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
Rochester Gas and Electric Corporation
for Electric Service — Case 09-E- ____

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- ____

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DIRECT TESTIMONY OF
HETHIE S. PARMESANO

September 17, 2009

Case 09-E-____; Case 09-G-____ (RG&E)

HETHIE S. PARMESANO

Q. Please state your name, current position and business address.

A. My name is Hethie S. Parmesano. I am a Senior Vice President at NERA Economic Consulting (NERA). My business address is 777 South Figueroa Street, Suite 1950, Los Angeles, CA 90017

Q. Please summarize your educational background and work experience.

A. My B.A. is from Colby College, where I majored in economics. I have M.A. and Ph.D. degrees in economics from Cornell University. Since 1980, I have worked for NERA, specializing in utility costing, pricing, strategic planning and regulatory reform. I have testified widely on these matters.

For more than two decades, I have taught seminars on electricity marginal costing and rate design. Attendees include staffs of utilities and regulatory commissions, as well as occasional commissioners. I have also participated regularly in the University of Florida Public Utility Research Center/World Bank International Training Program on Utility Regulation and Strategy, where I present sessions on electricity tariff design.

Since 1982, I have directed NERA's Marginal Cost Working Group, a utility group that is dedicated to improving methods for estimating and using marginal cost information in a variety of utility applications.

HETHIE S. PARMESANO

I have been involved in innovative rate design, energy sector restructuring, and regulatory reform in many jurisdictions around the world, including California, New York, Ohio, New Mexico, North Dakota, Minnesota, Maine, Illinois, Indiana, Maryland, Massachusetts, Arizona, Oregon, and South Dakota, as well as in Canada, India, Barbados, Brazil, Argentina, El Salvador, Mexico, Spain, Greece, Ireland, Kenya, Cambodia, Japan, Saudi Arabia, and the UK.

Q. Have you previously testified in other proceedings before the New York State Public Service Commission ("PSC" or the "Commission") or any other state or federal regulatory agency or court?

A. Yes. I provided direct and rebuttal testimony regarding marginal gas and electricity costs, revenue allocation and rate design on behalf of Rochester Gas and Electric Corporation ('RG&E") in Case Nos. 02-E-0198 & 02-G-0199 in 2002. I provided direct and rebuttal testimony on behalf of New York State Electric & Gas Corporation ("NYSEG") as part of NYSEG's rate/restructuring filing in compliance with PSC Opinion and Order 96-12 regarding retail access, September 27, 1996 and April 21, 1997.

HETHIE S. PARMESANO

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to (1) define marginal cost principles and explain why they are an appropriate basis for utility rate design, (2) describe the history of marginal cost-based rates in New York State, and (3) describe the development of the gas and electric marginal costs and the resulting efficient prices developed for use by RG&E in this case.

Q. Please summarize your testimony.

A. As the Commission has long recognized, electric and gas rates that are based on marginal costs provide price signals that: (1) encourage efficient energy-related consumption and investment decisions by consumers, (2) lead to consumption patterns and levels that allow the utility and other market participants to invest in only the amount of capacity consumers are willing to pay for and to make efficient use of the capacity that is available, and (3) promote effective competition in the energy sector**.**

Working closely with Company staff, my team (working under my supervision) and I developed estimates of RG&E's marginal costs of providing electric and gas delivery service. The marginal cost studies use methods tailored to current market arrangements and RG&E's situation, and make use of the best

available information. The marginal costs of each element of delivery service provide the starting point for efficient class revenue allocation and rate design.

Q. Are there differences in the marginal costing approaches you used for this case compared to those used in the Company's last-filed marginal cost studies?

A. Yes. The changes in approach appropriately reflect new circumstances and data availability. For example, the current studies include only delivery costs, while the older studies included both delivery and commodity costs. In addition, the new studies show marginal cost elements for which customers typically pay a portion up front in a customer contribution in aid of construction ("CIAC") two ways – before and after the upfront payment. The new studies also identify and exclude customer accounts expenses associated with the merchant function.

Q. Are you sponsoring any exhibits?

A. Exhibit __ (RGEHP-1) contains additional details on my credentials. Exhibit __ (RGEHP-2) and Exhibit __ (RGEHP-3) are the electric and gas marginal cost of delivery service reports, respectively, that my staff and I prepared for this case. Exhibit __ (NYSEGHP-4) provides an index of my workpapers. A copy of the workpapers was provided to Department of Public Service Staff.

HETHIE S. PARMESANO

THE ROLE OF MARGINAL COST PRICING AND ITS HISTORY IN NEW YORK

Marginal Cost Definition

Q. What are marginal costs?

A. Marginal cost is the additional cost incurred to provide a small increment of a good or service, or the savings from a small decrement. It is a forward-looking concept that ignores sunk costs and addresses the question: how would costs change if there were a hypothetical small change in output. While marginal costs do not include sunk costs, the utility's existing resources do affect the answer to this question. In addition, the costs of existing plant and recent historical expense levels are typically used as the starting point for developing estimates of marginal costs.

Q. What are the elements of the marginal costs of *electric* delivery service?

A. There are three major components of electric delivery service. First, there are customer-related costs that vary with the number of customers on the system. These costs include the meter and service drop (and their associated operation and maintenance expenses—"O&M"), as well as customer-related expenses such as meter-reading, billing, customer accounts, uncollectibles, and customer information services.

Second, there are costs associated with local distribution facilities that are sized based on the maximum expected loads (design demands) of customers using them. These costs are marginal when customers are initially connected to the distribution network, when there are major unanticipated changes in design demand that require local distribution facility capacity to be expanded, and when the local facilities are replaced at the end of their lives. (At this point, replacement of the facilities could be avoided if the customers using them no longer wanted service.) Local distribution facilities are not expanded with month-to-month or year-to-year variations in the loads of customers using them, so long as there is no change in design demand. As a result, the optimal way to recover the marginal costs of local distribution facilities is in a fixed charge applied to a measure of design demand, not in charges based on energy use or peak demand in the billing period.

The third major component of marginal electric delivery costs consists of delivery costs that do vary with a customer's changes in electricity use from month-to-month and the timing of that use within the month. These costs include marginal distribution substation and trunkline feeder costs, upstream line and substation costs, along with their associated O&M, and marginal transmission costs. Capacity of these elements of the system must be expanded

as their peak loads grow. These costs vary by season and time-of-day, depending on the likelihood that a particular period will include the relevant peak.

Q. What are the elements of the marginal costs of *gas* delivery service?

A. The elements of gas delivery service marginal costs parallel those of electric delivery service. First, there are customer-related costs—meter, regulator, relief valve and service lateral and their associated O&M, and customer-related expenses. Second, there are local facilities costs that vary with long-term expected peak-day demands (design demand). For RG&E, these local facilities costs consist of medium- and low-pressure regulator stations and lower medium- and low-pressure mains and their associated O&M. Third, there are marginal costs of transmission, high-pressure regulator stations, and upper medium-pressure mains. These plant components are sized based on near-term design-day demands and expanded as load grows. Furthermore, the costs of these components are seasonally-differentiated because there is a low probability that load growth in summer months will trigger the need for capacity expansion. Finally, there is the cost of storage (capacity and carrying charges on the gas stored) to provide reliability for the distribution system.

Role of Marginal Cost Pricing

Q. Why should class revenue allocation and rate designs be based on marginal costs?

A. There are three primary arguments, based on economic theory, for using marginal costs in setting electric and gas rates and as a basis for revenue allocation. The first is that consumers will make efficient energy-related consumption and investment decisions when the prices they face for electricity and gas reflect the underlying economic costs of using a little more or a little less. Although electric and gas delivery prices are only a portion of the total electric or gas bill, the delivery charges contribute to the total price signal to which consumers respond. In New York, the commodity portion of gas and electric bills generally reflect market conditions and, therefore, are approximately equal to marginal cost.

Q. How does a marginal cost delivery price signal contribute to efficient consumption and investment decisions by consumers?

A. Delivery prices are a component of the total price signal to consumers and the total price signal is the basis for their energy-related decisions. A consumer deciding what type of appliance to buy or how much to use existing energy-using equipment compares the cost of alternatives. If electricity and gas prices (including delivery charges) reflect the economic costs of service, those

comparisons can be made on an apples-to-apples basis because the prices of most energy-using and energy-saving alternatives are set by the market and also reflect the marginal cost of the last (highest-cost) successful supplier on the supply curve. In this situation, consumers deciding which alternative is most advantageous from a personal point of view are also picking the option which is best (most economically efficient) from society's point of view.

Q. What is the second economic reason for basing electric and gas delivery rates on marginal costs?

A. The second argument is that marginal cost pricing will lead to consumption patterns and levels that allow the utility to invest in only the amount of capacity consumers are willing to pay for and to make efficient use of the capacity that is available. As I testified earlier, marginal cost pricing promotes efficient energy use decisions. Because system expansion and operations are determined by energy use levels and patterns, economically inefficient prices may lead to unnecessary investment in new energy supply and delivery facilities or poor utilization of existing facilities. Efficient consumption is a prerequisite for efficient system expansion.

Q. Can you provide an example of this effect?

A. Yes. Peak-load pricing provides a good illustration of how failure to use marginal cost pricing can lead to inefficient system design. Since peak-period use has a higher marginal cost than off-peak use, if prices are not time-differentiated, consumers making the comparisons I mentioned earlier tend to consume more than the efficient amount of energy in the peak period and less than the efficient amount in the off-peak period. As a result, the utility (or other investors) will install more than the optimal amount of capacity to meet peak demands, and much of that capacity will be idle in off-peak periods because the off-peak prices are too high. Some customers may even be driven to install their own generation (at a cost higher than the utility's marginal cost), resulting in uneconomic bypass of the utility's system and further wasted resources.

Q. What is the third economic argument for marginal cost-based electric and gas delivery rates?

A. Marginal cost-based rates promote effective competition, both in terms of competition for customers and in terms of competition with alternative types of energy. When rates are based on marginal costs, business customers tend to migrate to, or expand production in, the area where their energy demands can be served at least cost, all else equal. Similarly, in choosing among various energy

types, consumers of all types tend to pick the energy type than can most efficiently power the end-use services they need.

Q. You have explained how marginal cost pricing is economically efficient. Are marginal cost-based rates also equitable?

A. Yes. Marginal cost pricing is equitable because every consumer pays the cost of supplying his/her requirements at the margin. If the customer consumes more, no one else provides a subsidy for the additional amount. If the consumer cuts back on energy use, his/her bill goes down by the amount of the costs avoided. Again, no other customer's bill is affected.

Q. You referred to marginal cost-*based* rates. Are such rates different from pricing *at* marginal cost?

A. Yes. In New York, a utility's total revenue requirement for delivery service is set equal to an allowed rate of return on rate base, plus depreciation, operating expenses and taxes. These costs are accounting costs and have little in common with forward-looking marginal costs. Therefore, charging marginal costs as prices would only by coincidence generate the approved level of revenue. The difference is called the marginal cost revenue gap. Some charges must be set above or below marginal cost to produce the correct amount of revenue.

Q. Are there reasons, other than closing the marginal cost revenue gap, to deviate from class revenue requirements and rate designs based on marginal cost?

A. Yes. Other ratemaking objectives such as metering and billing constraints and bill impacts are often taken into account.

Use of Marginal Cost Pricing in New York

Q. Has the philosophy of marginal cost rate design been used in New York State in the past?

A. Yes. In fact, marginal cost-based rate design is the accepted norm in New York, which was one of the first states to endorse marginal cost principles for utility rates. Beginning with its August 10, 1976 Opinion and Order Determining Relevance of Marginal Costs to Electric Rate Structures in the "Generic Electric Rate Design" case,[1] the Commission has continued to move forward with marginal cost pricing for electric service. In addition, the Commission, in its September 17, 1979 Opinion and Order Determining the Relevance of Marginal Costs to the Regulation of Gas Distribution Companies in the "Long-Range Gas Planning" case,[2] determined that marginal cost concepts are properly applicable to gas service. In subsequent decisions and pronouncements, the Commission

[1] Case 26806 -Proceeding on Motion of the Commission as to the Rate Design for Electric Corporations, 16 NYPSC 671.

[2] Case 26835, Proceeding on Motion of the Commission as to the Long-Range Plans of New York State's Gas Distribution Companies.

has continued to move electric and gas pricing toward more complete implementation of marginal cost principles.

Q. What indication is there that the Commission continues to support implementation of these principles, particularly in the case of RG&E?

A. With regard to electric cost allocation and rate design, as New York moved toward retail competition, the Commission stated that "as the company moves to a more competitive environment, the cornerstone of electric rate designs will be to approximate marginal cost in pricing."[3] The Commission went on to say: "Marginal cost-based pricing rests on the sound economic principle that efficient resource allocation is enhanced by pricing goods and services as closely as reasonably achievable to marginal costs. It has been our long-standing policy to price electricity such as consumers pay for the cost their consumption imposes on the utility so that scarce resources are efficiently allocated."[4]

More recently, the Commission's order in RG&E's 2002 gas and electric rate cases endorsed Staff's proposals for an across-the-board class revenue allocation of the revenue increase (except for SC 6 – Area Lighting) because a review of current revenue-to-revenue-requirement ratios in RG&E's marginal

[3] Cases 95-E-0673 et al. - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service, Opinion and Order Concerning Revenue Requirement and Rate Design, at 23 (issued Sept. 26, 1996).

[4] Id. at 23-24.

and embedded cost studies fell within the tolerance band.[5] The Commission also approved an increase of $1.50 per month in electric and gas monthly minimum charges for residential and small commercial classes to bring these rates closer to marginal costs, "which is in accordance with sound ratemaking principles and the 2002 New York State Energy Plan's goal of reflecting the true cost of service in the rates."[6] When electric and gas rates were unbundled, electric and gas customer charges and minimum charges were again increased and rate design for Street Lighting Service revised, moving these rates closer to marginal costs.[7]

Accordingly, the use of marginal cost philosophy in class revenue allocation and rate design in New York, and particularly with respect to RG&E's rates, continues to be supported by the Commission.

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[5] Cases 02-E-0198 and 02-G-0199 - Order Adopting Recommended Decision with Modifications, at 74-75 (Mar, 7, 2003).

[6] Id. at 75-78.

[7] Cases 03-E-0765, 02-E-0198, and 03-G-0766 - Order Adopting Provisions of Joint Proposals with Conditions, at 34-35 (May 20, 2004).

RG&E's MARGINAL COSTS OF ELECTRIC DELIVERY SERVICE

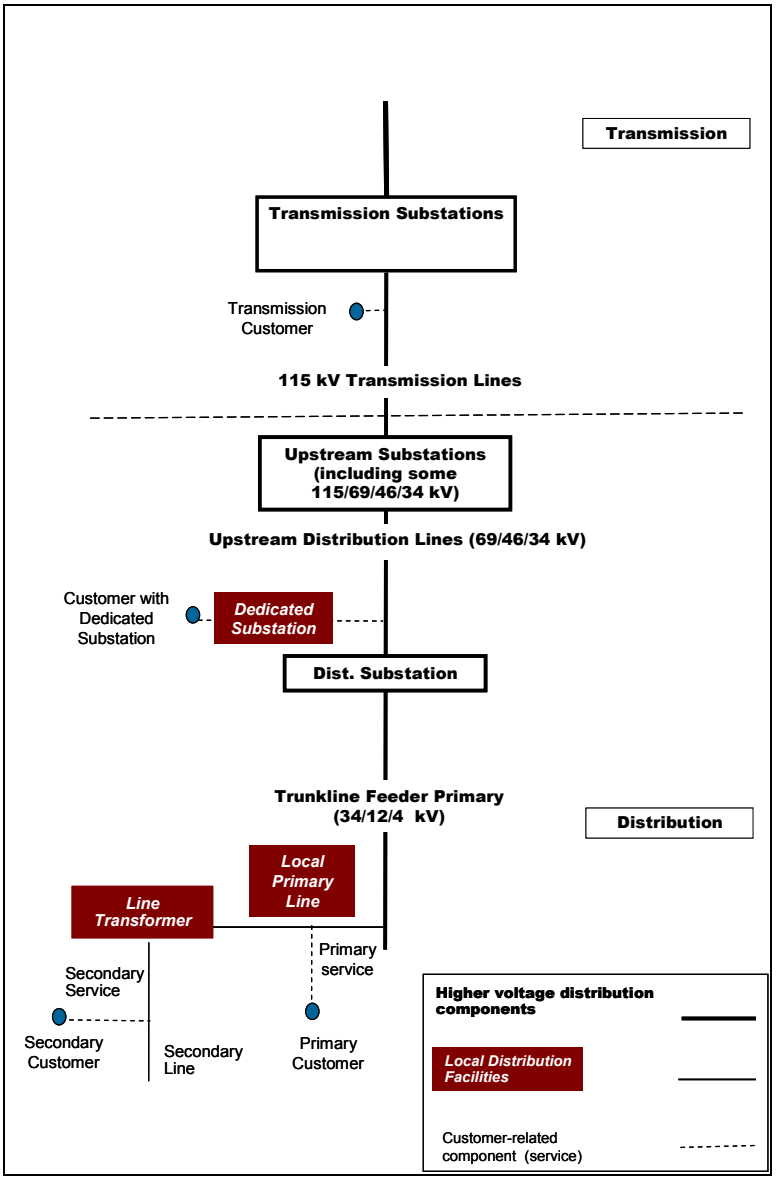
Methods Used

Q. What basic approach did you use to estimate RG&E's marginal costs of electric delivery service?

A. My basic approach was to determine the response of RG&E's planners and system operators to changes in the number and size of customers taking service and their electricity consumption in various seasons and times of the day. As I mentioned above, I analyzed marginal costs for the following components of electric delivery service:

- Customer-related costs
  - Meter and service
  - Customer accounts expenses
  - Customer service and information expenses
- Local distribution facilities
  - Secondary lines
  - Line transformers
  - Local primary lines
  - (for customers with dedicated substations) - Substation
- Time-differentiated delivery costs
  - Distribution substations and trunkline feeders
  - Upstream lines and substations
  - Transmission
- Lighting costs
  - Lighting equipment costs and related O&M
  - Relamping expenses

The diagram below illustrates the components of RG&E's delivery system. A full description of my approach is contained in Exhibit __ (RGEHP-2).



Q. Please describe your method for estimating marginal customer costs.

A. Using information supplied by RG&E, I computed the average investment in meters and services (before and after CIAC) for each class. I annualized these investments using an economic carrying charge, and added estimates of meter O&M, customer accounts expenses (excluding those related to the commodity function) and customer service and informational expenses. These marginal expense estimates were based on recent historical levels of expense and weighting factors based on meter cost, in the case of meter O&M, and results from RG&E's 2008 embedded cost-of-service study.

Q. How did you estimate the marginal cost of local electric distribution facilities?

A. RG&E developed estimates of the typical investment per kW of design demand (using summer peak demand as the measure of design demand) in secondary lines, transformers and local primary lines for various types and sizes of customers by calculating the replacement cost of the equipment on a sample of circuits. I computed estimates of local facilities investment for each service classification by averaging the costs identified for customers in the sample that are in a particular service classification. Local distribution facilities for customers served from a dedicated substation consist of their substations. RG&E provided the per-kVA cost of a typical dedicated substation for these

customers. I annualized the local facilities investment using an economic carrying charge and added estimates of O&M based on recent levels of distribution O&M, with distribution line expenses apportioned to secondary and primary lines on the basis of circuit miles.

Q. What approach did you use for estimating marginal distribution costs other than local facilities?

A. Local distribution facilities are connected to trunkline feeders, which are connected to distribution substations. Beyond these substations are lines and substations that I refer to as "upstream distribution equipment." RG&E provided estimates of the cost of planned distribution projects in these categories. I divided the cost (in 2010 dollars) of these typical projects by their capacity. To convert these costs per kW of capacity to a cost per kW of load, I multiplied by a typical reserve margin for distribution equipment. RG&E does not plan for a specific reserve margin in these facilities. However, their planning policy does result in capacity in excess of peak loads because of factors such as the lumpiness of capacity additions. To identify the typical reserve margin, RG&E identified substations where added capacity is likely to be needed in the near term, and I determined the median of these stations' 2008 reserve margins (71 percent). By looking only at substations experiencing growth, I avoided

distorting the typical reserve margin calculation by including substations with high reserve margins because they have lost load. A final adjustment takes into the account the fact that RG&E is not experiencing load growth in all portions of its service territory. Approximately 53 percent of load (as measured by substation peak loads) is in areas that would likely require additions to distribution capacity (above local facilities) in the event of load growth. The marginal investment in these components of the distribution system was annualized using an economic carrying charge, and adjusted by estimates of O&M on marginal plant investment. These O&M estimates use recent average historical levels of O&M as a starting point and take into account the fact that not all regions would require new investment and its corresponding O&M in the event of load growth.

I time-differentiated these components of marginal distribution costs using a statistical analysis of hourly loads on a sample of distribution substations for the years 2004-2008. I estimated the relative probability of any given hour's being the peak hour on the substation, taking into account the effects of ambient temperatures on the carrying capability of the equipment, and summarized the results by the two sets of pricing periods in RG&E's current residential and non-residential time-of-use rates. A final adjustment to these components of

marginal cost uses loss factors to convert the cost per kW at the equipment to a cost at the meters of secondary, primary and dedicated substation customers.

Q. How did you estimate marginal transmission costs?

A. As a transmission owner subject to the rules of the New York Independent System Operator (NYISO), RG&E's transmission revenue requirement is recovered in a Transmission Service Charge (TSC)—a flat price per MWh transported or sold. Users of RG&E's transmission system (implicitly including RG&E) are required to pay this charge. If RG&E's delivery service customers use more electricity, RG&E is responsible for additional TSC charges, which constitute RG&E's marginal transmission cost. Other NYISO charges are not marginal delivery costs and so are not included in this study. I used as a starting point average TSC charges for the most recent 12-month period. I adjusted these estimates of near-term TSC charges for average marginal energy losses by pricing period between the transmission tie point and customers' meters.

Q. How did you estimate marginal lighting costs?

A. RG&E provides circuit equipment (dedicated equipment comparable to a service drop for a non-lighting customer) that may include overhead wire, wood poles, underground conductor and conduit and buried cable and various lighting fixtures (bases, brackets and housings) and maintains this equipment for two

lighting service classifications: SC 6 (Area Lighting Service) and SC 1 (Street Lighting Service). RG&E contracts out most of the labor involved in installing and maintaining lighting equipment. The Company provided the current material costs of circuit and fixture equipment and contractor charges for fixture installation and maintenance. I computed a loader for RG&E's direct costs associated with maintenance of lighting equipment. Separate estimates of the material and labor costs of relamping were made for the various types of lamps used by RG&E's lighting customers.

Efficient Prices

Q. What would be the efficient design and levels of charges for RG&E's electric delivery service customers if there were no marginal cost revenue gap?

A. Efficient rate designs would mirror the structure of RG&E's marginal costs and charges for each rate component would be equal to marginal costs. Efficient rate designs for RG&E's electric delivery service customers would consist of a fixed monthly customer charge (see Table 1 below), a monthly facilities charge based on kW of design demand, perhaps based on ratcheted annual peak demand or, for homogeneous classes based on class average design demands and combined with the customer charge (see Table 1 below, which shows costs after CIAC), and time-differentiated charges based on monthly use. The upstream and

distribution substation marginal costs could be recovered either in a demand charge (see Table 2 below), with transmission costs recovered in a per-kWh charge (see Table 3 below), or combined with marginal transmission costs in time-differentiated per-kWh charges (see Table 4 below). There is seasonality to the non-local-facilities distribution and transmission marginal costs, so even customers without time-of-day meters would see more efficient prices if these components were seasonally differentiated. Lighting customers would pay monthly fixed charges for the equipment RG&E provides and maintains for them (see Table 5) and for relamping (see Table 6 below).

Table 1. Monthly Efficient Customer and Distribution Facilities Charges (After CIAC)

		Customer Class	Monthly Distribution Facilities Charge per kW of Design Demand (2010 $/kW/Month) (1)	Typical Design Demand (kW) (2)	or	Monthly Distribution Facilities Charge per Customer (2010 $/Month) (1) x (2) (3)	Monthly Marginal Customer Charge per Customer (2010 $/Month) (4)	Total Monthly Charges (2010 $/Month) (3) + (4) (5)
(1)	SC 1	Residential	$4.39	2.87		$12.59	$18.16	$30.75
(2)	SC 4	Residential TOU	4.47	7.17		32.06	27.43	59.49
(3)	SC 2	General Service - Small Use	5.24	24.83		130.12	19.89	150.01
(4)	SC 3	General Service - 100 kW Min.	3.03	154.09		466.90	107.97	574.87
(5)	SC 6	Area Lighting	na	na		na	1.14	1.14
(6)	SC 7	General Service - 12 kW Minimum	3.93	82.64		324.77	24.45	349.22
(7)	SC 8	LGS TOU - Secondary	3.16	452.43		1,429.69	101.28	1,530.97
(8)	New	Dedicated Substation Service	2.81	2,000.00		5,620.00	78.62	5,698.62
(9)	SC 8	LGS TOU - Primary	2.31	1,067.34		2,465.56	222.06	2,687.62
(10)	SC 8	LGS TOU Transmission	na	na		na	1,594.70	1,594.70
(11)	SC 9	General Service TOU	5.00	35.40		177.00	47.61	224.61
(12)	SL 1	Street Lighting Service	na	na		na	6.83	6.83
(13)	SL 2	Street Lighting Customer-Owned Equipment	na	na		na	6.83	6.83
(14)	SL 3	Traffic Signal	na	na		na	6.83	6.83

Table 2. Monthly Efficient Demand Charges to Recover Upstream and Distribution Substation Costs for Customers with Demand Meters

			Summer Season		Winter Season		Base Season	
			On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
			(2010 Dollars per kW per month)					
			(1)	(2)	(3)	(4)	(5)	(6)
	Residential (SC 4 Periods)							
	Secondary Service							
(1)	**TOD**	Upstream Distribution	$7.87	$0.26	$0.00	$0.00	$0.31	$0.12
(2)		Distribution Substation	$3.55	$0.12	$0.00	$0.00	$0.14	$0.05
			$11.43	$0.38	$0.00	$0.00	$0.44	$0.17
(3)	**Seasonal**	Upstream Distribution	$8.14		$0.00		$0.42	
(4)		Distribution Substation	$3.67		$0.00		$0.19	
			$11.81		$0.00		$0.61	
(5)	**Annual**	Upstream Distribution	$2.89					
(6)		Distribution Substation	$1.30					
			$4.19					
	Non-Residential (SC 8&9 Periods)							
	Transmission Service							
(7)	**TOD**		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(8)	**Seasonal**		$0.00		$0.00		$0.00	
(9)	**Annual**		$0.00					
	Dedicated Substation Service							
(10)	**TOD**	Upstream Distribution	$7.52	$0.25	$0.00	$0.00	$0.40	$0.00
(11)	**Seasonal**	Upstream Distribution	$7.76		$0.00		$0.40	
(12)	**Annual**	Upstream Distribution	$2.75					
	Primary Service							
(13)	**TOD**	Upstream Distribution	$7.68	$0.25	$0.00	$0.00	$0.41	$0.00
(14)		Distribution Substation	$3.47	$0.11	$0.00	$0.00	$0.18	$0.00
			$11.15	$0.37	$0.00	$0.00	$0.59	$0.01
(15)	**Seasonal**	Upstream Distribution	$7.93		$0.00		$0.41	
(16)		Distribution Substation	$3.58		$0.00		$0.19	
			$11.51		$0.00		$0.60	
(17)	**Annual**	Upstream Distribution	$2.82					
(18)		Distribution Substation	$1.27					
			$4.09					
	Secondary Service							
(19)	**TOD**	Upstream Distribution	$7.88	$0.26	$0.00	$0.00	$0.42	$0.00
(20)		Distribution Substation	$3.56	$0.12	$0.00	$0.00	$0.19	$0.00
			$11.43	$0.37	$0.00	$0.00	$0.60	$0.01
(21)	**Seasonal**	Upstream Distribution	$8.14		$0.00		$0.42	
(22)		Distribution Substation	$3.67		$0.00		$0.19	
			$11.81		$0.00		$0.61	
(23)	**Annual**	Upstream Distribution	$2.89					
(24)		Distribution Substation	$1.30					
			$4.19					

Table 3. Monthly Efficient Transmission Charges per kWh for Customers with Demand Charges

		Summer Season		Winter Season		Base Season		Annual Average	
		On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
		(2010 Dollars per kWh)							
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(1)	Marginal Transmission Cost	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368
	Residential (SC 4 Periods)								
	Secondary Service								
(2)	**TOD**	$0.00396	$0.00389	$0.00394	$0.00389	$0.00392	$0.00387	$0.00394	$0.00388
(3)	**Seasonal**	$0.00392		$0.00391		$0.00389			
(4)	**Annual**	$0.00391							
	Non-Residential (SC 8&9 Periods)								
	Transmission Service								
(5)	**TOD**	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368
(6)	**Seasonal**	$0.00368		$0.00368		$0.00368			
(7)	**Annual**	$0.00368							
	Dedicated Substation Service								
(8)	**TOD**	$0.00378	$0.00376	$0.00378	$0.00376	$0.00377	$0.00375	$0.00377	$0.00375
(9)	**Seasonal**	$0.00377		$0.00377		$0.00376			
(10)	**Annual**	$0.00376							
	Primary Service								
(11)	**TOD**	$0.00389	$0.00384	$0.00388	$0.00384	$0.00386	$0.00382	$0.00387	$0.00383
(12)	**Seasonal**	$0.00386		$0.00386		$0.00384			
(13)	**Annual**	$0.00385							
	Secondary Service								
(14)	**TOD**	$0.00395	$0.00389	$0.00394	$0.00389	$0.00392	$0.00387	$0.00393	$0.00388
(15)	**Seasonal**	$0.00392		$0.00391		$0.00389			
(16)	**Annual**	$0.00391							

Table 4. Monthly Efficient Transmission and Distribution Charges per kWh (if there are no demand charges)

			Summer Season		Winter Season		Base Season		Annual Average	
			On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
			(2010 Dollars per kWh)							
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Residential (SC 4 Periods)									
	Secondary Service									
(1)	**TOD**	Transmission	$0.00396	$0.00389	$0.00394	$0.00389	$0.00392	$0.00387	$0.00394	$0.00388
(2)		Upstream Dist.	$0.02586	$0.00061	$0.00000	$0.00000	$0.00101	$0.00027	$0.00904	$0.00032
(3)		Dist. Substation	$0.01167	$0.00028	$0.00000	$0.00000	$0.00046	$0.00012	$0.00408	$0.00014
			$0.04149	$0.00478	$0.00394	$0.00389	$0.00538	$0.00426	$0.01706	$0.00434
(4)	**Seasonal**	Transmission	$0.00392		$0.00391		$0.00389			
(5)		Upstream Dist.	$0.01112		$0.00000		$0.00057			
(6)		Dist. Substation	$0.00502		$0.00000		$0.00026			
			$0.02005		$0.00391		$0.00472			
(7)	**Annual**	Transmission	$0.00391							
(8)		Upstream Dist.	$0.00396							
(9)		Dist. Substation	$0.00179							
			$0.00965							
	Non-Residential (SC 8&9 Periods)									
	Transmission Service									
(10)	**TOD**	Transmission	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368
(11)	**Seasonal**	Transmission	$0.00368		$0.00368		$0.00368			
(12)	**Annual**	Transmission	$0.00368							
	Dedicated Sub. Service									
(13)	**TOD**	Transmission	$0.00378	$0.00376	$0.00378	$0.00376	$0.00377	$0.00375	$0.00377	$0.00375
(14)		Upstream Dist.	$0.02160	$0.00064	$0.00000	$0.00000	$0.00115	$0.00001		
			$0.02538	$0.00440	$0.00378	$0.00376	$0.00492	$0.00376		
(15)	**Seasonal**	Transmission	$0.00377		$0.00377		$0.00376			
(16)		Upstream Dist.	$0.01060		$0.00000		$0.00055			
			$0.01437		$0.00377		$0.00430			
(17)	**Annual**	Transmission	$0.00376							
(18)		Upstream Dist.	$0.00377							
			$0.00754							
	Primary Service									
(19)	**TOD**	Transmission	$0.00389	$0.00384	$0.00388	$0.00384	$0.00386	$0.00382	$0.00387	$0.00383
(20)		Upstream Dist.	$0.02207	$0.00066	$0.00000	$0.00000	$0.00118	$0.00001	$0.00785	$0.00022
(21)		Dist. Substation	$0.00996	$0.00030	$0.00000	$0.00000	$0.00053	$0.00001	$0.00354	$0.00010
			$0.03592	$0.00479	$0.00388	$0.00384	$0.00556	$0.00384	$0.01526	$0.00415
(22)	**Seasonal**	Transmission	$0.00386		$0.00386		$0.00384			
(23)		Upstream Dist.	$0.01084		$0.00000		$0.00056			
(24)		Dist. Substation	$0.00489		$0.00000		$0.00025			
			$0.01959		$0.00386		$0.00465			
(25)	**Annual**	Transmission	$0.00385							
(26)		Upstream Dist.	$0.00386							
(27)		Dist. Substation	$0.00174							
			$0.00945							
	Secondary Service									
(28)	**TOD**	Transmission	$0.00395	$0.00389	$0.00394	$0.00389	$0.00392	$0.00387	$0.00393	$0.00388
(29)		Upstream Dist.	$0.02264	$0.00067	$0.00000	$0.00000	$0.00121	$0.00001	$0.00805	$0.00023
(30)		Dist. Substation	$0.01022	$0.00030	$0.00000	$0.00000	$0.00054	$0.00001	$0.00363	$0.00010
			$0.03681	$0.00486	$0.00394	$0.00389	$0.00567	$0.00388	$0.01562	$0.00421
(31)	**Seasonal**	Transmission	$0.00392		$0.00391		$0.00389			
(32)		Upstream Dist.	$0.01112		$0.00000		$0.00057			
(33)		Dist. Substation	$0.00502		$0.00000		$0.00026			
			$0.02005		$0.00391		$0.00472			
(34)	**Annual**	Transmission	$0.00391							
(35)		Upstream Dist.	$0.00396							
(36)		Dist. Substation	$0.00179							
			$0.00965							

Table 5. Monthly Efficient Lighting Charges (Excluding Relamping)

		Monthly Charge per Unit (2010 $ per Mo.) (1)
Fixture Types		
Type 2d	F2d 15' post top, w/ HPS	$9.85
Type 2f	F2d 15' post top, w/ MH	8.86
Type 2g	Wood pole supporting a MH shoebox luminaire	5.04
Type 9c	F9c mast arm WP, w/ HPS	7.39
Type 9d	F9d mast arm WP, w/ MH	8.01
Type 10a	F10a 20-25' tub steel w/ MH	86.99
Type 10a-2	F10a-2 20-25' twin steel w/ MH	91.20
Type 10c	F10c 20-25' steel, w/ HPS	86.28
Type 10c-2	F10c-2 20-25' tub steel, w/ HPS	89.77
Type 11a	F11a 30-35' Steel w/ MH	90.28
Type 11a-2	F11a-2 30-35' Steel w/ MH	98.37
Type 11b	F11b 30-35' steel, w/ HPS	90.81
Type 11b-2	F11b-2 30-35' tub steel, w/ HPS	99.43
Type13a	F13a mast arm on WP, w/ HPS	9.56
Type13b	F13b mast arm on WP, w/ MH	10.34
Type 20b	F20b (owned by others)	4.67
Type 20g	F20g (owned by others)	4.05
Type 20i	F20i (owned by others)	6.19
Type 20j	F20j (owned by others)	5.20
Type 21a	F21a (owned by others)	8.77
Type 21b	F21b (owned by others)	9.06
Type C-4a	C-4a Flour. Underpass	0.00
Circuit Component		
Overhead Wire		0.03
Wood Pole Company Owned		7.06
Wood Pole Jointly Owned		3.53
Conduit & Cable		0.18
Buried Cable URD Subdivisions		0.04
Cable in Conduit owned by Others		0.02

	Monthly Charge per Unit (2010 $ per Mo.) (2)
Standard Fixture	
High Pressure Sodium	
HPS 70	$3.48
HPS 100	3.56
HPS 150	3.56
HPS 250	3.49
HPS 400	3.59
250/400 duel	5.14
Metal Halide	
MH 250	3.49
MH 400	3.49
Bracket Length	
30 inch	2.27
8 foot	3.45
12 foot	5.40
16 foot	8.19
20 foot	9.52
Flood Fixutre	
High Pressure Sodium	
HPS 150	0.45
HPS 250	5.24
HPS 400	5.26
HPS 1000	5.39
Metal Halide	
MH 250	3.07
MH 400	3.08
MH 1000	4.78
Bracket	
Bracket- single	1.40
Bracket- twin	0.58
Shoebox Fixture	
High Pressure Sodium	
HPS 250	0.45
HPS 400	0.45
Bracket Length	
30 inch	2.27
Added Facilities	
Additional wood pole installed for luminaire	8.08
Wire service (per foot of extension)	0.02

Table 6. Monthly Efficient Relamping Charges

Lamp Type Lumins	Wattage	Type	Monthly Relamping Charge per Unit (2010 Dollars per unit per Month)
1,260	116	Incandescent	$1.20
2,500	166	Incandescent	0.93
2,800	202	Incandescent	1.09
4,000	261	Incandescent	1.06
6,000	366	Incandescent	1.09
10,000	621	Incandescent	1.11
4,000	50	High Pressure Sodium	13.01
5,800	70	High Pressure Sodium	12.51
9,500	100	High Pressure Sodium	12.60
16,000	150	High Pressure Sodium	12.71
27,500	250	High Pressure Sodium	12.83
50,000	400	High Pressure Sodium	13.17
140,000	1,000	High Pressure Sodium	21.59
6,950	100	Fluorescent	5.27
6,950	100	Fluorescent	5.27
4,000	70	Metal Halide	21.72
5,850	100	Metal Halide	16.80
10,500	175	Metal Halide	13.01
17,000	250	Metal Halide	13.82
28,800	400	Metal Halide	13.12

Q. If RG&E were to set efficient (marginal cost) electric delivery rates using current rate designs, but without adjusting to a particular class or total revenue requirement, how would these rates compare to current rates?

A. Tables 7 though 12 below show these comparisons.

Table 7. Comparison of Current Rates and Marginal Costs (non-lighting classes)

	Current Rates							Marginal Costs (2010$)				
	Customer Charge	All kWh	1st 200 hrs of demand	All Other kWh	Delivery Peak Charge	Delivery Off-Peak Charge	Demand Charge	Customer Cost (after CIAC)	All kWh	Year-round Delivery Peak Cost	Year-round Delivery Off-Peak Cost	Year-round Monthly Marginal Demand Cost
	($/month)	($/kWh)					($/kw per mo.)	($/month)	($/kWh)			($/kw/mo.)
SC No. 1 Residential Service	$20.00	$0.0227						$30.75	$0.00965			
SC4 Residential Service - TOU Schedule I	$23.98				$0.02783	$0.02252		$59.49		$0.01706	$0.00434	
SC4 Residential Service - TOU Schedule II	$23.98				$0.04249	$0.02723		$59.49		$0.01706	$0.00434	
SC2 General Service - Small Use Secondary	$20.00	$0.0145						$150.01	$0.00965			
SC3 100kW Minimum Secondary	$160.00						$10.59	$574.87	$0.00391			$4.19
SC7 General Service 12 kW Minimum secondary	$50.00		$0.00102	$0.00074			$13.38	$349.22	$0.00391			$4.19
SC8 Large Time of Use - Secondary	$500.00						$7.93	$1,530.97	$0.00391			$4.19
SC8 Large Time of Use - Sub Transmission-Secondary	$800.00						$4.68	$5,698.62	$0.00376			$2.75
SC8 Large Time of Use - Primary	$450.00						$7.30	$2,687.62	$0.00385			$4.09
SC8 Large Time of Use - Sub Transmission - Industrial	$700.00						$3.31					
SC8 Large Time of Use - Sub Transmission - Commercial	$700.00						$3.39					
SC8 Large Time of Use - Transmission	$950.00						$3.38	$1,594.70	$0.00368			$0.00
SC9 Time of Use - Secondary	$50.00				$0.00663	$0.00389	$9.01	$224.61		$0.00393	$0.00388	$4.19

Table 8. Comparison of Current Rates and Marginal Costs – Lighting Service Customer and Network Delivery Charges

	Current Rates		Marginal Costs (2010$)	
Lighting Service Classification	Delivery without SBC (per kWh)	Bill Isuance Charge (per kWh)	Delivery (per kWh)	Customer Charge (per month)
SC 1 Standard lighting		$0.620	$0.0096	$6.83
SC 2 Customer-Owned				
24-hour Burning service	$0.0126	$0.620	$0.0096	$6.83
Dusk-to-Dawn service	$0.0352	$0.620	$0.0096	$6.83
Dusk-to-l:00 a.m. service	$0.1014	$0.620	$0.0096	$6.83
SC 3 Traffic Signal				
Energy Delivery per Billing Face:	$0.9692	$0.620	$0.0096	$6.83
SC 6 Area Lighting		$0.620	$0.0096	$1.14

Table 9. Comparison of Current Rates and Marginal Costs – SC 1 Fixture Charges

	Street Lighting SC No. 1 - Standard Street Lighting	Monthly Fixture Charges	
		Current Rates ($ per unit)	Marginal Cost (2010$ per unit)
	Fixture Charges		
1	Concrete pole supporting INC harp or globe type luminaire	$7.59	$9.85
1a	Concrete pole supporting HPS harp or globe type luminaire	$7.59	$9.85
2d	Pole (15 ft. max.) supporting HPS luminaire	$12.99	$9.85
2e	Pole (15 ft. max.) supporting octagonal HPS luminaire	$16.98	$9.85
2f	Pole (15 ft. max) supporting a MH post top luminaire	$12.27	$8.86
2g	Wood pole (17 ft. max.) supporting a MH shoebox type luminaire	$11.96	$5.04
3a	Fluted pole with arm supporting INC open type luminaire	$6.35	$7.39
3a-2	Fluted pole with two arms each supporting INC open type luminaire	$8.70	$7.39
5a	Wood pole with arm supporting an INC open type luminaire	$1.62	$7.39
6	Steel pole supporting an INC harp or globe type luminaire	$4.76	$7.39
6a	Steel pole supporting a HPS harp or globe type luminaire	$4.76	$7.39
9b	Wood pole with arm supporting an INC closed type luminaire	$2.61	$7.39
9c	Wood pole with arm supporting a HPS luminaire (150W max.)	$5.02	$7.39
9d	Wood pole with arm supporting a MH closed type luminaire (250W max)	$4.42	$8.01
10a	Davit pole (20-25 ft) supporting a MH luminaire (250W max)	$11.91	$86.99
10a-2	Davit pole (20-25 ft.) supporting two MH luminaires (250W max)	$17.47	$91.20
10c	Davit pole (20 - 25 ft.) supporting a HPS luminaire (150W max.)	$11.64	$86.28
10c-2	Davit pole (20 - 25 ft.) supporting two HPS luminaires (150W max.)	$17.21	$89.77
11a	Davit pole (30-35 ft.) supporting a MH luminaire (1000W max)	$14.02	$90.28
11a-2	Davit pole (20-25 ft.) supporting two MH luminaires (1000W max)	$21.14	$98.37
11b	Davit pole (30 - 35 ft.) supporting a HPS luminaire (400W max.)	$15.64	$90.81
11b-2	Davit pole (30 - 35 ft.) supporting two HPS luminaires (400W max.)	$24.68	$99.43
13a	Wood pole with arm supporting a HPS luminaire (400W max.)	$6.85	$9.56
13b	Wood pole with arm supporting a MH closed type luminaire (1000W max)	$4.40	$10.34
20b	Customer pole & arm supporting a HPS shoebox type luminaire	$6.99	$4.67
20d	Customer pole supporting Company high mast HPS luminaire installed by Customer	$8.53	$8.77
20g	Customer pole & arm supporting a HPS luminaire	$4.16	$4.05
20i	Customer pole supporting a HPS luminaire (250W max.)	$7.82	$6.19
20j	Customer pole & arm supporting a MH closed type luminaire	$2.77	$5.20
20k	Customer pole supporting a MH post top luminaire (250W max)	$3.40	$6.19
21a	Customer pole with Company arm supporting a HPS luminaire	$5.76	$8.77
21b	Customer pole with Company arm supporting a MH closed type luminaire	$4.08	$9.06
C-5	Conduit fed fixture with INC lamp burning 24 hours a day (2500 Lumen)	$2.47	$0.00
C-4a	Conduit fed fluorescent tunnel light	$9.21	$0.00
C-5a	Conduit fed fluorescent tunnel light burning 24 hours a day	$9.89	$0.00
C-6	Conduit fed fixture with two INC lamps (1260 Lumen ea.)	$4.99	$0.00

Table 10. Comparison of Current Rates and Marginal Costs – SC 1 Circuit Charges

Street Lighting SC No. 1 - Standard Street Lighting	Current Rates Monthly Circuit Charges ($ per unit)	Marginal Cost Monthly Marginal Circuit Costs (2010 $ per unit)
Circuit Charges		
Overhead wire	$0.0124	$0.0282
Street lighting wood poles, Company owned, per pole	$4.0533	$7.0629
Street lighting wood poles, jointly owned by Co. and 3rd party, per pole	$2.0267	$3.5332
Conduit and cable	$0.0876	$0.1812
Direct buried cable in URD subdivisions	$0.0406	$0.0394
Cable in conduit owned by others	$0.0312	$0.0236

Table 11. Comparison of Current Rates and Marginal Costs – SC 1 Lamp Charges

Street Lighting SC No. 1 - Standard Street Lighting	Current Rates			Marginal Cost
	Lumens	Watts	Lamp Charge ($ per light)	Relamping (2010$ per light)
Incandescent	1,260	116	$4.23	$1.20
Incandescent	2,500	166	$3.92	$0.93
Incandescent	2,800	202	$4.13	$1.09
Incandescent	2,800	202	$12.32	$1.09
Incandescent	4,000	261	$5.34	$1.06
Incandescent	6,000	366	$6.87	$1.09
Incandescent	10,000	621	$12.68	$1.11
High Pressure Sodium	4,000	50	$1.14	$13.01
High Pressure Sodium	5,800	70	$1.47	$12.51
High Pressure Sodium	9,500	100	$1.98	$12.60
High Pressure Sodium	16,000	150	$2.78	$12.71
High Pressure Sodium	27,500	250	$4.66	$12.83
High Pressure Sodium	50,000	400	$6.97	$13.17
High Pressure Sodium	140,000	1,000	$20.26	$21.59
Fluorescent (dusk-to-dawn)	6,950	100	$2.77	$5.27
Fluorescent (24-hour burning)	6,950	100	$4.48	$5.27
Metal Halide	4,000	70	$2.57	$21.72
Metal Halide	5,850	100	$2.54	$16.80
Metal Halide	10,500	175	$2.44	$13.01
Metal Halide	17,000	250	$2.45	$13.82
Metal Halide	28,800	400	$2.45	$13.12

Table 12. Comparison of Current Rates and Marginal Costs – SC 6 Fixture Charges

Area Lighting SC No. 6		Current Rate		Marginal Cost
Type of Luminaire	Lumen	Residential Monthly Charge (per unit)	Non-Residential Monthly Charge (per unit)	2010$ Monthly Costs (per unit)
Standard				
High Pressure Sodium				
HPS 70	5,800	$5.92	$5.88	$3.48
HPS 100	9,500	$5.99	$5.98	$3.56
HPS 150	16,000	$10.69	$10.61	$3.56
HPS 250	27.5	$14.08	$14.04	$3.49
HPS 400	50,000	$15.16	$15.24	$3.59
Metal Halide				
MH 250	22,000	$14.32	$14.29	$3.49
MH 400	36,000	$15.10	$15.18	$3.49
Bracket Length				
30 inch		$0.58	$0.58	$2.27
8 foot		$0.78	$0.78	$3.45
12 foot		$1.12	$1.12	$5.40
16 foot		$1.55	$1.55	$8.19
20 foot		$1.90	$1.90	$9.52
Flood Fixture:				
High Pressure Sodium				
HPS 150	16,000	$10.42	$10.35	$0.45
HPS 250	27,500	$11.51	$11.48	$5.24
HPS 400	50,000	$12.51	$12.57	$5.26
HPS 1000	140,000	$25.02	$25.25	$5.39
Metal Halide				
MH 250	19,500	$13.36	$13.30	$3.07
MH 400	32,000	$14.03	$14.05	$3.08
MH 1000	100,000	$23.49	$23.68	$4.78
Bracket				
Bracket- single		$0.49	$0.49	$1.40
Bracket- twin		$0.98	$0.98	$0.58
Shoe Box Fixture				
High Pressure Sodium				
HPS 250	27,500	$16.23	$16.23	$0.45
HPS 400	50,000	$17.14	$17.14	$0.45
Bracket Length				
30 inch		$0.58	$0.58	$2.27
Added Facilities				
Additional wood pole installed for luminaire		$3.62	$3.62	$8.08
Wire service (per foot of extension)		$0.02	$0.02	$0.02

RG&E's MARGINAL COSTS OF GAS DELIVERY SERVICE

Methods Used

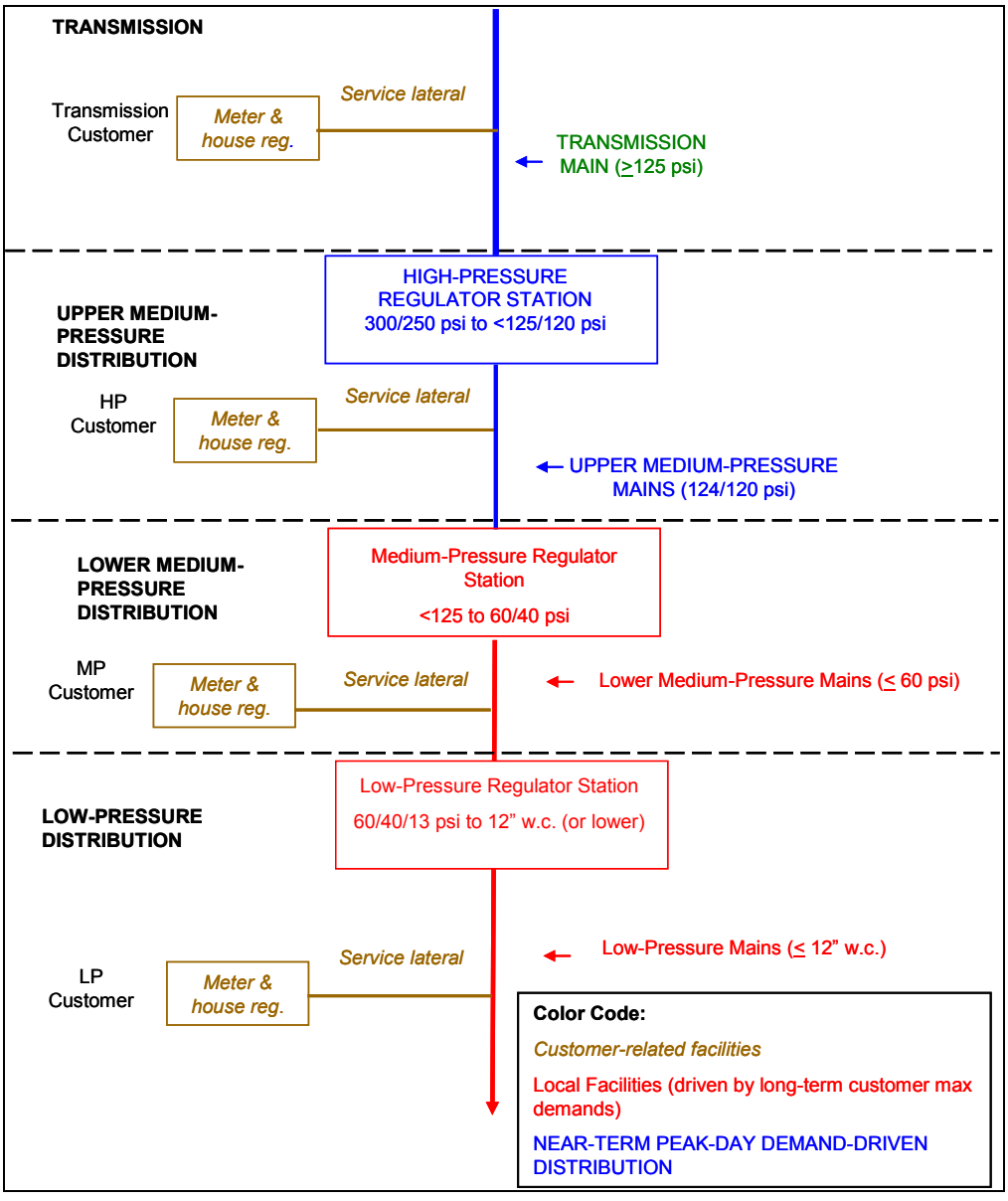
Q. What basic approach did you use to estimate RG&E's marginal costs of gas delivery service?

A. As was the case for the electric study, my basic approach for the gas study was to determine the response of RG&E's planners and system operators to changes in the number and size of customers taking service and their gas consumption by season. I analyzed marginal costs for the following components of gas delivery service:

- Customer-related costs
  - Meter, house regulator, relief valves and service lateral
  - Customer accounts expenses
  - Customer service and information expenses
- Local distribution facilities
  - Low-pressure lines
  - Low-pressure regulator stations
  - Lower medium-pressure mains
  - Medium-pressure regulator stations
- Seasonally-differentiated delivery costs
  - Reliability storage
  - Upper medium-pressure mains
  - High-pressure regulator stations
  - Transmission mains

HETHIE S. PARMESANO

The components of RG&E's gas delivery system are illustrated on the diagram below. A full description of the approach is contained in Exhibit __ RGEHP-3.



Q. Please describe your method for estimating marginal gas customer costs.

A. RG&E provided the average investment in meters and service laterals for each class. I annualized these investments using an economic carrying charge, and added estimates of meter and service lateral O&M, customer accounts expenses (excluding the portion associated with the merchant function) and customer service and informational expenses. These marginal expense estimates were based on recent historical levels of expense and weighting factors based on meter cost and a 10 percent / 90 percent split for residential/non-residential, in the case of meter O&M, and results from RG&E's 2008 embedded cost-of-service study for customer accounts and service expenses.

Q. How did you estimate the marginal cost of local distribution facilities?

A. For each component of local facilities, I computed the current replacement cost (in 2010 dollars) of all such facilities on RG&E's system (before and after CIAC). I divided the totals by estimates of design demand at customer's meters. I used meter capacity as the design demand estimate for all classes except residential. According to RG&E, residential meters have about 60 percent larger capacity than the design demand for which the local delivery system is sized.

Q. What approach did you use for estimating marginal mains and regulator station costs other than local facilities?

A. RG&E has not undertaken a gas transmission project in the past five years and has no such projects in its near-term plans. Consequently, I treated the marginal cost of transmission mains as zero in the near term. RG&E provided estimates of the cost of typical high-pressure regulator stations and upper medium-pressure mains. I divided the cost (in 2010 dollars) of these typical projects by their capacity. To convert these costs per kW of capacity to a cost per kW of load, I multiplied by RG&E's typical reserve margin for such equipment (7.5 percent). A final adjustment takes into the account the fact that RG&E is experiencing very little load growth overall, although growth in some areas is offset by losses in others. Marginal load growth would require additions to main and regulator station capacity (above local facilities) in only about 2 percent of the service territory. The marginal investment in these components of the delivery system was annualized using an economic carrying charge, and adjusted by estimates of O&M on marginal plant investment. These O&M estimates use recent average historical levels of O&M as a starting point and take into account the fact that not all regions would require new investment and its corresponding O&M in the event of load growth.

I seasonally-differentiated these components of marginal distribution costs using a statistical analysis of daily system demands for the years 2004-2008. I estimated the relative probability of any given day being the peak day, and aggregated these probabilities into summer and winter seasons.

RG&E maintains some local storage to provide reliability to the distribution system. Sale of additional distribution service requires providing additional reliability storage. I used as the estimate of marginal reliability storage cost the reliability surcharge developed by RG&E, adjusted to 2010 dollars. A final adjustment to these components of marginal cost uses an estimate of losses to convert the cost per near-term design-day MCF at the equipment to a cost at customers' meters.

Efficient Prices

Q. What would be the efficient structure and levels of charges for RG&E's gas delivery service customers if there were no marginal cost revenue gap?

A. Efficient pricing would use a rate design that mirrors the structure of RG&E's marginal cost and charges for each rate component set equal to marginal cost. Efficient rate designs for RG&E's gas delivery service customers would consist of winter charges per therm to recover high-pressure regulator station and upper medium-pressure mains costs, a year-round charge per therm for reliability

storage (which could be combined with the high-pressure and upper-medium pressure charges in winter), a monthly local facilities charge per MCF of design demand (which could be approximated by meter capacity, with an appropriate adjustment for the extra capacity in residential meters), and a monthly customer charge. For service classifications with similar design demands, the facilities change could be combined with the customer charge. Tables 13-15 below show what these charges would be.

Table 13. Efficient Gas Delivery Charges per Therm

	Seasonal Charges			
	Winter (Dec. - Mar.)	Summer (April - Nov.)	or	Annual Charge
	(2010 cents/therm)			(2010 cents/therm)
	(1)	(2)		(3)
Upper Medium-Pressure Mains	0.19325	0.00000		0.11458
High-Pressure Regulator Stations	0.00978	0.00000		0.00580
Reliability Storage (applies to SC1 and 5)	0.02175	0.02175		0.02175
Total	0.22478	0.02175		0.14213
Total without Reliability Storage	0.20303	0.00000		0.12039

Table 14. Efficient Gas Local Facilities Charges per MCF of Design Demand (or Per Customer)

Customer Classification	Description	Per MCF of long-term design day: Facilities Charge (after CIAC) 2010 $	or	Per customer per month: Facilities Charge (after CIAC) 2010 $
		(1)		(2)
(1) SC1RNH	SC 1 Residential Non Heat	$19.47		$58.60
(2) SC1RH	SC 1 Residential Heat	$19.47		$58.60
(3) SC1C	SC 1 Commercial	$19.47		$176.79
(4) SC1IND	SC 1 Industrial	$19.47		$808.98
(5) SC1MUN	SC 1 Municipal	$19.47		$443.14
(6) SC3C	SC 3 Commercial	$19.47		$2,607.23
(7) SC3IND	SC 3 Industrial	$19.47		$4,661.31
(8) SC3MUN	SC 3 Municipal	$19.47		$2,942.89
(9) SC3 HP	SC 3 High-Pressure	na		na
(10) SC5RNH	SC 5 Residential Non Heat	$19.47		$58.60
(11) SC5RH	SC 5 Residential Heat	$19.47		$58.60
(12) SC5C	SC 5 Commercial	$19.47		$265.38
(13) SC5IND	SC 5 Industrial	$19.47		$764.00
(14) SC5MUN	SC 5 Municipal	$19.47		$490.06
(15) SC7T	SC 7 Non-Residential for DG	$19.47		$6,230.40

Table 15. Efficient Gas Customer Charges

	Customer Classification	Description	Monthly Customer Charge (2010 Dollars) (1)
(1)	SC1RNH	SC 1 Residential Non Heat	$24.00
(2)	SC1RH	SC 1 Residential Heat	24.43
(3)	SC1C	SC 1 Commercial	43.64
(4)	SC1IND	SC 1 Industrial	102.29
(5)	SC1MUN	SC 1 Municipal	79.43
(6)	SC3C	SC 3 Commercial	269.96
(7)	SC3IND	SC 3 Industrial	395.78
(8)	SC3MUN	SC 3 Municipal	287.92
(9)	SC3 HP	SC 3 High-Pressure	2,254.65
(10)	SC5RNH	SC 5 Residential Non Heat	23.90
(11)	SC5RH	SC 5 Residential Heat	24.16
(12)	SC5C	SC 5 Commercial	52.98
(13)	SC5IND	SC 5 Industrial	108.92
(14)	SC5MUN	SC 5 Municipal	83.60
(15)	SC7T	SC 7 Non-Residential for DG	315.88

Q. If RG&E were to set efficient (marginal cost) gas delivery rates using current rate designs, but without adjusting to a particular class or total revenue requirement, how would these rates compare to current rates?

A. Tables 16 A and B below show these comparisons.

Table 16 A. Comparison of Current and Efficient Charges

		$/customer/mo.			$/therm	
		Current Rates	**Marginal Costs**		**Current Rates**	**Marginal Costs**
		Customer Charge	Monthly Fixed Costs		Volumetric Rate	All Therms
SC 1 Residential Non Heat						
	Bill issuance charge:	$0.62	Facilities Cost:	$58.60		
	First 3 therms:	$14.38	Customer Cost:	$24.00		
		$15.00		$82.60	Next 97: $0.17417	$0.14213
					Next 400: $0.16241	
					Next 500: $0.14358	
					Over 1000: $0.08398	
SC 1 Residential Heat						
	Bill issuance charge:	$0.62	Facilities Cost:	$58.60		
	First 3 therms:	$14.38	Customer Cost:	$24.43		
		$15.00		$83.03	Next 97: $0.17417	$0.14213
					Next 400: $0.16241	
					Next 500: $0.14358	
					Over 1000: $0.08398	
SC 1 Commercial						
	Bill issuance charge:	$0.62	Facilities Cost:	$176.79		
	First 3 therms:	$14.38	Customer Cost:	$43.64		
		$15.00		$220.43	Next 97: $0.17417	$0.14213
					Next 400: $0.16241	
					Next 500: $0.14358	
					Over 1000: $0.08398	
SC 1 Industrial						
	Bill issuance charge:	$0.62	Facilities Cost:	$808.98		
	First 3 therms:	$14.38	Customer Cost:	$102.29		
		$15.00		$911.27	Next 97: $0.17417	$0.14213
					Next 400: $0.16241	
					Next 500: $0.14358	
					Over 1000: $0.08398	
SC 1 Municipal						
	Bill issuance charge:	$0.62	Facilities Cost:	$443.14		
	First 3 therms:	$14.38	Customer Cost:	$79.43		
		$15.00		$522.56	Next 97: $0.17417	$0.14213
					Next 400: $0.16241	
					Next 500: $0.14358	
					Over 1000: $0.08398	
SC 3 Large T Commercial						
	Bill issuance charge:	$0.62	Facilities Cost:	$2,607.23		
	First 1000:	$409.38	Customer Cost:	$269.96		
		$410.00		$2,877.18	Next 29,000: $0.08429	$0.12039
					Next 70,000: $0.06679	
					Next 900,000: $0.02583	
					Over 1,000,000: $0.01333	
SC 3 Large T Industrial						
	Bill issuance charge:	$0.62	Facilities Cost:	$4,661.31		
	First 1000:	$409.38	Customer Cost:	$395.78		
		$410.00		$5,057.09	Next 29,000: $0.08429	$0.12039
					Next 70,000: $0.06679	
					Next 900,000: $0.02583	
					Over 1,000,000: $0.01333	
SC 3 Large T Municipal						
	Bill issuance charge:	$0.62	Facilities Cost:	$2,942.89		
	First 1000:	$409.38	Customer Cost:	$287.92		
		$410.00		$3,230.81	Next 29,000: $0.08429	$0.12039
					Next 70,000: $0.06679	
					Next 900,000: $0.02583	
					Over 1,000,000: $0.01333	

Table 16B. Comparison of Current and Efficient Charges (Continued)

	$/customer/mo.				$/therm			
	Current Rates		**Marginal Costs**		**Current Rates**		**Marginal Costs**
	Customer Charge		Monthly Fixed Costs		Volumetric Rate		All Therms
SC 3 Large Transportation High-Pressure							
Bill issuance charge:	$0.62	Facilities Cost:	na				
First 1000:	$879.38	Customer Cost:	$2,254.65				
	$880.00		$2,254.65		Next 29,000:	$0.02717	$0.12039
					Next 70,000:	$0.02717	
					Next 900,000:	$0.02717	
					Over 1,000,000:	$0.01403	
SC 5 Small Transportation Residential Non Heat							
Bill issuance charge:	$0.62	Facilities Cost:	$58.60				
First 3 therms:	$14.38	Customer Cost:	$23.90				
	$15.00		$82.51		Next 97:	$0.17417	$0.14213
					Next 400:	$0.16241	
					Next 500:	$0.14358	
					Over 1000:	$0.08398	
SC 5 Small Transportation Residential Heat							
Bill issuance charge:	$0.62	Facilities Cost:	$58.60				
First 3 therms:	$14.38	Customer Cost:	$24.16				
	$15.00		$82.76		Next 97:	$0.17417	$0.14213
					Next 400:	$0.16241	
					Next 500:	$0.14358	
					Over 1000:	$0.08398	
SC 5 Small Transport Commercial							
Bill issuance charge:	$0.62	Facilities Cost:	$265.38				
First 3 therms:	$14.38	Customer Cost:	$52.98				
	$15.00		$318.36		Next 97:	$0.17417	$0.14213
					Next 400:	$0.16241	
					Next 500:	$0.14358	
					Over 1000:	$0.08398	
SC 5 Small Transport Industrial							
Bill issuance charge:	$0.62	Facilities Cost:	$764.00				
First 3 therms:	$14.38	Customer Cost:	$108.92				
	$15.00		$872.93		Next 97:	$0.17417	$0.14213
					Next 400:	$0.16241	
					Next 500:	$0.14358	
					Over 1000:	$0.08398	
SC 5 Small Transport Municipal							
Bill issuance charge:	$0.62	Facilities Cost:	$490.06				
First 3 therms:	$14.38	Customer Cost:	$83.60				
	$15.00		$573.66		Next 97:	$0.17417	$0.14213
					Next 400:	$0.16241	
					Next 500:	$0.14358	
					Over 1000:	$0.08398	
SC 7 Non-Resid Transportation for DG (Summer)							
Bill issuance charge:	$0.00	Facilities Cost:	$6,230.40				
First 3 therms:	$15.00	Customer Cost:	$315.88				
	$15.00		$6,546.28		Next 97:	$0.05583	$0.12039
		Min. Fixed Charge:	$15.00		Next 400:	$0.05206	
					Next 500:	$0.04602	
					Over 1000:	$0.02692	
SC 7 Non-Resid Transportation for DG (Winter)							
Bill issuance charge:	$0.00	Facilities Cost:	$6,230.40				
First 3 therms:	$0.00	Customer Cost:	$315.88				
	$0.00		$6,546.28		Next 97:	$0.00000	$0.12039
		Min. Fixed Charge:	$15.00		Next 400:	$0.00000	
					Next 500:	$0.00000	
					Over 1000:	$0.00000	

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

A. Yes.