STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 02-E-0781 -	Consolidated Edison Company of New York, Inc. – Proceeding on Motion of the Commission as to an Electric Tariff Filing to Establish a New Standby Service in Accordance With Commission Order.
Case 02-E-0780 -	Orange & Rockland Utilities, Inc. – Proceeding on Motion of the Commission as to an Electric Tariff Filing to Establish Standby Service in Accordance With Commission Order.

PREFILED DIRECT TESTIMONY OF

MARK B. LIVELY

MARCH 20, 2003

CASE NOS. 02-E-0781 AND 02-E-0780

DIRECT TESTIMONY OF MARK B. LIVELY

Q. What is your name and address?

A. My name is Mark B. Lively. My address is 19012 High Point Dr., Gaithersburg, Md., 20879. I am an engineering consultant specializing in pricing issues related to natural gas and electricity.

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

A. My testimony in this proceeding addresses rate design issues presented by the Consolidated Edison and Orange & Rockland Utilities in their original filings and in the Joint Proposal filed March 11. I believe that the utilities, their customers, and the State of New York are ill served by the utility proposals in regard to standby service to be provided to on-site generators (OSG). The proposed design, especially in regard to the Contract Demand, falls into the trap of the California Debacle Syndrome. I therefore recommend that the Commission adopt:

- A pricing plan for OSG that differentiates between serving supplemental retail load versus providing backup for OSG;
- A pricing plan for providing backup for OSG that dynamically changes the price for such backup based on the conditions being experienced by the utility at the time and in the location that the backup is being supplied;
- Failing the adoption of dynamic pricing suggested in the previous paragraph, a less harsh approach to the formulation of the Contract Demand, including a moderation of the ratchet and the penalty for exceeding the Contract Demand;

- Again failing the adoption of dynamic pricing, a recognition that backup service is relatively inexpensive for the utility to supply since OSG outages are unlikely to occur during the heat storms that drive the peak on the utilities' distribution system.

Q. What is your educational background and experience?

A. I earned a Bachelor of Science degree in electrical engineering from the Massachusetts Institute of Technology in 1969. I earned a Master of Science degree in management from the Massachusetts Institute of Technology's Sloan School of Management in 1971. I am a registered professional engineer in the District of Columbia.

From 1971 to 1976, I worked for American Electric Power Service Corporation (AEPSC) in New York City, first in the Controller's Office, then in the Rate Department. AEPSC provides engineering and management services to its utility affiliates in Indiana, Michigan, Ohio, West Virginia, Kentucky, Virginia, and Tennessee. While in the rate department of AEPSC, I received on the job training on issues related to pricing electricity, including cost analysis. I note that Mr. Joel Charkow and Mr. Peter Schulhof of ConEd worked with me in the rate department of AEPSC.

From 1976 to 1991, I worked as a consultant in the Washington, D.C., utility office of the accounting firm of Ernst & Ernst, and its successors, first Ernst &

Whinney and then Ernst & Young, which I will collectively refer to as "Ernst". The Washington utility office provided audit, tax, and consulting services to its clients on electric and natural gas matters. My clients at Ernst included utilities, large industrial consumers, independent power producers, and regulators.

Since the beginning of 1992, I have been self-employed as a utility economic engineer specializing in the costing and pricing of electricity and natural gas. For the purpose of this and other proceedings in the State of New York, I am a consultant to The E Cubed Company, L.L.C. A copy of my CV is provided as Exhibit ___ (MBL-1)

Q. Have you testified in regulatory proceedings?

A. Yes. While I was with AEPSC I testified for the affiliated Michigan Power Company before the Michigan Public Service Commission on accounting adjustments, cost allocation, and rate design. While with Ernst, I testified before the Arkansas Public Service Commission, the Louisiana Public Service Commission, the Montana Public Service Commission, the Texas Public Utilities Commission, and the New Mexico Public Service Commission. Generally my testimony was on the issue of cost allocation, with some testimony on budgetary forecasts and innovative rate design. Since being self employed, I have testified before the Texas Public Utilities Commission on rate design, before the Public Service Commission of the District of Columbia on behalf of the D.C. Office of

People's Counsel on accounting issues in the failed merger between the Baltimore Gas & Electric and Potomac Electric Power, and before this Commission in a proceeding on behalf of St. Lawrence Gas Company. I have also filed comments in various FERC proceedings including RM01-12, FERC's current investigation into a Standard Market Design for Independent System Operators.

Q. Have you written any published papers or articles?

A. Yes. *Public Utilities Fortnightly* published several of my articles, beginning in 1989, and a few smaller commentaries. These articles include

- "Tie Riding Freeloaders--The True Impediment to Transmission Access," 1989 December 21;
- "WOLF Pricing," 1994 October 1;
- "Electric Transmission Pricing: Are Long-term Contracts Really Futures Contracts?" 1994 October 15;
- "Electricity Is Too Chunky: The Midwest power prices were neither too high nor too low. They were too imprecise," 1998 September 1;
- "FERC's Mandatory Gas Auctions: Are We Bidding the Right Product? -- Auctioning gas imbalances offers advantages over bidding on available pipeline capacity," 1999 January 1;
- "FERC's Dialogue on CBM: Reliability Gets Reappraised," 1999 July 1;

- "Distributed Generation: Setting a Fair Price in the Distribution Tariff,"2000 October 15
- "Saving California With Distributed Generation: A crash program to use small, standby diesel generators to keep the lights on," 2001 June 15
- "Keeping the Lights On: An Insurance Industry Model . . . to Stop Manipulation," 2002 July 1

The National Regulatory Research Institute (NRRI) published a few of my articles in its *Quarterly Bulletin*. NRRI is affiliated with the National Association of Regulatory Utility Commissioners. The articles published in the *QB* include

- "The FERC's Formula for Transmission Contacts: Using a Good Concept for the Wrong Service," Winter 1995
- "Thirty-One Flavors or Two Flavors Packaged Thirty-One Ways: Unbundling Electricity Service" Summer 1996
- "State Regulation of the Coming Competitive Market," Fall 1997
- "Electric Customer Participation in the Competitive Market: Reliability, Futures Contracts, and Arbitraging," Winter 1997
- "Metrics for Operating Reserves," Spring 1998
- ."Daily Cashouts of Gas Imbalances Using A Formulary Auction," Fall/Winter 1999

- "Good Market Segmentation or Bad: An Analysis of the California Electricity Market, Autumn 2000
- "Fungible Distribution Tariffs: Supporting Distributed Generation Without Bankrupting the Utility," Winter 2001

McGraw-Hill's Electrical World published an article I wrote in 1991. I have also presented papers to conferences sponsored by the American Society of Mechanical Engineers, the American Nuclear Society, and the Institute of Electrical and Electronics Engineers. I attach my complete resume as Exhibit___(MBL-1).

Q. What do you mean by having a pricing plan for OSG that differentiates between serving supplemental retail load versus providing backup for OSG?

A. Many OSGs are designed to serve part of the electrical load of the utility customer. The rest of the load must be served by the utility. This load that must be served by the utility is considered to be supplemental to what the OSG can provide. Since OSGs occasionally are not available, during such times the utility must serve more of the electrical load of the customer. The additional load served by the utility at these times is called standby or backup.

Q. Why is it important to have a pricing plan for OSG that differentiates between serving supplemental retail load versus providing backup for OSG?

A. Customers who wish to install small OSG projects generally do not want to see the discontinuity associated with a change in the price for the remaining portion of their load. Such a discontinuity creates uncertainty and greater risk for the customer and thus creates a barrier to greater penetration by OSG.

Q. Is a pricing plan for OSG that differentiates between serving supplemental retail load versus providing backup for OSG consistent with traditional rate making practices?

A. Yes. Traditional rate making practices includes the creation of customer classes with similar service requirements. A major issue in identifying customer classes is the commonality in their load shapes. For most customer classes for the utilities in this proceeding, the primary determiner of their load shape is the summer weather patterns. The utilities in downstate New York design their distribution systems to meet the summer peak air conditioning demand. This is true for customers served under the standard tariff and would be true for the supplemental load customers desire the utilities to serve in excess of what the OSG can provide. In contrast, the backup load will be determined by the outage characteristics of the OSG. These outage characteristics will generally be independent of the summer weather patterns. The weather independence of the outage characteristics of OSG suggests that this portion of customer consumption should be treated as a separate class of customers; at least conventional utility ratemaking suggests such treatment as a separate customer class.

Q. How can the utility determine how much electricity should be billed as supplemental versus the amount that should be billed as standby?

A. I present a separation procedure in Exhibit___(MBL-2). The separation procedure identifies the amount of electricity metered by the utility that should be billed as supplemental versus the amount of electricity that should be billed as backup. The procedure uses a customer owned interval meter to determine the amount of electricity that the customer is receiving from its OSG. The customer owned interval meter would be synchronized with the utility meter with the data from the customer owned meter made available to the utility in the same fashion that the utility obtains data from its own meter. Together, the two meters would determine the maximum monthly consumption by the customer. The historic capability of the on site generation would be subtracted from the site load to determine the supplemental demand of the consumer. The supplemental demand is the amount of electricity that the consumer could not supply to itself. This supplemental demand would be the basis for the demand charge under the standard tariff. Any electricity taken up to the supplemental demand during each interval would be considered to be supplemental load, subject to the terms of the standard tariff. Electricity in excess of the supplemental demand during each interval would be considered to be backup energy subject to the standby charges. A more complete explanation of this procedure is presented in Exhibit__(MBL-2).

Q. How should backup service be priced?

A. In this proceeding, I have proposed pricing backup service on a dynamic basis. Under such a pricing plan for providing backup, the price for such backup would be based on the conditions being experienced by the utility at the time and in the location that the backup is being supplied. Such a dynamic pricing plan would result in the OSG competing in larger markets. Not only would the OSG try to meet the electrical needs of the consumer, but also the OSG would also compete economically against the market run by the New York ISO and would also compete against the cost of the wires market run by the local utility. Thus, a dynamic pricing of the utility wires business results in OSG living up to its name of distributed generation, in that it would be generation that competes with the distribution services of the utility.

Q. You mentioned the California Debacle and an associated syndrome. What is the California Debacle?

A. I use the term California Debacle to refer to the yearlong period from the summer of 2000 to the spring of 2001 when wholesale prices soared in California and in much of the rest of the western part of the United States and Canada. During that period of time, the State of California mortgaged its future to pay for electricity that it consumed during that time period.

Q. How is the California Debacle similar to the Contract Demand proposal formulated by the utilities in this proceeding?

A. The utilities have proposed a Contract Demand that mortgages the future of consumers based on demands in the past. The utilities have proposed a Contract Demand with a permanent ratchet. Once a consumer imposes a demand on the utility, the utility proposes to use that demand indefinitely into the future for billing purposes. Thus, actions by the consumer mortgage the consumer's future for several years, just as actions by the State of California have mortgaged the future of its consumers for several years.

Q. Could the syndrome associated with the California Debacle be avoided for standby tariffs?

A. Yes. Though the specific structures of the Contract Demand in this proceeding are different from what happened in the California Debacle, I believe that the industry can learn by comparing the Contract Demand concept with the California Debacle. Specifically, I see an unwarranted mortgaging of the future, a missed opportunity for customer response, and an unnecessary prolonging of electrical constraints.

Q. Why do you say that the mortgaging of the future is unwarranted?

A. I say that the mortgaging of the future is unwarranted in that there are other, better economic ways to address the issue of high customer demands. One such approach is to have prices reflect the concurrent situation on the electrical network. This would encourage OSGs to operate when the distribution system is

constrained or when the NYISO has high prices in its settlement system. Though I point this out in regard to the Contract Demand structure posed by the utilities in this proceeding, the Contract Demand structure follows the syndrome of the California Debacle, in that California could have avoided mortgaging its future by implementing dynamic prices when the bulk power market became very expensive. Further, this unwarranted mortgaging of the future of the consumer is exacerbated by the method used by the utilities to allocate the revenue requirement between Contract Demand and As Used Demand.

Q. How did the utilities exacerbate the unwarranted mortgaging of the customer future by its revenue allocation?

A. I present as Exhibit___(MBL-3) an analysis of the allocation factors used by ConEd in setting the Contract Demand charge and the As Used Demand charge. Exhibit___(MBL-3) clearly shows how ConEd biased the result toward a higher Contract Demand charge than is warranted. ConEd achieved some of this effort by improperly aggregating several individual cost components into larger cost categories. ConEd's allocation analysis should have been done on these smaller cost components, which would have resulted in a much smaller Contract Demand charge.

Q. Why do you say that there is a missed opportunity for customer response?

A. Customers are generally not sophisticated enough to realize that charges based on demand ratchets are actually driven by some earlier action of the customer. Certainly, they are not aware at the time that they are establishing the peak that they are locking in costs that they will have to pay for over the next several years. In the same way, most consumers in California were not aware during 2000/2001 that their actions were committing them to pay off a huge debt over the next several years. If the California consumers had been aware of the costs that were being incurred at that time for them, there would have been an elasticity response that would have reduced the amount of electricity that was needed on their behalf. Similarly, most customers in New York would reduce their consumption during times of constraint if they realized that they were mortgaging their future by not doing so. When California finally raised prices in June of 2001, the damage had already been done; their futures had been mortgaged. Similarly, when customers see charges from the Contract Demand provision of the proposed standby rate, they will try to reduce their consumption, but by then it will be too late, their futures will have been mortgaged.

Q. Why do you say that there will be an unnecessary prolonging of electrical constraints?

A. When customers know that they are paying a higher price for the electricity that they are consuming, they will conserve. This conservation will show up in reduced electrical loading. In California, the retail rate increases occurred in June

2000 as the utilities were entering the high load summer period and leaving the low load spring period. At the same time, the rotating blackouts ended, as did the associated high prices in the bulk power market. The similarity in timing of these events illustrates the elasticity of demand for electricity, if commissions just allow such elasticity to operate. New York has had its own constraint problems, such as the distribution problems experienced by ConEd, as reported in "Con Edison's July 1999 Electric Service Outages: A Report To The People Of The State Of New York From The Office Of The Attorney General", March 9, 2000. Dynamic pricing would have resulted in a reduced demand on the ConEd distribution system, shortening the severity of the problem.

It is for these reasons that I believe that dynamic pricing is a preferred alternative to the Contract Demand structure for backup service proposed by the utilities in this proceeding.

Q. Should dynamic pricing be used for the supplemental portion of the consumer's load?

A. Not at this time. Though I believe that electricity consumption has some elasticity, as was illustrated by the significant reduction in California consumption after the retail price increases in June 2001, there is much greater elasticity in regard to the operation of OSG. The industry in New York should first take advantage of this high level of elasticity in regard to the operation of the OSG by

dynamically pricing backup service. Dynamically pricing supplemental service at this time would stifle the OSG industry by creating too much uncertainty for retail consumers about the pricing of the basic service they are taking from the utilities. At some time in the future, as the utilities gain experience with dynamically pricing their distribution services and as customers gain confidence in the fairness of such an approach, then it may be appropriate to price supplement service dynamically. At the current time, dynamic pricing of the supplemental use of the distribution grid should only be an option that customers could exercise as they become more comfortable with the utility's implementation of the concept.

Q. Why do you believe that failing the adoption of dynamic pricing that the utilities should change the formulation of the Contract Demand in a way that will moderate the ratchet and the penalty for exceeding the Contract Demand?

A. The current formulation of the Contract Demand includes a ratchet and a penalty for exceeding the Contract Demand. Ratchets are tariff mechanisms to spread revenue over an extended period of time. The ratchet proposed by the utilities is perpetual, in that once a demand is established, the customer pays a billing demand based on that established demand. Initially the demand for which the customer pays is an amount that is the estimated maximum load that the customer will impose on the utility. If the customer exceeds that amount, the ratchet increases the demand upon which the customer must pay and the penalty forces

the customer to pay a lump sum amount based on how much the customer exceeded the previous contract demand.

The utilities propose to impose a different ratchet for backup service than the ratchet that is currently being used for such customers. Having a different ratchet will provide a disincentive for customers to install OSG. Such a disincentive is contrary to New York State policy to encourage OSG.

The utilities also propose to impose a penalty for backup service that is different from any other provision that I know of in the utilities' tariffs. This distinction will provide a disincentive for customers to install OSG that is very similar to the disincentive associated with the perpetual ratchet.

Finally, the ratchet and the penalty both will violate the concept of revenue neutrality that has been proposed in the guidelines for this proceeding.

Q. How do the ratchet and the penalty violate the concept of revenue neutrality?

A. Ratchets and penalties are both mechanism to generate revenue for the utilities. The rate design work papers contain no allowance for the revenue that the utilities will earn as a result of the imposition of either the perpetual ratchets or the penalties. Accordingly, when customer actions result in the utilities collecting revenue from perpetual ratchets or from penalties, the revenue of the utilities will increase beyond the position currently established as the appropriate rate level for the utilities.

Q. Why do you believe that backup service is relatively inexpensive for the utility to supply?

A. I believe that backup service is relatively inexpensive for the utility to supply since OSG outages are unlikely to occur during the heat storms that drive the peak on the utilities' distribution system.

The utilities design their distribution systems to meet the peak summer air conditioning demands of their customers. This design consideration is reflected in the utilities retail tariffs. For instance, the price for using the distribution system in the summer is higher than the price for using the distribution system in the winter. Further, the utilities propose not to charge consumers for the use of the distribution system during the night. These rate design features show that the utility engineers design the distribution system to meet the daytime peak during the summer air conditioning hours.

In contrast to the utilities' typical air conditioning load, OSG backup service should not be highly correlated with the summer air conditioning load. OSG backup service will occur for two reasons, forced outages of the OSG and scheduled maintenance.

Forced outages of the OSG should occur randomly, at anytime, day or night, winter, spring, summer or fall. Accordingly, the forced outages of the OSG will have a smaller impact on the utilities' distribution grid than will the utilities'

typical air conditioning load. Utilities engineers will have less need to reinforce the distribution system to meet the forced outages of OSG than would they need to reinforce the distribution system to meet an increase in the utilities' typical load. This suggests that forced outages of the OSG are typically less expensive to serve and should face a lower price than should the utilities' standard air conditioning load.

Scheduled maintenance of OSG will be even less likely to occur during the periods that the utilities need their distribution system to provide electricity to air conditioning load. OSGs will try to schedule their maintenance periods when their associated air conditioning loads are low.

Thus, providing wire service for OSG maintenance service should similarly be less costly for the utility than providing wire service for standard loads.

Q. What is the implication of your analysis that the cost to the utility of serving OSG is less expensive than service standard loads?

A. A major issue in the negotiations has been exemptions from the standby tariffs for various types of OSG. If the standby tariff were appropriately cost based, then OSGs would be less interested in obtaining the exemptions, since the standby tariff would cost the OSG less than the standard tariff, which the exemptions attempt to retain for special OSGs.

Q. Does this conclude your testimony?

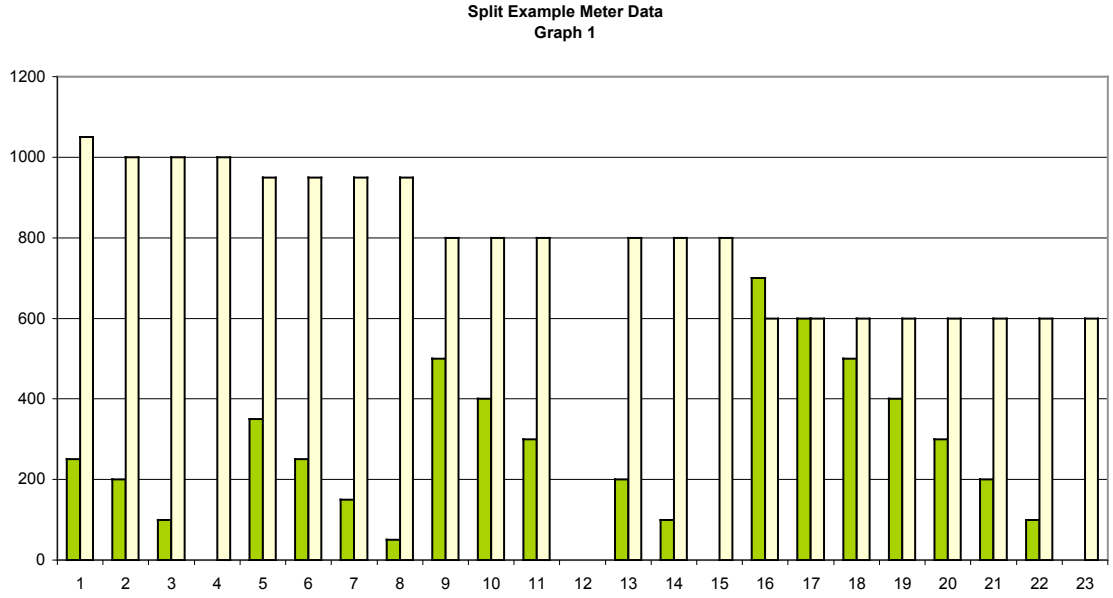
A. Yes.

Exhibit____(MBL-2)

Split Rate Mechanics

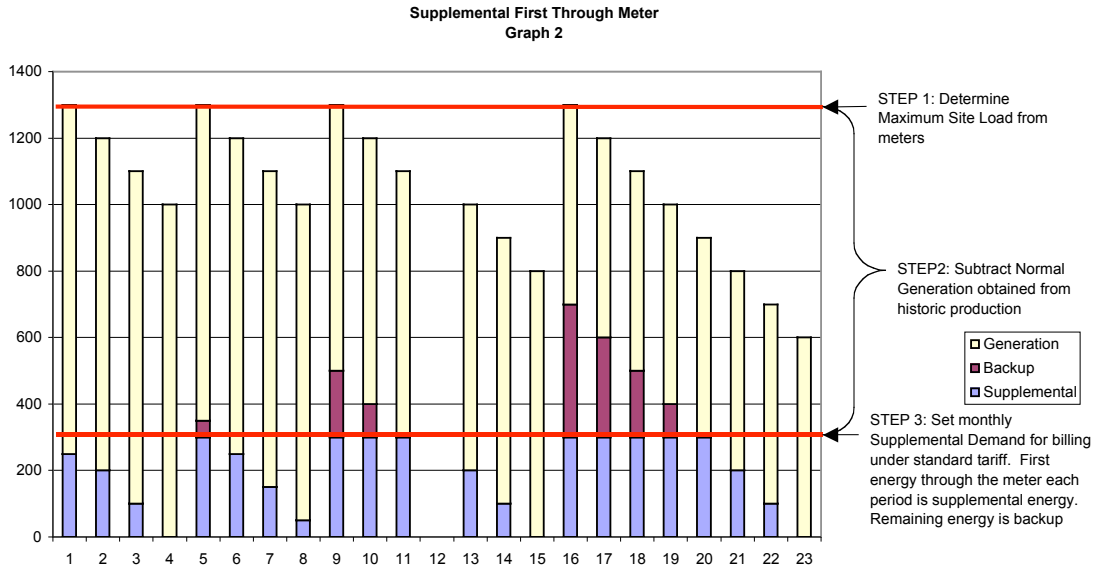
Supplemental power should be the first energy through the meter during each meter interval up to the monthly supplemental demand. The monthly supplemental demand should be the maximum site load during the month minus the normal generation level established by the on-site generator during the twelve months ending with the current month. The maximum site load during the month shall be determined using two synchronized interval meters, the utility interval meter and a customer owned interval meter for on-site generation. Energy through the utility meter in excess of the monthly supplemental demand shall be treated as backup/standby power.

The Joint Supporters advocate the concept of supplemental power being the first electricity through the meter during each meter interval. The Joint Supporters acknowledge that there are other methods for splitting the energy between supplemental energy to be billed under the standard tariff versus backup energy to be billed under the new tariff. The Joint Supporters believe their method is superior in that the Joint Supporter's method minimizes reliance on the data from the second meter, the meter owned by the customer. The method advocated by the Joint Supporters also results in the defined supplemental load having a load shape this is closer to the load shape ConEd experiences for most customers billed under its standard tariff.



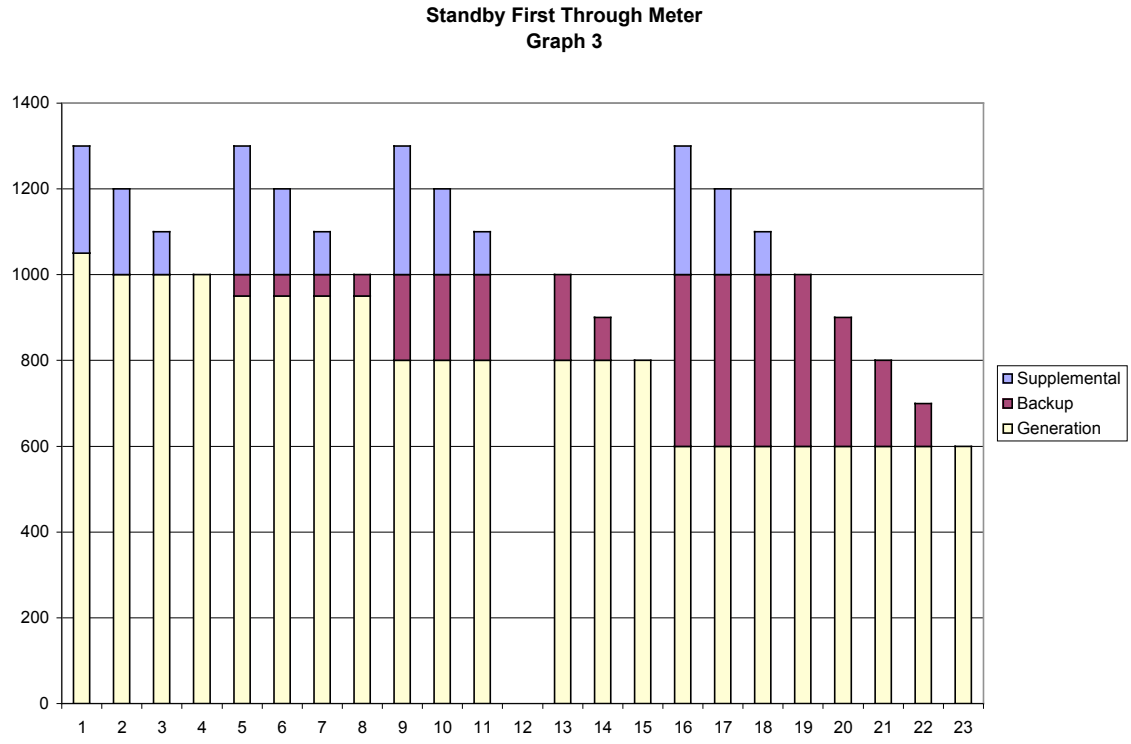
Graph 1 presents the hypothetical meter data that the Joint Supporters presented in its proposal of February 7. The various parties have used these data for illustrative

purposes, though not necessarily for issues supported by such parties. The first bar in each pair represents an amount that ConEd would have delivered to the customer during a meter interval, such as an hour. The second bar in each pair represents an amount that the customer would have generated itself. The bars in Graphs 1 are presented side by side. The pair of bars can also be stacked, either with the ConEd delivery on the bottom and the Generation on the top, or vice versa with the Generation on the bottom and the ConEd delivery on the top.



Graph 2 presents the approach developed and presented by the Joint Supporters. Here, the ConEd delivery is stacked on the bottom of each bar. Under the Graph 2 presentation, the sum of the two meter readings is used to develop the Maximum Site Load for the month. The capability of the generator is subtracted from the Maximum Site Load to determine the supplemental demand for the month. All energy through the ConEd meter during each time period up to the supplemental demand is treated as supplemental energy. Energy in excess of the supplemental demand during any time period is treated as backup energy.

Graph 3 presents an approach that can be characterized as standby as the first energy through the ConEd meter. The bottom portion of each bar is the amount of generation by the distributed generator. The next portion of each bar is standby demand, up to the capability of the generator. The top potion of each bar, if any, is supplemental demand, customer consumption in excess of the capability of the generator. A deficiency of this approach involves the constant reliance on the customer owned meter. The reading of the customer owned meter is necessary during each interval to determine which fraction of the ConEd delivery is standby/backup versus supplemental.



The approaches presented in Graph 2 and in Graph 3 each result in a supplemental demand of 300 KW and a standby demand of 400 KW. Other meter data might result in the two approaches producing billing demands that are not equal to each other. Table 1 presents a summary of the billing determinants that would be produced using these two competing methods to separate supplemental power from standby/backup Power.

Comparison of Billing Determinants Using Alternative Ways For the Split Between Standby and Supplemental
Table 1

	Supplemental First	Standby First
Supplemental Demand	300 KW	300 KW
Standby Demand	400 KW	400 KW
Supplemental Energy	4,300 KWH	2,350 KWH
Standby Energy	1,350 KWH	3,300 KWH

Note that the presentation in Table 1 of billing determinants for supplemental energy and standby energy is not meant to be pejorative of the ConEd proposal to develop a different type of billing determinant for the standby rate. The basic ConEd proposal is to use daily maximum demand as a commodity billing determinant. The Joint Supporters have not taken a position on the appropriateness of the use of such a billing determinant instead of energy. The Joint Supporters merely note that energy has traditionally been the commodity-based billing determinant in ConEd's rates.

Exhibit____(MBL-3)

IMPROPER ALLOCATION MATRIX

The Joint Supporters believe that ConEd developed the allocation matrix improperly. ConEd's approach seriously misstates its costs and results in allocating too much costs to the contract demand. Specifically, ConEd ignores distribution transformers as a separate cost category. Further, ConEd ignores the connection of some consumers directly to transformers and to substations instead of to a grid.

Table 1

Delivery Voltage Level

Distribution Delivery Costs	Secondary Customers		Primary Customers		Transmission Customers	
	% Contact	% As-Used	% Contact	% As-Used	% Contact	% As-Used
Secondary Distribution	100%	0%				
Primary Distribution	50%	50%	100%	0%	100%	0%
Substation	0%	100%	50%	50%	100%	0%
Transmission	0%	100%	0%	100%	50%	50%

The Table 1 reproduces the allocation table presented on Page 7 of Joel Charkow's letter of June 7, 2002 in this proceeding. The left column of the table identifies four categories of cost. Transmission and primary distribution each refer to a network of wires uses to move electricity throughout its service territory. Substation refers to installations that transform electricity from one voltage to another voltage. In contrast, secondary distribution refers to a combination of these two functions. Secondary distribution includes the wires used to move electricity throughout ConEd's service territory. It also includes the installations that transform electricity from one voltage to another.

Making Secondary Allocation Factors Consistent With Primary Allocation Factors

Table 2

Delivery Voltage Level

Distribution Delivery Costs	Secondary Customers		Primary Customers		Transmission Customers	
	% Contract	% As-Used	% Contract	% As-Used	% Contract	% As-Used
Secondary Distribution	100%	0%				
Transformers	50%	50%				
Primary Distribution	0%	100%	100%	0%	100%	0%
Substation	0%	100%	50%	50%	100%	0%
Transmission	0%	100%	0%	100%	50%	50%

Table 2 modifies Table 1 to reflect some of the deficiencies the Joint Supporters have identified in ConEd's presentation. Table 2 has an additional row for the transformers used to change the voltage of electricity from the ConEd's primary distribution voltage to the secondary distribution voltage. The inclusion of this row allows the allocation factors for secondary customers to be similar to the allocation factors ConEd has proposed for the Primary customers.

For the primary customers ConEd proposed in Table 1 to allocate to Contract all of the cost of primary wires that serve primary customers. For the allocation table to be consistent, for the secondary customers ConEd should allocate to Contract all of the cost of secondary wires that serve secondary customers. Table 2 uses that concept to show an allocation to Contract of all of the costs of wires that serve secondary customers.

Again for the primary customers, ConEd proposed in Table 1 to allocate to Contract only half of the cost of the substations necessary to transform the voltage of the electricity to the service voltage of primary customers. For the allocation table to be consistent, for the secondary customers ConEd should allocate to Contract half of the cost of the transformers used to transform the voltage of electricity to the service voltage of secondary customers. Table 2 uses that concept to show an allocation to Contract of half of the cost of the distribution transformers used to transform the voltage of the electricity to the service voltage of the secondary customers.

Again for the primary customers, ConEd proposed in Table 1 to allocate to Contract none of the cost of the wires for any voltage above the service voltage. For the allocation table to be consistent, for the secondary customers ConEd should allocate to Contract none of the cost of wires for any voltage above the service voltage. Table 2 uses that concept to show an allocation to Contract of none of the costs of wires for any voltage above the service voltage.

<u>Making Secondary and Primary Allocation Factors More Consistent With Transmission Allocation Factors</u>

Table 3

Delivery Voltage Level

Distribution Delivery Costs	Secondary Customers		Primary Customers		Transmission Customers	
	% Contract	% As-Used	% Contract	% As-Used	% Contract	% As-Used
Secondary Distribution	50%	50%				
Transformers	25%	75%				
Primary Distribution	0%	100%	50%	50%	100%	0%
Substation	0%	100%	25%	75%	100%	0%
Transmission	0%	100%	0%	100%	50%	50%

Table 3 modifies Table 1 and Table 2 to reflect some of the deficiencies the Joint Supporters have identified in ConEd's presentation. Table 3 has an additional row for the transformers used to change the voltage of electricity from the ConEd's primary distribution voltage to the secondary distribution voltage, much as Table 2 has. The inclusion of this row allows the allocation factors for secondary customers to be similar to the allocation factors ConEd has proposed for the Primary customers.

Table 3 further modifies Table 2 by emphasizing the allocation factors that ConEd says are appropriate for customers served at transmission voltages. ConEd says that for customers served at transmission voltages, only half of the transmission costs should be allocated to Contract demand. Consistency would suggest that ConEd should allocate to Contract demand only half of the cost of the wires at any voltage level to the customers who are served at that voltage level. This consistency is reflected in Table 3 for secondary customers, by the allocation to Contract Demand of half of the cost of secondary wires. This consistency is reflected in Table 3 for primary customers, by the allocation to Contract Demand of half of the cost of primary wires.