Before the
New York State Public Service Commission

In the Matter of

Consolidated Edison Company of New York, Inc.

Case 13-E-0030
Case 13-G-0031
Case 13-S-0032

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Prepared Direct Testimony of:

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On Behalf of:

The City of New York

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Harvey Arnett, and my address is 189 Gordon Road, Carmel, New York 10512.

Q. WHAT IS YOUR CURRENT POSITION?

A. I am an independent consultant doing business as Arnett Energy. For these rate proceedings, I have been retained on behalf of the City of New York ("City") to analyze certain aspects of Consolidated Edison Company of New York, Inc.'s ("Con Edison") Electric, Gas and Steam rate filings.

Q. COULD YOU BRIEFLY DESCRIBE YOUR EDUCATION AND EXPERIENCE?

A. I graduated from The Cooper Union School of Engineering and Science in June 1970 with a Bachelor of Engineering degree majoring in Chemical Engineering. I then began employment at the New York State Department of Public Service ("DPS"), where I was given progressive responsibilities.

In April 2005, I retired from the DPS as the Deputy Director of Electric and Gas Rates. I was a member of the DPS rate team responsible for oversight of Con Edison's Electric and Steam Departments for almost 30 years, and had been the lead rate engineer for that team for 25 years. While at the DPS, I testified before the New York State Public Service Commission ("Commission" or "PSC") in 35 proceedings covering a broad range of topics including revenue

requirements, revenue allocations, and rate design. In addition, I was regularly involved in issues associated with Con Edison's operation and maintenance expense and investment in plant, including its construction activities related to, and management and oversight of, its utility operations.

Since leaving the DPS, I have testified before the Commission in two Con Edison Electric Rate Proceedings (Cases 08-E-0539 and 09-E-0428), in two Steam Rate Proceedings (Case 07-S-1315 and Case 09-S-0794), and in one Gas Rate Proceeding (Case 09-G-0975).

I have also testified before the Connecticut Department of Public Utility Control.

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will address the following areas:

- Depreciation
- Utility Line Losses
- Unanticipated Storm Hardening Cost Recovery
- Steam Standby Rate Design
- Electric Vehicles
- Con Edison's Proposed Guide for Distributed Generation Projects Between 2-20 MWs

- Microgrids
- Con Edison's Surcharge Mechanism for New Gas Infrastructure
- Expanding the BIR Program
- Billing Issues for NYC

DEPRECIATION

Q. WHAT IS CON EDISON PROPOSING REGARDING DEPRECIATION?

A. The utility is proposing changes in service lives, life tables and net salvages for some accounts for all three Departments. I am not commenting on these proposals. However, Con Edison has two ongoing amortization accounts for Depreciation Reserve Deficiencies in the Electric Department. These amortization accounts have a revenue requirement impact of about $17.3 million (before tax effects) and $18.4 million (after tax effects) in Rate Year 1 ("RY1") (*see* City IR 637). In this proceeding, Con Edison proposes to establish a third amortization account that has a revenue requirement impact of $24.3 million (before tax) and $31.9 million (after tax) in RY1.

Q. DO YOU HAVE ANY COMMENTS ON DEPRECIATION?

A. Con Edison is reporting increasing negative net salvage values for its Electric, Gas and Steam Departments. These increases are a concern because they are contributing to growing Depreciation Reserve Deficiencies, as evidenced by the two existing amortizations, described above, and the proposal to establish a third.

Q. WHAT IS NEGATIVE NET SALVAGE?

A. When a depreciable asset is retired, there is a cost of removal and a potential salvage value. A negative net salvage value indicates the removal cost outweighs the salvage value. The negative net salvage is charged to the depreciation reserve.

Q. FOR PURPOSES OF YOUR TESTIMONY, DID YOU ACCEPT THE ACTUAL NEGATIVE NET SALVAGE VALUE THAT CON EDISON SHOWS ON THE RESPECTIVE EXHIBITS ___ (PTD-4)?

A. Yes. I have done no analysis on those numbers.

Q. WHAT IS A DEPRECIATION RESERVE DEFICIENCY OR SURPLUS?

A. A reserve deficiency or surplus is the difference between the Accumulated Depreciation Reserve on the utility books, and the Theoretical Depreciation Reserve that should be accrued to support the plant in service given the expected remaining life, the expected pattern of retirements, and the projected net salvages. The Commission's policy is to amortize surpluses or deficiencies that exceed a +/- 10 percent tolerance band (*see* Case 07-E-0523, Opinion and Order (issued March 25, 2008) at page 75).

Q. HAVE YOU PREPARED AN EXHIBIT THAT SHOWS THE POTENTIAL IMPACT ON DEPRECIATION RATES AND RESERVE DEFICIENCIES OF THESE RECENT INCREASES IN NEGATIVE NET SALVAGES?

A Yes, I have prepared Exhibit ___ HA-1 for this purpose. This exhibit has three

schedules, one for each Con Edison Department. In each case, I have calculated the Depreciation Expense and the Reserve Deficiency that would result from recognizing the most recent five year actual average negative net salvages in Depreciation Rates shown in the respective Exhibits ___(PTD-4).

For one Electric Account, Misc. Power Plant Equipment, the most recent five-year average was unusable because of limited data. For that account, I used the five year averages value for the period ending 2007. This exception is noted on the Exhibit___HA-1, Schedule 1.

For Gas, I used the actual negative net salvages provided in response to City IR 189, since the amounts shown in Gas Exhibit ___ (PTD-4) for three categories of plant represent a "capped level" of negative net salvage rather than the amount actually incurred. Capping negative net salvage will be discussed below. In addition, for one account, Transmission Structures and Improvements, I used an older five year average due to limited recent data. These exceptions are noted on Exhibit___HA-1, Schedule 2.

As noted on Exhibit___HA-1, Schedule 3, I used the five year average ending 2010 for accounts where the 2011 retirement of Hudson Avenue artificially lowered the negative net salvages because that generating station was retired, but the facilities were not removed.

Q. WHAT WERE THE RESULTS OF THIS ANALYSIS?

A. The results are summarized below:

	Electric		Gas		Steam	
	Dep Exp	Dep Reserve	Dep Exp	Dep Reserve	Dep Exp	Dep Reserve
Per Book	$557,678,574	$4,814,230,213	$93,708,665	$938,252,571	$62,472,306	$493,896,701
5 Year	$1,287,551,292	$10,836,730,855	$109,681,577	$1,180,324,985	$263,885,090	$1,475,355,118
Change	$729,872,718	$6,022,500,642	$15,972,911	$242,072,414	$201,412,784	$981,458,417
Percent	130.9%	125.1%	17.0%	25.8%	322.4%	198.7%

As can be seen in the table above, if the recent salvage experience of the Electric Department were to be fully recognized in depreciation rates, depreciation expense would have to increase by nearly $730 million, and the reserve deficiency would increase to over $6 billion.

For the Steam Department, depreciation expense would have to more than quadruple, and the deficiency would be equal to double the book reserve. On a percentage basis, the Steam Department outcomes are worse than the outcomes for the Electric Department.

The issue is less dramatic in the Gas Department, mainly because the five year average net salvages for Steel Mains and Services are not much higher than their capped values.

Q. HOW HAS THE UTILITY RESPONDED TO THESE NEGATIVE NET SALVAGE INCREASES?

A. In its rate filings, Con Edison proposed very conservative increases in negative net salvages for all three Departments. For instance, the workpapers of the

Property Tax and Depreciation ("PTD") panel supporting the three exhibits that make up Exhibit ___ (PTD-4) are duplicates of those exhibits with hand written notations explaining the bases for the utility proposed net salvages. One such notation, included in the Electric PTD panel's Workpapers, supports an increase in negative net salvage for Electric Account 9562, the largest account in terms of Gross Plant, stating:

> "All 1-yr bands since 1995 as well as all other data in study supports the need to increase net salvage percentage by a minimum of 10 percent at this time"

Con Edison's proposal is to increase the negative net salvage for this account from 55 percent to 65 percent. As is the case for many other accounts in these workpapers, this is a very minimal movement, given that the most recent five year average for Electric Account 9562 is over 250 percent negative net salvage. Con Edison's conservative approach to negative net salvage simply means that another reserve deficiency will develop because the accruals to cover negative net salvage are inadequate in relation to the actual costs Con Edison is incurring.

Modest increases to the depreciation rate are not a permanent solution to this problem and will only lead to additional requests for amortizations of the resulting Depreciation Reserve Deficiency.

Q. HOW WOULD YOU ADDRESS THIS PROBLEM?

A. In the past I have recommended that negative net salvage be recovered as it is incurred using an approach called "pay-as-you-go" ("PAYGO"). The PAYGO approach encompasses more than one means of recovery, but the general PAYGO principle is that recovery of negative net salvages occurs either simultaneously with the incurrence of the cost, through an operations and maintenance ("O&M") type allowance, or for some period thereafter, through an amortization. The Commission, while recognizing the issue of a growing depreciation deficiency, rejected this recommendation, citing a lack of proof of long term benefits (*see* Cases 08-E-0539 and 08-M-0618, Order Setting Electric Rates (issued April 24, 2009) at page 115). However, the depreciation deficiency problem that the PAYGO method was intended to fix remains an issue today.

Q. IN LIGHT OF THE COMMISSION'S RULING, DO YOU HAVE A DIFFERENT RECOMMENDATION?

A. Yes. In these cases I am proposing a solution developed from the approach that gas utilities in New York have used for decades. Currently, the problem is most immediate in the Electric Department, so my recommendation is focused on that service. However, I also recommend that the Commission: (1) adopt this change for the Steam Department, where a reserve deficiency can be expected in the near future; and (2) modify the current approach used for the Gas Department so all three Con Edison businesses are consistent.

Q. WHAT IS YOUR SPECIFIC RECOMMENDATION?

A. I am recommending that for any Electric, Gas or Steam Account with a proposed negative net salvage in excess of 50 percent, the amount of negative net salvage that can be charged to the depreciation reserve be capped at 50 percent. For Gas, my proposal would cover three categories that are currently capped, plus one additional account, Tunnels, where the proposed negative net salvage is in excess of 50 percent. Any amounts actually spent on salvage above this cap would be charged to O&M at the time it is incurred.

My recommendation would not apply to Common Plant Accounts, where the negative net salvages have not resulted in depreciation reserve deficiencies.

Q. HOW DOES YOUR PROPOSAL DIFFER FROM THE CURRENT APPLICATION OF CAPS IN NEGATIVE NET SALVAGE IN THE GAS DEPARTMENT?

A. Con Edison's Gas Department has caps on its three largest categories of plant. The caps are 60 percent negative for Transmission & Distribution Steel & Other Gas Mains; 100 percent negative for Transmission & Distribution Cast Iron Gas Mains; and 30 percent negative for Gas Services. The first two caps were established by the Commission in Order No. 89-34. The cap on Gas Services has been in place since 1960 *(see* testimony of Staff Witness Van Vranken in Case 88-G-0229, SM 924). My proposal differs from the caps that are now used for

Gas only in that I am recommending a uniform cap of 50 percent negative for all three of these types of plant. I am also proposing a 50 percent negative cap for Tunnels. And, of course, I am proposing to extend the capping mechanism to the Electric and Steam Departments.

Q. WHY ARE YOU RECOMMENDING ADOPTION OF A CAP ON NEGATIVE NET SALVAGE IN DEPRECIATION RATES?

A. The Electric and Steam reserve deficiencies are growing unchecked. My capping approach is a hybrid of the PAYGO approach, which charges all removal costs to current and future customers as those costs are incurred, and the current method, which seeks to recover all removal costs in advance over the service life of the plant. The use of caps on negative net salvage recovery shares many of the benefits provided by the PAYGO approach in that both methods control the cost of funding ever-growing reserve deficiencies driven by the Company's desire to collect, up front, high negative net salvage values.

Q. IS THERE ANY PRECEDENT FOR YOUR METHOD?

A. My recommended hybrid method has an established track record of success with the Con Edison Gas Department. Con Edison has had negative net salvage caps on three of its largest gas accounts for decades (*see* City IR 329), and Con Edison's Gas Department currently projects a Depreciation Reserve Surplus.

Further, the hybrid method would mitigate negative effects on the Company's cash flow because it still would allow recovery of significant negative net salvages well before the costs are incurred. Moreover, the hybrid method does not involve any true up between the O&M allowance and the actual net salvages in excess of the cap. Because Con Edison earnings could rise or fall depending on how actual negative net salvages compare to the O&M allowance, the utility has an incentive to control net salvage costs that the current system, which allows full recovery through its rate base treatment, does not provide.

Lastly, the negative net salvage cap of 50 percent is substantial enough to ensure intergenerational equity, because the net salvage collections from current and future customers can be considered fair to both groups.

Q. COULD YOU EXPLAIN WHY INTERGENERATIONAL EQUITY IS A CONCERN?

A. Con Edison's current method rests on the assumption that negative net salvage must be paid by customers served by a particular asset over the asset's life. This assumption is fundamentally flawed. Although Con Edison's utility facilities may become inadequate for the needs of future ratepayers or become technologically obsolete or simply fail, they will almost always be replaced by new facilities that may or may not be utility plant at the current sites. Thus, the removal of the retired equipment could be folded into the installation cost of the replacement

equipment, which would put the entire burden of any negative net salvage on future customers. Instead, the current practice puts the entire burden of projected negative net salvage on existing customers. The current Con Edison practice is akin to requiring homeowners to cover through their mortgage payments the eventual demolition of their new house when it becomes inadequate for the needs of the owners wanting to rebuild the home. The current method, therefore, creates an intergenerational inequity because it allocates an excessive amount of negative net salvage costs on existing customers, and an insufficient amount of such costs on future customers. This is unfair because these negative net salvages are being incurred, at least in part, to meet the needs of the next generation of ratepayers.

Q. WHAT IS THE BASIS FOR A UNIFORM CAP OF 50 PERCENT?

A. In setting depreciation rates under the current method, we are relying on estimated net salvage costs that are to be incurred far into the future. Service lives of 70 years and higher are common in each of Con Edison's three Departments.

Technology may or may not reduce removal costs, but inflation surely will increase them. For facilities installed early in the 20th Century that are now being retired, it is costing much more to remove them in nominal terms than the facilities' original cost. That explains why the recent negative net salvages are so large - removal costs incurred today are being divided by original costs incurred many decades before.

In the case of the new plant being installed today, charging the first year ratepayers a full share of a cost to be incurred far down the road is simply unfair. It should also be recognized that this first year customer would have to provide a return on the undepreciated investment, which is highest in the first year. A 50 percent cap on depreciation recoveries would ensure that all current and future customers who use the facility would contribute significantly to the eventual negative net salvage costs, thereby addressing the intergenerational equity issue.

Q. CAN YOU PROVIDE AN EXAMPLE TO ILLUSTRATE YOUR PROPOSAL?

A. Yes. Assume that the Company installs a plant in 2014 with a 50-year life, an original cost of $1 million, and a negative net salvage projected to be 150 percent ($1.5 million). Under the current methodology used by the Con Edison Electric Department, the first-year customers in 2014 would pay $20,000 in rates towards the original cost and $30,000 towards a removal cost expected to be incurred around the year 2064.

Under the alternative approach that I am proposing, the first year customers still would pay $20,000 towards the original cost. However, the first year customers' contribution toward the removal cost would only be $10,000 in today's dollars towards the future removal cost. The customers also would

contribute to an O&M expense for plant removals in 2014 whose costs might exceed the cap, if any, as would customers facing the same circumstance in 2064.

Q. HAVE YOU PREPARED AN EXHIBIT THAT SHOWS THE IMPACT ON DEPRECIATION RATES OF YOUR PROPOSAL TO CAP NEGATIVE NET SALVAGE FOR CERTAIN ACCOUNTS AT 50 PERCENT?

A. Yes, I have prepared Exhibit ___ HA-2. This exhibit has three schedules, one each for Electric, Gas and Steam, and is modeled after the Exhibit ____ (PTD-1) for each Department, except that it eliminates the columns showing the utility-proposed basis and the information on the Common Plant Accounts.

I have used the criteria that for any account where the PTD Panel is recommending a negative net salvage in excess of 50 percent, the negative net salvage be capped at that level. This would result in eight capped Electric accounts, four capped Gas categories, and two capped Steam accounts. The proposed capped net negative salvages are shown in ***bold and italics*** on Exhibit ___ HA-2.

Q. WHAT DOES YOUR PROPOSAL DO TO THE ELECTRIC ANNUAL DEPRECIATION RATES?

A. For the Electric Department, compared to the Company-proposed basis on Electric Exhibit ___(PTD-1), the proposed cap would reduce depreciation expense by $43 million, or 7.4 percent. This exhibit is based on 2011 data, not on the rate year

forecast. Applying the 7.4 percent reduction to the Company's Exhibit ___ (RM-2), Schedule 5, would decrease the Rate Year depreciation expense by $50.6 million.

Q. HOW DOES YOUR PROPOSAL IMPACT THE DEFICIENCY IN THE ELECTRIC DEPRECIATION RESERVE?

A. Electric Exhibit ___ (PTD-1) shows a reserve deficiency of about $680 million before adjustments to reflect ongoing and proposed amortizations. With my recommended caps in place, the reserve deficiency is reduced by $300 million to produce a deficiency of $380 million. This resulting deficiency equates to 8.53 percent of the theoretical depreciation reserve, which is within the +/- 10 percent tolerance band used to determine whether the booked depreciation reserve is adequate.

If the Commission adopts my recommendation, it should reject Con Edison's proposed new amortization of the Depreciation Reserve Deficiency. This would save ratepayers $24.3 million before taxes, and approximately $31.9 million after taxes, for Rate Year 1. Adopting my proposal also allows for discontinuance of the two ongoing amortizations of the Depreciation Reserve Deficiency, saving ratepayers another approximately $17.3 million before tax effects, and $18.4 million after taxes, in Rate Year 1. These prior amortizations can be discontinued because they largely resulted from the spread between actual

negative net salvages and the levels embedded in rates. The capping proposal, with an O&M allowance, will provide adequate recoveries going forward.

Overall, the depreciation expense reduction plus the elimination of three amortizations would decrease the Rate Year revenue requirement by approximately $100 million. This amount would be offset by an increase in O&M expense to cover any negative salvage forecasted to exceed the caps. I will discuss this offset later in my testimony.

Q. WHAT DOES EXHIBIT ___ HA-2 SHOW FOR THE GAS AND STEAM DEPARTMENTS?

A. Applying my recommended methodology to the Gas Department would increase the depreciation expense by $2.2 million and decrease the reserve by $2.5 million. These changes are small because I am basically replacing one set of variable caps with a set of caps fixed at 50 percent. The O&M allowance also would change.

For the Steam Department, application of my proposal would decrease the depreciation expense by approximately $2.8 million per year. The Theoretical Reserve would drop by $18 million. This would convert the deficiency into a surplus, but importantly, the surplus would not exceed the +/- 10 percent tolerance band that would warrant an amortization of the surplus.

While the Gas and Steam impacts from my recommendations may be somewhat modest, the Commission should adopt the negative net salvage caps for

these Departments to avoid future deficiencies and the accompanying amortizations, and to maintain consistency among the three Departments.

Q. HAVE YOU ESTIMATED THE INCREASES IN O&M EXPENSES THAT WOULD GO ALONG WITH YOUR CAPPED APPROACH?

A. Yes. I asked Con Edison for detailed projections of future net negative salvages and was told such projections are not available by account (*see* City IRs 84, 126, 144 and 147). To develop an estimate, I used as inputs the historic values of amounts spent on negative net salvage for 2009 to 2011, the most recent three years available, as contained in the Exhibit ___ (PTD-4) for Electric and Steam.

For the Gas Department, I used the comparable values from the Gas Exhibit ___ (PTD-4) for the one account, Tunnels, that I am proposing be capped for the first time. For the remaining Gas Accounts that are already capped, I used the responses to City IR 189 (amount spent historically) and City IR 608 (RY O&M Allowances).

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THESE RESULTS?

A. Yes. Schedules 1 and 3 of Exhibit __ HA-3 compare the incurred negative net salvages shown on the respective Electric or Steam Exhibit __ (PTD-4) to 50 percent of the original cost of plant retired in these same years. Under my approach, any amount of negative net salvage incurred over the 50 percent cap would be recoverable in an O&M allowance. Because the inputs were based on

2009 to 2011 costs, I escalated the allowance to 2014 using a two percent annual rate for four years (the GDP deflator for the past three years is about this level). For the Electric Department, the increase in O&M expense would be almost $95 million; for the Steam Department, it would be almost $5.4 million.

For the Gas Department, which has depreciation caps and an existing O&M allowance in place, I compared what the O&M allowance should have been for 2009 to 2011 using the 50 percent across the board cap to the O&M Allowance for RY 1 provided in response to City IR 608. Again, I increased the historic values by a two percent annual escalation factor for four years. The resulting decrease in Gas O&M expense for RY1 is $2.6 million. I note that if my proposal is not accepted and the existing Gas caps continue, according to this analysis, the RY 1 Gas O&M allowance embedded in the Con Edison filing is overstated and should be reduced by about $1.7 million.

In sum, in addition to curing the problem of growing depreciation reserve deficiencies, based on the data available, I estimate that my depreciation cap proposal would: (a) reduce Electric rates by about $5 million (a $100 million decrease in depreciation expense less the $95 million increase in O&M expenses); (b) reduce Gas rates by about $0.4 million (a $2.6 million decrease in O&M expense less the increase in depreciation expense of $2.2 million); and (c) increase

Steam rates by about $2.6 million (a $2.8 million decrease in depreciation expense offset by the $5.4 million increase in O&M expense).

UTILITY LINE LOSSES

Q. WHAT ARE LINE LOSSES?

A. Each of Con Edison's three utility departments includes a delivery system. In each system, some energy is lost during the transmission of electricity, gas, or steam through that delivery system. Thus, the amount of energy that must be put into the system is greater than the amount all customers receive.

Q. HOW DO LINE LOSSES IMPACT CUSTOMERS?

A. On an ongoing basis, the lower the losses, the lower the rates that customers have to pay. This is because Con Edison's rate adjustment mechanisms contain true ups to actual fuel costs, so that higher or lower line losses will impact rates.

In recognition of the fact that line losses occur, Con Edison's Gas and Steam Departments contain incentive mechanisms that reward or penalize the Company based on how actual line losses compare to a target set in the tariff. However, there is no incentive mechanism for the Electric Department.

Q. CAN CON EDISON TAKE ACTION TO MINIMIZE LINE LOSSES FOR THE THREE DEPARTMENTS?

A. Yes. While some losses are unavoidable, Con Edison can exert some control over line losses through advances in system design and operations (*see* City IR 574 for

examples for the Steam Department).

Q. HOW HAS CON EDISON ADDRESSED THE LINE LOSS ISSUE IN ITS RATE FILINGS?

A. For Gas, Company Witness Carnavos, beginning on page 39, proposes certain updates to the existing Gas Incentive Mechanism. In brief, this testimony recommends that: (1) the incentive mechanism be based on a five year rolling average of line losses as a percentage of throughput; (2) a deadband be set equal to 2 times the standard deviation of this set of data; and (3) an outside limit for earning incentives or penalties be set equal to four times the standard deviation. Under this proposal, Con Edison's Gas Department would earn an incentive or penalty equal to all energy cost variations between the end of the deadband and the outside limit (i.e., between two and four standard deviations). While the earned maximum penalty or reward would depend on actual fuel cost, based on the current marginal commodity cost and volumes in Exhibit ___ (PTC-1), the maximum gain or loss to the Gas Department would be approximately $3.5 million (*see* City IR 634), or about 11 basis points return on equity (for this I used $31.2 million as equivalent to a 100 basis points (*see* UIU IR 2)).

Q. WHAT HAS THE COMPANY PROPOSED FOR STEAM LINE LOSSES?

A. I could find no reference to Steam line losses (or Steam Variance) in the Steam rate filing. Con Edison provided the forecast level of line losses, as well as 5

years of historic Steam Variance, in response to interrogatories and also confirmed that it is not proposing to change the current Steam Variance Incentive Mechanism and its targets in this case (*see* City IRs 365, 366, 367, 372 and 373).

Q. WHAT DOES THE COMPANY PROPOSE FOR ELECTRIC LINE LOSSES?

A. There is no existing incentive mechanism, nor is one proposed. The rate filing discusses a tariff change impacting the Market Supply Charge ("MSC") with a specific line loss factor based on a 2008 study, and there is an implicit line loss factor contained in the Electric Forecasting Panel's exhibit unique to each Rate Year. The Forecasting Panel's line losses appear to be derived from the difference between the Panel's sales models and its sendout model. The utility states that using two different loss factors does not impact ratepayers or the utility due to the reconciliation provision of the MSC (*see* City IR 564)

Q. DO YOU HAVE ANY OBJECTIONS TO CON EDISON'S PROPOSAL ON GAS LINE LOSSES?

A. No.

Q. DO YOU HAVE ANY COMMENTS ON THE PROPOSED TREATMENT OF STEAM VARIANCE?

A. Yes. The Rate Year forecast of Steam Variance, at about 3,900 MMlbs, is much higher than the average level of the past five years (3,700 MMlbs). As described

in its response to City IR 373, Con Edison earned an incentive in each of the past five years and its forecasts for the three rate years are close to the incentive end of the deadband. Based on recent actual performance, Con Edison's proposal would increase the likelihood that it will continue to earn a reward under the incentive mechanism. Accordingly, if Con Edison's forecast is adopted, then current incentive targets must be updated.

Here is the current tariff incentive provision for steam losses:

> Commencing with the 12-month period ending September 30, 2011, if the variance exceeds 4,200 MMlb in any annual period, the Company will recover 90% of the variance-related fuel costs in excess of 4,200 MMlb, provided, however, that its unrecovered variance-related fuel costs will not exceed $5 million. If the variance is less than 3,900 MMlb in any annual period, the Company will credit Customers with 90% of the variance-related fuel cost savings less than 3,900 MMlb, provided, however, that the Company will retain no more than $5 million.

To ensure that this Steam mechanism provides an incentive for improved performance, I recommend that the tariff incentive mechanism be updated to be consistent with the incentive mechanism used for Gas, including the impact that the maximum incentive could have on the equity return provided by the Steam Department.

Q. PLEASE CONTINUE ON THE STEAM LINE LOSS INCENTIVE.

A. The most recent five year average Steam Variance for the 12 months ending September was about 3,700 MMlbs. The standard deviation was about 200,000 Mlbs. Utilizing Con Edison's Gas approach, a deadband of between 3,300

MMlbs and 4,100 MMlbs should be applied. Con Edison would earn a reward for Steam Variance that ranges from +/- 400,000 Mlbs to an outside limit of 2,900 MMlbs and 4,500 MMlbs. Based on a Rate Year fuel cost of $6.50 per Mlbs (*see* City IR 567), the potential maximum gain or loss would be about $2.6 million. Based on the response to COW IR 22, this incentive is equivalent to 16.7 basis points. This is greater than is the case for the Gas Incentive. I recommend that the incentives be equalized. This can be achieved by applying a 65 percent shareholder, 35 percent ratepayer split to the Steam Incentive Mechanism.

Lastly, the Steam Incentive Mechanism, as is the case for Gas, should automatically adjust to the latest five year rolling average so that, unlike the current provision, unduly high targets are not allowed to remain in place and reward the utility indefinitely.

Q. DO YOU HAVE ANY COMMENTS ON THE TREATMENT OF ELECTRIC LINE LOSSES?

A. The same logic that led to Gas and Steam tariff incentive mechanisms, that is, losses are to some extent under the control of the utility, suggest that Electric should have one as well. The most recent five calendar year average line loss percentage was 5.9 percent. The standard deviation was about 0.2 percent. That would mean an incentive mechanism should use a deadband of between 5.5 percent and 6.3 percent. This would establish a potential earning zone of +/- 0.4

percent, so that the outside limits would be 5.1 percent and 6.7 percent.

Q. WHAT WOULD BE MAXIMUM INCENTIVE OR PENALTY ASSOCIATED WITH ADOPTING YOUR PROPOSAL FOR THE ELECTRIC DEPARTMENT?

A. The Rate Year Sales forecast presented on Electric Exhibit ___ (FP-7) is 57,521 million kWh. The maximum incentive or penalty using a 0.4 percent spread and a Rate Year supply cost of 10.3 cents per kWh (*see* City IR 638) would be approximately $23.7 million. Based on UIU IR 2, this is equivalent to about 16 basis points. As was the case for Steam, this incentive is disproportionate to that in place for the Gas Department. Again, a 65 shareholder, 35 percent ratepayer split of the gain or loss would result in an incentive comparable to the Gas Mechanism.

The Electric Incentive Mechanism should also automatically adjust to the latest five year rolling average.

UNANTICIPATED STORM HARDENING COST RECOVERY

Q. WHAT HAS THE UTILITY PROPOSED FOR RECOVERY OF UNANTICIPATED STORM HARDENING COSTS?

A. In its three rate filings, Con Edison proposed approximately $1 billion in storm hardening projects. Although the Company proposes that the full suite of projects in the Storm Hardening program be reflected in the base rates contained in Con

Edison's initial filings and updates, it also asserts there may be future investments in storm hardening projects "that cannot be timely addressed in rate proceedings or through multi-year rate plans." (Muccilo at 68 [Electric].)

To address the cost recovery associated with these yet-to-be-defined, incremental storm hardening projects, Con Edison proposes to implement a Surcharge Mechanism for its Electric, Gas and Steam Departments. As proposed, if an unanticipated project arises, then the utility would make a filing to the Commission explaining the "location and scope of the project(s) and/or program(s); the benefit to the system; past impact of storms on the to-be-modified infrastructure; the current ability of the system to withstand severe weather events; and future design capabilities of the system to be achieved via targeted projects." Con Edison would also have to explain why it did not include the project within its existing capital budget.

Under Con Edison's proposal, the filing would then be evaluated by DPS Staff and other interested parties. DPS Staff would present a recommendation to the Commission within 60 days of the Company's filing, stating which projects DPS Staff believes should be implemented. Con Edison would proceed with a project following Commission approval. The surcharge would be collected from all customer classes "in a manner consistent with the allocation of costs approved in Con Edison's most recent rate case."

Q. DO YOU AGREE THAT A NEW SURCHARGE MECHANISM IS NEEDED FOR STORM HARDENING INVESTMENTS?

A. No. Initially, although the City strongly supports prudent storm hardening investments, and even is submitting separate and far-reaching recommendations on how such investments should be planned and bolstered, the bottom line is that planned and unplanned storm hardening projects should be addressed as part of Con Edison's normal capital budgeting process. Here, Con Edison speculates that it may spend $1 billion on projects to improve the resilience of its Electric, Gas and Steam Systems. These projects are no different than any other capital investment plan that the Company has undertaken. The Company routinely is expected to manage the projects and budgets associated with such plans. This includes shifting project priorities and expenditures in response to changing system needs. The Company has not provided any explanation or justification as to why the Storm Hardening Program should be given special treatment, or why the Company may be unable to manage its Storm Hardening Program as it does every other capital investment plan that it administers.

Q. ARE THERE OTHER REASONS FOR OPPOSING THIS APPROACH?

A. Yes. The 60-day timeframe from initial Company filing to DPS Staff recommendation is an insufficient amount of time for adequate review of any specific proposal. Con Edison's proposed process also does not address whether

any such submission would be subject to the notice and comment period afforded by the New York State Administrative Procedure Act. Nor does Con Edison's proposal provide for further opportunity for comment from interested stakeholders if there is disagreement among stakeholders and DPS Staff regarding proposed Storm Hardening Projects. Given their implications for public safety and reliability, any such proposed projects will be of vital interest to the City and other parties, and provision should be made to invite broad public participation with adequate notice.

Further, there already are a number of costs that Con Edison recovers outside of its base rates. The addition of another surcharge is likely to confuse customers and could lead to, or present the appearance of, excessive spending. For example, in Case 04-E-0572 the Commission approved a reconciliation of the carrying charge on Con Edison Electric T&D investment. The utility far exceeded the targeted amounts, by $1.6 billion over the three year period, leading to considerable controversy in the subsequent electric rate case.

Finally, allocating the new storm costs using the last approved revenue allocation may not be fair. For example, if it were an unanticipated Storm Hardening Project for Con Edison-owned generation, any allocation to NYPA would be unfair because NYPA supplies its own customers' generation needs.

STEAM STANDBY RATE DESIGN

Q. PLEASE EXPLAIN THE RATES PAID UNDER STEAM SERVICE CLASSIFICATION ("SC") NO. 4 – BACK-UP/SUPPLEMENTARY SERVICE ("STEAM STANDBY RATE").

A. The Steam Standby Rate mainly consists of three charges: (1) the Contract Demand Charge; (2) a Usage Charge; and (3) a Customer Charge.

Q. IS THERE A PROBLEM WITH CON EDISON'S STEAM STANDBY RATE?

A. Yes. There are two problems. First, too many costs are being recovered in the Contract Demand Charge. Second, as currently designed, the Contract Demand Charge is equal to the customer's monthly maximum demand during any hour in the months of November – April. The Steam Standby Demand Rate defines a peak period customer as a customer who uses steam between the hours of 5 AM to 6 PM weekdays, November through April. The problem is that standby customers sometimes need to utilize steam for cooling purposes during the months of November and April, and it is possible for the customer's peak steam demand for cooling purposes to exceed peak steam demand for heating purposes. Thus, as currently designed, the Steam Standby Rate has the unintended and perverse impact of penalizing the use of steam for cooling purposes.

Unless modified, the SC 4 rate design will impose unnecessary costs on, and discourage the development of, distributed generation ("DG") in the Con

Edison service territory, a result that would be at odds with important State and City policies designed to advance DG opportunities.

Q. WHAT IS IN THE CONTRACT DEMAND CHARGE?

A. The Contract Demand Charge is designed to recover 100 percent of the Demand Portion of the Distribution System plus 40 percent of Demand Related Production Costs. The Commission should take another look at how it allocates Demand Related Distribution costs between the Contract Demand and the As Used Demand Charges. Including 100 percent of Demand Related Distribution costs in the Contract Demand charge appears to be excessive. It suggests that Con Edison must build its entire distribution system as if every Standby Steam Customer were taking their full contracted amount on the peak hour, which is not a reasonable assumption.

Further, recovering 100 percent of Demand Related Distribution Costs in the Contract Demand charge is inconsistent with assigning a much lower percentage, 40 percent, of Production Costs to the Contract Demand. Since only 40 percent of the Standby Load needs to be covered by production capability, then the Contract Demand should not be charging 100 percent for the distribution lines coming out of that production facility.

Q. ARE THE COSTS RECOVERED BY THE CONTRACT DEMAND CHARGE SPECIFIC TO THE INDIVIDUAL CUSTOMER?

A. Not necessarily. If the customer's peak load is in an hour when the Steam System is not being fully utilized, no additional distribution or production facilities are needed to accommodate that customer's peak load.

Q. HAS THE COMMISSION BEEN PREVIOUSLY PRESENTED WITH YOUR RECOMMENDATION ON COOLING LOAD?

A. Yes. On March 26, 2012, Vornado Realty Trust ("Vornado") filed a petition for a declaratory ruling seeking a similar revision to the Steam Standby Rate ("Vornado Petition"). The Commission denied the petition on September 17, 2012 in Case 12-S-0147 ("Vornado Order"). However, the Commission explicitly recognized that the issues and policies raised by the Vornado Petition "are particularly relevant to a rate case proceeding where customers of all service classes are generally represented and all other issues regarding the utility's revenue requirement and customer rate responsibility are examined" (Vornado Order pages 7 and 8). In addition, as noted below, the Commission has previously recognized the value of steam cooling at times when the system is not under stress.

Q. DID THE VORNADO ORDER COMMENT ON THE CURRENT STEAM STANDBY RATE?

A. Yes. The Commission stated (page 7):

> The Back-Up/Supplementary Service charges are based on the principle that the charges are recovering: (1) the fixed costs associated with the

steam system components that are specific to the individual customer (contract demand charges), (2) the variable costs associated with the customer's actual steam energy usage to recover the costs of facilities that are needed to meet system peaks and therefore are shared among customers rather than the individual customer (as used demand charges), and (3) the customer costs.

Q. DO YOU AGREE WITH THE COMMISSION'S CHARACTERIZATION OF STEAM STANDBY RATE CHARGES?

A. No. In particular, I disagree with how the Commission described the costs that are recovered by each element of the Standby Rate. For the large Standby Demand Customers that take service under SC 4 Rate IV, the Customer Charge is based on the full Customer Costs contained in the Steam Embedded Cost of Service ("ECOS") study. Specifically, the Customer Charge recovers the class average Customer Costs, including Billing, Services, Meters, Installations on Customer Premises and the costs of the Minimum Grid, which encompass nearly all of the costs that are specific to the individual customer. The current Customer Charge already approaches $7,000 per month for these SC 4 Rate IV customers.

Q. IF A LARGE STANDBY CUSTOMER'S PEAK STEAM LOAD IS ACHIEVED WHEN USING STEAM FOR COOLING PURPOSES, BUT THE CUSTOMER'S CONTRACT DEMAND IS SET BASED UPON THE CUSTOMER'S PEAK HEATING LOAD, WON'T CON EDISON INSTALL FACILITIES TO SERVE THE CUSTOMER THAT THE CUSTOMER WILL NOT PAY FOR?

A. No. I already explained how Steam distribution and production facilities are not impacted by higher off peak cooling loads. It may be true that in some isolated circumstances facilities specific to the customer, like Meters and Services, may have to be larger than they would be just for the heating load if there is a much higher cooling demand. But, even if that did happen, these on-site costs would still be fully recovered on an average basis from all similarly situated customers in their Customer Charges. It would be a double count to assess a Steam Standby Customer with full ECOS-based average Customer Charge and then impose another adder for a higher "customer-specific" cost caused by a cooling load.

Q. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THAT COOLING LOAD SHOULD NOT DRIVE THE DEMAND CHARGE FOR STEAM CUSTOMERS TAKING SERVICE UNDER THE CONVENTIONAL (NON-STANDBY) STEAM DEMAND RATE?

A. Yes. The criteria for the Steam Standby Rate, including the six month Winter Period of November - April, were set by the Commission in 2000. The Conventional Steam Demand Rate is more recent. When the Commission first approved Demand Billing in 2004, the Winter Period definition for Demand Billing originally included the same six months that the Steam Standby Rate still includes. However, after more data was developed on bill impacts, the Commission, by Order issued January 17, 2008 in Case 05-S-1376, accepted Con

Edison's filing to reduce the Winter Billing Period for conventional steam demand customers by eliminating the shoulder months of November and April.

Q. DID THE COMMISSION EXPLAIN WHY IT ELIMINATED THE SHOULDER MONTHS IN THE DETERMINATION OF THE DEMAND CHARGE FOR CONVENTIONAL STEAM CUSTOMERS?

A. Yes. The Commission specifically recognized that incorporating the shoulder months could result in cooling loads causing a monthly peak, which could result in significant bill impacts for customers. Two quotes from the January 17, 2008 Order, on pages 4 and 6 respectively, clearly indicate that the Commission did not want customers to be penalized by demand charges that reflect cooling loads in November or April:

> As required under the Joint Proposal, Con Edison held a meeting on July 17, 2007 with interested parties to discuss the impact that the new demand charges would have on a customer's bill (based on the sample bills provided during the winter of 2006-2007). At the meeting, the company indicated that the bill impacts for those customers that used steam air conditioning during the "shoulder" months of November and April were significant. Based on the customer feedback, Con Edison proposed an alternative steam demand charge rate design that collects 25% of the pure base revenue (i.e., base revenues less the base cost of fuel, station electric usage charges, and the customer charge) for the four winter billing months of December through March instead of the original six month period.

And:

> *As the company states, significant bill impacts on steam cooling customers would be contrary to the Commission's policy of promoting steam air conditioning and reducing demand on the electric system during peak periods.* The Joint Proposal adopted by the Commission in the September

> 22 Order provided for the company to determine the need for and nature of any modifications to the demand rates, and other related issues, based upon the impact of demand charges on customers bills. *The company's four month demand charge rate design, addresses the possibility that some cooling loads could cause a monthly peak in November or April resulting in significant bill impacts.* Staff finds the company's demand charge rate design to be reasonable (emphasis added).

Q. IS THERE ANY REASON WHY THE STANDBY CONTRACT DEMAND CHARGE SHOULD BE SET ON THE BASIS OF COOLING LOAD?

A. No. It does not make any sense to penalize customers during November and April, or at any time whatsoever, for using steam for cooling purposes during unseasonably warm weather. First, steam used for cooling during winter months does not contribute to the system peak. Steam usage for cooling purposes should therefore be encouraged and not penalized. And, as discussed above, setting the Standby Contract Demand charge based on peak heating demand does not impact Con Edison's ability to recover customer-specific costs from the Standby Customer because they already are collected through the Customer Charge.

Second, the current Steam Standby Rate acts as a barrier to further DG development in Con Edison's service territory. If cooling demand is allowed to set the SC 4 Contract Demand, customers with DG projects could be subject to substantial additional costs not imposed on conventional steam customers. This disparate treatment of Steam Standby Customers is unfair and should not be allowed to continue. The current rate design is contrary to the Commission's

January 17, 2008 Order, which rejected the notion that demand charges should be set by cooling loads.

Q. HOW SHOULD THIS PROBLEM BE REMEDIED?

A. There are two simple ways for the Commission to remedy this problem. One solution would be to measure the Contract Demand for Steam Standby based on the same four month, five hour period as the Demand Charges apply in Conventional Demand Rates. In other words, the SC 4 Rate IV tariff should be modified so that the Contract Demand is established during the months December – March and is based on peak loads during the hours of 6:00 a.m. – 11:00 a.m. This would ensure that the unfair practice of setting S.C. 4 demand based on cooling loads is terminated, and put S.C. 4 customers on the same basis as conventional demand customers.

In the alternative, the Commission could clarify that the SC 4 Contract Demand will be based solely on steam used for heating, not cooling, purposes. This can be achieved by setting a temperature threshold. Then, customer peak loads that are registered when the temperature is above the threshold would not be relevant to setting the Contract Demand.

Q. WOULD YOUR PROPOSAL TO CHANGE THE DETERMINATION PERIOD FOR MEASURING STEAM STANDBY CONTRACT DEMAND HAVE ANY IMPACT ON CON EDISON'S STEAM SALES FORECAST?

A. It might, but it is not likely to be material, particularly when measured against what continuation of the current practice might do (i.e., drive customers off the steam system). Other than Vornado, I know of no other S.C. 4 customers that have Contract Demands based on cooling load. In any event, for the reasons I have stated, the current rate design is discriminatory and indefensible and should be changed.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS?

A. Yes. My recommendations are designed to ensure that the S.C. 4 rate is fair and reasonable. If the cost of Steam Standby service is overstated, then the current rate design is contrary to several important State and City policies encouraging broader DG deployment, including New York State's Energy Plan and *PlaNYC 2030*. And, as noted earlier, an unduly high S.C. 4 rate could compel DG developers to exit the Steam System by installing redundant steam generation, a truly bizarre result for a system that can ill-afford to lose large existing customers.

ELECTRIC VEHICLES

Q. WHAT IS THE CITY'S POSITION ON PLUG-IN ELECTRIC VEHICLES (PEV)?

A. The City is interested in encouraging PEVs. For example, in his State of the City, Mayor Bloomberg announced his commitment to electric vehicles, by creating 10,000 electric vehicle charger ready parking spots across the City,

expanding what is already one of the largest electric vehicle fleets in the nation, and increasing the use of electric vehicles as taxis.

Q. DOES THE UTILITY FILING ADDRESS PEVs?

A. Yes. The Electric Rate Panel is proposing to modify Con Edison's existing SC 1 Voluntary Time of Use Rate ("VTOU") to promote off peak charging of PEVs.

Q. DO YOU AGREE WITH THE CON EDISON PROPOSED CHANGES TO THIS VOLUNTARY RATE?

A. The new rate design is an improvement over the existing SC 1 VTOU+ rate. I agree with the introduction of a super peak period for the four summer months where Capacity Costs would be recovered. I also agree with treating weekends and weekdays the same. Residential customers are clustered, and weekend peaks at area substations serving these customers are very plausible.

I do not agree that the off peak period should begin at 1 AM and end at 7 AM. Instead, I recommend that the current start time of 11 PM be continued and that the end time be set at 8 AM.

Q. WHAT WAS THE UTILITY BASIS FOR STARTING ITS PROPOSED OFF PEAK PERIOD AT 1 AM?

A. We asked a multipart question on how the utility selected the off peak period for this rate (*see* City IR 628). Con Edison replied that it is proposing that the off peak period begin at 1 AM, citing an analysis that showed that area substations

were at least 95 percent of their peak loads over a broader period than the existing VTOU on peak period, ending as late as midnight. The reply also stated that the Residential Class existing peak was from 7 PM to 11 PM and that the Company was concerned with establishing new area substation peaks if it started the off peak period too close to the existing peak, due to potentially high adoption rates and clustering of early adopters.

Con Edison did not rely on NYISO energy prices in setting the time periods, stating that: "The decision to align supply and delivery pricing periods was based on rate design simplicity, administration and customer understanding."

Q. DO YOU AGREE WITH THE UTILITY'S CONCLUSIONS?

A. I appreciate the utility concerns on establishing new peaks as expressed in the response to City IR 628. However, given the public interest in promoting PEVs, the Commission should make the VTOU rate as user friendly as possible for customers in general. If in the future, the PEV penetrations are such that new area substation peaks are being created beyond 11 PM, then the off peak time periods can be adjusted at that time.

The utility analysis of when area substations are within 95 percent of their peak load does not support the statement that for some area substations the 95 percent of peak load ends as late as midnight. As shown on the chart provided in

response to City IR 628, and the half hour load curves provided in response to City IR 579, loads decline rapidly after 11 PM.

With an average area substation coincident load of 213 MW (13,189 MW peak, 62 Area Substations per Electric Infrastructure and Operation Panel testimony), the 5 percent cushion is equivalent to about 10.6 MW of load. To erase this cushion, assuming a 1.5 kW load for a Type I home charger, about 7,000 PEVs would have to be added to a specific area substation. If Type 2 chargers become prevalent, at 6.6 kW, there would have to be over 1,000 PEVs served by that area substation. And, these hypotheticals are based on coincident load - the average area substation capacity must be higher than 213 MW because of load diversity. In short, given the nascent state of the PEV industry, there is sufficient cushion in peak loads to avoid reducing the off-peak charging period now based on unreasonable assumptions of PEV penetration.

Q. YOU NOTED THAT CON EDISON DID NOT EXAMINE NYISO ENERGY PRICES IN MAKING ITS DECISION TO SHORTEN THE OFF-PEAK PERIOD. DID YOU?

A. Yes. Unlike the utility, I have looked at NYISO energy prices, and they also support bundling the hours beginning 11 PM and Midnight with off-peak hours.

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THESE MARKET ENERGY PRICES?

A. Yes, I have prepared Exhibit ___ HA-4. This exhibit shows the average Zone J (NYC) locational based market price ("LBMP") for all 168 hours of the week, over the 12 months ending March 31, 2013. The two hour period from 11 PM to 1 AM exhibit average LBMPs that are far closer to those in the utility recommended off peak hours (a difference of $6 per MWH) than to the peak hours (a difference of $15 per MWH).

Q. WHY ARE YOU SUPPORTING ENDING THE OFF PEAK PERIOD AT 8 AM RATHER THAN THE 7 AM END TIME PROPOSED BY CON EDISON?

A. As I did in recommending an earlier start to the off peak period, in recommending a later end to the off peak period, I have relied on three sets of data, the hours when substations are within 95 percent of their peak (City IR 628), the peak day half hour loads for each Con Edison class (City IR 579) and the average Zone J energy prices shown in Exhibit ___ HA-4.

For the 7 AM hour, there are no area substations within 95 percent of their peak load. The SC 1 loads for the 7 AM hour on the peak day are only roughly 2/3 of their peak loads. As for the Zone J energy prices, they are rising, but are still well below the average for the 8 AM to 11 PM recommended peak hours (difference of about $10 per MWH). Accordingly, an 8 AM end time is more appropriate than the 7 AM time proposed by the Company.

The off peak period should begin at 11 PM and end at 8 AM. If adjustments are required in the future, there will be ample opportunity to do so before PEVs cause over loadings on the distribution system.

Q. DO YOU HAVE ANY OTHER COMMENTS ON HOW PEVS CAN BE ENCOURAGED BY CON EDISON?

A. Yes. First, although I recognize that the Commission has issued a notice requesting comments in a new proceeding, Case 13-E-0199, to address Electric Vehicles Policies, I offer the following additional comments for consideration here.

There are two submetering options that should be explored as ways to encourage PEV. In June of 2012, the utility began a Pilot Program to test the technology and customer interest in an energy gateway and an energy measuring device called a load device controller in conjunction with a standard revenue grade meter in a system that is capable of separately measuring the PEV energy consumption from the whole house. If the consumption of the PEV charger can be measured using revenue quality technology, implementing this program would be extremely beneficial to homeowners who are reluctant to place their entire household on TOU rates.

Another option could be to introduce a new program modeled after the Solar Water Heating Special Provision D rate that Con Edison is seeking to

discontinue. Under Special Provision D, there was a modest $3 per month charge for a second meter, and a time clock was used to ensure that the water heater would not operate in peak hours. Any off peak consumption would be priced at the VTOU's off peak rate. It would seem that this rather simple arrangement, with the updated definitions of peak and off peak time periods, would also be attractive to PEV owners.

Q. HAS THE UTILITY RAISED ANY OBJECTION TO THE SUBMETERING PROPOSAL?

A. Yes. The City has asked Con Edison whether a residential customer with a PEV charger can continue to receive service as a residential customer. I understand the utility position to be that if the PEV charger is separately metered, or submetered, it must be billed at the non-residential rate. If it is not separately metered, then pricing under the residential rate is permissible (compare City IR 629 and IR 630).

The City believes this artificial separation is not cost justified. For one thing, it would make the two submeter options I just discussed undoable. What constitutes residential usage should change over time, as technology evolves. I know of no reason why a PEV charger installed for the homeowner's own use should not be considered as just another household appliance.

Q. ARE THERE ANY OTHER ISSUES REGARDING PEVS THAT YOU WOULD LIKE TO ADDRESS?

A. The City was concerned that a new curbside charging station would have to pay for any new service to connect to Con Edison. This is no longer an issue given the utility response to City IR 633. Specifically, Con Edison's response to this IR states that the Company would treat such a charging station the same as any other customer requesting service.

THE NEW DG GUIDE

Q. DO YOU HAVE ANY CONCERNS ABOUT CON EDISON'S PROCEDURES FOR INTERCONNECTING NEW DG PROJECTS?

A. Yes. I am concerned about certain aspects of the new procedure that Con Edison is developing for DG installations greater than 2 MWs and less than 20 MWs ("New DG Guide"). In particular, I am concerned Con Edison will have no obligation to abide by the interconnection timeframes contained in the New DG Guide and customers will have no recourse in the event Con Edison deviates from these timeframes.

Q. WHY IS CON EDISON DEVELOPING THE NEW DG GUIDE?

A. Based on collaborative discussions in 2011-2012, Con Edison agreed to develop a draft procedure for DG installations greater than 2 MWs and less than 20 MW. The New DG Guide would be similar to Con Edison's Distributed Generation

Guide ("Existing DG Guide"), which outlines the steps Con Edison currently follows to connect DG projects sized 2 MW or less to its electric grid.

Con Edison circulated its first draft of the New DG Guide in October, 2012. The City, and presumably other interested stakeholders, submitted comments and proposed revisions to the New DG Guide on December 21, 2012. On February 4, 2013, Con Edison circulated a revised version incorporating some of the comments submitted by the City, and on February 11, 2013 Con Edison held a conference call with interested stakeholders to explain certain aspects of the New DG Guide. The City submitted additional written comments on the New DG Guide on March 7, 2013.

Q. HAS CON EDISON ADDRESSED ALL OF THE CITY'S CONCERNS?

A. No. The City asked Con Edison (1) to revise its electricity tariff to state that DG projects between 2-20 MW will be processed pursuant to the New DG Guide and (2) to include the New DG Guide as a tariff addendum. The Existing DG Guide is a tariff addendum. Although Con Edison was responsive to some of the City's other concerns, Con Edison did not adopt the City's request to include the New DG Guide as part of its tariff. Instead, Con Edison included a statement in the New DG Guide stating it will "present a redacted report in July and January of each year on compliance" with the time frames in the New DG Guide. Con Edison did not specify to whom it will present this redacted report.

Q. WHY IS IT IMPORTANT TO INCORPORATE THE NEW DG GUIDE INTO THE TARIFF?

A. Although the New DG Guide enumerates certain time frames, it is not clear what obligation Con Edison has to abide by these time frames, nor is it clear what remedies the customer has in the event Con Edison deviates from them.

Counsel advises that including the New DG Guide in the tariff will provide customers with enforcement rights in the event Con Edison deviates from the time frames. For example, decisions on customer complaints to the Public Service Commission are based in part on utility tariffs. 16 NYCRR § 12.4. This regulation does not state complaint decisions can be based on utility guides. Further, customers can pursue a declaratory ruling if the New DG Guide is incorporated into the tariff. The New DG Guide becomes a "rule…enforceable by the Commission" once embedded in the tariff. *See* 16 NYCRR § 8.1.

Q. HAS CON EDISON PROVIDED A REASON FOR NOT INCLUDING THE NEW DG GUIDE IN ITS TARIFF?

A. Yes. During the February 11, 2013 conference call, Con Edison raised a concern that incorporating the New DG Guide into its tariff will make it difficult to periodically update the New DG Guide because Con Edison will need to request a tariff change for every change to the New DG Guide.

Q. DO YOU AGREE WITH CON EDISON'S CONCERN?

A. No. The City does not anticipate numerous changes to the New DG Guide and, in any event, the process to submit a tariff change is not administratively burdensome, and Con Edison is well-versed in submitting such changes. I also note that there already are four Addenda to Con Edison's Electric Tariff. In any event, Con Edison's administrative concern does not outweigh the customers' need for a remedy in the event Con Edison is not abiding by its interconnection standards. And as I mentioned, the Existing DG Guide is a tariff addendum. There is no justification for disparate treatment of the New DG Guide.

MICROGRIDS

Q. WHAT IS A MICROGRID?

A. The New York State Energy Research & Development Authority ("NYSERDA") describes "microgrids" as:

> [S]mall-scale distribution systems that link and coordinate multiple distributed energy resources (DERs) into a network serving some or all of the energy needs of one or more users located in close proximity. DERs include distributed generation (e.g., solar photovoltaic, small wind installations, small engines, combustion turbines and fuel cells), energy storage technologies, and power system control devices. In a microgrid, such DERs are linked together with multiple local energy users by separate distribution facilities (i.e., wires and pipes) and managed with advanced metering infrastructure, communications, and automated control systems.
>
> Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State, September, 2010, p. S-1 ("NYSERDA Study").

The New York State Legislature recently defined a microgrid as follows:

> Shall mean a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode.
>
> Section 1 of Part T of Chapter 58 of the Laws of 2013 ("Microgrid Law").

Q. WHY ARE MICROGRIDS IMPORTANT?

A. Microgrids potentially offer several important benefits, including reductions in energy costs and line losses, deferral of utility investment, increased reliability and power quality and reduced emissions. NYSERDA Study at S-3 – S-7. In recent addresses, both Mayor Bloomberg and Governor Cuomo have promoted microgrid development, especially for critical care facilities. Page 8 of Mayor Bloomberg's December 6, 2012 post-Sandy press release states:

> We'll also work to modernize our energy infrastructure by incentivizing large buildings and hospitals to invest in co-generation systems – which allow them to generate their own heat and power. That has worked to a great extent. We will work with Governor Cuomo to explore how we can accelerate investments in distributed energy, micro-grids, energy storage, and smart grid technologies.

In his 2013 State of the State address, Governor Cuomo said we must "[identify and resolve] barriers that are discouraging microgrid development." 2013 State of the State, p. 221.

Q. DOES A MICROGRID HAVE TO OPERATE IN ISOLATION FROM THE UTILITY NETWORK?

A. I do not believe that isolation from the utility is necessary. The economics of the project might be better if the Con Edison delivery system provides standby power as required. However, island operation in the event that Con Edison had an outage is critical because it would provide the added resiliency that is a major benefit of a microgrid.

Q. HAS THE COMMISSION APPROVED MICROGRIDS IN THE PAST?

A. Yes. Commission decisions interpreting the Public Service Law have, over time, authorized a variety of "microgrids." For example, Section 3 of the Public Service Law exempts qualifying DGs from being regulated as Electric or Steam Corporations if their customers are at or near the project site. Further, a DG customer with an internal distribution system serving its own set of buildings can be considered as a microgrid, as can a campus-style DG as defined under the Con Edison Standby Tariff. In this sense, there are likely to be microgrids now operating or under construction within Con Edison's territory

Q. WHAT IS YOUR RECOMMENDATION FOR MICROGRIDS IN CON EDISON'S SERVICE TERRITORY?

A. The State and the City have called for expanding microgrids, and the Commission should require Con Edison to report on how it is encouraging microgrid development. In addition, the Microgrid Law requires NYSERDA to consult with the Commission to develop recommendations regarding the establishment of microgrids in the State, with priority given to locations that suffered "severe storm damage in the two years prior to the effective date of this act." As set forth in the testimony of the City's Infrastructure Panels, significant portions of the Con Edison service territory meet the this location-based priority.

NYSERDA is required to report its recommendations by March 29, 2014, one year from the effective date of the legislation. I recommend that, within 60 days of the issuance of the NYSERDA report, Con Edison file a plan with the Commission that details how it will implement the findings of the report. The plan could include the development of one or more pilot programs. In the alternative, Con Edison can explain why it cannot implement those findings. Parties then should have 30 days to comment to the Commission on the Con Edison proposal.

Microgrids are not the only means of achieving high efficiency and resiliency. If properly designed, DG installations may do the same for a single

location. The Commission may want to consider programs, possibly through NYSERDA, that promote high efficiency, high capacity factor and high resiliency DG to customers, particularly where the customer is a critical facility to the community.

CON EDISON'S SURCHARGE MECHANISM FOR NEW GAS INFRASTRUCTURE

Q. DO YOU HAVE ANY CONCERNS REGARDING THE COSTS IMPOSED ON CUSTOMERS FOR NEW GAS MAIN?

A. Yes. When Con Edison needs to install new gas main and service lines in order to serve a new customer, Con Edison's tariff contains rules on how the costs associated with this new gas infrastructure are allocated between Con Edison and new customers. These rules are located in General Rule III of Con Edison's gas tariff, and are based on 16 NYCRR Part 230. As discussed below, I recommend three changes to the existing rules to reduce up front infrastructure costs for new customers, while still providing Con Edison with the opportunity to fully recover its costs.

Q. WHAT DO THE EXISTING RULES PROVIDE?

A. For residential applicants and for non-residential applicants that will be firm, non dual-fuel customers, Con Edison is responsible for the material and installation costs relating to up to 100 feet of main and appurtenant facilities. If Con Edison has to install more than 100 feet of main and appurtenant facilities, the Company

is required to impose a surcharge subject to the provisions of General Rule III.3(C). In general, the surcharge cannot exceed 20 percent per year of the actual reasonable cost of any such facilities that exceeds the portion that Con Edison is required to install without charge to an applicant. The surcharge commences once gas service is first available and is paid ratably for each billing period.

Under General Rule III.3(C)(1)(b), the surcharge is reduced by 50 percent of adjusted gas revenues, but the credit cannot exceed the amount of the surcharge. Adjusted gas revenues are defined as the revenues realized from the applicable service classification rates and charges, minus revenue taxes, the minimum charge and the total cost of gas. General Rule II. (4).

The surcharge ceases whenever the total adjusted gas revenue from all customers served from a main extension equals or exceeds 40 percent of the cost of such extension in excess of that required to be provided without charge, in each of any two consecutive calendar years; or after a period of ten years following its commencement. General Rule III.3(C)(1)(d)(ii)-(iii). No surcharge is imposed if the total adjusted gas revenue from all customers served from a main extension is estimated to exceed 40 percent of the actual reasonable cost of such extension in each of any two consecutive calendar years. General Rule III.3(C)(1)(e).

Q. WHAT ARE YOUR RECOMMENDATIONS FOR CHANGING THE EXISTING RULES?

A. I recommend two changes to Con Edison's existing tariff:

1. If the credit from adjusted gas revenues exceeds the surcharge amount, Con Edison should credit the excess to the customer's account and carry the credit over to reduce future surcharges.

2. The tariff should clarify that, whenever more than one customer is connected to a main extension, the material and installation costs that will be paid by the Company will include the costs and expenses relating to 100 feet of main multiplied by the total number of Customers being connected contemporaneously.

Q. PLEASE EXPLAIN YOUR FIRST RECOMMENDATION REGARDING CREDITS FROM ADJUSTED GAS REVENUES.

A. As noted above, the tariff currently provides an offset to any surcharge equal to 50 percent of adjusted gas revenues that Con Edison realizes from all customers served by the new gas main. The credit cannot exceed the surcharge.

Under the existing provision, the customer must forfeit any credits that exceed the amount of the surcharge. If a customer's gas usage is high enough in a certain year to fully offset any surcharge, and would technically produce a negative surcharge, that customer should not have to forfeit credits. Rather, those excess credits should carry forward and be used to offset any future surcharges. The tariff currently does not provide for such a carry forward and therefore should be changed.

Q. WHAT IS THE PURPOSE OF YOUR SECOND RECOMMENDATION REGARDING THE FREE FOOTAGE ALLOWANCE PROVIDED TO NEW GAS CUSTOMERS?

A. This recommendation clarifies that, for main extensions serving multiple customers, the customers will receive the maximum permissible benefit, thereby reducing the magnitude of the surcharge and fostering the Company's ability to attract new customers and grow its business (and revenues). For example, assume three customers require a total main extension of 400 feet. Customer 1 needs 70 feet, Customer 2 needs 90 feet, and Customer 3 needs 240 feet. Under the current tariff, Customer 1 pays nothing, Customer 2 pays nothing, and Customer 3 pays for 140 feet. Under the proposed revision above, Customer 1 still pays zero, Customer 2 pays zero, but Customer 3 pays only for 100 feet of main.

Q. ARE YOUR RECOMMENDATIONS REGARDING COSTS FOR NEW GAS MAINS CONSISTENT WITH COMMISSION REGULATIONS?

A. Yes. Although Con Edison's tariff closely tracks the minimum cost-sharing obligations set forth in 16 NYCRR Part 230, this regulation specifically states that it only provides the "minimum obligations of gas corporations." Con Edison is allowed to extend its minimum obligations in its tariff, to the extent any changes are cost-justified. The recommendations I discuss above are designed to relax the cost-sharing responsibilities of customers not located within 100 feet of an

existing gas main, but still provide Con Edison with sufficient cost recovery to avoid impacts on other customers.

Q. ARE YOUR RECOMMENDATIONS CONSISTENT WITH THE COMMISSION'S GOALS IN CASE 12-G-0297: PROCEEDING ON MOTION OF THE COMMISSION TO EXAMINE POLICIES REGARDING THE EXPANSION OF NATURAL GAS SERVICE?

A. Yes. On November 30, 2012, the Commission instituted this new proceeding to, among other things, examine possible changes to 16 NYCRR Part 230. The Order Instituting Proceeding specifically recognized the flexibility provided by Part 230, but bemoaned the fact that utilities only rarely seek to employ such flexibility. My recommendations here would utilize the flexibility inherent in the regulations in order to make new natural gas service more affordable to new customers, and would therefore be consistent with the Commission's goals in Case 12-G-0297.

Q. DIDN'T CON EDISON RECENTLY PROPOSE NEW TARIFF PROVISIONS TO ENCOURAGE NATURAL GAS CONVERSIONS?

A. Yes. On April 1, 2013, Con Edison submitted a tariff filing proposing new tariff rules that would establish Area Growth Zones. Potential customers located within each zone will have a specified time to apply for gas service and receive such

service with no customer contribution towards the connection cost. This tariff filing is currently pending under Case No. 13-G-0156.

Q. DOES THIS NEW TARIFF FILING ADDRESS THE CONCERNS YOU HAVE IDENTIFIED ABOVE?

A. No. Con Edison's new tariff filing will only apply to customers located within the designated Area Growth Zones. My recommended changes would apply to all customers, in particular those customers that are not fortunate enough to be located within an Area Growth Zone.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING THE COMPANY'S TARIFF ADDRESSING RECOVERY OF INFRASTRUCTURE COSTS?

A. Yes. The tariff provisions addressing infrastructure cost recovery should be amended to require that the Company provide affected customers with a detailed breakdown of how any surcharge (or lump sum payment made in lieu of surcharge payments) is calculated and, later, the actual costs that were incurred. The Company's current policy is to provide supporting documentation regarding the surcharge calculation only upon request by the customer (*see* City IR 167).

Moreover, in response to City IR 166, Con Edison provided a typical "Cost Breakdown" listing the customer costs for new gas infrastructure. This breakdown includes eight line items, and these line items do not provide

customers with meaningful information to support the significant infrastructure costs asked of customers. For example, in the "Cost Breakdown" provided in City IR 166, one of the line items is titled "Labor" and equals nearly $100,000. Con Edison should know the labor rates associated with installation and should therefore be able to provide customers with the labor rates and the man-hours, plus a breakdown of any other labor-related expenses and costs. This same breakdown should be available for the seven other line items, as well.

In addition, the Company should be required to update customers when other customers hook up to the mains. The current tariff does not specify any level of notice or require any specific billing information rates and, therefore, a customer could be left in the dark about why and how much they are being surcharged. Under its prior gas rate plan, Con Edison was required to monitor, at least semi-annually, the use of new gas facilities being funded by customers served under Rider H of the Company's gas tariff through surcharge or other upfront payment to determine if new customers are using the gas facilities. This obligation should be continued and extended to cover all gas customers that are asked to pay for new gas infrastructure either through a surcharge or other upfront payment.

EXPANDING THE BIR PROGRAM

Q. DO YOU HAVE ANY RECOMMENDATIONS ON THE BIR PROGRAM, RIDER J?

A. The City has developed a program to revitalize areas hard hit by Hurricane Sandy. The cores of many Sandy-impacted neighborhoods are the local commercial corridors that provide employment opportunities and services to those who live and work around them. In many cases, though, these corridors were devastated by the storm.

The City wants to amend the business incentive rate ("BIR") program to allow it to be extended to impacted small businesses and non-profit organizations in these communities. Specifically, the City would like to expand the BIR program, for a limited duration, to cover: (a) small retail businesses (i.e., those with 10 or fewer employees) that have received post-Sandy support from City-sponsored loan and grant programs; and (b) small non-profits (again, those with 10 or fewer employees) in the following communities: (1) Southern Manhattan (below Chambers Street and 100-year flood zones on the west and east side up to approximately 42nd Street); (2) East and South Shores of Staten Island from approximately Ft. Wadsworth to Tottenville; (3) Brooklyn-Queens Waterfront (coastal neighborhoods from Sunset Park through Long Island City); (4) Southern Brooklyn (Coney/Brighton peninsula plus inundated mainland areas (Gerritsen Beach, Sheepshead Bay, Gravesend)); and (5) South Queens (Rockaway

Peninsula plus bay-lying communities (Broad Channel, Howard Beach, Old Howard Beach, Hamilton Beach)).

To be eligible for the BIR program, the customer must have either: (a) received a grant funded with Community Development Block Grant--Disaster Recovery funds as conferred by a local municipality or a state agency to promote disaster recovery in Con Edison's territory following Hurricane Sandy or otherwise meet the eligibility requirements under Section (A)(1)(a) or (b) of the BIR Rider; or (b) operate as a non-profit organization pursuant to Section 501(c)(3) of the Internal Revenue Code within one or more of the five communities identified above. Under the expanded program, eligible customers would be eligible for the BIR discount for five years up to a maximum discount of $50,000 per business or nonprofit.

The City expects that about 5 MW of BIR would be used under this program and that the maximum aggregate benefit under the program would be $5.0 million.

Q. IS THERE ANY PRECEDENT FOR INCLUDING RETAIL BUSINESS IN THE BIR?

A, Yes. Section (A)(3)(b) of Con Edison's Rider J allows businesses receiving a Small Firm Attraction and Retention Grant or the World Trade Center Business Recovery Grant in lower Manhattan with a demand between 10 kW and 400 kW to be eligible for the BIR.

Q. ARE YOU PROPOSING ANY OTHER CHANGES TO RIDER J?

A. Yes. The City is interested in extending the BIR discount to smaller businesses and non-profit organizations; in this case, those with 10 or fewer employees. Currently, however, the BIR program is limited to demand metered (SC 9) customers. Because the intent of the expanded program is to provide relief that will keep small businesses and non-profit organizations in operation, the City wants to make sure that eligible SC 2 customers are not excluded. Accordingly, I propose that the BIR program be expanded, for this purpose only, to include eligible SC 2 customers. To do this, Con Edison could either develop a delivery rate discount unique to SC 2, or the existing BIR discount that is applied to the SC 9 delivery rate could be applied to the energy charges in SC 2.

BILLING ISSUES FOR NYC

Q. HAS THE CITY ASKED YOU TO ADDRESS ANY BILLING ISSUES?

A. Yes, the City has a number of billing issues that it asked me to raise in this proceeding.

The first group of issues applies to all three Con Edison Departments. The City would like to receive better quality data. For electric, the billing information often does not adequately describe the customer and the meter location.

For Gas, the City needs improved quality and detail for electronic gas billing data such as information about account changes (‘exchanges’ on

account/meter numbers to differentiate from new accounts; and notation for closure when an account terminates). This is necessary to distinguish between accounts that have been closed and accounts that are simply not billed in a current billing period. Further, a breakdown is needed to identify cost components for delivery, commodity, customer charges, and fees and taxes. Currently, electronic gas billing data only provides commodity charge, gas purchase price adjustment, and total amount. It is not clear which elements of the bill are included in the commodity charge. Gas purchase price adjustment is a term that is no longer used.

For Steam, Con Edison has begun to provide a monthly file with some electronic billing data, but the process is informal at this point and not explicitly matched to the information in a paper bill or pdf image of a paper bill. Missing are: detail on billing adjustments; meter information; and account and meter exchange information.

Q. HAVE THERE BEEN PROBLEMS WITH UTILITY CONSTRUCTION COST ESTIMATES?

A. Yes. For Gas, and more so for Electric, there has been an issue over the utility's failure to stick to construction cost estimates where upgrades are needed. The Department of Parks and Recreation ("DPR") has recently had two such instances.

Example 1: Wallenberg Square project. This project was to reconstruct a sitting area and perform miscellaneous site work at Wallenberg Square in Forest Park. The scope of work required Con Edison to bring electricity to the property. The original quote was provided by Con Edison in January of 2012, and was for $26,004. This quote expired (quotes are valid for 6 months) and when Con Edison provided an updated quote on December 17, 2012, the cost was $56,521, more than double. The explanation that Con Edison provided for this increase was "changes in Company/Contactor labor cost and Duct work." DPR is currently (April 2013) trying to process a change order to pay for the work, and if this is not approved by early June, the quote will again expire and the City will be at risk of having it increase further.

Example 2: The project is Goodwill Park, again providing electric service. The quote that Con Edison gave initially expired on September 15, 2012. A new quote is pending and the City is concerned that it will again be much higher.

The City believes that it would be helpful if Con Edison provided a Service Entrance Layout Agreement, which commits them to cost and scope, in the design phase of a project, before projects are sent out to bid.

Q. WHAT OTHER ISSUES HAS THE CITY ASKED YOU TO ADDRESS?

A. The City needs more information on excess distribution charges. Excess distribution charges apply when a customer requests a service installation more expensive that what the utility normally provides. The charges cover the maintenance and taxes on the excess facilities and may be paid as a lump sum, or as annual payments as long as service is still being provided to that location. The City pays approximately $400,000 a year in annual excess distribution charges. The City has been working with Con Edison on identifying which of the accounts are no longer active and thus should no longer be billed the excess distribution charge.

For a customer requiring excess facilities, there is no tariff amount or formula. There is also no tariff language explaining how the lump sum alternative payment option relates to the annual distribution charge option. The City believes these two aspects of the excess distribution fee should be standardized and spelled out in the tariff.

The City would also like to the option of paying some of its existing annual distribution charges as a lump sum payment.

Q. DO YOU HAVE AN EXHIBIT THAT CONTAINS THE INTERROGATORY RESPONSES AND WORKPAPERS YOU WISH TO OFFER AS EVIDENCE?

A. Yes, I have prepared Exhibit ____ HA-5 for this purpose

1 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

2 A. Yes.