

BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service	Case 09-E- 0715
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Gas Service	Case 09-G- 0716
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service	Case 09-E- 0717
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Gas Service	Case 09-G- 0718

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**REBUTTAL TESTIMONY OF
HETHIE S. PARMESANO**

February 12, 2010

**REBUTTAL TESTIMONY OF
HETHIE S. PARMESANO**

1 Q. Please state your name.

2 A. My name is Hethie S. Parmesano.

3 Q. Did you sponsor direct testimony on behalf of New York State Electric & Gas
4 Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E")
5 (together, the "Companies") in these proceedings?

6 A. Yes.

7 Q. What is the overall purpose of your rebuttal testimony?

8 A. The purpose of my rebuttal testimony is to address certain aspects of the direct
9 testimony of the New York State Department of Public Service Staff ("Staff")
10 Electric Rates and Gas Rates Panels, New York State Consumer Protection Board
11 ("CPB") Witness Tariq N. Niazi, and Multiple Intervenors ("MI") Witness Alan
12 Rosenberg regarding marginal cost issues. Other intervenors are silent on these
13 issues. I also provide revisions to my direct testimony.

14 Q. Are you sponsoring any exhibits in support of your rebuttal testimony?

15 A. Yes. I am sponsoring seven exhibits. Exhibit __ (RGEHP-2) Rebuttal and Exhibit
16 __ (NYSEGHP-2) Rebuttal are revised versions of the RG&E and NYSEG
17 Electric marginal cost of service ("MCOS") studies, respectively. Exhibit __
18 (RGEHP-3) Rebuttal and Exhibit __ (NYSEGHP-3) Rebuttal are revised versions
19 of the RG&E and NYSEG Gas MCOS studies, respectively. Exhibit __ (HP-5) is
20 an expanded version of a simplified example of the Transmission Service Charges
21 ("TSC") operation that I originally prepared in response to IR MI-178. Exhibit __
22 (HP-6) consists of replacement tables for my NYSEG and RG&E direct

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1 testimony. Exhibit __ (HP-7) contains the interrogatory responses referenced in
2 my rebuttal testimony.

3 Q. Do you have any preliminary comments concerning Staff's or other intervenors'
4 testimony in these proceedings?

5 A. Yes. Although the Staff Electric Rates Panel confirms that local facilities costs are
6 incurred on the basis of design demand, they recommend deviating from cost
7 causation principles of rate design and recovering half of these costs on a
8 volumetric basis because the volumes of service through the facilities vary. This
9 justification makes no sense from a cost causation or price signaling point of
10 view.

11 The Staff Gas Rates Panel recommends continuing the Economic Development
12 Zone Incentive ("EDZI") and Economic Development Zone ("EDZ") discounts
13 because they believe the marginal cost of gas delivery service is zero. The
14 Companies' MCOS studies clearly show that this is not the case.

15 CPB Witness Niazi incorrectly believes that the Companies' MCOS studies have
16 defined local facilities costs as customer-related costs. In fact, these costs are
17 marginal with respect to design demand and this treatment is consistent with
18 marginal costing techniques used in New York and elsewhere. The Companies'
19 proposal to recover these marginal costs as part of the fixed charge (for electric
20 rates) or first block (for gas rates) is a reasonable simplification of the rate design.

21 MI Witness Rosenberg's objections to use of the TSC as the basis for marginal
22 transmission costs are unwarranted. The Companies' approach to marginal

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1 transmission costs is consistent with accepted practice in New York and other
2 jurisdictions, and is supported by my correctly structured simplified example. In
3 addition, the choice of historical TSC charges used in the average calculation
4 provides the best available basis for estimating future charges.

COMMENTS ON STAFF ELECTRIC RATES PANEL TESTIMONY

6 Q. Did the Staff Electric Rates Panel address the MCOS studies you prepared for the
7 Companies?

8 A. Yes. The Staff Electric Rates Panel reviewed the MCOS studies and, with one
9 exception, noted no problems with the methods used or results obtained.

10 Q. What was the one exception?

11 A. The one issue Staff identified was the treatment of local distribution facilities
12 marginal costs. Staff agrees that these costs are incurred on a design demand, or
13 fixed, basis. However, Staff does not believe these costs should all be recovered
14 in a fixed charge, but rather 50% on a demand (or volumetric) basis and 50% on a
15 fixed per-customer basis. As discussed on pages 13 -14 of the Electric Rates
16 Panel's testimony, Staff's rationale for proposing that 50% of these design-
17 demand-related costs be recovered on a volumetric basis is "consistency with the
18 [Staff] recommendations on the ECOS study" and "the volumetric nature of the
19 output from the equipment."

20 Q. Do you agree with Staff's recommendation?

21 A. No. A fundamental tenet of rate design is that charges should follow (to the extent
22 feasible given constraints such as metering and customer understanding) cost

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1 causation. Staff confirms that local facilities costs are incurred on the basis of
2 design demand. They seek to deviate from cost causation principles of rate design
3 because of the curious notion that "output from the facilities is volumetric." A
4 similarly irrelevant argument could be made that the meter cost should be
5 recovered on a volumetric basis because the output from the meter is volumetric.
6 The Companies' treatment of local facilities marginal costs as a fixed cost per kW
7 of design demand that should be recovered in a fixed charge is appropriate if
8 efficiency of price signals is an objective.

9 Q. Has this approach been used by the Companies in previous cases?

10 A. Yes. This approach has been used in previous electric MCOS studies submitted
11 by the Companies.

COMMENTS ON STAFF GAS RATES PANEL TESTIMONY

13 Q. Did the Staff Gas Rates Panel raise any issues about the Companies' gas MCOS
14 studies?

15 A. Not directly. However, the Companies have proposed discontinuing EDZI rates
16 because marginal delivery costs exceed proposed base delivery rates. Staff
17 opposes this proposal.

18 Q. What is Staff's objection to the proposal?

19 A. Without addressing the details of the Companies' MCOS studies, Staff contends,
20 on page 40 of the Staff Gas Rates Panel's testimony, that "the incremental cost to
21 provide an additional gas delivery unit to customers is essentially zero," that "any
22 incremental billing costs and customer care costs [for new customers] ... are

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1 relatively small," and that even when the addition of a large new load requires
2 system upgrades, the customer is required to pay up front for some of the
3 incremental investment. Staff is "unaware of any major distribution capacity
4 constraints on either system."

5 Q. Do you agree with the Staff Gas Rates Panel that the marginal cost of gas delivery
6 service is essentially zero?

7 A. No. The Companies' MCOS studies include a detailed analysis of each component
8 of delivery service and demonstrate that the marginal cost of most components is
9 not zero. While the addition of a new customer or load growth by existing
10 customers may not immediately trigger capacity expansion or additional O&M
11 (other than customer-related costs for a new customer), analysis of the
12 Companies' budgets and planning processes reveal that load growth does require
13 capital improvements (and additional O&M) to maintain service quality. Local
14 delivery facilities must be replaced periodically to provide safe and reliable
15 service. Thus the fact that existing customers continue to take gas service means
16 there is a marginal cost associated with continuing to provide these local facilities
17 for their use. While some parts of the service territories have sufficient capacity to
18 accommodate load growth, other areas are requiring capacity additions. The
19 MCOS study takes both situations into account in developing system-wide
20 marginal cost estimates.

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1 Q. If some parts of the Companies' service territory do have excess capacity, and
2 therefore have zero or low marginal costs, why isn't continuation of the EDZI and
3 EDZ discounts appropriate?

4 A. The EDZI and EDZ discounts are not customer- or site-specific. Therefore, it is
5 appropriate to use the system-wide marginal cost estimates to evaluate whether
6 discounts are justified, as the Companies have done.

7 Q. What is your response to the Staff Gas Rates Panel's contention that large new
8 customers are required to fund some portion of incremental costs of investment
9 required to serve them?

10 A. To the extent that new customers contribute upfront to system expansion costs,
11 these contributions have been taken into account in the MCOS studies.

COMMENTS ON CPB WITNESS NIAZI'S TESTIMONY

13 Q. What marginal cost issues does CPB Witness Niazi address in his direct
14 testimony?

15 A. While not offering any comments on the methods used to calculate marginal costs
16 of local distribution facilities in the Companies' MCOS studies, Dr. Niazi
17 opposes, on pages 40-41 of his NYSEG testimony and pages 39-40 of his RG&E
18 testimony, the proposed increases in residential monthly electric customer charges
19 and first block gas charges because they are based on the sum of marginal
20 customer and marginal local facilities costs (inclusion of the latter of which he
21 claims is "extremely controversial").

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1 Q. What support does Dr. Niazi provide for his position?

2 A. He supports his position by referencing a Recommended Decision and
3 Commission Opinion in a 1983 Con Edison case (Case 27353) and a section of a
4 1978 EPRI report (*Critical Issues in Costing Approaches for Time Differentiated*
5 *Rates*), which concluded, respectively, that local distribution system costs should
6 not be considered customer costs unless it can be demonstrated that they vary
7 with customer numbers; and that the preferred definition of customer costs is the
8 sum of only the service, meter and customer accounting expenses.

9 Q. Dr. Niazi quoted from the Recommended Decision in Case 27353, in which the
10 Administrative Law Judge ("ALJ") agreed with Staff that "there is a certain
11 portion of the distribution system which would be required to link the company
12 and its customers, even if demand were minimal," but stated that "this minimum
13 system cannot be (or at least in this case, has not been) shown to vary either with
14 energy, demand or numbers of customers." Do you agree with the ALJ that this
15 portion of the distribution system should therefore be treated as a "common cost"
16 and excluded from marginal cost?

17 A. No. The quotation from the 1983 Recommended Decision reflects a generally
18 accepted view at that time that marginal distribution costs vary with energy,
19 demand or number of customers. As explained in the Companies' MCOS studies,
20 more recent analysis indicates that components of distribution marginal costs have
21 the following three drivers: number of customers (meters and services), design

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1 demand (secondary lines, transformers and local primary lines) and metered
2 demand (trunklines and distribution substations).

3 Q. Dr. Niazi also quoted from the Commission's Opinion in that case, where the
4 Commission suggested further analysis of distribution marginal costs. He stated
5 that the "Commission concluded that until it can be demonstrated that local
6 distribution system costs vary with customer numbers, such costs should be
7 regarded as residual." Is the Companies' approach to local distribution costs
8 inconsistent with this Opinion?

9 A. No. In the section of the final Decision in the Con Ed case just before the
10 language quoted by Dr. Niazi is the following: "First, the company's use of
11 statistical techniques to separate its distribution system into distinct cost
12 components is basically on the right track." The Commission urged additional
13 analysis because the results of the zero-intercept calculations did not seem to be
14 the whole story. What was missing was the concept of a component of
15 distribution costs based on design demand. This is the more modern approach
16 used in the Companies' MCOS studies.

17 Q. Do you agree with the recommended definition of customer costs included in the
18 quotation from the EPRI report cited by Dr. Niazi?

19 A. Before I answer, I would like to comment that Dr. Niazi's use of this particular
20 report as support for excluding the local distribution costs from customer costs is
21 curious. This report is part of a long series of studies undertaken in the mid and
22 late 1970s when the industry was just beginning to figure out how to estimate

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1 marginal costs. This particular report was the product of a Task Force. As the
2 "Note to Readers" at the beginning of the report indicates:

3 This is not a report of the Project Committee. The publication of
4 this document is for the general information of the industry....
5 Many of the issues in the Rate Design Study are controversial, in
6 some cases data are lacking, and in certain instances value
7 judgments are necessary. Thus, readers are cautioned to make their
8 own careful assessments of this report and to consider other
9 sources of information... (p. ii)

10 Furthermore, the Chairman's Forward to the report notes:

11 This report has greater emphasis on critical issues where
12 individuals and groups within Task Force No. 4 volunteered to
13 concentrate on issues of concern to them. Although each report
14 focuses on a separate topic and was reviewed several times by the
15 whole Task Force and endorsed by a majority of the members, the
16 views in individual chapters are sometimes incongruent with views
17 in other chapters. (p. v)

18 In fact, the chapter after the one quoted by Dr. Niazi discusses the development of
19 an "aggregate zero intercept method" for estimating customer-related distribution
20 costs beyond the service drop. Therefore, the selective quotation by Dr. Niazi
21 should in no way be interpreted as evidence that the EPRI Project Committee or
22 even Task Force No. 4 was in agreement back in 1978 that customer-related costs
23 consist of only meter, service drop and customer-related expenses, or that it is
24 inappropriate to identify local distribution costs that are marginal with respect to
25 design demand.

26 Now in answer to your specific question, yes I do agree that marginal customer
27 costs consist of the cost of meters and services plus customer-related expenses.

28 That is the assumption in the MCOS studies I prepared for NYSEG and RG&E.

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1 Q. Dr. Niazi says that the Companies' Revenue Allocation and Rate Design Panels'
2 statement that "the cost of a utility's delivery system is substantially fixed in
3 nature, meaning that the cost of providing delivery service does not vary with the
4 use of the delivery system" means that the "Company acknowledges that local
5 facilities costs do not vary by customer numbers or by any other factor." Is this an
6 accurate representation of the Companies' position?

7 A. No. It is true that local facilities costs do not vary systematically with number of
8 customers. It is not true that these costs do not vary with any other factor. The
9 four MCOS studies describe in detail and quantify how these costs vary with
10 design demands of the customers using them. In fact, the quoted statement by the
11 Revenue Allocation and Rate Design Panel is entirely consistent with the MCOS
12 studies, which identify only marginal substation and trunk feeders and only high
13 pressure and upper medium- pressure gas facilities as varying with use of the
14 system. All other delivery costs vary either with design demand or number of
15 customers.

16 Q. Dr. Niazi seems concerned that the Companies have defined local facilities costs,
17 which the Companies agree do not vary with number of customers, as customer-
18 related costs. Is this what the Companies have done?

19 A. No. Dr. Niazi is confusing the definition of marginal customer costs with the
20 setting of fixed monthly charges. Note that the issue addressed in the documents
21 he references is not whether local facilities costs are incurred on the basis of
22 design demand, which is the assumption in the Companies' MCOS studies, but

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1 rather whether these costs are marginal customer costs, which is not the
2 Companies' contention. Given that local facilities costs are incurred on the basis
3 of design demand (as the Staff Electric Rates Panel agrees on page 13 of its direct
4 testimony), these costs could be recovered in a separate charge per kW (or per
5 MCF/Day) of design demand. However, to simplify the rate structure and avoid
6 adding a separate charge, the Companies propose to include both marginal
7 customer costs and marginal local facilities costs for the average customer in the
8 class in the fixed monthly charges/first block. This is an appropriate approach.

9 Q. You mentioned that the treatment of local facilities costs as design demand-
10 related is more recent than the 1983 case and the 1978 EPRI study referenced by
11 Dr. Niazi. When was the new approach developed?

12 A. Recognition that local facilities costs are not appropriately considered as either
13 customer or (metered) demand-related costs, but rather have a different cost
14 causation – design demand – dates back to the late-1980s. NERA's Marginal Cost
15 Working Group (of which NYSEG and RG&E were long-time members) held
16 discussions of this approach beginning in 1987. Many utilities use (and regulators
17 accept) a separate marginal cost component for local facilities, which is consistent
18 with the distribution design practices of the utilities. NYSEG and RG&E have
19 used this approach in their past MCOS studies.

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COMMENTS ON MI WITNESS ROSENBERG'S TESTIMONY

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Q. Did MI Witness Alan Rosenberg comment on the Companies' MCOS studies?

A. Yes. He examined the Companies' electric MCOS studies and identified two concerns.

Q. What is his first concern?

A. He objects to the fact that the MCOS studies do not identify marginal costs for customers served at subtransmission voltage, and to the use of primary voltage costs to compute marginal cost revenues for existing subtransmission customers.

Q. What is your response to this concern?

A. NERA computed marginal costs for the classes and voltage levels requested by the Companies. It is my understanding, based on discussions with the Companies, that with today's system characteristics, there is no discernible difference between marginal costs for customers previously identified as taking service at primary and subtransmission voltage. In addition, the Companies (not NERA) computed marginal cost revenues. Their treatment of existing subtransmission customers in these calculations is addressed in the rebuttal testimony of the Companies' Revenue Allocation and Rate Design Panel.

Q. What is Dr. Rosenberg's second concern about the electric MCOS studies?

A. He objects to the use of a forecast of TSCs as the basis for marginal transmission costs.

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1 Q. To what aspects of the use of the TSC as the basis for marginal transmission costs
2 does Dr. Rosenberg object?

3 A. First, on page 15 of his NYSEG testimony and on pages 16-17 of his RG&E
4 testimony, he states that transmission costs are fixed in the short-run, thus short-
5 run marginal transmission costs are zero. In the long-run, he states, marginal
6 transmission costs are demand-related and should be calculated per kW of
7 demand, not as a marginal cost per kWh. He concludes, on pages 15-16 of his
8 NYSEG testimony and on pages 16-17 of his RG&E testimony, that the TSC is
9 not a marginal cost at all, but a charge designed to ensure recovery of embedded
10 costs.

11 Q. How do you respond to these points?

12 A. Our approach to marginal transmission costs is to estimate the marginal *financial*
13 transmission cost associated with changes in load. This is an approach used in
14 previous cases and approved by the Commission. For example, the Commission's
15 May 9, 2003 Order in Case 01-E-0359 (pages 9-10) says "NYSEG correctly
16 begins the design of the EDZI rate by setting transmission cost at the NYISO
17 transmission charges including line losses. This approach is reasonable under
18 these circumstances because NYSEG must pay the NYISO charges for the
19 transmission services it supplies to meet prospective customer load or existing
20 customer incremental load."

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1 Q. Is this marginal financial cost approach used in other jurisdictions?

2 A. Yes. This approach is also used in other states where the utilities are members of
3 Independent System Operators (e.g., Minnesota, North Dakota, South Dakota,
4 California).

5 Q. Dr. Rosenberg suggests that marginal transmission costs are costs per kW, not per
6 kWh. Do you agree?

7 A. No. Because utilities in New York incur these marginal financial costs on the
8 basis of kWh, it is appropriate to compute them on that basis. To be useful, a
9 MCOS study must reflect the institutional arrangements under which a utility
10 operates. For the Companies, that is the New York Independent System Operator.

11 Q. Dr. Rosenberg suggests that because the TSC is designed to recover an embedded
12 cost revenue requirement, it cannot also be a marginal cost. Do you agree?

13 A. No. Although the TSC charges are designed to recover embedded costs, because
14 of the way the charges are imposed, they also represent a marginal financial cost
15 for the Companies. Below I provide a numerical example that illustrates this
16 point.

17 Q. Dr. Rosenberg states, on page 16 of his NYSEG testimony and on page 17 of his
18 RG&E testimony, that bookkeeping entries, such as the TSC, "should not
19 influence, let alone dictate, cost-of-service analysis." Do you agree?

20 A. This statement is very surprising. Embedded cost-of-service studies are almost
21 entirely composed of bookkeeping entries, and many components of marginal
22 cost-of-service studies, including those approved by the Commission in the past,

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1 use bookkeeping entries as the starting point for estimates of future marginal
2 costs. Dr. Rosenberg did not object to the use of bookkeeping entries in other
3 areas of the Companies' MCOS studies.

4 Q. What is Dr. Rosenberg's next objection to the use of the TSC as the basis for
5 marginal transmission costs?

6 A. On page 15 of his NYSEG testimony and on page 16 of his RG&E testimony, he
7 states that NERA used an arbitrary time frame to compute the average TSC
8 charge in the NYSEG MCOS study.

9 Q. What is your response to this objection?

10 A. The goal of the MCOS study is to estimate marginal costs for 2010. Although the
11 TSC charges are affected by many unpredictable factors, they represent the best
12 available measure of the Companies' marginal financial transmission costs.
13 Forecasts of the TSC charges were not available. In discussions with Company
14 staff, NERA determined that the best basis for estimating 2010 TSC charges
15 would be the charges in the most recent 12 months, replacing months that were
16 unusual and, therefore, not good predictors of 2010 charges, with the
17 corresponding month's charges from the previous year.

18 In the case of RG&E we used an average of TSC charges in August 2008 – July
19 2009.

20 In the case of NYSEG, as explained in detail in response to IR MI 182 (NYRC-
21 733): "The TSC charges were atypical in August – December of 2008 because
22 they were much lower than normal. This was caused by very large credits of other

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1 transmission revenue items that are part of the TSC calculation (mainly TCC
2 revenue) that were so large that the rate actually went negative in some of these
3 months. NYSEG received FERC's approval to keep the rate at zero for those
4 months and roll the revenue that would have caused the rate to go negative over to
5 the following month(s) until the rate actually went back positive." Consequently,
6 we used the average of August – December 2007 and January – July 2009. This
7 was not an arbitrary choice, but use of the historical information most likely to
8 produce a reasonable estimate of 2010 average charges.

9 Q. What is Dr. Rosenberg's third objection to the use of the TSC to estimate marginal
10 transmission costs?

11 A. As I understand Dr. Rosenberg's testimony, he believes that additional
12 transmission use by Company delivery customers does not increase the revenue
13 responsibility of the Companies and their customers, and that the TSC is not a
14 reasonable estimate of the additional cost responsibility incurred in response to an
15 additional kWh of energy use. He modified a simple numerical example that I
16 provided in response to IR MI-178 (NYRC-729) to support his position.

17 Q. What was the purpose of the simplified example you provided in response to MI's
18 IR?

19 A. IR MI 178 requested an explanation of how the Companies are responsible for
20 more TSC charges when delivery service customers use more electricity, although
21 the Company does not make explicit TSC payments. Included in my response
22 (which Dr. Rosenberg recreated and included in his direct testimony as Exhibit

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1 AR-1 Schedule 2) was a simplified numerical example designed to answer this
2 question. It illustrates how the revenue responsibility of the Companies' delivery
3 customers increases with a specific increase in their kWh use in each of three
4 months relative to the base case. The example was not intended to demonstrate
5 that "the incremental cost of transmission use is exactly equal to the TSC" as Dr.
6 Rosenberg theorized on page 17 of his NYSEG testimony. However, the
7 particular example yielded a marginal cost per kWh of added load that is
8 approximately equal to the TSC before adjustments for over/under collection. Dr.
9 Rosenberg did identify a small mistake in my calculation of the over/under
10 collection. The correct marginal financial cost in the three months shown in the
11 example is not the \$0.01000 on my original example, but rather \$0.01031 (shown
12 in the first box on Exhibit AR-1, Schedule 3, page 1), which is very close to the
13 original TSC rate of \$0.01000. The small error does not affect the point of the
14 example, which is to demonstrate that NYSEG's share of the TSC revenue
15 requirement is affected by its delivery customers' energy use.

16 Q. Were the other modifications that Dr. Rosenberg made to your example
17 appropriate?

18 A. No. Dr. Rosenberg claims that my example is flawed because it neglects to
19 account for over/under recoveries at the end of the three-month period. His
20 "correction" (shown at the bottom of Exhibit AR-1, Schedule 3, page 1)
21 unaccountably assumes that all of the remaining reconciliation will be made in
22 months when the Company is the only customer. This assumption is inappropriate

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1 because the whole point of the exercise is to show that the Company's share of the
2 revenue requirement is a function of the Company's share of the energy
3 transmitted. Of course if the Company is the only entity using the system, its
4 share is the total revenue requirement.

5 Q. What is the appropriate way to take into account adjustments for over/under
6 collection after the horizon shown in the example?

7 A. In Exhibit __ (HP-5) I have extended my example out three additional months,
8 but with no added Company load in Scenario 2 in those months. In the added
9 months, the amount of over/under collection alternates between plus/minus \$2.50
10 in the base case and plus/minus \$8.58 in the added load scenario. This means that
11 there is no need to account for over/under collections beyond the example's time
12 horizon, as they will net out to zero over time. My averaging of historical TSC
13 charges in the MCOS studies for NYSEG and RG&E is consistent with this fact.
14 The extended example also results in a marginal cost per kWh quite close to the
15 initial TSC charge of \$0.01 per kWh.

16 Q. What further modifications to your example did Dr. Rosenberg make in Schedule
17 3, page 2 of his Exhibit AR-1?

18 A. It is not clear what this example is intended to show. Unlike my example, which
19 calculated changes in TSC cost allocation from a specific increase in monthly
20 energy use by the Company's delivery customers, Dr. Rosenberg's final example
21 uses a load increase in one month and load reductions in the other two months

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1 (with a net change of nearly zero (0.3%)). Clearly the example is not useful to
2 demonstrate the effect of marginal energy use on the allocation of TSC costs.

3 Q. What are your conclusions regarding Dr. Rosenberg's critique of the marginal
4 transmission costs developed by NERA for NYSEG and RG&E?

5 A. Our approach to marginal transmission costs is consistent with accepted practice
6 in New York and other jurisdictions, and is supported by my correctly structured
7 simplified example. In addition, the choice of historical TSC charges used in the
8 average calculation provides the best available basis for estimating future charges.

9 **CORRECTIONS TO PARMESANO DIRECT TESTIMONY**

10 Q. Do you have any corrections to your prefiled direct testimony?

11 A. Yes. Exhibit __ (NYSEGHP-2) Rebuttal is a revised version of the NYSEG
12 Electric MCOS Study. It reflects updated marginal customer expenses and
13 incremental capital structure and a revision to marginal facilities and service
14 costs. Exhibit __ (RGEHP-2) Rebuttal is a revised version of the RG&E MCOS
15 Study. It reflects updated marginal customer expenses. Exhibit __ (NYSEGHP-3)
16 Rebuttal is a revised version of the NYSEG Gas MCOS Study. It reflects updates
17 to customer expenses and incremental capital structure and a revision in design
18 demand. Exhibit __ (RGE HP-3) Rebuttal is an updated version of the RG&E Gas
19 MCOS Study. It reflects updates to the customer expenses and incremental capital
20 structure. Exhibit __ (HP-6) consists of replacement tables for my NYSEG and
21 RG&E direct testimony that incorporate the changes in the MCOS studies. In

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1 addition, I have made the following revisions to the description of the gas MCOS
2 studies in both my NYSEG and RG&E direct testimony:

3 For NYSEG Testimony:

4 On pages 31-32, take out the following sentence: "To convert these costs per kW
5 of capacity to a cost per kW of load, I multiplied by NYSEG's typical reserve
6 margin for such equipment (7.5 percent)."

7 Replace with these sentences: "It is necessary to multiply these costs per
8 MCF/Day of capacity by a margin typical of NYSEG's system for such equipment
9 (7.5 percent). The term margin is used to represent the NYSEG practice to design
10 reinforcements to accommodate background load growth and provide contingency
11 in actual system operating pressures."

12 For RG&E Testimony:

13 On page 37, take out the following sentence: "To convert these costs per kW of
14 capacity to a cost per kW of load, I multiplied by RG&E's typical reserve margin
15 for such equipment (7.5 percent)."

16 Replace with these sentences: "It is necessary to multiply these costs per
17 MCF/Day of capacity by a margin typical of RG&E's system for such equipment
18 (7.5 percent). The term margin is used to represent the RG&E practice to design
19 reinforcements to accommodate background load growth and provide contingency
20 in actual system operating pressures."

21 Q. Does this conclude your rebuttal testimony at this time?

22 A. Yes, it does.