus, when customers have a choice as to which rate under which they will receive service, the utility will see an erosion of revenue. This can be solved by having all customers switched to the new rate or limiting the amount of load being switched, such as by introducing a split rate. I think that the introduction of a split rate is a superior solution to the 15% limitation introduced by Section 5 of the April 7th Joint Proposal in this NYSEG proceeding.

In the current situation, NYSEG has introduced a new rate scheduled that is applicable to customers with on-site generation (OSG). Because the rate structures of the two sets of rate schedules are different, NYSEG would generally not collect the same amount of revenue from a particular customer under the proposed rate structure as NYSEG now collects from that same customer under the current rate structure. This creates a problem for NYSEG that in this context I call revenue erosion.

Q. How bad is the potential for revenue erosion in these proceedings?

A. I have not attempted to calculate the potential revenue erosion for NYSEG. I note that during O&R/ConEd proceedings, I pointed out that ConEd public data responses suggest that ConEd could experience a revenue erosion of $70 million in regard to the wires charges on its commercial tariffs. I used two ConEd

publicly disclosed documents to make this estimate that the revenue erosion potential is about 7% of its wires charges. I note that this estimate is based on ConEd's proposal for the allocation of revenue between the Contract Demand provision versus Daily As Used Demand provision. The revenue erosion potential could be more, or less, under the allocation contained in the April 7th Joint Proposal. My best guess in this NYSEG proceeding is that the 7% estimate is a rough approximation of the revenue erosion potential that NYSEG might experience.

Q. How does the April 7th Joint Proposal handle the issue of revenue erosion?

A. The April 7th Joint Proposal does not directly address the issue of revenue erosion except for the section I quoted above from the April 7th Joint Proposal. Thus, to the extent that the 15% proportion is meant to address the revenue erosion issue, it does not prevent the exploitation of the differential between the two rates, while a split rate would. Further, giving NYSEG the right to petition the Commission to disqualify a customer from the standby rate can be a lengthy process, based on my prior experience with NYSEG customer disputes taken to this Commission.

Q. How would a split rate prevent the exploitation of the differential between the current rate and the proposed rate?

A. The split rate proposal advanced by the Joint Supporters would limit the revenue erosion to the portion of the electricity that customers draw from the utility

actually to backup OSG. Supplemental electricity, which is any draw from the utility in excess of the amount of electricity actually used to backup OSG, would be priced at the current tariff rate. The approach that I included as "Split Rate Mechanics" in Exhibit___(MBL-2) submitted with my direct testimony is currently used in Florida.

As a consultant to Tampa Electric Company in 1992, I developed a definition of "Normal Generation" that would effectively address the issue raised in the O&R/ConEd proceeding of "a non-OSG customer who might find the standby rate advantageous, and install a small OSG facility only for the purpose of switching its load to the standby service". Under the definition I developed for Tampa Electric, the customer would have to incur substantial cost by operating the OSG for many hours each year to qualify for the standby service. A customer could not just install a small OSG facility and demand service under the standby rate.

The concept I developed in Florida defined normal generation level based on operating experience for the past twelve months. The concept was explicit and based on meter readings, as opposed to the subjective terminology used in the April 7th Joint Proposal.

Q. How should backup service be priced?

A. In this proceeding, I have proposed pricing backup service on a dynamic basis. Under such a pricing plan for providing backup, the price for such backup would be based on the conditions being experienced by the utility at the time and in the location that the backup is being supplied. Such a dynamic pricing plan would result in the OSG competing in larger markets. Not only would the OSG try to meet the electrical needs of the consumer, but also the OSG would also compete economically against the market run by the New York ISO and would also compete against the cost of the wires market run by the local utility. Thus, a dynamic pricing of the utility wires business results in OSG living up to its name of distributed generation, in that it would be generation that competes with the distribution services of the utility.

Dynamic pricing of the backup service would also provide NYSEG with a mechanism to pay for line loading relief provided by OSG participating in the NYISO market. NYSEG's lines are likely to be heavily loaded at the same time that the NYISO is experiencing constraints on its generators and calls for OSG to operate their generators. Thus, the operation of OSG at the behest of NYISO will provide savings to NYSEG, savings that should be reflected in payments made by NYSEG to OSGs participating in NYISO programs.

Q. You mentioned the California Debacle and an associated syndrome. What is the California Debacle?

A. I use the term California Debacle to refer to the yearlong period from the summer of 2000 to the spring of 2001 when wholesale prices soared in California and in much of the rest of the western part of the United States and Canada. During that period of time, the State of California mortgaged its future to pay for electricity that it consumed during that time period.

Q. How is the California Debacle similar to the Contract Demand proposal formulated by NYSEG in this proceeding?

A. NYSEG has proposed a Contract Demand that mortgages the future of consumers based on demands in the past. NYSEG has proposed a Contract Demand with a permanent ratchet. Once a consumer imposes a demand on NYSEG, NYSEG proposes to use that demand indefinitely into the future for billing purposes. Thus, actions by the consumer mortgage the consumer's future for several years, just as actions by the State of California have mortgaged the future of its consumers for several years.

Q. Could the syndrome associated with the California Debacle be avoided for standby tariffs?

A. Yes. Though the specific structure of the Contract Demand in this proceeding are different from what happened in the California Debacle, I believe that the industry can learn by comparing the Contract Demand concept with the California Debacle. Specifically, I see an unwarranted mortgaging of the future, a missed

opportunity for customer response, and an unnecessary prolonging of electrical constraints.

Q. Why do you say that the mortgaging of the future is unwarranted?

A. I say that the mortgaging of the future is unwarranted in that there are other, better economic ways to address the issue of high customer demands. One such approach is to have prices reflect the concurrent situation on the electrical network. This would encourage OSGs to operate when the distribution system is constrained or when the NYISO has high prices in its settlement system. Though I point this out in regard to the Contract Demand structure posed by NYSEG in this proceeding, the Contract Demand structure follows the syndrome of the California Debacle, in that California could have avoided mortgaging its future by implementing dynamic prices when the bulk power market became very expensive. Further, this unwarranted mortgaging of the future of the consumer is exacerbated by the method used by NYSEG to allocate the revenue requirement between Contract Demand and As Used Demand.

Q. How did NYSEG exacerbate the unwarranted mortgaging of the customer future by its revenue allocation?

A. I present as Exhibit___(MBL-3) an analysis of the allocation factors used by NYSEG in setting the Contract Demand charge and the As Used Demand charge. Exhibit___(MBL-3) clearly shows how NYSEG biased the result toward a higher

Contract Demand charge than is warranted. NYSEG achieved some of this effort by improperly aggregating several individual cost components into larger cost categories. NYSEG's allocation analysis should have been done on these smaller cost components, which would have resulted in a much smaller Contract Demand charge.

Q. Why do you say that there is a missed opportunity for customer response?

A. Customers are generally not sophisticated enough to realize that charges based on demand ratchets are actually driven by some earlier action of the customer, at least not until it is too late to act. Certainly, customers are generally not aware at the time that they are establishing the peak that they are locking in costs that they will have to pay for the next several years. In the same way, most consumers in California were not aware during 2000/2001 that their actions were committing them to pay off a huge debt over the next several years. If the California consumers had been aware of the costs that were being incurred at that time for them, there would have been an elasticity response that would have reduced the amount of electricity that was needed on their behalf. Similarly, most customers in New York would reduce their consumption during times of constraint if they realized that they were mortgaging their future by not doing so. When California finally raised prices in June of 2001, the damage had already been done; their futures had been mortgaged. Similarly, when customers see charges from the Contract Demand provision of the proposed standby rate, they will try to reduce

their consumption, but by then it will be too late, their futures will have been mortgaged.

Q. Why do you say that there will be an unnecessary prolonging of electrical constraints?

A. When customers know that they are paying a higher price for the electricity that they are consuming, they will conserve. This conservation will show up in reduced electrical loading. In California, the retail rate increases occurred in June 2000 as the utilities were entering the high load summer period and leaving the low load spring period. At the same time, the rotating blackouts ended, as did the associated high prices in the bulk power market. The similarity in timing of these events illustrates the elasticity of demand for electricity, if commissions just allow such elasticity to operate.

It is for these reasons that I believe that dynamic pricing is a preferred alternative to the Contract Demand structure for backup service proposed by NYSEG in this proceeding. Further, I note that dynamic pricing is an integral part of the new energy legislation passed in April by the U.S. House of Representatives.

Q. Should dynamic pricing be used for the supplemental portion of the consumer's load?

A. Not at this time. Though I believe that electricity consumption has some elasticity, as was illustrated by the significant reduction in California consumption after the retail price increases in June 2001, there is much greater elasticity in regard to the operation of OSG. The industry in New York should first take advantage of this high level of elasticity in regard to the operation of the OSG by dynamically pricing backup service. Dynamically pricing supplemental service at this time would stifle the OSG industry by creating too much uncertainty for retail consumers about the pricing of the basic service they are taking from NYSEG. At some time in the future, as NYSEG gains experience with dynamically pricing their distribution services and as customers gain confidence in the fairness of such an approach, then it may be appropriate to price supplement service dynamically. At the current time, dynamic pricing of the supplemental use of the distribution grid should only be an option that customers could exercise as they become more comfortable with NYSEG's implementation of the concept.

Q. Why do you believe that failing the adoption of dynamic pricing that NYSEG should change the formulation of the Contract Demand in a way that will moderate the ratchet and the penalty for exceeding the Contract Demand?

A. The current formulation of the Contract Demand includes a ratchet and a penalty for exceeding the Contract Demand. Ratchets are tariff mechanisms to spread revenue over an extended period of time. The ratchet proposed by NYSEG is perpetual, in that once a demand is established, the customer pays a billing

demand based on that established demand. Initially the demand for which the customer pays is an amount that is the estimated maximum load that the customer will impose on the utility. If the customer exceeds that amount, the ratchet increases the demand upon which the customer must pay and the penalty forces the customer to pay a lump sum amount based on how much the customer exceeded the previous contract demand.

NYSEG proposes to impose a different ratchet for backup service than the ratchet that is currently being used for such customers. Having a different ratchet will provide a disincentive for customers to install OSG. Such a disincentive is contrary to New York State policy to encourage OSG.

NYSEG also proposes to impose a penalty for backup service that is different from any other provision that I know of in NYSEG's tariffs. This distinction will provide a disincentive for customers to install OSG that is very similar to the disincentive associated with the perpetual ratchet.

Finally, the ratchet and the penalty both will violate the concept of revenue neutrality that has been proposed in the guidelines for this proceeding.

Q. How do the ratchet and the penalty violate the concept of revenue neutrality?

A. Ratchets and penalties are both mechanism to generate revenue for NYSEG. NYSEG has not produced rate design work papers that contain any allowance for the revenue that NYSEG will earn as a result of the imposition of either the

perpetual ratchets or the penalties. Accordingly, when customer actions result in NYSEG collecting revenue from perpetual ratchets or from penalties, the revenue of NYSEG will increase beyond the position currently established as the appropriate rate level for NYSEG. Further, as was developed during the hearing in the O&R/ConEd proceeding, additional excess revenue will be produced when customers set their own contract demand at an exceptionally high level out of fear of the penalties built into the Contract Demand concept.

Q. Why do you believe that backup service is relatively inexpensive for NYSEG to supply?

A. I believe that backup service is relatively inexpensive for NYSEG to supply since OSG outages are unlikely to occur during the heat storms or arctic blasts that drive the peak on NYSEG's distribution system.

NYSEG designs its distribution systems to meet either the peak summer air conditioning demands of their customers or the winter heating loads of their customers. This design consideration is reflected in NYSEG's retail tariffs. NYSEG proposes not to charge consumers for the use of the distribution system during the night. These rate design features show that NYSEG engineers design the distribution system to meet the daytime peak.

In contrast to NYSEG's typical air conditioning load and heating load, OSG backup service should not be highly correlated with the summer air

conditioning load or winter heating load. OSG backup service will occur for two reasons, forced outages of the OSG and scheduled maintenance.

Forced outages of the OSG should occur randomly, at anytime, day or night, winter, spring, summer or fall. Accordingly, the forced outages of the OSG will have a smaller impact on NYSEG's distribution grid than will NYSEG's typical air conditioning load. NYSEG engineers will have less need to reinforce the distribution system to meet the forced outages of OSG than would they need to reinforce the distribution system to meet an increase in NYSEG's typical load. This suggests that forced outages of the OSG are typically less expensive to serve and should face a lower price than should NYSEG's standard air conditioning or heating load.

Scheduled maintenance of OSG will be even less likely to occur during the periods that NYSEG needs its distribution system to provide electricity to air conditioning and heating load. OSGs will try to schedule their maintenance periods when their associated air conditioning loads and heating loads are low.

Thus, providing wire service for OSG maintenance service should similarly be less costly for the utility than providing wire service for standard loads.

Q. What is the implication of your analysis that the cost to the utility of serving OSG is less expensive than service standard loads?

A. A major issue in the negotiations has been exemptions from the standby tariffs for various types of OSG. If the standby tariff were appropriately cost based, then OSGs would be less interested in obtaining the exemptions, since the standby tariff would cost the OSG less than the standard tariff, which the exemptions attempt to retain for special OSGs.

Q. Does this conclude your testimony?

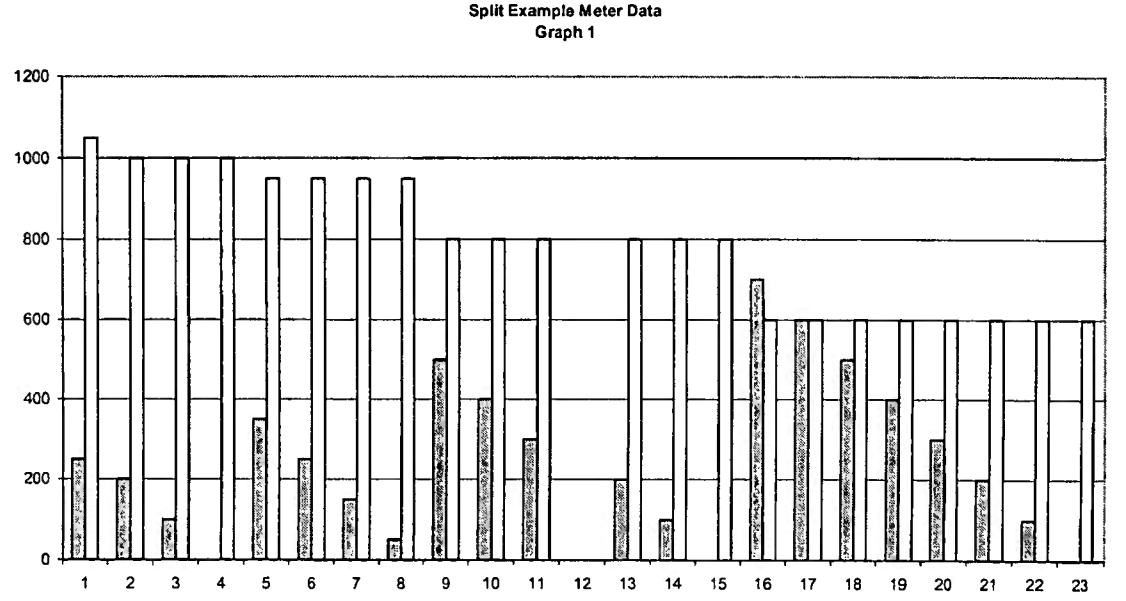
A. Yes.

Exhibit___(MBL-2)

Split Rate Mechanics

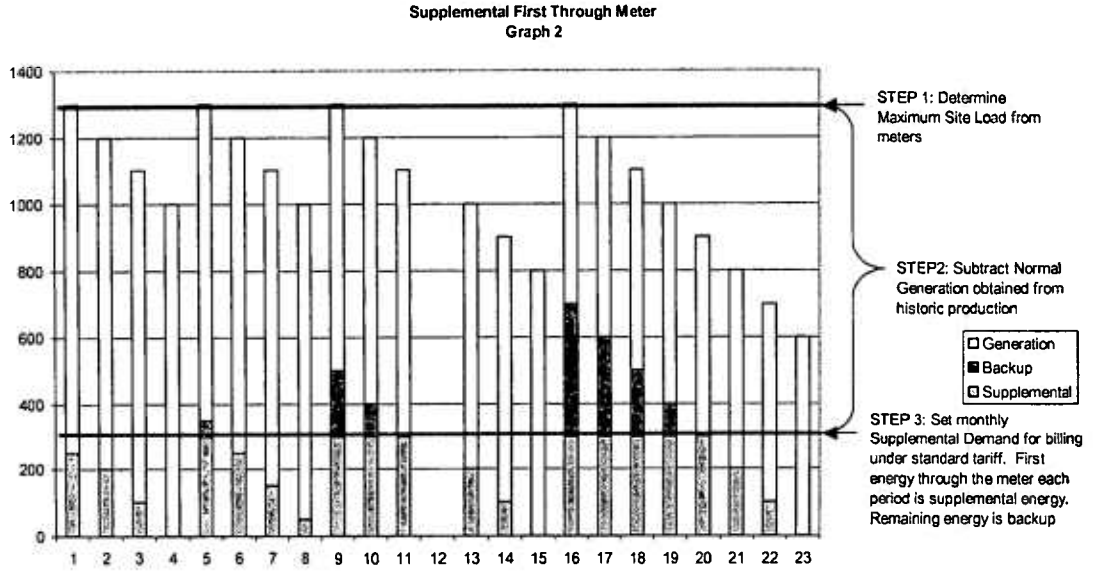
Supplemental power should be the first energy through the meter during each meter interval up to the monthly supplemental demand. The monthly supplemental demand should be the maximum site load during the month minus the normal generation level established by the on-site generator during the twelve months ending with the current month. The maximum site load during the month shall be determined using two synchronized interval meters, the utility interval meter and a customer owned interval meter for on-site generation. Energy through the utility meter in excess of the monthly supplemental demand shall be treated as backup/standby power.

The Joint Supporters advocate the concept of supplemental power being the first electricity through the meter during each meter interval. The Joint Supporters acknowledge that there are other methods for splitting the energy between supplemental energy to be billed under the standard tariff versus backup energy to be billed under the new tariff. The Joint Supporters believe their method is superior in that the Joint Supporter's method minimizes reliance on the data from the second meter, the meter owned by the customer. The method advocated by the Joint Supporters also results in the defined supplemental load having a load shape this is closer to the load shape NYSEG experiences for most customers billed under its standard tariff.



Graph 1 presents the hypothetical meter data that the Joint Supporters presented in the O&R/ConEd proceedings. The various parties in that proceeding used these data for

illustrative purposes, though not necessarily for issues supported by such parties. The first bar in each pair represents an amount that NYSEG would have delivered to the customer during a meter interval, such as an hour. The second bar in each pair represents an amount that the customer would have generated itself. The bars in Graphs 1 are presented side by side. The pair of bars can also be stacked, either with the NYSEG delivery on the bottom and the Generation on the top, or vice versá with the Generation on the bottom and the NYSEG delivery on the top.

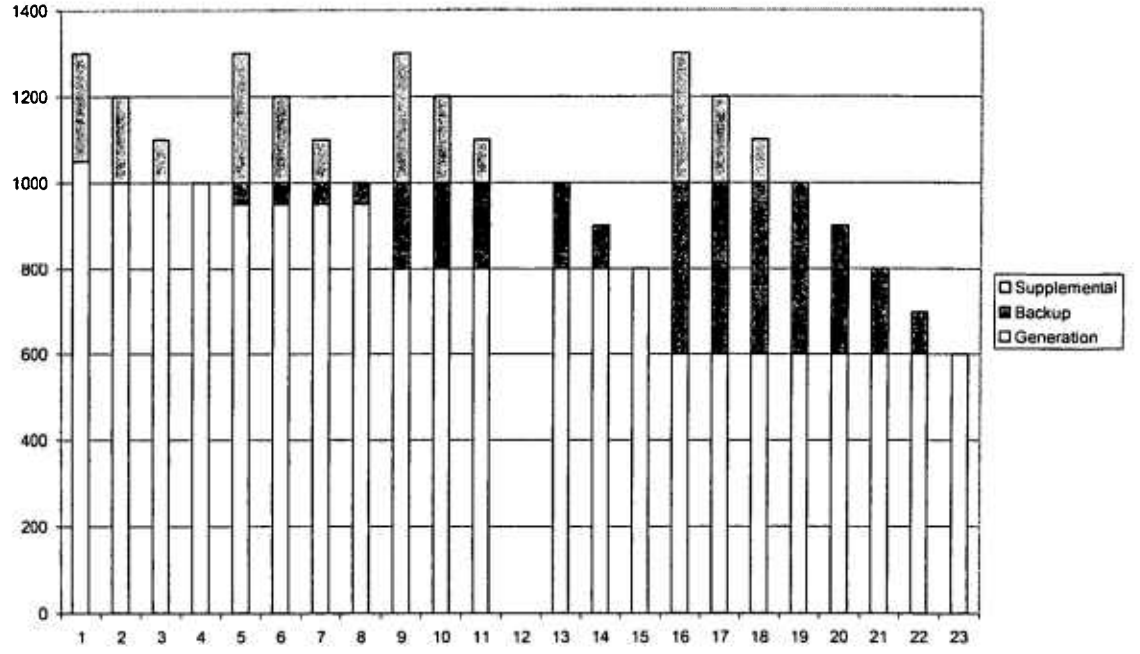


Graph 2 presents the approach developed and presented by the Joint Supporters. Here, the NYSEG delivery is stacked on the bottom of each bar. Under the Graph 2 presentation, the sum of the two meter readings is used to develop the Maximum Site Load for the month. The capability of the generator is subtracted from the Maximum Site Load to determine the supplemental demand for the month. All energy through the NYSEG meter during each time period up to the supplemental demand is treated as supplemental energy. Energy in excess of the supplemental demand during any time period is treated as backup energy.

Graph 3 presents an approach that can be characterized as standby as the first energy through the NYSEG meter. The bottom portion of each bar is the amount of generation by the distributed generator. The next portion of each bar is standby demand, up to the capability of the generator. The top potion of each bar, if any, is supplemental demand, customer consumption in excess of the capability of the generator. A deficiency of this approach involves the constant reliance on the customer owned meter. The reading of the customer owned meter is necessary during each interval to determine which fraction of the NYSEG delivery is standby/backup versus supplemental.

Exhibit____(MBL-2)

Standby First Through Meter
Graph 3



The approaches presented in Graph 2 and in Graph 3 each result in a supplemental demand of 300 KW and a standby demand of 400 KW. Other meter data might result in the two approaches producing billing demands that are not equal to each other. Table 1 presents a summary of the billing determinants that would be produced using these two competing methods to separate supplemental power from standby/backup power.

Comparison of Billing Determinants Using Alternative Ways For the Split Between Standby and Supplemental
Table 1

	Supplemental First	Standby First
Supplemental Demand	300 KW	300 KW
Standby Demand	400 KW	400 KW
Supplemental Energy	4,300 KWH	2,350 KWH
Standby Energy	1,350 KWH	3,300 KWH

Note that the presentation in Table 1 of billing determinants for supplemental energy and standby energy is not meant to be pejorative of the NYSEG proposal to develop a different type of billing determinant for the standby rate. The basic NYSEG proposal is to use daily maximum demand as a commodity billing determinant. The Joint Supporters have not taken a position on the appropriateness of the use of such a billing

determinant instead of energy. The Joint Supporters merely note that energy has traditionally been the commodity-based billing determinant in NYSEG's rates.

IMPROPER ALLOCATION MATRIX

The Joint Supporters believe that NYSEG developed the allocation matrix improperly. NYSEG's approach seriously misstates its cost and results in allocating too much cost to the contract demand. Specifically, NYSEG ignores transformation as a separate cost category. Further, NYSEG ignores the connection of some consumers directly to transformers and to substations instead of to a grid.

Table 1

	Secondary		Primary		Subtransmission		Transmission	
	Contract	As-Used	Contract	As-Used	Contract	As-Used	Contract	As-Used
Secondary	100%	0%	0%	0%	0%	0%	0%	0%
Primary	75%	25%	75%	25%	0%	0%	0%	0%
Subtransmission	25%	75%	50%	50%	75%	25%	0%	0%
Transmission	0%	100%	25%	75%	25%	75%	25%	75%

The Table 1 reproduces the allocation table presented by NYSEG at various times as the Company's Proposal. The left column of the table identifies four categories of cost, separated by voltage level. Secondary and primary each refer to a network of wires used to move electricity throughout NYSEG's service territory at distribution voltage levels. Subtransmission and transmission each refer to similar networks of wires at higher voltage levels. The titles across the top refer to the way the consumer is being served.

During the settlement discussion of March 10, Independent Power Producers of New York, Inc., pointed out that they "are connected to both 115 kV and 34.5 kV within substations". This fact suggests that Table 1 is inadequate for representing how NYSEG serves its customers, in that some customers are served from the substations that reduce the voltage to subtransmission levels while some customers are served from the network of wires that operate at substransmission level.

Making Service Classes Consistent With How Customers Are Served

Table 2
Contract Demand Allocation Factor Modified For How Customers Are Served

	Secondary		Primary		Subtransmission		
	Wires	Trans.	Wires	Station	Wires	Station	Transmission
Secondary	100%	100%	0%	0%	0%	0%	0%
Primary	75%	75%	75%	75%	0%	0%	0%
Subtransmission	25%	25%	50%	50%	75%	75%	0%
Transmission	0%	0%	25%	25%	25%	25%	25%

Table 2 modifies Table 1 to reflect some of the deficiencies the Joint Supporters have identified in NYSEG's presentation. The modification to create Table 2 reflects the situation that some customers are served directly from a substation or transformer, while other customers are served from a network of wires between the customer and the nearest transformation. For space consideration, Table 2 only presents the Contract Demand allocation factor instead of the also presenting the As-Used Demand allocation factor, which perforce must be one minus the Contract Demand allocation factor.

The IPPNY comment is addressed in the second and third columns from the right. The IPPNY site would be covered in the second column from the right, which should be a distinctly different service situation from the third column from the right. The second column from the right is for customers who are situated at the station reducing the voltage to the service level. The third column from the right is for customers who are situated away from the station along the subtransmission system.

The concept is repeated in the primary substation column in the fourth column from the right and in the transformer column in the sixth column from the right. The Contract Demand allocation factors in each station or transformer column merely replicates the allocation factors proposed by NYSEG for those voltage levels instead of being allocation factors proposed by the Joint Supporters.

Making Allocation Factors More Consistent With Service Classes

Table 3
Contract Demand Allocation Factor Modified For Costs Associated With How Customers Are Served

	Secondary		Primary		Subtransmission		
	Wires	Trans.	Wires	Station	Wires	Station	Transmission
Secondary	75%	0%	0%	0%	0%	0%	0%
Transformer	25%	75%	0%	0%	0%	0%	0%
Primary	0%	25%	75%	0%	0%	0%	0%
Substation	0%	0%	25%	75%	0%	0%	0%
Subtransmission	0%	0%	0%	25%	75%	0%	0%
Substation	0%	0%	0%	0%	25%	75%	0%
Transmission	0%	0%	0%	0%	0%	25%	25%

Table 3 is a modification of Table 2 to reflect the different cost bases associated with how NYSEG serves customers. In the example cited above of the IPPNY customer being served from the 34.5 kV substation, NYSEG incurs the cost of owning and operating a substation for this customer but does not incur the cost of owning and operating substransmission wires for this customer. Thus, this IPPNY customer, in the second column from the right, should not be involved in the issue of allocating the cost of

subtransmission lines, which is the third row from the bottom. In Table 3, the intersection of this column with this row is shaded, indicating the irrelevance of the cell.

The IPPNY station also illustrates the lack of dedication of transformation capacity. Thus, the stations mentioned in the IPPNY Settlement Offer serve both (1) IPPNY and (2) NYSEG's subtransmission and distribution system. This dual service situation provides NYSEG with the advantages of economies of scale and the diversity of loading. Thus, the substations are likely to have a lower cost per kW of its available capacity and the substations are able to provide service to more kW of connected load because the loads occur at a slightly different times. Accordingly, the Contract Demand allocation factors presented by the Joint Supporters have 75% for the cost category at which the customer is served and 25% for the cost category one step removed from where the customer is served.