STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.	Case 14-E-0493
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service.	Case 14-G-0494

DIRECT TESTIMONY

OF

UIU Rate Panel

Dated: March 20, 2015
Albany, New York

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I. INTRODUCTION AND OVERVIEW

Q. Would the UIU Rate Panel please state their names and business address.

A. **(Johnson)** My name is Ben Johnson, and my business address is 5600 Pimlico Drive, Tallahassee, FL 32309.

(Panko) My name is Danielle M. Panko and my business address is 99 Washington Avenue, Suite 640, Albany, NY 12231.

Q. By whom are you employed, in what capacity, and what are your professional backgrounds and qualifications?

A. **(Johnson)** I am employed as a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation. Over the course of more than 35 years, I have been actively involved in more than 400 regulatory dockets, involving electric, natural gas and other utilities. I have presented expert testimony on more than 250 occasions, before federal regulatory agencies, various state courts, and regulatory commissions in 40 states, two Canadian provinces and the District of Columbia.

The majority of this work has been performed on behalf of regulatory commissions, consumer advocates, and other government agencies involved in regulation, but our firm has worked for other types of clients as well, including large industrial consumers and non-profit entities like the American Association of Retired Persons ("AARP") and the North Carolina Sustainable Energy Association ("NCSEA").

(Panko) I currently hold the position of a Utility Analyst III with the Utility Intervention Unit ("UIU") of the New York State Department of State's Division of Consumer Protection. I received a Bachelor of Science in Mathematics from the State University of New York at New Paltz in 2001 and a Master of Science in Electrical Engineering from the State University of New York at New Paltz in 2008.

From 2000 to 2001, I served as an intern with Central Hudson Gas and Electric Corporation ("Central Hudson") located in Poughkeepsie, New York, in the Accounts Service Department and subsequently in the Electrical Engineering Department. In 2004, I joined Philips Semiconductors in the Integration and Reliability Department located in the IBM Plaza in East Fishkill, New York, where I held various reliability engineering positions with increasing responsibilities. In 2007, I joined Consolidated Edison Company of New York, Inc. ("Con Edison") in the Rate Engineering Department – Division of Finance located at 4 Irving Place, Manhattan, New York, as an Analyst in the Gas Rate Design Section. After two years, I was promoted to Senior Analyst with increasing responsibilities in the same section.

In 2012, I began my employment as a Utility Analyst III with the New York State Department of State's UIU. My primary responsibilities include advocating on behalf of the UIU in Public Service Commission ("PSC" or "Commission") proceedings, researching utility policy and regulatory related issues, and representing the UIU during various utility-related meetings and rate case negotiations. These include: 14-E-0318 and 14-G-0319 (Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central

Hudson Gas & Electric Corporation for Electric and Gas Services); 14-M-0101 (Reforming the Energy Vision ("REV") Proceeding); 13-W-0303 (Proceeding on Motion of the Commission to Examine United Water New York, Inc.'s ("United Water") Development of a New Long-Term Water Supply Source); 13-W-0246 (Verified Petition of Untied Water for Implementation of a Long-Term Water Supply Surcharge, and Related Tariff Amendment); 13-W-0295 (Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations for United Water); 13-E-0030 and 13-G-0031 (Proceedings on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Con Edison for Electric and Gas Services); 12-M-0476 (Proceeding on Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-residential Retail Energy Markets in New York State); and 12-M-0192 (Joint Petition of Fortis Inc. et. al. and CH Energy Group, Inc. by Fortis and Related Transactions).

Q. Have you previously testified before the New York State Public Service Commission?

A. **(Johnson)** Yes. I previously submitted testimony in Cases 13-E-0030 and 13-G-0031, involving Con Edison.

(Panko) Yes. I have previously submitted testimony in Cases 13-E-0030, 13-G-0031, 14-E-0318, and 14-G-0319.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes, Exhibit _ (URP-1) through (URP-6) accompany our testimony.

Q. What is the nature of this testimony?

A. We are testifying on behalf of the UIU and will focus on some key aspects of the tariff changes requested by Orange and Rockland Utilities, Inc. (“Orange and Rockland” or the “Company”). Although we touch on some other topics, like customer outreach efforts, our testimony is primarily focused on the Company's embedded cost of service (“ECOS”) studies and aspects of the Company’s rate design that discourage energy conservation. Consistent with this focus, we recommend various changes to the Company's requested rate design, particularly with respect to customer charges, volumetric rates, and time-sensitive rates including Voluntary Time of Use (“VTOU”) rates.

Q. How is your testimony organized?

A. Our testimony has six sections. This first section is an introduction to the forthcoming testimony. In the second section, we briefly summarize our recommendations. In the third section we briefly discuss the background of the Company’s previous electric and gas rate cases (initiated in 2011 and 2008, respectively) and this current electric and gas rate case.

In the fourth section we discuss Orange and Rockland's ECOS methodology and place this discussion into a broader context by explaining some of the problems and limitations that are inherent in fully allocated ECOS studies, and the appropriate role these studies should play as a tool for the Commission in carrying out its responsibility to establish just and reasonable rates that serve the public interest. In this section, we also discuss in detail the methodology the Company used to classify and allocate various fixed or “joint” costs to customer classes. In the fifth section, we discuss the Company's proposed revenue distribution and offer an alternative approach for the Commission's consideration.

In the sixth and final section we discuss key aspects of the Company's current rate design for electric and gas residential and small commercial customers, and we examine key aspects of the Company's rate and tariff proposals in this proceeding as they affect these customers. We explain certain problems with both the current and proposed rates and provide recommendations for how the Commission could improve the Company's rate design to be more equitable and more consistent with the Commission's stated public policy goals, particularly with respect to the encouragement of energy conservation. We also briefly discuss the Company's current opt-in VTOU rate for residential customers and offer suggestions for further investigation.

II. SUMMARY OF RECOMMENDATIONS

Q. Please briefly summarize your recommendations.

A. Our recommendations are presented in the order of my testimony and are as follows:

<u>Electric and Gas Cost of Service</u>

We recommend changing the manner in which the "minimum system" costs are allocated, by allocating these fixed costs giving equal weight to data related to three different factors: the volume of energy flowing through the system, non-coincident peak demand, and the number of customer accounts. Energy usage should be considered because the primary purpose of the system – and the ultimate “cause” that explains why the minimum system is constructed – is to deliver energy to customers. Non-coincident peak demand should also be considered, consistent with the manner in which the rest of these cost categories (the portion in excess of the minimum system) are being allocated by the Company. Finally, we recommend giving some consideration to the Company's preferred customer-based C01 allocation factor, in the interests of methodological continuity.

Electric and Gas Revenue Allocation

There is no need to drastically adjust the existing revenue relationships based on the ECOS results, since it is merely a tool, which should be just one part of the overall ratemaking process. However, that tool should be used in a more consistent manner, thereby ensuring that residential and small commercial customers are treated fairly.

For example, the Commission should reject the Company's proposal to increase the residential and commercial winter space heating rates by 28.66% and 13.55%, respectively. There is no justification for this extreme disparity in percentage rate increases. The current residential rates are already higher than the commercial rates, and both our ECOS study and the Company's ECOS study show residential heating customers are generating a higher class rate of return than the commercial heating customers. Similarly, both ECOS studies indicate the small commercial customers who do not have interval demand meters are generating high class rates of return. The Commission should take this into consideration in setting rates by allocating a below-average share of the overall rate increase, as was done with other customer groups that were shown to be generating high rates of return.

Also, we believe the Company is going too far in some of its revenue allocation proposals. In particular, it is proposing a significant shift in the revenue burden from commercial to residential gas customers, based on its decision to effectively eliminate one-third of the adjusted deficiencies and surpluses in a single year. If this pace were continued in each year of a multi-year settlement, the entire amount of the adjusted class-specific deficiencies and surpluses would be eliminated in just three years. In our view there is no need to adjust the existing revenue relationships this quickly, nor would it be appropriate to do so.

<u>Rate Design</u>

Electric customer charges, block rates and seasonal differentials

We recommend the Commission adjust the Company's rate design for residential and small commercial customers to better advance the state's public policy goals by creating price signals that promote energy efficiency and conservation and ensuring fairness for all customers – including low income customers and low usage customers. At minimum, we recommend not increasing the fixed monthly customer charges; the authorized revenue increase should instead be collected through the volumetric delivery rates, thereby providing stronger price signals to encourage energy efficiency and conservation. Depending upon the magnitude of the final authorized revenue requirement, it may be feasible and preferable to modestly lower the monthly customer charges. In general, we recommend shifting the rate design to recover a slightly larger share of the residential and small commercial customers' share of the revenue requirement from the second usage block during the summer period and a slightly smaller share from the first block in the winter, thereby introducing a slight incline in the winter, and creating a slightly greater disparity between summer and winter rates. Similar adjustments should be made to rates paid by Service Classification (“SC”) 2 small commercial customers, including a movement toward a flatter rate structure where declining rates currently exist.

Gas Minimum Bills and Volumetric Rates

We recommend the Commission take steps to improve the Company's rate design to more effectively advance its public policy goals. In particular, we recommend not increasing the fixed minimum bill amount for either residential or small commercial firm gas customers. Any rate increase should be recovered through the volumetric delivery rates, thereby improving fairness and sending stronger price signals to encourage energy efficiency and conservation. We also recommend modest steps toward flattening the Company’s declining block rate structures for residential and commercial service, in order to improve fairness, encourage energy efficiency and conservation, and provide more opportunities for customers to control their monthly energy bill.

Rate Design Study

We recommend that the Company be required to prepare a detailed study evaluating the various factors that impact residential and small commercial customer load shape and cost characteristics, and the role that rate design can play in encouraging energy efficiency and conservation, integrating lessons learned from previous studies in New York State. We recommend forming a collaborative with all interested parties in this proceeding within 60 days after issuance of the final order to fine-tune the scope of work and help ensure the study provides useful information that can help inform discussion of these issues in the REV proceeding and future rate cases.

Customer Education and Outreach

We recommend the Company expand upon its customer outreach and education program to provide more information to customers – particularly low and moderate income customers – with respect to how the Company's rates are structured, and how customers can control their monthly energy bill by taking steps to control their usage. We also recommend training the Company's customer-facing employees concerning these issues, so they can more effectively help the Company's residential and small commercial end-use classes control their monthly bills.

Time-Sensitive Rate Structures

In addition to continuing to offer residential customers the existing VTOU rates, the Company should experiment with offering other types of time-sensitive rates, which provide effective incentives for residential customers to reduce load during peak times, and to shift load from peak to off-peak time periods, taking into account actual system load conditions. More specifically, we recommend that the Commission require the Company to implement a Critical Peak Pricing ("CPP") Pilot Demonstration Program as part of the first wave of proposed demonstration projects arising out of this proceeding.

III. BACKGROUND

Q. Please briefly discuss the Company's previous electric rate case initiated in 2011.

A. In its Order Adopting Terms of the Joint Proposal, with Modification, and Establishing Electric Rate Plan, issued, June 15, 2012, in Case 11-E-0408, the Commission approved a three-year rate plan designed to increase electric delivery revenues by $19.4 million (7.9%), $8.8 million (3.3%), and $15.2 million (5.6%) (a phase-in of $15.2 million per year to base rates) for three successive rate years, July 1, 2012 through June 30, 2015. In an effort to mitigate bill impacts, the Commission approved the transfer of $2.1 million of the $15.2 million base rate increase in rate year ("RY") 3 into the Company's Energy Cost Adjustment ("ECA") rather than increasing the cost of service in the last rate year (see page 9 of the Order).

Q. Please briefly describe the Company's previous gas rate case initiated in 2008.

A. In its Order Adopting Joint Proposal and Implementing a Three-Year Rate Plan, issued, October 16, 2009, in Case 08-G-1398, the Commission approved a three-year rate plan designed to increase gas delivery revenues by $8.9 million each year (2009 through 2011) on a levelized basis, instead of a traditional cost of service approach which would have increased delivery rates by $12.8 million (RY1), $5.2 million (RY2), and $4.5 million (RY3). This was in an effort to minimize the 2009 rate increase under the economic conditions that existed then; the Company received $318,000 in interest payments which ratepayers were responsible for paying back over time. No additional gas rate increases have been requested by the Company until now, which has helped stabilize gas delivery rates for more than four years.

Q. Would you now provide some background information concerning the current cases as it relates to your testimony?

A. Yes. In its filing on November 14, 2014, Orange and Rockland is seeking an electric revenue increase of $33.4 million and a natural gas revenue increase of $40.7 million for a one-year case – which will affect customers in all or parts of Orange, Rockland, and Sullivan Counties. The Company states the request is largely due to a rise in property taxes, additional electric and gas infrastructure investments (including the installation of Advanced Metering Infrastructure ("AMI") in Rockland County), and costs related to Superstorm Sandy. If approved, the average delivery revenue will increase by 11.5% and 35.1% for electric and gas service respectively. Assuming the Company's projected supply costs do not change, the average customer bill will increase by 5.2% and 16.8% for electric and gas service respectively.

The requested increase to the Company's electric and gas revenues would impact approximately 227,915 electric customer accounts, of which 192,183 (84%) are SC1 residential accounts, and 133,136 natural gas accounts, of which 121,071 (91%) are residential accounts, as shown in the Company's Electric and Gas Rate Design Workpapers. The Company mitigated the proposed rate increases by making modifications to reduce its healthcare costs, extending the amortization periods of certain deferrals, negotiating long-term agreements to reduce taxable properties, and by proposing a lower return on equity ("ROE").

The rate increase proposed for some individual customer classes differ from the overall average increase, reflecting the results of the Company's ECOS study. The Company attempted to mitigate this impact to a degree, by considering only no more than one third of the calculated customer class deficiencies and surpluses from the ECOS study.

IV. COST OF SERVICE

A. Introduction

Q. Can you briefly introduce your discussion of Orange and Rockland's ECOS studies?

A. Yes. The underlying foundation for Orange and Rockland's proposed rate design and revenue distribution are ECOS studies for the electric and gas distribution systems. The ECOS studies were developed using a two-step process.

The first major step involved functionalization and classification of costs to various operating functions (e.g., transmission, distribution, customer accounting and customer service). During this step, all costs were organized into three classifications: demand-related, commodity-related and customer-related. For instance, the Gas Rate Panel at page 7 of its testimony explains that costs were classified as being "demand-related" if they were primarily "caused by the peak hourly loads placed on the various components of the gas system." A similar approach was used in the electric study. The Company explains that "commodity-related costs are variable costs caused by the total quantities of gas delivered during the year" (Gas Rate Panel at page 7) and "Energy-related costs are variable costs resulting from the total kilowatthours ["kWh"] delivered during the year" (Demand Analysis and Cost of Service Panel – Electric at page 15).

The third classification, "customer-related costs," consists of fixed costs that do not neatly fit into the "demand-related" or "commodity-related" (gas) or "energy-related" (electric) classifications. The Company labels (classifies) them as "customer-related" costs because they are "fixed costs which are caused by the presence of customers" and because these costs do not vary with fluctuations in demand or energy usage. (Demand Analysis and Cost of Service Panel – Electric at page 15; see also Gas Rate Panel at page 8)

We are disputing the Company's treatment of these costs, and will be discussing them in considerable depth. For the moment it is sufficient to point out that many of these costs do not directly vary with the number of customers just as they do not directly vary with peak usage or energy consumption. These are fixed costs that are necessary to deliver energy to customers, but they do not increase or decrease in proportion to the number of customers connected to the Company's system.

The second major step, "allocation," involves the development and application of various percentage factors to spread costs to particular customer classes and rate schedules. The allocation factors were derived from various data sources, and tend to closely track the initial decisions concerning how costs are functionalized and classified. For example, transmission related costs were allocated based upon estimates of system-wide coincident peak demand for various classes.

Q. Please briefly elaborate on the purpose of fully allocated embedded cost studies, and explain some of their limitations.

A. Yes. Fully allocated cost of service studies divide total test-year revenues, rate base, and operating expenses among the various customer classes to estimate the rate of return earned from each class. These types of studies have long been used by this Commission and other regulators as a tool to assist with developing electric and gas rates. As long as their limitations are recognized, and reasonable allocation formulas are employed, fully allocated ECOS studies can be useful in determining an appropriate distribution of the revenue requirement amongst the various customer classes.

Because they are based upon embedded costs, these studies do not always report direct cause-and-effect relationships between the consumption decisions of the class members and the costs incurred by the utility. Thus a "cost" is not necessarily the actual expense that a particular group of customers causes or imposes on the system, or a measure of the amount by which total costs would be reduced if that customer or group of customers were to leave the system. Although people sometimes speak of ECOS studies as reflecting “cost-causation,” this is only true to a limited degree.

The extent to which a study reflects cause-and-effect relationships varies with the category of costs in question, and the allocation factors chosen by the analyst. The relationship is most attenuated, and the degree of arbitrariness or subjectivity is most serious, when dealing with the portion of the utility's revenue requirement that reflects fixed costs that economists would define as being either joint or common costs. Joint and common costs (as economists define these terms) cannot be directly traced to any one class. These costs are neither caused by nor unambiguously attributable to any specific customer class. These costs must be allocated by a formula based upon subjective judgments that largely control the final outcome. The final results depend on how joint and common costs are initially classified, as well as the specific allocation formulas chosen by the analyst (which generally follows from decisions made during the classification process).

Q. Can the judgment and arbitrariness be eliminated if the analyst is completely unbiased and if sufficient effort is applied to the task?

A. No. Embedded cost allocation studies are simply a tool for evaluating the relative fractions of the total revenue requirement that can reasonably be recovered from each class. At best, these studies provide a helpful yardstick for judging whether or not each customer class is paying a reasonable and appropriate share of the joint and common costs. The real question is whether the yardstick is reasonably straight and true, or whether it is bent to favor particular classes at the expense of others.

Widely differing results can be developed for the same set of customers served by the same utility, depending upon the particular year in which the costs are studied, the quality of the load research data and other inputs used, and/or the particular allocation approach that is used in preparing the study. When there is a dispute concerning the results of an ECOS (as there is in this case), the underlying source of the dispute is rarely with the people performing the studies or with the amount of effort and resources devoted to the analysis. Rather, it is inherent in the very concept of allocating embedded costs, and the decisions that are made concerning how to classify and allocate costs that are not readily traceable to specific customers or customer classes.

B. Common, Joint and Fixed Costs

Q. Can you please elaborate on how economists categorize and analyze different types of costs?

A. Yes. Over the past 100 years, economists have developed a highly refined and robust understanding of different types of costs incurred by firms and how these different types of costs are generally recovered through prices paid by customers. Three concepts are particularly relevant to this proceeding: common costs, joint costs and fixed costs.

Common costs are incurred when production processes yield two or more outputs. They are often common to the entire output of the firm but can be common to just some of the outputs produced by the firm. An increase in production of any one good will tend to increase the level of common costs; however, the increase will not necessarily be proportional. The costs of producing several products within a single firm may be less than the sum of the analogous costs that would be incurred if each of the products were produced separately.

Joint costs are a specific type of common cost—ones that are incurred when production processes yield two or more outputs in fixed proportions. A classic example arises in the joint production of leather and beef. Although cattle feed is a necessary input for the production of both gloves and hamburgers, there is no economically meaningful way to separate out the feed costs that are required to produce each. If the quantity of leather and beef is reduced, there will be a savings in the amount of cattle feeding costs, but it is impossible to say how much of this change in cost results from the change in the quantity of leather and how much from the change in the quantity of beef.

Fixed costs (as distinguished from variable costs) are simply those elements of the firm's total cost which do not increase as the volume of output increases. The difference between fixed costs and sunk costs is that the former can be reduced or eliminated if the firm is willing to exit the market entirely (e.g., by converting its equipment over to another purpose). In contrast, sunk costs can be thought of as an extreme case or special type of fixed cost – sunk costs cannot be avoided or changed even by discontinuing production entirely; thus, unlike most fixed costs, sunk costs (once they are incurred) are irrelevant for most economic decisions. A typical example of a fixed cost is the cost of owning a factory building; as long as the building is in use as a factory, its costs are unavoidable (and they do not vary with the volume of output produced by the factory). However, if the firm discontinues production, and sells the building to someone who converts it to another use, it will avoid the costs of ownership. Hence, the cost is fixed, but it is not sunk because the building can be readily converted to another purpose.

A simple example of a sunk cost is the cost of writing a novel. Once this cost is incurred, it cannot be avoided, reduced, or eliminated, regardless of whether or not the novel is published, or how many copies are sold. Stated another way, sunk costs are irretrievable once the decision to incur them is implemented. From that time forward, they are completely irrelevant to any pricing, production, or other economic decisions that must be made.

Q. How do these economic cost concepts relate to the use of ECOS studies in regulatory proceedings?

A. In unregulated markets decisions made by producers and consumers interacting in the market determine what costs are incurred by producers and the extent to which costs are recovered from specific consumers or customer groups. Prices tend to reflect direct costs – particularly marginal, or variable costs – plus a contribution toward joint and common costs that varies depending on market conditions and the strength of demand for different products or services. In unregulated markets, the determination of prices occurs through the interaction of supply and demand, which determines the relative share of joint and common costs recovered from different customer groups. In regulated markets, on the other hand, regulators decide what prices are charged which in turn largely determines the extent to which joint and common costs are recovered from specific consumers or customer groups.

In this case, as in most regulatory proceedings, there is little or no controversy concerning the appropriate recovery of costs that are clearly and unambiguously caused by specific customers – e.g., variable costs that would no longer be incurred if the customer reduces its use of the system, or were to leave the system entirely. A good example is the cost of sending the customer a bill each month. Where controversy tends to arise is with the appropriate recovery of joint and common costs. The classic solution favored in regulatory proceedings is to use an ECOS study to evaluate what share of the joint costs should be recovered from each of the joint products.

ECOS studies are administratively convenient, since they provide regulators with a quantitative benchmark to help them decide how much to charge different customers. But, as economic theory demonstrates, this tool is not all-powerful and it can be misleading, or lead to sub-optimal pricing decisions. From an economic perspective, these ECOS studies do not report the "correct" prices that ought to be charged, because there is no unequivocally "correct" way to allocate joint and common costs. Furthermore, an embedded cost allocation study does not eliminate the use of, or need for, judgment – it simply shifts the focus to judgments made during the allocation process, rather than judgments made during the rate design process.

The Commission has the responsibility for ensuring that the public interest is served, that public policy goals are advanced, and that rates are fair, just and reasonable. If the ECOS is misinterpreted as some form of objective "truth" that must be followed by the Commission when setting prices, it can obscure the judgments that underpin the Company's rate proposals, and potentially conflict with the Commission's use of its own judgment and its responsibility to arrive at rates that advance the public interest.

Q. How does this discussion relate to your disagreement with certain aspects of the Company's ECOS studies?

A. We are disputing the treatment of four categories of costs in the electric study: Underground Lines – Customer, Overhead Lines – Customer, Transformers – Overhead Customer and Transformers – Underground Customer. In the gas ECOS we are disputing the treatment of costs in one category: Distribution – Customer. In both the gas and electric studies, these costs are being allocated using similar allocation factors, which are called "C01" in each case.

All of the disputed costs are fixed costs that do not vary as a direct function of the level of peak demand or the number of customers who are connected to the system. Instead, they primarily vary as a function of the number of miles of streets served by the system. These categories contain the fixed portion of the cost of underground and overhead lines and gas distribution mains. The variable portion of the cost of these facilities has been placed into a different category, to be allocated based on peak.

The disputed costs are a significant part of the overall ECOS, and often exceed the variable portion of the system components in question. For instance, the cost of opening a trench and installing a gas or electric distribution line of the smallest feasible size is sometimes described as the “minimum system cost” while the portion of the cost of the line that exceeds that theoretical minimum is classified as “demand-related” and allocated using a peak demand allocation factor.

Q. Please elaborate.

A. The costs of installing a gas or electric distribution system of minimum size clearly fit the definition of common costs – many different types of customers share the benefit of being served by the same system. It is difficult or impossible to disentangle the cost of serving one customer from the cost of serving another customer, and the costs don't necessarily vary in exact proportion to variations in the volume of use of each individual customer.

Looking more closely at the definition of common costs given earlier, it is apparent that an increase in the volume of gas or electricity distributed to a specific customer or group of customers will cause an immediate change in the variable energy costs – the cost of purchasing the gas or electricity that the Company delivers to that customer or group of customers. A somewhat similar phenomenon applies to the costs the Company classifies as “demand” costs, but only over the longer run. Increases in the volume of energy delivered to customers results in the need to build a larger capacity that can efficiently handle that larger volume of energy. Thus, in the long run the "minimum system" cost itself is appropriately viewed as a fixed cost, whereas costs in excess of that minimum are correctly viewed as variable costs that can more clearly and directly be attributed to specific customers and customer groups.

Particularly once the "minimum system" costs are considered, the average cost of serving customers will vary depending on how large a system is built. Put another way, the changes in total cost that occur as system capacity increases will not necessarily be proportional to percentage increases in usage. This phenomena occurs because of what economists refer to as "economies of scale" and "economies of scope."

In fact, the costs of providing gas or electricity service to multiple customer classes within a single firm tend to be less than the sum of the analogous costs that would be incurred if each customer class were served separately. In other words, gas and electricity distribution systems enjoy pervasive economies of both scale and scope, which in turn means that controversies concerning joint and common cost recovery will loom large in determining how the benefit of those economies should be shared amongst different customers and customer classes.

Q. Please continue.

A. Because of the pervasive impact of economies of scale and scope, there is no unambiguous or perfect method available for allocating the fixed costs of the distribution system – whether based on principles of "cost causation" or otherwise. The most that can be hoped for is an allocation method that produces reasonable and equitable results, and does not conflict with other public policy goals.

Strictly speaking, the cost of installing pipes is a sunk cost; once the pipe is in place, no future decision will alter those installation costs, or allow them to not be incurred. If the company is able to salvage some of the material involved, the salvageable portion of the pipe cost would be considered a fixed cost, but not sunk. However, the labor needed to engineer and install the facilities is irretrievable. Therefore, once the labor costs of installation have been incurred, from an economic perspective, they are irrelevant to future decisions about the appropriate price level for the service or services that utilize the pipe (or wire). But even if one simplifies somewhat and thinks of the “minimum system” costs as being fixed costs, about the same conclusion is reached from an economic perspective: principles of cost causation are not sufficient to determine the appropriate method of recovering these costs, because these costs don't vary with individual customer purchasing decisions.

In the calculation of marginal or incremental cost, fixed and sunk costs are canceled out in the computations. This technique is one of the most distinctive attributes of the economist's concept of marginal cost and helps set this concept apart from more familiar notions of average or total cost. The reason for this distinctive treatment is straightforward: Since fixed and sunk costs do not change with the volume of output, they have no direct impact on the level of marginal cost, which is the change in total cost associated with a change in output. Thus economic theory tells us that recovery of these costs is dependent upon other factors – notably, forces of supply and demand, and the degree to which different customers and customer classes benefit from the system components that give rise to the costs in question.

Q. You are disputing the Company's treatment of the “minimum system” costs. Can you explain how the Company is handling these costs in its ECOS studies, and why you disagree with this treatment?

A. Because they are classified as “customer-related,” the Company is allocating these fixed costs based upon the number of customers in each class. The implication of this treatment is that small customers should contribute the same amount toward recovery of these costs as much larger customers notwithstanding that (1) large customers use the system more intensively than small customers, (2) they gain more benefit from the system than smaller customers, and (3) they can typically afford to pay more than smaller customers. Yet, uniform per-customer cost recovery is merely an artifact of the proposed cost allocation methodology – the costs in question do not, in fact, vary directly with the number of customers on the system, and thus there is no compelling economic reason to recover these costs on a uniform per-customer basis.

In this regard it is important to realize that the Company is classifying the “minimum system” in a similar manner as they classify costs that directly vary with the number of customers, like the cost of rendering the monthly bill, and the cost of meter reading. Yet, the “minimum system” costs have fundamentally different characteristics. In our view, these costs should be recovered in a manner that best achieves the Commission's public policy objectives, consistent with the economic principles applicable to joint cost recovery.

Q. Can you clarify how the “minimum system” costs relate to your explanation of joint and common costs?

A. In competitive markets, to the extent common costs vary with output, they are recovered in the same manner as direct costs: common costs directly affect the marginal cost of producing each service, and thus directly influence prices (in competitive markets, prices tend to equilibrate towards marginal cost). Joint costs, on the other hand, have no impact on marginal cost, and thus these costs do not directly determine prices in unregulated, competitive markets. Instead, joint costs are recovered through the prices charged for all of the different products or services produced through the joint production process. The respective proportions will vary depending upon supply and demand conditions generally, the degree to which purchasers of different products benefit from the joint production process, and the relative strength of demand for the various services or products that benefit from the joint production process.

Stated another way, in competitive markets each customer does not contribute a uniform dollar amount toward the recovery of joint costs, without regard to how much of the product they purchase, or how much they benefit from the joint production process. Instead, cost recovery varies with larger customers contributing more than smaller customers, and different types of customers contributing different amounts based upon the strength of demand in different markets or submarkets. In general, the stronger the demand – and in that sense, the greater the benefit received from the joint production process – the greater the share of joint costs that will be borne by the respective product, service, or customer group. If the demand for leather goods is strong, and purchasers of gloves are willing to pay more for leather gloves than for cloth gloves, they will end up paying a significant share of the cost of cattle feed, even if hides are merely a byproduct, with cattle primarily being grown for their meat.

This well-established insight from the economic literature is intuitively logical and fair. The purchasers of both leather gloves and hamburgers benefit from the joint production process, the demand for both beef and leather products is strong, so it intuitively makes sense that market forces would ensure that both types of customers contribute toward the joint costs. But there is no intuitive reason why someone buying a single pair of gloves should contribute the same amount as someone buying a leather coat, or that someone buying a hamburger should contribute the same amount as someone buying a standing rib roast. To the contrary, economists have determined that various groups of customers share the burden of joint costs like cattle fed in proportions that vary based upon the demand side of the supply and demand equation. Customers do not all pay the same amount; instead, those who benefit a lot from the joint production process (whose demand is strong) pay more of the joint costs than those who benefit just a little (whose demand is weak).

The Commission does not need to implement prices that precisely follow the manner in which joint costs are recovered in unregulated, competitive markets. But, the patterns observed in unregulated markets are both relevant and instructive. There is no logical reason to recover a uniform portion of the joint costs from both small and large customers, nor is there any reason to ignore the vast differences in benefits received from different sizes and types of customers who use the system. To the contrary, the Commission can and should use its discretion to establish prices that recover joint costs in a more equitable manner – while advancing other important public policy goals like the encouragement of economic efficiency and energy conservation.

C. Minimum System Cost Allocation

Q. Can you please explain how this issue affects the residential customers that UIU represents in this proceeding?

A. Yes. The significance of this issue can be seen on page 1 of Exhibit ___ (URP-1). The Company is allocating approximately 80% of the minimum system costs to the Residential SC1 General category (based upon the large number of customer accounts in this category); yet these customers receive just 37% of the electricity delivered through the system. In other words, the Company's methodology places a greatly disproportionate share of the joint cost burden on residential customers, relative to the benefits they receive from the system, as indicated by the volume of energy that is delivered to them through the system.

If the Company had not separately analyzed the minimum system costs, but had simply allocated all of the costs of underground and overhead lines and transformers using Non-Coincident Peak demand, the Residential (SC1) General category would have been allocated approximately 64% of these costs instead of 80%. Put another way, if the Company had not split these accounts into the “fixed” portion (based upon a hypothetical minimum size system), and the portion that varies with demand, and had simply allocated all of the costs based on non-coincident peak demand, residential customers would be allocated just 64% of these costs, rather than 80%. This further confirms that the Company's methodology shifts the cost burden onto residential customers.

Similar patterns can be seen in the gas ECOS study. As shown on page 5, the Company is allocating nearly 95% of the minimum system costs to the Residential and Space Heating (SC1) category (based largely on the number of gas customer accounts in each category), yet these customers receive less than 72% of the gas delivered through the Company's system.

If the Company had not analyzed the minimum system costs separately, but had simply allocated all of the costs of its distribution mains using Non-Coincident Peak demand, the Residential and Space Heating (SC1) category would have been allocated approximately 76% of these costs.

Q. Is there a similar impact on the small business customers?

A. Yes, although it is not as easily quantified, the same sort of impacts apply to small commercial customers relative to large commercial customers. Under the Company's allocation approach, all of the customers in the C&I (SC2) Secondary category are effectively being allocated a similar share of the minimum system costs, regardless of how small or how large they are. In other words, a large business that uses the system to a great extent is being allocated about the same dollar amount as a small business that uses the system (and benefits from the system) to a much smaller extent. This is not fair, is not consistent with the manner in which joint costs are recovered from different size businesses in competitive markets, and is not consistent with the public interest.

Q. Have you developed a better approach to use in this proceeding?

A. Yes. We developed an alternative version of the Company's gas and electric ECOS studies that changes the manner in which the “minimum system” costs are allocated. More specifically, we began by classifying the minimum system costs as “Fixed Costs” rather than “Customer Costs.” We then allocated these fixed costs giving equal weight to data related to three different factors: the volume of energy flowing through the system, non-coincident peak demand, and the number of customer accounts.

Although we accepted the Company's allocation of all other costs across classes, this should not be interpreted as a blanket endorsement of all other aspects of the Company's studies. Instead, we decided to minimize the number of issues in dispute, in order to focus on this one key issue, which is particularly important to residential and small business customers, and is particularly significant with respect to some of the Commission's public policy goals.

Our recommended approach gives one-third weight to energy usage (total gas or electricity usage) since the primary purpose of the system is to deliver energy to customers. Including energy in the allocation process helps ensure that larger customers contribute more than smaller customers toward the minimum system costs, consistent with the greater benefits they receive from the system. We have also considered non-coincident peak demand, consistent with the manner in which the rest of these cost categories (the portion in excess of the minimum system) are being allocated by the Company. Finally, we have given one-third weight to the Company's preferred customer based C01 allocation factor, in the interests of methodological continuity. By giving some weight to this historically accepted approach, we are attempting to alleviate the concerns of those who might otherwise view our recommendations as being too radical a departure from the status quo.

We believe our recommended approach is an improvement over the Company's methodology since it is more consistent with the manner in which these sorts of fixed costs are recovered in competitive markets. Under competitive market conditions, larger customers, who gain more value or benefit from the system, make a larger contribution toward recovery of fixed costs than smaller customers. It is also an improvement because it tends to provide price signals that are better aligned with the Commission's public policy goals, as we will explain in greater detail below.

Q. How would you respond if someone were to argue that your approach doesn't follow principles of cost causation while the Company's approach does?

A. First, the costs in dispute cannot readily be traced to the number of customers on the system, or any other readily available data that is useful in developing an allocation study precisely because they are fixed costs that do not vary with usage, the number of customers, or any other straightforward data set.

Second, the entire distribution system – including both the portions running down the street and the portion running from the street to the meters – is designed to accommodate customers' peak demands. On that basis, the entire cost of the lines that distribute gas and electricity to customers could plausibly be allocated on the basis of peak usage (e.g., non-coincident demand). The argument is straightforward; the system is designed to meet peak demand, so this is the simplest and best proxy for what "causes" these costs to be incurred.

There is certainly more merit to this peak allocation approach than the one being used by the Company. However, we do not think it is the ideal solution. The problem is that the cause and effect relationship tends to break down when a distinction is drawn between fixed and variable costs. In fact, the concept of a hypothetical "minimum system" was developed because some observers argued that only the "extra" cost of building a larger-than-minimum-scale system can be attributed to variations in peak demand, and that a large portion of the cost of the system is actually fixed with respect to peak demand. We concede there is some merit to this reasoning, but it does not solve the problem of how to recover the fixed costs. These costs are not caused by the decisions of individual customers to connect to the system, and there is no straightforward, indisputable way to attribute the fixed costs which are incurred on an aggregate basis, down to specific customers or customer groups based on principles of cost causation.

Q. Can you please elaborate?

A. Yes. We believe that the principle of "cost causation" supports giving considerable weight to the volume of energy used by different customers, because anticipated energy volumes are a key part of what "causes" (influences decisions to construct or connect to) the minimum system to exist in the first place.

While peak demand is an important focus of the engineering design phase, the decision to build the minimum size system (or to extend that system down additional streets) is no more readily traced to anticipated peak demand than it is to the anticipated number of customers. In general, these sorts of decisions are made on the basis of projections of the extent to which the proposed system is anticipated to be economically viable over the life of the equipment. Stated another way, if the system planners anticipate that sufficient economic demand exists for distributing gas or electricity to households and businesses on that street, and if that demand is strong enough to justify the investment, the system will be built or expanded.

Consider the cost of expanding a gas system into new neighborhoods, or along additional roads where there is no governmental mandate to do so. It will make economic sense to expand the gas system to serve a new area if the planners anticipate that over time enough new buildings will be constructed and connected to the system, and/or enough existing buildings will convert from propane or oil to natural gas, and that these buildings use enough energy. The key question is not whether the buildings exist, but whether the owners or tenants use enough energy and will benefit from the system enough to pay for its construction and upkeep. In essence, the new or expanded system needs to generate enough revenue to cover its costs, and this is directly related to the volume of energy that will be delivered over the system if it is built.

Bear in mind, the cost of building or expanding the system primarily depends on the size of the area and the number of miles of roads along which distribution mains will need to be installed – not on the number of buildings in the area. If the system is built, each building owner or tenant will decide whether or not to connect to the system based on their individual cost-benefit analysis, which will heavily depend upon how much energy they use. A small user who is relying on propane may have little or no incentive to connect to the system, whereas a large user will have a much greater incentive to do so, because of the larger potential cost savings from the lower commodity costs associated with natural gas, relative to propane or fuel oil.

Q. Can you please elaborate on how energy usage influences the decision to construct the minimum system in the first place?

A. Yes. From a system planning perspective, an analogous cost-benefit analysis takes place, which focuses on aggregate numbers. The decision to expand the system into a specific area will primarily focus on how much energy is being used in this area (or will be used in the future), and thus whether the planners anticipate the system will handle enough volume, and generate enough revenue, to be cost-justified. If the area is sparsely populated with small buildings that use very little energy, and the prospects for growth are not very promising, the planners are much less likely to conclude the system is cost-justified than if the area is densely populated, or it includes some large customers that use a large amount of energy.

The individual analysis and the system analysis are both closely related to the question of whether enough energy will be delivered over the system to justify the individual cost of connecting to the system, or the aggregate cost of building the system. For that reason, we believe it is important to recognize that the ultimate purpose or “cause” of the system is delivering energy and benefits to customers – not simply increasing the number of customers without respect to how much they benefit from the system. If the anticipated volume of energy to be distributed to a particular part of the city, or set of buildings, were negligible, there would be no economic incentive to create the delivery system in the first place (there would also be little reason for government authorities to require the system to be built into those areas).

In fact, some parts of the United States do not have a natural gas distribution system for precisely this reason, despite the existence of businesses and residences in the area. In other words, the existence of potential customers alone is not sufficient to justify building a distribution system – if those customers are fulfilling their energy needs using propane, fuel oil, solar, or other energy sources, and they have no desire to switch to natural gas – or the cost of extending the system to serve those customers would be too high, relative to the potential cost savings from switching to natural gas from alternative energy sources.

Q. If energy usage is the most important factor in determining whether the system is constructed in the first place, why are you also giving weight to two other factors in developing your recommended ECOS studies?

A. We recognize that a purely energy-based allocation approach might seem to be too radical a departure from the Company's historical practice, which has long been accepted by the Commission. Further, we recognize that system costs do vary somewhat as a function of peak demand, and this variation is the focus of much of the engineering planning process. Hence, the incremental cost of installing larger pipes or wires rather than smaller ones is a function of peak demand. We also recognize that the cost of the system will vary somewhat with the number of customer locations (but not the number of customers, per se). For instance, the incremental cost of installing service lines to connect each customer location to the nearest distribution main or line is partly a function of the number of buildings, which is loosely correlated with the number of customer locations.

Q. Are you saying there is a one-to-one relationship between the number of customer locations and the cost of installing connections from customers to the distribution lines or mains?

A. No. In some cases a single line serves a single customer, but in other cases the same line may be shared by multiple customers. In general, the cost of service lines is strongly influenced by the configuration of buildings – how many buildings are served, how close together they are, how far back they are from the right of way where the distribution main or line will be located, and so forth.

In fact, a single service line can connect a large apartment building, a quadraplex, or an individual house to the distribution system. The size and cost of the respective services may vary, but not so much due to differences in the number of residences in each building as much as the anticipated peak load that will need to be handled by that line. While a larger line may be used to serve an apartment building than a duplex, the cost differences are not due to differences in the number of customers served. Neither the design of the service, nor the cost, is a simple function of the number of customers. This can easily be seen by comparing two hypothetical examples. Consider a 4,000 square foot quadraplex and a 4,000 square foot single family home. If the anticipated electrical consumption is the same for both buildings, the cost of the electrical lines that connect these buildings to the system might be identical – yet one building could contain as many as four customers, while the other would have no more than one customer.

The importance of energy consumption, and the relative insignificance of the number of customers can be even more dramatically illustrated by considering a hypothetical building containing 30 apartments. The decision to install a service line to the building, and the size of the service line, will depend upon decisions made by the original owner or developer of the building – whether he or she anticipates the occupants will be using electricity for all of their energy needs, or will be using gas for some of their requirements. Suppose the owner or developer decides to use electricity for everything except water heating; in that case, the developer or owner will still need to decide whether to install a centralized system that provides hot water circulating throughout the building, or install a separate water heater in each apartment, and whether to use solar, natural gas or propane to heat the water. All of these decisions will be driven by anticipations concerning energy usage over the life cycle of the investment decisions – including his perceptions concerning convenience, cost effectiveness, and other factors relating to the relative merits of each energy choice. What is striking about this hypothetical example is not only that the cost of serving the building is largely a function of decisions made based on an evaluation of the merits of natural gas or electricity relative to alternative energy sources, but also that the costs are almost entirely independent of the number of customers in the building.

The flaw in analyzing and recovering the fixed costs of the system on a per-customer basis can also be vividly illustrated with another simple example. Consider a 30 unit apartment building which can be converted from individual metering to a master meter (or vice versa). While the landlord or building association may perceive an opportunity to save money by using a single meter (in order to take advantage of the volume discounts built into the Company's rates), in reality the fixed costs of connecting that building to the system may not change in the slightest – aside from the savings associated with fewer meters.

From an economic standpoint, it is clear that utilities do not build a distribution system to connect to buildings that use no energy. Rather, these investments are made in anticipation of distributing gas or electricity to those buildings. Unless this particular energy source is viewed favorably, relative to other alternatives, (e.g., there is strong enough demand for natural gas), customers will not connect to the system, and ultimately the system itself would not exist. This reasoning applies most strongly to the minimum system, but it also applies to other parts of the system, like the service lines that connect buildings to the system.

Q. Have you developed estimates of the impact of following your recommendations concerning minimum system costs on the electric ECOS results?

A. Yes, we have. We developed some estimates of the impact of applying our recommended allocation approach by applying equal weight to customers, energy, and demand, as shown on Exhibit ___ (URP-2). For ease of development and comparison, these calculations were based on the same overall numbers used by the Company. Thus, for example, the overall rate of return in the electric study (11.20%) is the same figure shown in the Company's study. However, our recommended approach generates noticeably different rates of return for some of the individual customer classes, relative to the Company's results.

The rates of return for the electric system are compared on Page 1 of Exhibit ___ (URP-2). For example, the rate of return for Residential (SC1) General Service is 10.94% in our study, compared to 10.24% estimated by the Company. The rate of return for Residential (SC1) with Space Heating is 14.52%, compared to 14.34% estimated by the Company. Residential (SC19) Voluntary Time of Use has a rate of return of 8.69% in our study and 9.64% in the Company's study.

Commercial and Industrial (SC2) Secondary in our study has a return of 10.01%, compared to the 11.44% rate of return estimated by the Company. The small commercial customers that are not metered generate a return of 26.40% in the Company's study and 37.60% in our study. Similarly, the small commercial customers that are metered using regular (non-demand) meters generate a return of 20.67% in the Company's study and 32.23% in our study. The rate of return for the C&I (SC2) Primary customer classes average 12.37% in both studies. This is consistent with the fact that these customers are being served at higher voltage levels, and thus they are not being allocated any of the minimum system costs in either study.

Q. Have you prepared a similar exhibit comparing the results of your recommended allocation approach for the gas system?

A. Yes. Page 3 of Exhibit ___ (URP-2) compares the rates of return in our gas embedded cost study to the corresponding results in Orange and Rockland's gas ECOS study. As shown, using our recommended approach to allocating the minimum system costs, the rate of return being earned by the Residential and Space Heating (SC1) class is 2.99%, compared to the Company's estimate of 2.16%. As we explained earlier, the Company's approach places too much of the cost-recovery burden on these small customers. Similarly, the rate of return for the General Service (SC2) class is 10.18% using our approach and 14.23% using the Company's approach. Bear in mind this is a very broad class; if results were split out separately for small commercial customers, the discrepancy would be greater.

V. REVENUE ALLOCATION

Q. How has the Company proposed to distribute its proposed revenue increase among the various customer classes?

A. For both gas and electric services, the company began by calculating adjusted revenue requirement surpluses and deficiencies using a “tolerance band” of plus or minus 10% applied to the class rates of return derived in its ECOS studies. It concluded that attempting to entirely eliminate these adjusted surpluses and deficiencies would result in excessively large revenue impacts on some classes. Accordingly, it decided to apply just one-third of the adjusted class-specific deficiencies and surpluses, then spread the remainder of the rate increase on a uniform basis across all classes.

Q. Can you please briefly elaborate on the “tolerance bands” mentioned above?

A. Yes. For both gas and electric services, the Company evaluated the class rates of return developed in its ECOS studies relative to a ±10% tolerance band around the total system rate of return shown in the ECOS. In other words, classes were not considered to have a “surplus” or “deficiency” if the class ECOS rate of return fell within this tolerance band. Classes that fall outside a range of 10.08% to 12.32% (electric) or a range of 3.73% to 4.55% (gas) were considered to be surplus or deficient by the revenue amount necessary to bring the realized return to the upper or lower level of the tolerance band.

Q. Was the Company consistent in its application of its ECOS results to all groups of customers?

A. No. As the Company’s Electric Rate Panel explained, it used the results of its 2013 ECOS Study during the revenue allocation process, by including a step in which “delivery revenues at the current rate level for each SC were realigned to reflect the deficiency and surplus indications identified in the… ECOS.” However, this realignment process was not carried forward all the way through the revenue allocation process in a manner that was consistent for all of the customer groups (classes or sub-classes) that were separately analyzed and reported in the Company's ECOS study.

The customers in some groups were kept separated throughout the entire revenue allocation and rate design process, thereby ensuring these groups received the full benefit of their adjusted surplus (or bore the full brunt of their adjusted deficiency) all the way to the end of the revenue allocation and rate setting process. Other groups of customers were analyzed separately in the

ECOS study, but they were merged with other, dissimilar customer groups during the revenue allocation process. As a result of this merger process, the actual rates of return reported for some groups were largely ignored when setting rates for these particular groups.

A good example is the group of small commercial customers who do not have interval demand meters. These customers pay higher rates than most other commercial customers and, as shown on page 1 of Exhibit ___ (URP-2), these higher-than-average rates translate into a higher-than-average class rate of return (22.73% according to the Company's ECOS study and 21.17% under the UIU ECOS study). Based upon this high rate of return, the Company computed an adjusted surplus for this class of $343,745 – a relatively large amount considering the small size of this group of customers – as shown on page 1 of Exhibit ___ (URP-3).

Despite the significance of this reported surplus – and this is the crucial point – it was not walled off or retained for the exclusive benefit of this group of customers. Instead, the surplus generated by this group of small commercial customers was combined with the surpluses and deficiencies generated by other types of commercial customers, most of whom pay much lower rates and generate lower rates of return. In fact, most of the surplus generated by these small commercial customers was flowed by the Company through to the benefit of other, much larger commercial customers – who are already paying much lower rates. There was no need to merge the commercial customer groups in this manner, and no need to avoid lowering the disparity between the high rates paid by these small commercial customers and the lower rates paid by larger commercial customers. Doing so largely defeats the purpose of treating these customers as a separate sub-class in the ECOS study. The merged treatment that was applied during the revenue allocation and rate design process tends to perpetuate the existing rate disparity, despite the ECOS results. This example demonstrates that, whether intentionally or otherwise, the Company is <u>not</u> consistently applying the results of its ECOS study, nor is it consistently moving toward non-discriminatory “cost-based rates.”

Q. Can you provide additional examples of the Company's failure to consistently apply the results of its ECOS results?

A. Yes. As shown on page 1 of URP-2, the Company’s 2013 ECOS Study indicates that Residential space heating customers are generating an above-average rate of return (14.34%), while the Commercial space heating customers are generating a below-average rate of return (3.46%). There is no indication in the Company's rate design work papers that it has adjusted any of its rate proposals in an effort to specifically move these rates of return toward the overall system average, despite the fact that both class returns fall outside the plus or minus 10% tolerance band. To the contrary, the adjusted surplus and deficiency amounts generated by these customer classes were merged with other residential and commercial classes (respectively) during the revenue allocation process, and their above-average and below-average returns (respectively) were largely ignored during the rate design process.

As shown on page 2 of URP-4 the Company is proposing to increase the commercial winter space heating rate from $0.02155 to level that is still very low

– just $0.02447. This works out to an increase of less than three-tenths of a penny per kWh on a rate that is already extraordinarily low (some commercial customers are paying more than five cents a kWh in the winter), and translates to a percentage increase of just 13.55%. No explanation has been offered why Orange and Rockland did not propose a larger increase in this rate element, considering that the Company's ECOS study shows this class is currently generated one of the lowest returns of any of the classes reported in its ECOS (3.46% compared to an overall system average of 11.20%). This failure to adequately take into consideration the results of the Company's ECOS study cannot simply be attributed to an unwillingness to increase individual rate elements by significantly more than the system average increase of 11.55%, since it is proposing to increase the 0-5 KW demand charge for commercial customers by as much as 88.10%, as shown on page 2 or URP-5.

The failure to maintain consistency in its application of the ECOS results is even more striking with respect to the residential space heating customers. The Company is proposing to increase the residential winter space heating rate by 28.66% – far more than its proposed 13.55% increase to the commercial winter space heating rate – despite the fact that the residential group is currently generating an above-average rate of return, while the commercial group is generating a return that is far below-average. If the Company had intended to reflect the ECOS results in its rate proposals it would have made more sense to propose an increase in the commercial rate of 28.66% or more, and an increase in the residential rate of 13.55% or less.

Q. Can you please discuss other aspects of the Company's revenue allocation proposals, particularly with respect to the handling of surpluses and deficiencies?

A. Yes. The rate of return for the Residential (SC1) General Service class falls within the 10% tolerance band in both the Company's study and in our study. This reduces (but does not eliminate) the significance of the disputed treatment of minimum system costs, which was discussed above. This costing dispute has a more significant impact during later stages of the rate design process, which we'll discuss later in our testimony.

In general, we support the use of a tolerance band, since it helps achieve “rate continuity.” For this same reason, we support the Company's decision to only give targeted treatment to a portion of the adjusted class-specific deficiencies and surpluses in the revenue allocation process before spreading the remainder of the rate increase on a uniform basis across all classes. We do, however, disagree with the decision to use a factor of one-third for this purpose. This effectively eliminates one-third of the adjusted deficiencies and surpluses in a single year. Whether or not this is intentional, if this pace were continued in each year of a multi-year settlement, the entire amount of the adjusted class-specific deficiencies and surpluses would be eliminated in just three years. In our view there is no need to adjust the existing revenue relationships this quickly, nor would it be prudent to do so, considering that the ECOS results are merely a tool, which should be just one part of the overall ratemaking process.

We believe ECOS studies can be useful, and believe it is worthwhile to make methodological improvements to these studies where feasible, as with our recommended improvements to the handling of the “minimum system” costs.

However, we do not believe the revenue allocation should be designed merely to track the results of a particular cost-of-service study. Instead, we believe thought should be given to the potential hardships imposed on particular classes, historical relationships among the classes, and other elements of interclass equity.

Moreover, the Commission should recognize that efforts to achieve perfectly uniform class rates of return are mostly fruitless. Even if a consistent ECOS methodology is employed from case to case, fluctuations in weather, economic conditions, and other variables can easily produce absolute fluctuations in the absolute class rates of return of 1%-3% or even more, defeating any such attempt at perfect uniformity. If an above-average increase is imposed in one case (because a class appears to earning less than the average return), a below-average increase may appear appropriate for that same class in the next case, simply because of fluctuations in economic conditions, weather or usage patterns – even if the underlying methodology is not changing. Of course, where changes in the costing methodology are involved, the class returns can fluctuate by even wider margins, due to differences in allocation techniques.

Given the inherent instability and subjectivity of the various allocations, the goal of absolute uniformity in class rates of return can probably never be achieved. Such an effort is an attempt to hit a moving target, and that effort can potentially conflict with important policy objectives, like rate continuity, gradualism and stability.

Furthermore, the returns earned by each of the classes depend in large part on data used in that particular the cost-of-service study. In some cases, a class that falls outside the tolerance band might have fallen inside the tolerance band if data had been used from a slightly different time period. This is most easily understood in the context of a service like municipal street lighting, which may or may not be part of the system peak, depending on when the peak occurs relative to when the sun goes down. In some years, the lights may be off during all of the peak hours, while in other years they may be on during some of the peak hours. When proposals are made to make substantial changes to the existing rate relationships (shifting more costs on to or off of specific classes based on the ECOS results), it is preferable to verify that similar results have occurred in earlier studies – something the Company did not discuss in its testimony in this proceeding.

Q. Have you developed some revenue allocation recommendations, taking into account the Company's ECOS studies, as well as your recommended changes to the ECOS studies?

A. Yes. We recommend that the Commission use greater consistency than the Company in its treatment of substantial deviations in the individual class rates of return relative to the overall system average. If a customer group is currently paying relatively high rates, and this is translating into a class rate of return that is far higher than the overall system average, the Commission should make an effort to constrain the rate increase imposed on those customers – either by moderating the increase applied to rate elements that are specifically paid by those customers, or by moderating rates that are particularly important to those customers (e.g., moderating the increase in the winter tail block rate relative to the summer tail block rate, will disproportionately benefit the residential space heating customers, thereby helping to bring their rate of return closer to the system average).

Similarly, if a customer group is currently paying relatively low rates, and this is translating into a class rate of return that is far lower than the overall system average, an effort should be made to increase rates paid by those customers relative to other customers who are currently paying higher rates and generating a higher rate of return. This can be done by targeting rates that are specifically paid by those customers for an above-average percentage increase, or by doing this to rates that are particularly important to those customers.

For example, the Commission should reject the Company's proposal to increase the residential and commercial winter space heating rates by 28.66% and 13.55%, respectively. There is no justification for this extreme disparity in percentage rate increases. The current residential rates are already higher than the commercial rates, and considering that both our ECOS study and the Company's ECOS study show residential heating customers are generating a higher class rate of return than the commercial heating customers.

Another example concerns small commercial customers who do not have interval demand meters (as well as those who receive service on an unmetered basis). These customers currently are paying relatively high rates per kWh and they are generating high class rates of return in both the Company's ECOS and ours. The Commission should allocate a below-average share of the overall rate increase to these groups, as the Company did with other customer groups that were shown to be generating high rates of return.

However, we also believe the Company is going too far in some of its revenue allocation proposals. In particular, it is proposing a significant shift in the revenue burden from commercial to residential gas customers, based on its decision to effectively eliminate one-third of the adjusted deficiencies and surpluses in a single year. There is no need to adjust the existing revenue relationships this quickly, nor would it be appropriate to do so.

VI. RATE DESIGN

A. Background

Q. Would you please describe some of the impacts to customers based on the Company's rate design proposals?

A. Yes. The Company currently offers a modestly inclining block rate structure for SC1 residential electric customers during the summer period and a flat rate structure during the other months. The SC1 rate class still includes discounts for electric space and water heating services – although the discounts have been reduced and they have not been available to new customers (since July 1, 2011). In Case 11-E-0408, the space and water heating discounts were gradually decreased, and in this case, the Company proposes to reduce the discounts by an additional 1/3rd, to move further in the direction of eliminating the discounts. Per the Commission's order in Case 11-E-0408, the Company is moving to a flat rate structure for its SC 2 and SC 3 electric customers. For its gas customers, the Company proposes to continue with its existing declining block rate structure.

If the full amount of the delivery base rate increase is approved, the net delivery and commodity impact would be an increase of approximately 5.8%-6.1% per month for electric non-heating customers - assuming average residential electric usage of 791 kWh (summer) and 620 kWh (winter), market supply projected costs, and current surcharge factors. Average residential natural gas bills are estimated to increase by approximately 19%-25% per month for gas customers - assuming typical residential gas usage of 25-100 ccf, market supply projected costs, and current surcharge factors. For its residential electric VTOU customers, the Company only proposes minor modifications to the customer charges and rate structure. Bill impacts are harder to quantify for this customer class, due to the variation in customer usage, but we provide an extensive discussion about bill impacts for these customers later in this section.

Q. What are the customer accounts and load profiles for the Company's residential electric and gas service classes?

A. The Company currently has approximately 192,183 residential electric customers under Electric SC1, of whom approximately 96% are heating and 4% are non-heating. The majority of Electric SC1 accounts are located in Orange (45%) and Rockland County (51%) and the remaining accounts are located in Sullivan County. Residential Electric SC19 VTOU accounts currently consist of approximately 2% of all residential electric accounts. As for gas, there are approximately 121,071 residential gas customers in the Company's service territory, of whom 96% are heating customers. There is only one gas heating customer account in Sullivan County; the remaining accounts are located in

Orange (31%) and Rockland County (69%). Residential electric and gas customers classified under SC1 are comprised of approximately 84% of the electric accounts and 91% of the gas accounts; responsible for 42% and 56% of the Company's electric and gas system load, respectively; and generate 49% and 71% of the total electric and gas revenues. It is estimated that 6% (electric) and 8% (gas) of residential customers currently participate in the low income discount program. According to Exhibit ___ (URP-6), UIU-1 IR No. 42, low income electric and gas customers on average are using less kWh and ccf per year than average residential customers.

B. Electric Customer Charges and Volumetric Delivery Rates

Q. What are Orange and Rockland's current and proposed customer charges and volumetric charges for electric residential and small commercial customers?

A. For Electric SC1 customers, the Company proposes to increase the customer charge from $20 to $25 (moving toward their ECOS results which show $28.36 per month) – a 25% increase. Additionally, the Company proposes to increase the existing volumetric rate structure by 10.5% for the first 250 kWh and 11.1% over 250 kWh during the summer period, slightly steepening the existing inclining block structure of the Company. It proposes to increase the flat volumetric charge (a uniform rate per kWh for all usage) during all other months by 10.5%. The 25%, 10.5%, and 11.1% proposed rate increase can be seen on page 1 of Exhibit ___ (URP-5). The same rates will apply to the electric residential heating and non-heating customers, except customers who are grandfathered to receive electric space and water heating discounts. For those specific customers, the

Company proposes to reduce the volumetric discounts by 1/3rd, to gradually move closer to eliminating the discounts.

For small commercial electric customers, the Company proposes to increase the electric SC 2 customer charge from $18 to $21, a 17% increase. Volumetric rates are expected to increase by 14%. With the exception of the Company's proposal to eliminate electric space and water heating discounts, the Company proposes to maintain the current delivery volumetric rate structures for residential and small commercial customers.

Q. Do you agree with Orange and Rockland's customer charge proposals for electric residential and small commercial customers?

A. No. The Company's stated rationale for its proposal to increase customer charges for both residential and small commercial customers is the desire to align those rates more closely with the results of its 2013 ECOS Study. However, it must be noted that the Company does <u>not</u> consistently use this theory for all customers. For example, according to the Company's electric rate design workpapers, the largest percentage increase in the customer charge is placed on residential customers – a 25% increase for Electric SC1 residential customers. Smaller increases are proposed for other classes – generally ranging from 12% to 20%. However, the discrepancy in percentage increases does not consistently track the pattern of cost results generated by the Company's ECOS study. For example, the Company proposes to increase the customer charge for the Electric SC20 class by the same dollar amount ($5/month) as the Electric SC1 class, which translates to a percentage increase of just 14%, yet the cost discrepancy for this class is greater than for Electric SC1 in both absolute and percentage terms.

The inconsistencies are even more obvious with respect to some of the other classes, which receive little or no increase at all. For example, the Company's ECOS results suggest a customer cost of more than $624 per month for the Electric SC9 class, while the current customer charge is $500 per month. Yet, the Company is not proposing any increase to this rate element, despite the fact that the discrepancy is significant (more than 20% and more than $100/month). These inconsistencies suggest the Company’s proposals with respect to increasing customer charges are arbitrary, or at least have been influenced by judgments that are not explained in its testimony.

Q. Aside from these inconsistencies, do you have any objections to Orange and Rockland’s proposed customer charges?

A. Yes. Setting customer charges at high levels results in setting the per-kWh rates at relatively low levels. There is a direct tradeoff between the goal of setting high customer charges (or the goal of recovering fixed costs through fixed monthly charges) and the goal of encouraging energy conservation (or the goal of rewarding customers for reducing their energy usage by charging them less).

We explained earlier in our testimony that the method used to recover the minimum system costs is a matter of discretion for the Commission. In competitive markets these sorts of fixed costs tend to be recovered from customers based upon the volume of service they purchase, thereby ensuring that customers who only use a little of a product or service contribute relatively little toward the firm's joint and common costs. The goal of recovering fixed costs on a relatively uniform per-customer basis is not only inconsistent with this standard pattern, but it also tends to place a greater burden on small customers. As well, because high customer charges tend to translate into lower per kWh rates, this rate design also tends to reduce the incentive for customers to conserve energy.

In our view, the Company's current rate structure does not provide the right price signals to encourage energy efficiency and it does not sufficiently incentivize customers to purchase more energy efficient products (such as rooftop solar, higher efficiency refrigerators, more efficient air conditioning units, and compact fluorescent or Light Emitting Diode ("LED") light bulbs). Not only is the Company failing to take steps to improve this situation, its proposal to increase the customer charge takes the rate design in the wrong direction, further weakening the incentive for energy conservation.

In an effort to advance policy goals set forth in the 2014 Draft State Energy Plan (system efficiency, carbon reductions, customer empowerment, and energy affordability) in conjunction with the Commission's goals undergoing development in the ongoing REV proceeding, the Commission should steer the Company away from status quo or business-as-usual practices toward innovative rate design methodologies coupled with customer engagement technologies that allow customers to take greater control over their utility bill, and more clearly and effectively rewarding them for using energy more efficiently.

Q. Can you please elaborate?

A. Yes. As stated on page 55 of the Order Adopting Regulatory Policy Framework and Implementation Plan, issued February 26, 2015, pertaining to customer engagement: "Staff notes that the majority of customers in New York currently lack the information, products, technologies, and incentives to fully participate in energy markets and take control of their monthly electricity bills." Increasing the customer charge (which cannot be avoided no matter how much a customer conserves energy) is aligned 180 degrees away from the policy implications set forth in that statement and the REV order as a whole. Increasing the fixed element of the bill (which cannot be avoided) and reducing the kWh rate reduces the customer's ability to control their monthly electricity bill. We believe that, from a public policy perspective, the Commission should be heading in the opposite direction. By holding constant or decreasing the fixed element of the bill and thereby increasing the per kWh rate, the Commission can offer a more pronounced price signal which provides a stronger incentive to fully participate in energy markets, and a stronger incentive to learn about energy efficient products and technologies. Restructuring tariffs to move away from high customer charges towards low customer charges and a change to their block rate structure (placing more of an emphasis on inclining block rate structures) will help customers take control over their monthly energy bills, and reward them with lower bills when they replace older, less efficient appliances with newer, more efficient products and technologies.

The Commission should take the opportunity to move toward a rate structure that better advances the goals of REV, more fully embraces New York State’s long term energy efficiency policies, and advances the broad public interest.

Q. Can you please clarify how REV relates to this issue?

A. Many elements of REV are centered on the assumption that customers have an opportunity to respond to price signals with changes to their load. It is expected that commercial and industrial customers will be the first adopters of the REV concepts because their load tends to be larger and more concentrated, making it easier for Distributed System Platform (“DSP”) providers and third party marketers to identify and develop opportunities for increasing energy efficiency. Whereas the participation in REV by residential consumers, particularly low to moderate income customers, is expected to lag because of the complexity to coordinate many small dispersed load that may have varying usage patterns and varying individual's priorities that may result in different responses to price signals. Accelerating adoption of REV in the residential and small commercial sectors will require a better understanding of those sector's consumer usage and personal priorities, in order to identify the opportunities and develop innovative offerings that appeal to residential consumers and clearly demonstrate how they can benefit from improving their energy efficiency and taking other steps that advance REV. A continued insistence on high fixed charges based on historical ratemaking practice suggests the utilities do not truly understand the difficulties involved in expanding REV to the residential and small commercial customer classes – or perhaps they perceive a conflict between their internal corporate goals and the Commission's goals for REV, and are favoring the former over the latter.

All of these numbers, and the approach taken by the Company in developing this part of its rate design, is a direct continuation of Orange and Rockland's claims that many of its fixed costs should be classified as "customer costs" and recovered on a per-customer basis. Essentially, the Company is arguing that since these parts of its distribution systems are fixed (not varying with the volume of gas or electricity that moves through the system or the peak rate of energy usage), the costs should be attributed to the "customer" category and recovered on a uniform per-customer basis.

As should be apparent from the earlier discussion, we do not agree with that reasoning or that conclusion. We do not dispute that many of the costs of a natural gas or electric distribution system are fixed (or sunk, once the investment is made), but even when one takes a long run view of these costs, they do not actually vary with the number of customers. Even during the planning phase, before investments are made, it's apparent that most of these costs are actually determined by the configuration of the road network, the positioning of buildings relative to that network, the size of the buildings, and various other factors that are not directly tied to the number of customers that are, or will be, located in those buildings or served by the system.

Q. Does your earlier discussion of the company's ECOS study also relate to its customer charge and minimum gas charge proposals?

A. Yes. In our ECOS study, which allocates the fixed costs of the minimum size system using a blended allocation factor that gives weight to peak demand, energy usage and the Company's C01 allocation factor, the calculated customer costs are substantially lower than those developed in the Company's ECOS study, as shown in Exhibit ___ (URP-4). In fact, for some classes the existing customer charges are already higher than the calculated level of customer costs. No further increases in these rate elements are warranted, and it would be preferable to gradually shift away from this revenue source toward higher volumetric rates.

When customer costs are analyzed in a more appropriate manner, and customer charges are set at lower, more reasonable levels, they are an acceptable rate-design tool for recovering a portion of a regulated utility's costs. However, the Company's proposed customer charges and minimum bill amounts are already higher than necessary. Further increases in these rates are not necessary, nor are they justified by cost considerations. Further increases in the customer charge and minimum bill tends to conflict with such important policy objectives as economic efficiency, energy conservation, and inter-customer equity.

Q. It might be argued that a fixed monthly fee is the correct way to recover costs that are fixed (do not vary from month-to-month). How would you respond to that line of reasoning?

A. While we concede there is some intuitive appeal to this argument, this is more of a pricing tactic than a goal. Increasing fixed rates, or matching fixed rates to fixed costs might be one of the Company's corporate goals, advancing the Company’s corporate interests by providing a more stable and more predictable revenue stream. However, it does not advance the public interest, and it is not an appropriate public policy goal. In fact, we think this leads to prices that are inconsistent with the public interest – for the reasons mentioned earlier. In particular, higher fixed rates make it harder for customers to control their monthly bill, and they reduce the incentive for improving energy efficiency.

Given the tradeoffs, we think the Commission's public policy goals including the ones set forth in REV order, as well as the goals of achieving fair, just and reasonable rates can best be achieved by recovering fixed costs through usage charges. In our opinion, recovering fixed costs is fully consistent with typical way most unregulated businesses often recover their fixed overhead costs - through payments that are closely related to the value received from the joint or common production process that gives rise to the fixed costs.

Q. Aside from the impact of your disagreement with its customer charge proposals, do you agree with other aspect of the Company's volumetric block rates?

A. Not entirely. In general, we are disappointed the Company is not making more of an effort to move its rate design toward one that encourages energy conservation. Where the Company is currently using a flat structure, or a mildly inclining block structure, it has generally proposed to roughly maintain the status quo. It has made little or no effort to improve the price signals in its tariffs, or to demonstrate whether the Company's existing rate structures are already optimal. Our impression is that some further movement toward mildly inclining block rates would be desirable.

We say this for essentially the same reasons we offered in the context of our earlier discussion of customer charges and energy efficiency. We believe a greater share of the fixed costs of the system can be appropriately recovered from larger users within the residential and small commercial rate classes. We also believe that movement toward moderately higher tail block rates will improve price signals and provide a greater incentive for customers to conserve energy. Inclining block rates tend to encourage energy conservation and they reward customers who take the initiative to adopt newer, more efficient technologies. Moving toward mildly inclining block rates removes the economic disincentive for customers to conserve energy, and it strengthens the incentives for customers to invest in more energy efficient appliances, add insulation, adjust thermostats, and take other steps to use less energy. This reasoning holds true for both gas and electric services.

In general, inclining block rates place a lighter burden on low use customers, including those who own few appliances, set their thermostat at a high level during the summer or at a low level in the winter – or find other ways to use relatively little gas or electricity. Inclining block rates tend to reward users for their efforts at limiting their energy usage, and they tend to encourage customers to install more insulation and upgrade to more energy-efficient appliances, or to take other steps to conserve energy. They also send price signals that better communicate to consumers the high cost of consuming more energy. Finally, we would note that they also put the typical consumer in a better position to take control over their monthly energy bill. With inclining block rates their bill is more responsive to their energy consumption decisions, and thus they are empowered to control their overall costs if they choose to do so (e.g., by analyzing and making adjustments to their usage, or by investing in newer, more efficiency technologies).

Q. What are your recommendations pertaining to customer charges and volumetric rates for electric residential and small commercial customers?

A. We recommend the Commission not increase the Company’s fixed monthly charges for residential and small commercial electric customers. Instead, the proposed revenue increase should be collected exclusively through increases in these customers' delivery volumetric rates. If the Commission concludes that the requested revenue requirement is overstated, and adopts a lower revenue requirement, it may be appropriate to modestly lower the fixed monthly charges, rather than maintaining them at their current level. In general, we recommend shifting the rate design to recover a slightly larger share of the residential and small commercial customers' share of the revenue requirement from the second usage block during the summer period and a slightly smaller share from the first block in the winter, thereby introducing a slight incline in the winter, and creating a slightly greater disparity between summer and winter rates.

Q. Do you have any other recommendations pertaining to customer charges and volumetric rates?

A. Yes. We recommend a detailed study be implemented by the Company in an effort to better understand residential and small commercial usage behavior and the various factors that impact residential bills and customer reactions to those bills. The study should include a comprehensive review of the Company's residential and small commercial load characteristics that can be used to develop alternative rate design structures. This study could also be beneficial to use as a guide in Track 2 of the REV proceeding which will investigate rate design alternatives that can lead to energy efficiency. The study should also analyze additional factors that impact customer pricing on low income, medium income, and all other customers such as: essential vs. non-essential needs; net metering systems; heating vs. non-heating; volumetric block rate structure; affordability issues; housing stock, and load shapes.

As part of the study, we recommend development of an inventory of studies and surveys that have been conducted to synthesize the findings in the REV proposal, New York SUN initiative, New York Green Bank, and the Clean Energy Fund ("CEF") to identify where additional information is needed. The following is a preliminary list: (1) REV Survey – a survey was conducted as part of REV by New York State Energy Research and Development Authority ("NYSERDA"), DPS, and the New York State ("NYS") Smart Grid Consortium that interviewed end-use customers in various service areas in NY; (2) CEF Market Research – (a) NYSERDA conducted primary and secondary research to determine how to engage with market actors to achieve CEF goals and (b) NYSERDA conducted a survey of more than 1,500 residential customers that included owners, renters, and various income levels in various geographic areas of the state; and (3) Residential Baseline Study – NYSERDA, DPS, and the NYS Evaluation Advisory Group conducted a comprehensive residential baseline study of new and existing single family homes (1-4) units and existing multifamily buildings.

We recommend a Collaborative be formed to fine-tune the scope of work within 60 days after completion of this proceeding. After the comprehensive study is complete, the Company should present the results of the study to all the parties in this proceeding, identifying various options for establishing an optimal energy efficiency block rate structures for residential and small commercial customers – similar to the Company's analysis of the impacts of eliminating declining block usage rates in Electric SC2 and SC3 in case 10-E-0362. All parties should be allowed to provide comments on the study and details of the new rate design methodologies and services proposed.

As REV moves towards an energy market that includes the concept of customer empowerment in conjunction with the Company's lack of outreach and education program specifically geared towards rate design issues besides related to VTOU as mentioned in Exhibit ___ (URP-6) - UIU-1 IR No. 79, we also propose to enhance the Company's customer outreach and education program to educate residential and small commercial customers about the relationship between rate structures, customer usage, and bill impacts. As mentioned in the recent REV and Retail Access proceedings, residential and small commercial customers typically lack the knowledge concerning rate design and bill impacts. Enhanced customer outreach efforts that includes rate design is a step in the right direction to deploy successful energy efficient rate structures and encourage consumers to reduce their energy at a reduced costs.

C. Gas Customer Charges and Volumetric Delivery Rates

Q. Can you briefly describe Orange and Rockland's current and proposed customer charges and volumetric charges for firm gas customers?

A. Yes. The Company proposes to: (1) increase the Gas SC1 residential customer charge for the first 3 ccf or less from $18.63 to $26 (a 40% increase) and increase the existing delivery declining volumetric rate structure (where rates decreases as usage decreases) by 39% and (2) increase the SC Nos. 2 Commercial and Industrial Gas customer charge for the first 3 ccf or less from $29.08 to $40 (a 38% increase) and increase their declining volumetric rate structure by approximately 23% per declining block. For these SCs, customer charges and volumetric rates remain the same for each SC no matter if a customer is identified as heating or non-heating.

Q. Do you agree with Orange and Rockland's customer charges and volumetric rate proposals for firm gas residential and small commercial customers?

A. No. By increasing gas customer charges and by placing a smaller percentage on volumetric rates, the Company's approach places too much of the cost-recovery burden on small usage customers and discourages energy conservation. Furthermore, the combination of a high customer charge and declining delivery block rates fails to reward customers who take advantage of energy efficiency/weatherization programs and products currently offered to customers – such as efficient gas heating systems and insulation. For some customers, these programs may provide energy efficiency products and services at no or little cost. However, with today's gas rate structure model for residential and small commercial customers there is no incentive for customers to react to price signals or invest in any of these energy efficiency products to control or reduce their gas usage. For those customers who do take advantage of these programs will end up paying a larger share of the fixed and overhead costs and of the entire gas system – which defeats the purpose of the goals of these programs. Additionally, incorporating a declining rate structure incentivizes customers to use more gas instead of providing a signal to discourage customers to use less. For example, in Case 12-G-0404 the Commission approved a declining block rate to increase consumption instead of for energy efficiency purposes for Reserve Gas Company. On page 23 of the Order Determining Revenue Requirement and Rate Design issued April 22, 2013 states the following:

> The declining block rate structure provides a declining average unit cost to the customer, and may provide a greater incentive for customers to use gas by providing a lower marginal cost.

We are aware that gas usage is more volatile during the winter season and a shift away from declining rates may impact gas customers (particularly heating customers). However, we don't believe this concern outweighs the other concerns that we have mentioned.

Q. What are your recommendations pertaining to customer charges and volumetric rates for firm gas residential and small commercial customers?

A. First, we recommend not increasing the minimum monthly charge, and instead recovering the revenue burden through the volumetric rates. Second, we recommend reducing the degree of decline reflected in the Company's volumetric rate design. Both of these recommendations – minimizing any increase in the customer charge and further shifting away from a declining block structure – will encourage energy efficiency and improve fairness of the distribution of costs among customers. We firmly believe there are benefits to slowly moving in the direction of an energy efficiency oriented rate structure. By slowly transitioning rates the Commission can avoid rate shock and provide time to fully evaluate the optimal mix of policies that incentivize customers to conserve energy (i.e., additional weatherization programs, energy efficiency programs, and rebates for the installation of high efficiency heating systems) – including consideration of policies that help low to moderate income consumers. Apparently, there are more low income customers on waiting lists for weatherization services in Orange and Rockland County than there are low income customers who are actually receiving weatherization services.

We realize there is not enough information available to design an optimal policy mix at this time. But, we don't think it is logical or desirable to delay movement in the right direction. We believe a slow transition is more appropriate than a rapid one, and this can best be achieved by starting (or continuing) the process now. In general, we recommend shifting the rate design to recover a slightly larger share of the residential and small commercial customers' share of the revenue requirement from the second usage block, thereby further flattening the rates. Our recommended approach to rate design will provide price signals that encourage conservation, generate financial incentives for consumers to use less gas, and fairly distribute the cost recovery to various types and sizes of customers.

Although our proposal incorporates a modest redesign of the Company's residential and small commercial rate structures, we recommend that a detailed study be implemented by the Company to assist in evaluating the end point of the transition – for instance, should all tail block rates be higher than early block rates, and by how much? Similar to our proposal for electric rate design, the study should evaluate various factors that impact customer usage and pricing such as: customer usage patterns, weatherization and installation of energy efficiency products, price elasticity, block rate differentials, housing stock, affordability, bill impacts (low income, median income, and all other customers), and weather sensitivities. The gas study should follow the same approach as our proposed electric study – as a collaborative with interested parties should finalize the scope of the study and be given the opportunity to provide comments of the study afterwards. Customer outreach and education is essential for this set of customers, therefore we also recommend the Company enhance its outreach and education efforts to include rate design and customer bill awareness targeted to customers.

D. Voluntary Time of Use Rates

Q. Can you please provide a brief background of the Company's current and historical opt-in VTOU rate?

A. The Company's residential VTOU program under Electric SC19 has been in existence for more than 20 years (see Exhibit ___ (URP-6), UIU-1 IR No. 19). VTOU rates are only offered as opt-in rates by utilities in New York State as an alternative rate structure that promotes efficiency by reducing peak demand. The general theory behind VTOU rates is to reduce peak load by sending price signals that reflect the variations in electric production costs. A typical VTOU rate design includes higher prices during peak hours (when production costs are high) and lower prices during off peak hours (when production costs are low). Most VTOU rate designs are fairly simplistic, and they can be implemented with generally an AMR meter (instead of an AMI meter). Rates are typically predefined during specific on/off peak hours and all that is required is a meter that is able to record usage during these intervals of time. To a certain extent, VTOU rate design provide customers with incentives to reduce usage during peak hours and to shift load away from on-peak/interim hours when the production costs are higher.

Over the years, there have been a few modifications to the Company's VTOU rate structure, but no major innovations have been introduced, despite the widespread availability of new technologies that could potentially support a more sophisticated approach to TOU pricing. The brief overview of the changes are described in the Company's response to Exhibit ___ (URP-6), UIU-IR No. 34:

> SC 19 was originally created as a Voluntary Time of Use ("VTOU") Rate for residential customers in the late 1980s. It provided opportunities for customers to respond to prices and lower their energy bills by adjusting behaviors to consume energy during off-peak hours. Then pursuant to Opinion No. 92-94 in Case 91-E-0450, which was issued and effective August 18, 1992, the Company instituted Mandatory Time of Use ("MTOU") Rates for its largest residential customers (i.e., with four month usage in excess of 8,000 kWh). Later, the Company eliminated its MTOU rates from SC 19 consistent with the Commission's Order issued October 20, 1997 in Case 97-E-1795.

The Company defines the VTOU rating periods as follows: (1) Period I – 12 p.m. to 7 p.m., Monday through Friday, except holidays, June through September; (2) Period II – 10 a.m. to 12 p.m. and 7 p.m. to 9 p.m., Monday through Friday, except holidays, June through September; (3) Period III – 10 a.m. to 9 p.m., Monday through Friday, except holidays, October through May; and (4) Period IV – 9 p.m. to 10 a.m., Monday through Friday, all hours on Saturday, Sunday, and holidays, all months. It is estimated that 3,680 customers (2% of the Company's residential customer population) currently participate in the SC19 VTOU program.

The Company currently offers detailed information about the VTOU rate on the Company's website but it does not provide a price comparison bill calculator that compares SC1 residential electric standard rates to SC19 VTOU rates (see Exhibit ___ (URP-6), UIU-1 IR No. 30). It is difficult for customers to know how much energy they use during the on- and off-peak time periods, compared to a typical customer, and it is even harder to predict how successful they will be in shifting usage away from the peak hours. Customers who opt-in to the VTOU rate risk paying much higher rates than normal, if it turns out they have higher than normal usage during peak hours, and they are unable to shift enough of their on-peak load to the off-peak hours to offset the adverse impact of changing rates. Customers must remain on this rate for at least one year, yet Orange and Rockland does not currently offer any price guarantees for customers served under the VTOU rate (see Exhibit ___ (URP-6), UIU-1 IR No. 37) and it is difficult or impossible for customers to predict in advance whether they will benefit from switching to the VTOU rate.

Q. What is Orange and Rockland's proposal regarding the current voluntary time of use rates under SC19?

A. Orange and Rockland proposes to maintain a VTOU rate structure under SC19 with some modifications. The Company proposes to increase customer charges and rates as follows: the customer charges will increase from $32 to $37 (about 15.6%) and Rate I, II, III, and IV delivery rates will each increase about 15%. Additionally, the minimum charge per contract will increase from $384 to $444 (about 15.6%).

Q. What is your response to the Company's residential VTOU proposal?

A. We are supportive of the Company offering residential customers time-sensitive rates that send more accurate price signals during actual load conditions. However, we question if the Company's VTOU rate structure is optimally designed and attractive to customers – as only 2% of the residential population opt for this VTOU rate structure. Perhaps a more attractive design (or maybe several designs) could attract a wider range of customers. With advances in technology and increased awareness of the benefits of shifting usage and costs away from peak hours, we believe it is time to explore more options.

Unfortunately, the Company was unable to provide an analysis of the existing VTOU rate compared to the Company's standard rate, therefore it is unknown how many of the existing customers are saving money on this type of rate structure (see Exhibit ___ (URP-6), UIU-1 IR. No. 22, 26, 27, and 28). Additionally, the Company also has not evaluated the load factors for this particular customer class (see Exhibit ___ (URP-6), UIU-1 IR No. 18). The Company also does not offer SC19 VTOU customers information about their total usage and charge over the year compared to standard rates (see Exhibit ____ (URP-6), UIU-1 IR No. 23). And, the current program does not offer a price guarantee or other incentive to encourage customers to try out the VTOU rate structure (see Exhibit ___ (URP-6), UIU-1 IR No. 37).

There is also a lack of tools and technologies that would enable customers to learn more about their energy consumption patterns, or test their responsiveness to price signals that encourage users to shift usage from the off-peak periods (i.e., bill calculators, monthly shadow bills, real time on-line usage information and other technology tools) which limits customers' ability to control their power usage (see for example Exhibit ____ (URP-6), UIU-1 IR Nos. 30 and 73). According to our discovery findings, the Company has not considered or been a part of any studies that analyzed other time-sensitive rate options for residential customers (see Exhibit ___ (URP-6), UIU-1 IR No. 32 and 17).

Q. What are your recommendations regarding Orange and Rockland's residential VTOU rate proposal?

A. First, we recommend not to increase the current VTOU monthly customer charge by 16% as proposed by the Company – similar to our position for standard residential customer charges. Second, we recommend that the Company offer residential customers more alternative time-sensitive rate options with attractive rates and incentives. Specifically, we propose that the Company explore time-sensitive rate methodologies that produce accurate time responsive price signals coupled with advanced technologies that incentivize customers to reduce peak demand. Rate design should be particularly focused during critical peak periods events when the cost of electricity is the highest – as costly infrastructure capacity investments are driven by peak usage during these events. The

Commission has sent clear indications of the direction it is heading with its policies in the REV proceeding, and we realize much work remains to be done in that proceeding. However, we see no reason to hold in abeyance other efforts to move in the same direction on a pilot basis outside the purview of that docket. Pending other major restructuring of the energy market, it would be prudent to explore and implement time-sensitive rate alternatives on a pilot or experimental basis at this time, especially since peak loads are growing five times faster than base sales (page 16 of the February 2015 REV Order). Additionally, by creating a rate structure geared toward reducing peak load the Commission can provide customers with greater control over their monthly energy bill, and potentially provide all customers with significant cost savings. As mentioned on page 20 of the recent REV Order,

> The pressure on rates that will be caused by aging infrastructure replacement, reliability and security needs, carbon rules, and other factors can be mitigated by the cost reductions that are available through increased system efficiency achieved through markets and improved regulation. Increasing responsiveness of demand will reduce price volatility in the near term and price inefficiency in the long term. If, for example, the 100 hours of greatest peak demand were flattened, long term avoided capacity and energy savings would range between $1.2 billion and $1.7 billion per year.

There has been movement toward improved time-sensitive rate designs in other parts of the United States over the past few years and the Commission has taken notice. For example, the Commission's Ordering Clause 10 issued and effective February 21, 2014 on pages 56-57 approved a time-sensitive pilot plan in the Brooklyn area in the recent Con Edison Rate Case 13-E-0030. Also, Con

Edison's time-sensitive pilot program in addition to the Brooklyn Queens Demand Management ("BQDM") Programs have been highlighted in the recent REV proceeding as innovative demand response alternatives (see Case 14-M-0101, Staff Straw Proposal on Track One Issues, issued August 22, 2014, pp. 10, 28, and 31). As mentioned in the Company's Reforming the Energy Vision Panel and AMI Panel Testimonies, the Company proposes a similar innovative project, similar to Con Edison's BQDM project, which will focus on demand reduction alternatives in an effort to defer the construction of a new Pomona Substation in northern Rockland County. Since the Pomona area is primarily comprised of residential customers, this is a perfect location to incorporate a time-sensitive rate design project. Lessons learned from a properly designed pilot program in the Orange and Rockland territory will further advance the rate design and policy initiatives in the REV proceeding.

Q. Do you have any more specific recommendations?

A. Yes. We specifically recommend that the Company implement a CPP Demonstration Program in their first phase of demonstration programs that come out of this rate case. This price-responsive demand response program will test whether and to what degree such a program reduces peak load by evaluating customer response to several combinations of time-sensitive rate design with critical peak components, communication tools, and enabling technologies targeted towards residential and small commercial customers.

Q. What do you mean by "Critical Peak Pricing"?

A. Rather than charging a higher price during every single summer weekday afternoon, regardless of how mild the weather, or ample the supply of electricity available to the system, it would be preferable to target a smaller number of hours with very high prices. This would offer the greatest possible incentive for customers to reduce their usage during the specific hours when society would gain the most benefit from a reduction in their usage. Ideally, this narrowly targeted peak price would not only be focused on a smaller number of hours per year, it would be precisely focused on the specific times when costs are highest – the particular hours each year when weather is the hottest and the system is experiencing unusually high loads, or when unusual generating and transmission capacity constraints exist, or both.

In other words, rather than charging the highest prices during every single summer weekday from noon until 7 p.m., the highest prices would be applied during a much smaller number of hours when a high price is most justified – what we will refer to as the "Critical Peak" hours for the sake of clarity. The actual timing of Critical Peak hours is not dependent upon the calendar, but upon actual events. The Critical Peak hours occur when there is unusually hot weather, when one or more major generating units are down for unscheduled or emergency maintenance, or for some other reason system supply costs happen to be running at unusually high levels.

To be equitable and fully effective, customers need to be informed of the critical peak before it occurs, so they have an opportunity to adjust their thermostats, avoid running their dishwasher or doing their laundry, turn off their water heater, and take other actions to minimize their load during the critical peak period. With today's technology, it is perfectly feasible to inform even a large number of residential customers that a critical peak is about to occur. Nor does it have to be costly to do this – particularly if you accept the idea that not every single customer will receive the communication that is sent out. But, if all customers on the CPP plan are contacted using a combination of emails, text messages and "robo-calls" (recordings sent to the customer's telephone), a very high percentage of these customers can be expected to receive advance notification of the peak period, the per-customer cost of this notification effort would be minimal, and there would be an excellent opportunity for customers to try to minimize their load during the critical peak hours. If successful, this effort will minimize their individual bills, and help society by avoiding the high costs (and risks of brownouts and blackouts) that occur during critical peak hours.

We believe a CPP approach has the potential for being more popular than conventional approaches to time of use pricing, like the Company is proposing, for the simple reason that customers would be subject to the risk of sharply higher prices during a much smaller number of hours of the year. In any event, we think there is enough upside potential for this type of narrowly focused, timely price signal to make it well worth testing. A lot can be learned from trying this concept even on a small pilot basis, applied to a relatively small number of customers who volunteer to try this pricing approach.

The CPP demonstration project can be modeled after the Oklahoma Gas and Electric's ("OG&E") successful time-based rate program called SmartHours (https://smarthours.com/about-the-study), which includes smart programmable thermostats; customer access to usage data via a web portal; short weekday peak hours with pricing varying based on demand; advance notice of next days' on-peak prices send by phone, text, and/or email; and occasional critical events called on a same-day basis with at least two hours' notice. OG&E's study initially started with 25 homes. By the end of 2014, the Company had established a customer base of 120,000 accounts. The success of the program allowed for deferral of the construction of two peaker plants by at least 2020. Silver Springs Networks, a leading networking platform and solutions provider for smart energy networks which worked on the SmartHours pilot project, summarizes in a report called "Implementing a Smart Grid-based Peak Reduction Program" that OG&E's time-varying pricing pilot program has:

- Achieved 119 MW of peaker power reduction (2013)
- Delivered average annual bill savings of about $150 per participating customers (as of October 2013)
- Installed nearly 54,000 smart thermostats

The results suggests that a time-sensitive pilot program like that of Orange and Rockland can be highly successful in other areas of the country, including New York. For these reasons, we strongly urge the Company to implement a program, like the CPP Pilot Program implemented in Oklahoma to provide more attractive rate alternatives to residential customers. Specific experimental design parameters can be developed in a collaborative process based on the review of existing market research and load studies.

Q. Does this conclude your direct testimony?

A. Yes.