STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service.	Case 16-E-0060
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service.	Case 16-G-0061
Proceeding on the Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service.	Case 15-E-0050
Tariff filing by Consolidated Edison Company of New York, Inc. to revise General Rule 20 Standby Service contained in its electric tariff schedules, P.S.C. Nos. 10 and 12.	Case 16-E-0196

STATEMENT OF THE UTILITY INTERVENTION UNIT ON THE JOINT PROPOSAL

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INTRODUCTION

The Utility Intervention Unit ("UIU") of the New York State Department of State's Division of Consumer Protection submits this statement in opposition to portions of the Joint Proposal ("JP") filed on September 20, 2016 in the above-captioned proceedings, and in response to the Public Service Commission's ("Commission") Ruling on Schedule issued September 28, 2016.

On January 29, 2016, Consolidated Edison Company of New York, Inc. (the "Company") filed amended tariff leaves and accompanying testimony and exhibits for new electric and gas rates and charges to become effective January 1, 2017. On June 10, 2016, the Company issued a

Notice of Settlement initiating settlement discussions. Following several meetings of the parties, the Department of Public Service Staff ("Staff") filed this JP on September 20, 2016.

The JP was signed by 20 parties (collectively, "Signatory Parties")[1], eight of which have indicated disagreement with, or have reserved the right to oppose, portions of the JP.[2] Fifteen parties did not sign the JP, including UIU[3]. The JP would authorize three-year rate plans for the Company's electric and gas businesses, including electric delivery revenue increases of $178.5 million (or 3.6%), $201.6 million (or 3.9%), and $212.2 million (or 3.9%) for rate years 1 thru 3, respectively; and gas delivery revenue increases of $35.5 million (or 3.1%), $92.3 million (or 7.5%), and $89.5 million (or 6.7%) for rate years 1 thru 3. In general, these rate increases are higher for customer classes comprising smaller customers (i.e., residential and small commercial customers):

[1] The Signatory Parties include the Company, together with Staff, the City of New York, United States General Services Administration, Consumer Power Advocates ("CPA"), New York Energy Consumers Council, Inc. ("NYECC"), Pace Energy and Climate Center ("Pace"), Environmental Defense Fund, National Resources Defense Council, Acadia Center, Metropolitan Transportation Authority ("MTA"), Time Warner Cable, Inc., Community Housing Improvement Program, Northeast Clean Heat and Power Initiative, Energy Concepts Engineering PC, Association for Energy Affordability, Inc., Great Eastern Energy, Digital Energy Corp., Joint Supporters, The E Cubed Company, LLC and Real Estate Board of New York.

[2] These eight parties comprise the City of New York, Pace, Digital Energy Corp., the E Cubed Company, Energy Concepts Engineering PC, Great Eastern Energy, Joint Supporters, the Northeast Clean Heat and Power Initiative.

[3] The parties that did not sign the JP are UIU, the Public Utility Law Project, Inc. ("PULP"), SolarCity Corporation, Tesla Motors, Inc., the United Plant and Production Workers, R.G. Vanderweil Engineers PC, the Retail Energy Supply Association, the New York Independent Contractors Alliance, Utility Workers Union of America, AFL-CIO, Local 1-2, Related Companies, the Urban Green Council, the New York Oil Heating Association, Inc., Energy Spectrum, Inc., Jeffrey Buss, and Andrew Cohen.

Table 1: Electric Delivery Revenue Increases Under JP[4]

Rate Year	SC1 Residential	SC2 Commercial	All other CECONY	NYPA	Total
Revenue Increase					
Rate Year 1	$80,380,718	$15,650,282	$55,528,454	$26,932,878	$178,492,332
Rate Year 2	$92,174,238	$15,903,100	$69,315,381	$24,189,033	$201,581,752
Rate Year 3	$96,187,653	$16,564,826	$74,599,087	$24,848,059	$212,199,625
3-Year Total	$268,742,609	$48,118,208	$199,442,922	$75,969,970	$592,273,709
Percent Change					
Rate Year 1	4.2%	4.4%	2.7%	4.7%	3.6%
Rate Year 2	4.6%	4.2%	3.2%	4.0%	3.9%
Rate Year 3	4.5%	4.1%	3.3%	3.9%	3.9%
3-Year Total	14.1%	13.4%	9.6%	13.2%	12.0%

Table 2: Gas Delivery Revenue Increases Under JP[5]

Rate Year	SC1 & SC3 Residential	All Other SCs	Total
Revenue Increase			
Rate Year 1	$30,403,034	$3,851,966	$34,255,000
Rate Year 2	$71,668,840	$17,473,160	$89,142,000
Rate Year 3	$70,208,554	$16,149,445	$86,357,999
3-Year Total	$172,280,428	$37,474,571	$209,754,999
Percent Change			
Rate Year 1	3.7%	1.3%	3.1%
Rate Year 2	8.2%	5.8%	7.5%
Rate Year 3	7.2%	5.0%	6.7%
3-Year Total	21.1%	12.6%	18.8%

If approved, the JP would set the Company's electric and gas rates and services for the next three rate years, commencing January 1, 2017. As explained below, the JP's revenue allocations and rate changes are not in the public interest, and they do not satisfy the

[4] *See* Case 16-E-0060 *et. al*, Joint Proposal (filed September 19, 2016) ("JP"). Values presented in this chart reflect electric delivery revenue increases listed in the JP Appendix 19 Table 2a, Column 4 and Column 7 on page1; and Column 1 and Column 6 on pages 2-3.

[5] *See id*. at Appendix 21. Values presented in this chart reflect gas delivery revenue increases listed in the JP Appendix 21 Table 1, Column 1 and Column 8 on pages 1-3.

Commission's Procedural Guidelines for Settlement ("Settlement Guidelines").[6] UIU therefore respectfully urges the Commission modify the terms of the JP consistent with UIU's recommendations as described herein.

PRELIMINARY STATEMENT

UIU has a statutory mandate to advocate on behalf of *all* energy consumers in New York State.[7] This mandate requires UIU to work toward an equitable balance of revenue allocations among all customer classes – large customers as well as small. As smaller customers tend to be disproportionately underrepresented in rate proceedings, UIU often places extra focus on issues important to smaller customers, but only insofar as such focus is consistent with fair treatment of all customers.

UIU does not object to resolving rate cases through negotiated settlements that are equitable to the parties and in the public interest. The desire of the parties (including UIU) to reach an expeditious settlement in these proceedings does not relieve the Commission from seeking an allocation of revenues that is fair to all customers – not only those who signed the JP. This JP fails in this respect. If approved, it would implement seriously flawed revenue allocations that would favor a select group of large customers at the expense of all other consumers. This central aspect of the JP is therefore not in the public interest.

In particular, the UIU opposes portions of the JP for the following reasons:

1. The allocation of revenues under the JP is based on a pair of deeply flawed embedded cost of service (ECOS) studies.
    - The ECOS studies were based on a subjective choice of "minimum system" methodology, which tends to favor larger customers and results in misallocation of delivery service costs.

[6] *See* Cases 90-M-0255, *Proceeding on Motion of the Commission Concerning its Procedures for Settlement and Stipulation Agreements*; and 92-M-0138, *In the Matter of the Rules and Regulations of the Public Service Commission Contained in 16 NYCRR, Chapter I, Rules of Procedure – Proposed Amendments to Subchapter A, General, Part 2, Hearings and Rehearings by the Addition of a New Section 2.6, Settlement Procedures, filed in C 11175*, Opinion 92-2, Order and Resolution Adopting Settlement Procedures and Guidelines (issued March 24, 1992) ("Settlement Guidelines").
[7] N.Y. Exec. L. § 94-a.

- The JP would extend the tendency of the Company's ECOS approach to over-allocate cost responsibility onto small customers to the Company's primary distribution system. The Company has failed to identify a factual or legal basis for adding a portion of primary distribution plant to its minimum system.
- The Company's electric ECOS study estimates a minimum secondary distribution system that is actually much larger than minimum and therefore amplifies the cost-misallocation impacts inherent to the minimum system methodology.
- The Company's electric ECOS study employs a "minimum" size conductor cost that is over 3 times more expensive than 1 AWG wire. This cost is not based on the actual cost of a specific conductor size.
- The Company's electric ECOS study mistakenly includes, in its "minimum" system, costs of transformers that far exceed the minimum theoretically necessary to connect customers and inappropriately includes "rectifiers" in its "minimum" transformer calculation.
- The electric ECOS study's D08 allocator blends service classes' Non-Coincident Peak Demand (NCP) with their Individual Customer Maximum Demands (ICMD). This incorporation of ICMD into the D08 allocator is unique to the Company among New York utilities, does not reflect actual system planning considerations, and disproportionately shifts costs to smaller customers.
- The Company's gas ECOS model relies on inputs that are not consistent with the minimum system methodology. Among other problems noted in UIU's testimony, the Company's gas ECOS study incorrectly employs a "minimum system" that is far more expensive than the minimum actually needed to serve customers under the minimum system methodology. The Company based its gas "minimum system" upon pipes that are significantly more costly than smaller pipes currently embedded in its system.

2. The revenue allocations proposed in the JP would shift approximately $49.1 million of costs onto smaller customers, predominantly those in electric Service Class (SCs) 1 (residential) and SC2 (commercial); and gas SC1 (residential cooking).[8] This realignment

[8] The electric revenue allocation calculations are provided in Exhibit __ (UERP-JP-7) Schedule 5. Gas revenue allocation calculations were made based on the JP Workpapers received from the Company.

of revenue responsibilities is unjust, inequitable, and inconsistent with the evidence in this proceeding.

3. The JP does not satisfy any of the six prongs of applicable test described in the Commission's *Settlement Procedures and Guidelines*.

For these reasons, UIU is compelled to oppose the JP's proposed revenue allocations and corresponding rate changes.

ARGUMENT

I. The Joint Proposal Is Not In the Public Interest.

A. Electric and Gas Revenue Allocation[9]

Over its three-year rate plan, the JP would allocate revenues among service classes exclusively according to the results of the Company's electric and gas ECOS studies[10] – which, as discussed in further detail in Parts (B) and (C) below, each suffer from serious deficiencies. The JP's proposed lockstep adherence[11] to a single pair of ECOS studies – to the exclusion of all other considerations – would ignore other important revenue allocation factors, would run contrary to Commission precedent, and as discussed *infra*, would implement fatal flaws in those studies that the JP has failed to repair. Furthermore, the JP disregards evidence concerning rate impacts and unaffordability for low-to middle income residential customers, and ignores policy considerations applicable to the costs of the Company's Advanced Metering Infrastructure (AMI) program. UIU accordingly recommends that the Commission modify the allocation of the Company's requested rate increases for both electric and gas systems.

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[9] JP §§ G(1) and H(1). At the September 21, 2016, procedural conference, Administrative Law Judges Wiles and Lecakes expressed a preference that the parties' comments correspond to the order in which the issues are presented in the Joint Proposal. These comments do so to the maximum degree practicable; however, certain comments equally applicable to both electric and gas issues are presented together to avoid redundancies.

[10] JP §§ G(1) ("The [electric] revenue allocation reflects one-third of the revenue surplus/deficiency indications in each Rate Year based on the Company's Embedded Cost of Service ("ECOS") Study (see Table 1 of Appendix 19)", H(1) ("The [gas] revenue allocation reflects one-third of the revenue surplus/deficiency indications, resulting from the Company's Gas Embedded Cost of Service Study, in a revenue neutral manner in each Rate Year.")

[11] The JP shifts 100% of the purported deficiencies outside of a narrow 10% tolerance band over the course of the three rate years, without any other mitigation measures, or consideration of any other evidence concerning appropriate rate levels for the various firm service classes. *Id.* at §G1 and § H1.

1) Revenue Allocations Should Consider Other Factors In Addition to Cost-of-Service.

Cost responsibility (or "cost-of-service") is one factor that guides the allocation of costs among customer classes ("revenue allocation"). This is based on the principle that a customer's rates should, to some extent, reflect the costs the utility incurs to provide safe and reliable service to that customer. But cost-of-service is not the only guide of revenue allocation. The Commission has historically considered additional factors including gradualism (i.e., the desire to avoid sudden rate changes),[12] proportionality (i.e., the desire to avoid disparate rate increases among different service classes), and the circumstances of the utility's customers.

As the Commission approvingly noted in its Order in Case 94-G-0885,

> [Department of Public Service] staff says that **no responsible rate design analyst would rely wholly on an embedded cost study to set gas rates**; but such a study does provide some guidance about the direction and magnitude of rate changes required to ensure that rates remain competitive.[13]

Thus, even where the methodology or results of an ECOS study are not in dispute, other considerations can – and should – factor into the rate changes to be assigned to each customer class. One such consideration applicable to these rate proceedings is the ongoing unaffordability crisis among the Company's residential electric and gas customers, which as discussed in Part (A)(5) below, has not been addressed in this JP.

In prior cases, Staff has recommended that an ECOS study's results should not comprise the sole guide of revenue allocations. Staff has made this recommendation in testimony filed in both other major rate cases currently pending before the Commission,[14] Brooklyn Union Gas Company d/b/a National Grid (KEDNY) and Keyspan Gas East Corporation d/b/a National Grid

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[12] UIU notes that Exhibit ___ (UERP-7) shows the UIU ECOS results suggest an increase larger than the system average in NYPA's revenue allocation is merited and Exhibit UGRP-JP-2 and Exhibit UGRP-JP-5 both suggest an increase larger than the system average in SC-2 General Service Heat's revenue allocation is merited. UIU also notes that NYPA was found to have a significant deficiency in prior ECOS studies but has been receiving special treatment due to a Memorandum Of Understanding developed in 2005 following the Company's 2004 electric rate case (Case 04-E-0572) ("2005 MOU");. *See infra* notes 109-110 at 33 discussing the history of NYPA's revenue allocation.

[13] Case 94-G-0885, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service, Opinion and Order Determining Revenue Requirement and Rate Design 51 (filed September 15, 1995) (emphasis added).

[14] Note that no party besides Corning Natural Gas has yet filed direct testimony in that company's rate case (Case 16-G-0369).

(KEDLI) (Cases 16-G-0058 and 16-G-0059)[15] (which both serve parts of New York City, suggesting their gas systems and customers' circumstances are comparable to the Company's); and National Fuel Gas, Inc. (Case 16-G-0257), in which Staff testified:

> The Company did not propose to shift revenues to correct for return imbalances as shown in the [embedded cost of service] study. We, therefore, believe the [revenue allocation] methodology is reasonable.[16]

Furthermore, reasonable minds can and do differ with respect to determining a customer's embedded cost of service. As discussed in Parts (B) and (C) *infra*, the assumptions that underlie an ECOS study can have serious implications on the study's results. Many of these assumptions represent judgment calls, not cut-and-dried fact (though some of the assumptions in the Company's ECOS studies are, in fact, demonstrably inconsistent with the facts). The subjectivity inherent in an ECOS study, and the high degree to which that subjectivity influences the study's results, diminishes the study's reliability as a guide of revenue allocation even where the study is not disputed.

2) The Commission Has Not Relied Exclusively on the Company's ECOS Studies When Setting Rates in Past Cases.

Despite the controversial nature of the Company's ECOS studies, and the evidence demonstrating flaws in those studies, the JP would rely on the Company's ECOS study to a greater extent than in past cases. The JP would strictly apply the results of the Company's ECOS study with a narrow tolerance band of +/-10%.[17] The Commission has rejected past requests to approve such narrow application of the Company's ECOS study results, and should do so again here.

The Commission has often implemented revenue allocations that deviate from the results of the Company's ECOS study. These allocations have tended to benefit larger-customer parties. For example, in the Company's 2007 litigated rate proceeding (Case 07-E-0523), the Commission

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[15] Cases 16-G-0058 and 16-G-0059, Staff Gas Rates Panel Direct Testimony at 44-45 (noting the "many assumptions used in the development of a [ECOS] study of this nature" and recommending a revenue allocation that does not strictly follow ECOS study indications.)

[16] Case 16-G-0257, Staff Gas Rates Panel Direct Testimony at 75.

[17] In the 2013 Con Edison electric rate case (13-E-0030), some of the parties to the JP advocated using a much wider 20% tolerance band. *See e.g.*, Case 13-E-0030, Direct Testimony of Ronald J. Liberty on behalf of the New York Power Authority 4 (filed May 31, 2013) (advocating for a 20% tolerance band and noting "Furthermore, the size of the tolerance band (±10%) used in the study proposed by Con Edison is one of the smallest used by the Commission in decisions involving ECOS studies to allocate revenues for other electric utilities in New York State during the last 5 years."

declined to rely exclusively on the Company's ECOS study, and instead assigned NYPA only one-half of the rate increase indicated under the Company's ECOS study. The Commission found that such a revenue allocation "is justified by the amount of rate increase all customers will experience and the need to avoid abrupt rate changes. Gradualism is warranted here."[18]

Each of Con Edison's recent rate plans developed through settlement has similarly deviated from the Company's ECOS study results. In 2004, the Commission approved a Joint Proposal that assigned NYPA a revenue increase of 1.66 times the overall increase, less than the Company's recommended increase of 2 times. NYPA again received a discounted revenue allocation in 2009 (Case 09-E-0428), where the Commission approved a Joint Proposal that allocated to NYPA "approximately $25.2 million, as compared to $43.2 million had the results of the Company's embedded cost of service ([ECOS]) study been fully implemented."[19] The Commission expressly found that this revenue allocation, which reduced costs allocated to NYPA by over 40% compared to the Company's ECOS results, was "reasonable and appropriate" and "ensures that NYPA customers will cover their deficiency without causing a rate change with unreasonable rate impacts."[20] Similarly, the Joint Proposal in Case 13-E-0030 assigned NYPA only 2/3 of the deficiency indicated under the Company's ECOS study.[21] The Commission subsequently reconfirmed this lower-than-indicated allocation when it extended the Company's rates for an additional year in 2015 (Case 15-E-0050).[22]

In fact, in the past 12 years (if not longer), the Commission has only once allocated the Company's electric revenues solely according to its ECOS study results, in 2008 (Cases 08-E-0539/08-M-0618). But in that case, the Commission rejected the Company's proposal to apply a +/-10% tolerance band to its ECOS study results, and in recognition of deficiencies of the ECOS study and its application, instead adopted a wider tolerance band of +/-15%.[23] One result of

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[18] Case 07-E-0523, *Proceeding on the Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Order Establishing Rates for Electric Service 134 (issued March 25, 2008)
[19] Case 09-E-0428 and 08-M-0152, Order Establishing Three-Year Electric Rate Plan 16, 34 (issued March 26, 2010).
[20] *Id.* at 34.
[21] Cases 13-E-0030 and 15-E-0050, Joint Proposal at 72, Appendix 20. The JP notes "(t)he NYPA revenue allocation is not the result of the use of any particular methodology or of a particular embedded cost of service study tolerance band."
[22], Cases 13-E-0030 and 15-E-0050, Joint Proposal at 19-20.
[23] Cases 08-E-0539 and 08-M-0618, Order Setting Electric Rates 204-206 (issued April 24, 2009).

applying this wider band was a smaller allocation of revenues to certain customer classes, including [NYPA].[24]

3) Revenue Allocation Should Recognize Customer Savings Attributable to Advanced Metering Infrastructure (AMI).

The JP would authorize the Company to spend over $640 million on electric and gas AMI capital costs over the three rate years.[25] This expenditure, which does not include the costs of removing those meters that are already installed,[26] comprises just under half of the estimated capital costs of the AMI program.[27] The Company would begin collecting these AMI costs from customers in the first rate year.[28]

The JP does not expressly describe how these AMI costs would be allocated among customer classes, despite the Commission's instruction that allocation of AMI cost "be determined in rate proceedings."[29] The Company's responses to UIU-90 suggests that under the Company's initial rate filing, AMI costs would have been allocated to customers in the same proportions as all other transmission and distribution revenues. Given the lack of language in the JP to the contrary, the JP presumably continues to allocate AMI costs in this same way.

This allocation of AMI costs is unfair to lower-use customers because it would ignore the drastically different levels of cost savings that different types of customers will realize from AMI. AMI's anticipated benefits were central to the Commission's decision to approve its costs – to now ignore the distribution of those benefits for the purposes of distributing the burden of AMI costs would be contrary to the program's purpose and inconsistent with the Commission's goals of *Reforming the Energy Vision* (REV), and would yield unjust results. UIU therefore recommends an AMI cost-recovery approach expressly tied to the program's benefits.

[24] See Cases 08-E-0539 and 08-M-0618, Staff Initial Brief 264 (filed November 21, 2008) (noting Staff's proposal for a 15% tolerance band would significantly decrease NYPA's class deficiency from $15.101 million to $6.7 million).
[25] JP Appendix 10 at 1-2.
[26] JP at 34 notes the electric and gas revenue requirements set forth in Appendix 10 exclude removal costs
[27] JP at 33 ("The AMI Order [issued March 17, 2016 in Case 15-E-0050] authorized the Company to implement its AMI Business Plan subject to a $1.285 billion cap on capital expenditures.")
[28] JP at 34 ("The electric and gas revenue requirements reflect the Average AMI Plant In Service Balances (excluding removal costs) set forth in Appendix 10 for the Company's installation of AMI during RY1, RY2 and RY3.").
[29]Cases 15-E-0050 et al, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions 49 (issued March 17, 2016) ("AMI Order").

a. <u>AMI Is Not Like Other Utility Capital Investments, and Consequently Warrants Separate Allocation of Costs.</u>

The Company's AMI program represents an immense – and unique – undertaking. The Company initiated its AMI program as part of the one-year extension of electric rates the Commission approved on June 19, 2015 in Case 15-E-0050.[30] AMI on this scale is new to New York, and is expected to have transformative effects. As the Commission has observed,

> [T]he deployment and use of AMI in the Company's electric and gas businesses will transform the relationship between Con Edison and its electric and gas customers It is an important and valuable contribution to enabling the Company to assume the role of the DSP, facilitating customer access to products and services provided by third parties.[31]

The Company's AMI program is also a vanguard project advancing the Reforming the Energy Vision ("REV") initiative (Cases 14-M-0101 *et. al.*), which aims in part to redefine how utilities engage customers and realign how they earn revenues.[32]

The program's novelty and extremely high costs (estimated at over $1.5 billion)[33] were so significant as to warrant a 5-month long collaborative;[34] the submission of a detailed business plan,[35] two Benefit Cost Analyses (BCAs), and numerous other filings;[36] and a separate Commission Order that closely examined the program's anticipated functions, costs, benefits, and implementation.[37]

This unprecedented level of review for a single capital project was appropriate given that AMI is not necessary for the Company to fulfill its statutory obligation to provide safe and reliable service.[38] The Company's existing metering system (including the $400 million worth of

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30 AMI Order at .3.
31 AMI Order at 19.
32 *See* Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework 2 (issued May 19, 2016) ("Rev Track Two Order") *see also* AMI Business Plan at 1.
33 AMI Order at 21 (noting "…the Company expects to invest $1.285 billion in capital spending in nominal dollars and incur $552 million in operational costs.").
34 Cases 13-E-0030 and 15-E-0050, Order Adopting Terms of Joint Proposal to Extend Electric Rate Plan, Appendix A p. 14-16 (issued June 19, 2015) (JP proposed a 5-month long collaborative process).
35 Case 15-E-0050, Con Edison Advanced Metering Infrastructure Business Plan (filed November 16, 2015) ("AMI Business Plan") .
36 *See e.g.,* Case 15-E-0050, Supplemental Testimony on AMI (filed April 21, 2016); *See also* Case 16-E-0050 et al, Advanced Metering Infrastructure Customer Engagement Plan (filed 07/29/2016).
37 AMI Order, Appendix A.
38 *See* Pub. Serv. L. § 65.

undepreciated legacy meters that will be scrapped to make room for AMI meters[39]) remains capable of meeting this obligation.[40]

The Company's justifications for AMI, and the Commission's grounds for approving it, instead lie in the program's anticipated net economic benefits. The Company has estimated that AMI will produce $2.795 billion in benefits, compared to $1.547 billion in costs, on a 20-year net present value (NPV) basis.[41] This yields a projected net benefit of $1.248 billion. The Commission makes it clear at several points in the AMI Order that it approved the AMI program because its benefits are expected to outweigh its costs, including at page 2:

> AMI as proposed by Con Edison has immediate operational benefits that exceed its costs. It also has long term unquantified benefits that may be even greater. By this Order, subject to the conditions contained herein, the Commission approves Con Edison's AMI Business Plan.

AMI is thus like no other utility capital programs of comparable scale. Traditional infrastructure investments, such as pipes, wires, substations, and customer billing systems, may be required to provide safe and reliable service to customers, and so are typically not subject to benefit-cost analysis[42] (and, indeed, would defy such analysis, as it may be difficult or impossible to assign a quantifiable "benefit" to essential system components).[43] Meters are necessary. Advanced meters, and the extensive supporting infrastructure and O&M costs they require, are discretionary, and so rely on a positive BCA for justification.

AMI's many novel applications place it further outside conventional conceptions of utility infrastructure and cost recovery. An advanced meter is not, as some parties might assert, just a meter. When considered together with their communications backbone *as a system* – as the Commission did when it approved the program – AMI meters yield functionalities far beyond the

[39] AMI Business Plan at 39
[40] Indeed, the AMI Order noted that the Company's investments in its existing metering system were presumptively prudent. AMI Order at 48.
[41] Case 15-E-0050, Con Edison BCA Framework (filed August 1, 2016).
[42] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework 1-2 (issued January 21, 2016) ("BCA Order")
[43] Other discretionary investments subject to BCAs, such as procurement of distributed energy resources (DER) (*see* BCA Order at 1-2), tend to yield highly-localized benefits, which do not lend themselves to parallel cost-recovery in the absence of localized rates. These projects' costs are therefore appropriately socialized system-wide, at least until localized rates are developed. *See also id.* at 22 (noting the City of New York's recommendation to assess avoided transmission and distribution costs on a more localized basis). In contrast, many of AMI's expected benefits, as discussed in Part I(A)3, will be realized by customers throughout the Company's systems.

traditional metering function, including, as discussed below, enabling the Company to dramatically reduce the costs of energy commodity passed on to customers.

The Regulatory Assistance Project (RAP) discusses smart meter functionalities, and the novel cost-recovery issues they present, in *Smart Rate Design For a Smart Future* (July 2015). RAP writes:

> Smart meters, and the support systems necessary for them to realize their full potential, are a costly investment. These costs have been justified by the full spectrum of benefits described above, many of which are related to energy savings, peak load management, and distribution cost controls, not just the billing of consumers.
>
> Therefore, these additional costs of smart meters should not be recovered in fixed monthly charges. Traditionally, in utility cost analysis, "meters" were considered a customer-related cost, allocated based on the number of customers in each class because each customer typically required one meter. Those costs were typically reflected in rates as part of the monthly customer charge.
>
> When those meters only performed the function of providing input to the billing system, this made sense; however, smart meters are very different. Because of all of the non-billing functions that smart meters provide, a portion of the cost of smart meters and the associated data collection and data management system should be treated as energy costs, peak load management costs, distribution system reliability costs, or other types of costs, not just as customer-related costs. Smart meter functions related to capacity, reliability, or other aspects of the electric system should be recovered in the same manner as other investments made for those purposes.
>
> . . .
>
> Smart meters and the associated MDMS perform multiple functions. The costs associated with smart grid investments should be apportioned so that all aspects of utility service that benefit share in the costs. Simply stated, to justify deployment of smart meters and an MDMS, there should be an expected net savings to the utility customers over the life of the investments. No single category (energy, capacity, customer) should be assigned costs that exceed that particular benefit.[44]

[44] Exhibit__(UERP-JP-8), Jim Lazar and Wilson Gonzalez, Regulatory Assistance Project, *Smart Rate Design for a Smart Future,* 56-58 (July 2015), *available at* http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf

In short: advanced metering infrastructure warrants an advanced cost recovery approach. A full implementation of the RAP report's recommendations may not be possible at this time, as the Company has not provided evidence attributing specific portions of AMI costs to corresponding non-metering functionalities. Fortunately, as discussed below, the Company has provided a disaggregation of the quantifiable benefits of AMI, which can and should serve as a guide for cost allocation in these proceedings.

Finally, the Commission's AMI Order made the allocation of AMI costs ripe for consideration in this rate case: "Cost allocation among customer classes and among Con Edison's various services (electric, gas, and steam) will be determined in rate proceedings."[45] The Company proposes to collect AMI-related costs during the term of the JP; the JP's proposed allocation of those costs is now before the Commission for its review.

By expressly ordering that the allocation of AMI costs be determined in rate cases, the Commission indicated that the issue warrants careful – and separate – consideration. The need for such separate consideration suggests that the Commission acknowledges that the appropriate allocation of AMI costs will not necessarily follow the allocation of non-AMI costs.

b. AMI's Benefits Will Disproportionately Flow to Higher-Use Customers.

The Company identifies two broad categories of benefits attributable to AMI: "cost reduction benefits" (which correspond to avoided capital and O&M expenses) estimated at $1.276 billion, and "customer and company benefits" estimated at $1.519 billion. These two categories together comprise 19 subcategories of quantifiable benefits. From the customer's perspective, each of these subcategories of quantifiable benefits will "reach" the customer (i.e., will decrease the customer's bill) in one of three ways: by reducing delivery charges, or reducing supply charges, or a mix of both.[46] The following chart illustrates the Company's estimates of how each benefit will reach customers, in descending order of the magnitude of the benefit:

[45] AMI Order at 49.
[46] See Exhibit__(UERP-JP-6) (Company's Response to UIU Information Requests 3-4 filed in Case 15-E-0050).

Table 3: AMI Projected Benefits and Bill Impacts[47]

Benefit Subcategory	Benefit Value (20-year NPV), in $ millions	Type of Bill Reduction (Delivery Rates/Supply Charges/Both)
Conservation Voltage Optimization (CVO)	533	Supply Charges
Meter Accuracy/Irregular Meter Conditions	449	Supply Charges
Meter Reading Labor	417	Delivery Rates
Revenue Protection	355	Supply Charges
Meter Capital	280	Delivery Rates
Field Services Labor	217	Delivery Rates
Demand Side Management Expansion	81	Supply Charges
Contractor and Company Outage Management Labor	78	Delivery Rates
Inactive Meter/Unoccupied Premises	68	Both
System Retirement	59	Delivery Rates
Gas Meters	45	Delivery Rates
Interval Metering	43	Delivery Rates
Call Center Labor	35	Delivery Rates
Distribution System Capital Expenditure Reductions	33	Delivery Rates
Solar Support	33	Delivery Rates
Bad Debt	31	Both
Billing Improvements	14	Delivery Rates

[47] *See id.* To the best of UIU's knowledge and belief, the Company had not publicly released this disaggregation of customer bill impacts attributable to AMI by the time parties filed initial and rebuttal testimony in these proceedings. The Company produced these data on August 22, 2016 in response to UIU's IR submitted August 11, 2016.

Meter Reading Support Systems	14	Delivery Rates
Distribution Transformers O&M Savings	7	Delivery Rates

The precise extent to which AMI may yield lower delivery charges rates versus lower supply charges remains unclear, as the Company does not appear to have disaggregated estimated delivery-related and supply-related bill impacts for those benefit subcategories that yield both types of benefits.[48]

Nevertheless, even without an exact disaggregation of benefits, it is clear that AMI's benefits will overwhelmingly accrue to those customers that consume more energy. This is most apparent with respect to AMI's expected supply-charge reductions. Three of the four largest subcategories of AMI benefits – CVO, Meter Accuracy, and Revenue Protection – will each allow the Company to purchase less energy commodity, the savings from which will be passed through to customers in the form of lower supply costs. Together with the supply savings attributable to Demand Side Management Expansion, **these supply-related benefits total $1.418 billion, or more than half of AMI's total projected benefits**. Including the supply-cost reductions attributable to Inactive Meters and Bad Debt will push this number even higher. These supply savings are greater than the entire net benefit of the AMI program; without such savings, the Company's AMI program would fail the BCA and would not be built. AMI's expected supply-cost reductions are thus integral to its justification.

It is self-evident that reductions in supply costs flow to customers in direct proportion to those customers' energy consumption. To a great degree, delivery rate savings will also accrue to customers largely in proportion to their energy consumption, as the Company collects 84 percent of electric delivery revenues and 75% of gas delivery revenues through the volumetric component of customers' delivery rates.[49]

[48] *See, e.g.,* Exhibit__(UERP-JP-6) (Company's Response to UIU Information Requests 8-9) When asked identify the extent to which the Company recovers Unaccounted-for-Energy ("UFE") and Bad Debt costs from customers through fixed delivery charges, volumetric delivery charges, supply charges, merchant function charges, and other charges the Company stated costs are "recovered through a variety of charges including …" and simply made a list of possible charges without identifying estimates of the costs recovered through each category of charges.

[49] The amount of revenue collected through the volumetric component varies depending on the type of customer. Small customers tend to pay a smaller portion of their bill though the volumetric component and therefore have less opportunity to benefit from AMI. For instance, the average SC 1 (Residential Non Heat) gas customer pays just 16% of their bill through the volumetric component, while the average SC 2 - II (General Service

Higher-use customers may also be better positioned to take advantage of the less-directly-quantifiable benefits of AMI. Larger customers are more likely than small customers to have the resources and capabilities to understand and utilize the rich usage data that AMI will provide.[50] A customer that uses more energy will similarly have far more financial incentive to become familiar with AMI's abilities to manage demand and consumption.[51] The AMI benefits a customer derives as a result of his or her own actions will, of course, differ depending on the individual circumstances and choices of each customer. But the **aggregate quantifiable** impacts of those circumstances and choices are already reflected in the Commission-approved projections of AMI's benefits, rendering those projections a reasonable basis for regulatory decision making.

c. The JP Would Allocate AMI's Costs Out of Proportion to its Customer Benefits.

The revenue allocations contained within the JP do not fairly apportion AMI's costs in relation to the benefits it will confer on customers. The JP's allocation of revenues are based exclusively on the Company's electric and gas ECOS studies – which only examine delivery costs. Energy consumption varies widely among different customer classes, and does not correspond directly to delivery cost responsibility. For example, electric SC1 customers consumed 28.7% of total system energy while being assigned 46.6% of delivery costs. This mismatch between energy consumption and delivery costs demonstrates that avoided delivery costs are not a good proxy for benefits that are largely energy-related.

Thus, even independent of the Company's ECOS studies' flaws, the revenue allocations derived from these ECOS studies do not provide an appropriate basis for allocating AMI costs, because they do not consider commodity costs, which are dispositive factors justifying the AMI investment.[52] An allocation that is based purely on delivery revenues is grossly unfair to small

Heat) customer pays 85% of their bill through the volumetric portion of their bill. UIU notes these calculations were derived from data provided by the Company in its JP workpapers.

[50] Direct Testimony of UIU Electric Rate Panel on the JP at pgs. 38-39

[51] It is self-evident that customers with large bills stand the most to gain from any potential actions they can take in response to the information provided to them by AMI. The smaller the customer, the less like they will individually benefit enough from AMI to justify the time and effort required to become familiar with AMI, study the data provided by an advanced meter, or invest in technologies that are linked to AMI. Even the cost of installing something as simple and straightforward as an automated thermostat will be less attractive to smaller customers, who use so little energy their potential "payoff" from the thermostat will be much smaller than for a larger customer contemplating the same option.

[52] Even assuming, *arguendo,* the Commission were inclined to consider using revenues to allocate AMI costs, it should, at bare minimum, use total revenues including an estimate of commodity revenues collected.

customers, who pay much higher delivery rates than larger customers. It is also illogical, because many AMI benefits will flow to customers through savings on the commodity portion of their bill.[53]

d. UIU Recommends Aligning AMI Costs with AMI Benefits to the Maximum Extent Practicable.

UIU recommends that the Commission apply the regulatory justification for the AMI program's costs to the allocation of those costs. Specifically, the Commission should allocate AMI costs on the basis of the quantifiable (and quantified) benefits that AMI will yield customers.[54] Because energy represents the best available proxy of AMI benefits in this proceeding (and is a far better proxy than the JP's implicit allocation), UIU recommends that energy serve as the basis of AMI cost allocations unless and until a more detailed accounting of benefit by customer type becomes available.[55]

In addition to the self-evident fairness of this approach, and its advancement of the Commission's policy objectives as discussed below, UIU's recommendation is also consistent with cost-causation. AMI's projected benefits are the reason it is being built at all. Those benefits are, therefore, cost-causative in a direct and meaningful (albeit non-traditional) way.

e. UIU's Recommended Allocation of AMI Costs Would Advance REV.

UIU's recommended allocation of AMI costs is consistent with – and may even be required by – the mandates of the Reforming the Energy Vision ("REV") proceeding (cases 14-M-0101 *et. al.*). In its Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) ("Framework Order"), the Commission stated that REV "aims to reorient both the electric industry and the ratemaking paradigm toward a consumer-centered approach that harnesses technology and markets."[56] The Framework Order further presaged a companion REV

[53] Furthermore, the Company's ECOS studies employ a historic test year of 2013, before any AMI plant was in service.
[54] UIU recognizes that any projected allocation of benefits due to AMI will be, by necessity, an estimate. This is not a reason to not rely on such projections, particularly given that the Commission has accepted and approved AMI's projected benefits as the justification for the program.
[55] UIU Electric Rates Panel prefiled Direct Testimony, Page 30, Lines 8-12 and Rebuttal Testimony Page 16, Lines 14-19. UIU Gas Rates Panel prefiled Rebuttal Testimony, Page 30, Lines 18-20.
[56] Framework Order at 3

Order designed to "adopt ratemaking reforms **to secure equitable allocation of benefits and costs among customers** and to align utilities' financial interests with the objectives of reform."[57]

On May 19, 2016, the Commission issued this companion REV Order (Order Adopting a Ratemaking and Utility Revenue Model Policy, or "Ratemaking Order") as a major step toward realigning utility earnings with customer value. The Commission introduced the Ratemaking Order as follows:

> The ratemaking changes adopted in this order add to other actions taken by the State and by this Commission under REV to enable the growth of a retail market and a modernized power system that is increasingly clean, efficient, transactive and adaptable to integrating and optimizing resources in front of and behind the meter. **The focus of this decision is to create a modern regulatory model that challenges utilities to take actions to achieve these objectives by better aligning utility shareholder financial interest with consumer interest.** We build from the conventional cost-of-service ratemaking approach to add a combination of market-based platform earnings and outcome-based earning opportunities.[58]

The Ratemaking Order goes on to extensively discuss the shortcomings of cost-of-service ratemaking, including the dangers of relying on entrenched regulatory techniques:

> Due to both the critical importance of the power industry and its inherent complexity, there is an inertial tendency for regulation to preserve the status quo and to follow change, as opposed to developing mechanisms to facilitate or lead it. However, as we noted in the Framework Order, the fundamental changes occurring in technology, markets, and consumer demands create a greater risk to the State from ignoring these factors and straining to maintain existing systems. **When regulators and companies ignore changing circumstances and set policies based solely on the rear view mirror, they do so at the peril of the constituencies they are seeking to protect and the financial integrity they are looking to preserve.**[59]

Given the decreasing ability of traditional cost-of-service ratemaking to meet changing circumstances and progressive policy objectives, the Commission concluded in part:

> In light of both the disincentives inherent in cost-of-service regulation, and the opportunity inherent in transitioning to a platform market, we agree fully

[57] *Id.* at 4 (emphasis added).
[58] Ratemaking Order at 2 (emphasis added).
[59] *Id.* at 36.

> with Staff that a fundamental realignment of utility revenue incentives is needed.[60]

REV thus contemplates, endorses, and may even require a nontraditional treatment of AMI costs "to secure equitable allocation of benefits and costs among customers." As a spearhead initiative designed in part to "help meet [] REV objectives,"[61] AMI is clearly distinguishable from the "conventional rate-based infrastructure" that the Commission recognizes may not yet be ripe for distinct regulatory treatment.[62] Furthermore, the Commission has indicated that these rate proceedings are the appropriate venue in which to determine the allocation AMI costs. The Commission should therefore modify the allocation of AMI costs in this rate plan to explicitly require AMI costs to be allocated in a way that is consistent with the distribution of benefits, as recommended in UIU's testimony in this proceeding.[63]

4) The JP's Revenue Allocation Does Not Account for the Unaffordability Crisis Among Residential Customers.

By assigning an above-system average revenue increase to SC1, the JP would exacerbate the growing unaffordability crisis among residential customers. In extensive direct testimony submitted on behalf of the PULP, witness William D. Yates demonstrated that the Company's residential customers are increasingly unable to pay their energy bills. Mr. Yates cited a laundry list of metrics that indicate this unaffordability crisis, including:

- Compared to 2005, the amount of debt for the average residential customer in arrears has more than doubled.[64]
- Compared to 2005, the Company today issues 75% more termination notices to residential customers.[65]
- The default rate of residential customers on deferred payment agreements (DPAs) is the highest on record.[66]

[60] *Id.* at 38.
[61] AMI Business Plan at 1.
[62] Ratemaking Order at 39.
[63] UIU Electric Rates Panel Direct prefiled Testimony at 29; UIU Gas Rates Panel prefiled Rebuttal Testimony at 30.
[64] Direct Testimony of William D. Yates at 12-13.
[65] *Id.* at 13.
[66] *Id.*

- The percentage of residential households in the Company's service territory that experience housing cost burden (which includes energy burden) has sharply increased over the last 10 years. The increase is particularly severe for residential renters earning between $50,000 and $75,000 annually, whose rates of housing burden have nearly doubled since 2005.[67]

Mr. Yates concluded that "there is a utility affordability crisis in the Company's service territory that must be addressed in this rate case proceeding."[68] No other party has questioned this conclusion, nor has any other party submitted testimony demonstrating that other classes of customers suffer from a comparable level of hardship. Rather, Mr. Yates's findings have largely been ignored, including by this JP.[69]

Note that the Company's implementation of Commission orders in Case 14-M-0565 the *Proceeding on the Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers* ("Low Income Proceeding") will not resolve this unaffordability crisis. Several Petitions for Reconsideration of the Commission's May 20, 2016 Order in that case are presently pending before the Commission. Unless the Commission substantially expands low-income discount levels and eligibility criteria (which seems unlikely, and in any event is speculative and should not be relied upon for the purposes of evaluating this JP), many residential customers that are slightly above the eligibility threshold will likely suffer from a higher energy burden and will not receive any additional relief.

Rather than mitigating the mounting affordability obstacles that residential customers face, the JP's revenue allocations would make them worse. The electric delivery rate increases that would be assigned to residential electric SC1 customers – 4.2%, 4.6%, and 4.5% for each respective rate year – would be four times the current Consumer Price Index (CPI) inflation rate of 1.1%.[70] This Rate Year 1 increase assigned to SC1 customers would be 45% larger than the average increase of 2.9% assigned to all other general-service Con Edison customers.[71]

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[67] *Id.* at 23.
[68] *Id.* at 12.
[69] UIU's recommended ECOS studies and revenue allocations, in contrast, would ease (somewhat) residential customers' affordability crisis.
[70] U.S. Bureau of Labor Statistics, "Consumer Price Index – August 2016" (September 16, 2016), *available at* http://www.bls.gov/news.release/pdf/cpi.pdf.
[71] *See* JP Appendix 19, Table 2a. Transmission and distribution rate increases are shown in column 7. Average non-SC1 CECONY customer rate increases derived by dividing the non-SC1 rate increase (column 4) by the current non-SC1 bundled T&D revenues (column 1). Compared to SC1 rate increases of 4.2%, 4.6%, and 4.5% in each respective rate year, non-SC1 customers would receive increases of 2.9%, 3.4%, and 3.5%.

The JP would impose even more severe (and disproportionate) impacts on the Company's SC1 residential cooking gas customers. In each respective rate year, SC1 customers would receive delivery rate increases of 5.4%, 10.4%, and 9.2% - far more than the rate increases assigned to any other service class.[72] In fact, the rate increase assigned to SC1s in Rate Year 1 would be **more than double** the average increase assigned to non-SC1 firm gas customers.[73] SC-3 residential heating customers would experience similar (albeit less severe) disparity, receiving respective rate increases of 3.2%, 9.1%, and 5.2% per rate year.[74]

These disproportionate rate increases are particularly concerning because they shift more of the revenue burden onto residential service classes. All else being equal, residential customers should be given particular attention in rate cases – unlike for other types of customers, unaffordable residential rates can put lives at risk. The JP's revenue allocation gives no consideration to the unaffordability crisis among the Company's residential customers, which suggests that it is not in the public interest.

5) The Company's ECOS Studies Contain Flaws that Disproportionately Favor Larger Customers.

The JP's disproportionate allocations of rate increases is a direct consequence of errors and assumptions in the Company's electric and gas ECOS studies that inappropriately shift apparent cost responsibility from larger customers onto smaller ones. These studies should therefore not be relied upon for the purposes of revenue allocation unless and until their flaws are remedied. A discussion of these defects, and UIU's recommended modifications to correct them, are presented in Part B (Electric ECOS) and Part C (Gas ECOS).

B. Electric ECOS Study

The Company's electric ECOS study relies heavily on inappropriate, incorrect, and/or untested assumptions. These flawed assumptions tend to shift apparent cost responsibility to

[72] Appendix 21, Table 1.
[73] *Id.* Non-SC1 gas customers would receive an average rate increase of 2.6%, 7.0%, and 6.2% per respective rate year. Average non-SC1 gas rate increases were derived in the same method as average non-SC1 electric rate increases.
[74] *Id.*

smaller customers, which are concentrated in SC1 (residential) and SC2 (commercial). This ECOS study therefore should not serve as the basis of revenue allocations.

To some extent, the ECOS study's assumptions that harm smaller customers may reflect the relative underrepresentation of those customers in past Con Edison rate proceedings. Of the parties to the instant proceedings, PULP and UIU are the only parties that focus on the interests of residential customers, despite the fact that those customers represent the vast majority of Con Edison's ratepayers. In contrast, nine parties to this proceeding expressly represent the interests of larger customers and/or are themselves larger customers: MTA,[75] NYECC,[76] CPA,[77] the City of New York,[78] NYPA,[79] the County of Westchester,[80] Community Housing Improvement Program

[75] *See* Cases 16-E-0060 *et. al*, Direct Testimony of Steven D. Wilso 2-3 (filed May 27, 2016) ("The MTA and it subsidiary and affiliate agencies (collectively with MTA, the "MTA Group") operate North America's largest public transportation network, serving a population of 15.2 million people in the 5,000 square mile area fanning out from New York City through Long Island, southeastern New York State and Connecticut ("MTA Service Area")…. The MTA Group was billed by NYPA for approximately 6.97 million kilowatts and 2.91 billion kilowatt hours in 2013 and 6.9 million kilowatts and 2.9 billion kilowatt hours in 2014. Out of all NYPA customers, the MTA Group is the biggest consumer of high tension power.

[76] *See* Case 16-E-0060 *et. al*, Direct Testimony of David F. Bomke 6 (filed May 27, 2016) ("The primary focus of my testimony is to emphasize the importance of 2 minimizing the economic burden and bill impact upon large electric 3 energy consumers located within Con Edison's service territory and to 4 discuss Con Edison's testimony regarding its proposed increase in the 5 revenue requirement, additional cost burdens to electric ratepayers, 6 and the need for further cost mitigation.")

[77] *See* Case 16-E-0060 *et. al,* Direct Testimony of Catherine Luthin 3 (filed May 27, 2016) ("CPA members are typically high load factor customers, most of whom receive their electric service under Con Edison's SC-9 Rate II Time of Day (TOD) rate.")

[78] *See* Case 16-E-0060 *et. al*, Direct Testimony of Robert Stephens on behalf of City of New York 3 (filed May 27, 2016) ("City of New York facilities take delivery service from Con 1 Edison via the delivery rates charged to the New York Power Authority ("NYPA") class. ") See also Case 04-E-0572, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Direct Testimony of Dr. Alan Rosenberg filed on behalf of the City of New York, the Metropolitan Transportation Authority and the Port Authority of New York and New Jersey 4 (filed September 10, 2004) "Q: Why is this rate application important for the city? A: As stated in a recent report prepared for the Mayor, the City and the New York City Housing Authority (NYCHA) use more than 10% of the total energy consumed in the entire City. This energy is utilized by over eighty different City agencies, including schools, courts, police precincts, homeless shelters, recreation centers and parks, and 181,000 dwelling units managed by NYCHA. Q: Could you please elaborate on that last point? A: Yes over 99% of the City's needs are served under PASNY No. 4 Delivery Service."

[79] *See* Case 16-E-0060 *et. al,* Direct Testimony of Ronald J. Liberty on behalf of the New York Power Authority 4 (filed May 27, 2016) ("NYPA serves approximately 12,000 governmental 11 customer accounts in Con Edison's service territory with a peak load of approximately 2,200 MW.")

[80] *See* Case 16-E-0060 *et. al*, Direct Testimony of Whitfield A. Russell on behalf of the Intervenor – the County of Westchester 2-3 (filed May 27, 2016) ("Consolidated Edison Company of New York, Inc. ("Con Ed" or Company") serves all of the electric customers located in Westchester County except for a relatively small number of customers in the north/northeastern portion of Westchester County, who are served by New York State Electric & Gas Corporation. Municipalities in Westchester County receive power from the Power Authority of the State of New York (NYPA) distributed over Con Ed's transmission and distribution system.")

(CHIP),[81] the Real Estate Board of New York (REBNY),[82] and the United States General Services Administration.[83] The disproportionate representation of different electric customer classes in this case is, unfortunately, consistent with prior Con Edison rate cases.

Residential and small commercial consumers have traditionally been underrepresented in these proceedings, and have suffered for it. One example of such harm to smaller customers, likely due to their underrepresentation, is the selection of distribution plant components included in the Company's electric ECOS study. As discussed further in Part B2a(i) below, this aspect of the electric ECOS study clearly favors larger customers, and the 2005 Memorandum of Understanding ("MOU") that dictates this aspect the ECOS study does not reflect the participation of small-customer representatives.

The flaws in the Company's electric ECOS study, and UIU's recommended corrections to them, are separately presented below.

1) The ECOS Study Underlying the JP is Based on a Subjective Choice of "Minimum System" Methodology, Which Tends to Favor Larger Customers.

The foundation of the Company's ECOS study – the choice to employ a "minimum system" methodology – is itself highly questionable, belying the near-absolute faith that the JP would place on that study's results. The Company's adoption (and expansion) of this methodology represents a controversial and subjective choice that has a well-documented tendency of shifting apparent cost responsibility to smaller customers.

a. <u>The Company's Use of the Minimum System Methodology Results in Misallocation of Delivery Service Costs</u>

The Company uses a Minimum System methodology which is supposed to estimate the portion of distribution plant costs (i.e., FERC Account 364 (poles, towers, and fixtures), FERC

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[81] CHIP "is a trade association representing more than 2,500 apartment-building owners in New York City's five boroughs." CHIP Website, "About Us," *available at* http://www.chipnyc.org/index.php/about-us.

[82] REBNY is real estate trade association whose membership consists of "than 16,000 property owners, developers, brokers, managers, attorneys, architects, insurance companies, banks, utilities, quasi-public agencies, title companies, appraisers, consultants and other institutions and individuals professionally interested in New York City real estate." REBNY website, "Who Belongs to REBNY," *available at* https://www.rebny.com/content/rebny/en/about.html#collapse2

[83] Case 13-E-0030, Initial Brief of the General Services Administration 1 (August 30, 2013) ("(t)he United States General Services Administration (GSA) intervened (in that rate case) on behalf of all Federal agencies and facilities served by Con Edison in New York City and West Chester County.")

Account 365 (overhead conductors), FERC Account 366 (underground conduit), and FERC Account 367 (underground conductors and devices)) that are incurred simply in order to connect customers to electric or gas service.[84] The National Association of Regulatory Commissioner's 1992 Electric Utility Cost Allocation Manual ("Electric NARUC Manual") provides that the "minimum system" (or "minimum-size method" "assumes that a minimum size distribution system can be built to serve the minimum loading requirements of a customer.[85] The costs of this "minimum size system" thatare classified as customer related are then allocated on the basis of the number of services (lines that connect customer meters to distribution lines) of each rate class.

Obviously, each customer relies on a portion of the Company's electric distribution plant to connect to the grid. A distribution system that lacks poles, conductors, or cables cannot serve most (or any) customers. But it does not follow, however, that the number of customers was a significant cause of the cost of each of these distribution plant components.

The central problem with assigning "customer-related" costs using the "minimum system" methodology" is, essentially, that a "minimum system" is not minimum. Because all distribution plant components installed by a utility installs have the capacity to carry energy, any "minimum system" based on such components also accommodates demand. The methodology ignores this demand-carrying capacity of the "minimum system," and mischaracterizes it as a "customer-related" cost.[86]

This mischaracterization harms lower-demand customers and benefits higher-demand customers. The inherent load-carrying capacity of the larger-than-minimum "minimum system" is fixed, so the lower a customer's demand, the greater the share of his or her demand that can be delivered by the "minimum system." As discussed in Part (B)(2) below, the load-carrying capacity of the Company's "minimum system" is greater than the maximum demands of many customers – yet the "minimum system" methodology would allocate enough plant to these customers to serve their load and then allocate additional "demand-related" costs to those customers. Thus, the minimum system's "demand-related" costs, as well as any unused load-carrying capacity

[84] See Case 04-E-0572, Memorandum of Understanding on Embedded Cost of Service Study, 2-3 (filed March 17, 2006) ("2005 MOU") Exhibit__(UERP-JP-9)

[85] Electric NARUC Manual at 90.

[86] An alternative methodology, the zero-intercept method, attempts to circumvent this problem by statistically determining the costs of installing a hypothetical distribution system that carries no load. This method suffers from its own deficiencies, but because the Company has not proposed a zero-intercept approach in these cases, a detailed discussion of this approach is not needed here.

mischaracterized as "customer-related" costs, represent costs of distribution plant that these small customers are required to pay for but do not use. This effectively reduces the share of revenue requirement that must be recovered from high-demand customers – which is why large customers, unsurprisingly, often support the minimum system methodology.[87]

The minimum system methodology's mischaracterization of some demand-related costs as "customer-related," and its resulting cost-shifting impacts, is well-documented. For example, the Electric NARUC Manual notes that "the analyst **must be aware** that the minimum size distribution equipment has a certain load-carrying capability, which can be viewed as a demand related cost."[88] As a result, "some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs . . . . [T]hose customers receive a second layer of demand costs that have been mislabeled as customer costs."[89] The minimum system method's tendency to shift apparent cost responsibility is not in dispute: the Electric NARUC Manual further acknowledges that compared to the zero-intercept method (which attempts to approximate a truly "minimum system" that carries 0 load), the minimum system method "generally produces a larger customer component."[90]

George Sterzinger further explored this effect in 1981:

> [A] more severe problem with this [minimum system] methodology arises from the consequences of classifying distribution system costs into both customer and demand portions. Simply put, this practice leads invariably to a double allocation and possibly a double collection of these costs from low-use residential customers and a misallocation of costs among customer classes.[91]

The Company's ECOS study has not solved this double-allocation problem inherent in the minimum system methodology.[92] Instead, it ignores the problem altogether; and continues to overallocate distribution system costs on the number of customers/services.

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[87] *See e.g.*, Case No. 16-E-0060, Rebuttal Testimony of Robert R. Stephens on behalf of City of New York 5 (June 17, 2016) ("Although I raised some limited concerns with Con Edison's application of the minimum system concepts, I fully agree with Con Edison's inclusion of a customer component in its classifications of the High Tension and Low Tension asset costs")
[88] NARUC Electric Manual at 95 (emphasis added).
[89] *Id.*
[90] *Id.* at 91.
[91] George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs," PUBLIC UTILITIES FORTNIGHTLY (July 2, 1981) at 31-32.
[92] Mr. Sterzinger proposes a potential means by which a minimum system analysis might be corrected to ameliorate or mitigate this overallocation impact. "One way to solve the double allocation problem would be to determine, for each piece of minimum equipment, the demand level it would be capable of serving, and then adjusting the demand

b. The Company Has Not Justified Expanding the Minimum System Methodology to the Primary Distribution System.

Rather than correcting (or even addressing) the tendency of the Company's ECOS approach to over-allocate cost responsibility onto small customers, the JP would extend this methodology to the Company's primary distribution system. The Company's ECOS study filed in this case proposes, for the first time, to classify a portion of primary distribution system costs as "customer-related." This would subject a new – and very large[93] – category of costs to the misallocation impacts of the minimum system methodology.

Until this rate filing, the Company's electric ECOS studies have been aligned with UIU's recommended approach with respect to primary system classification; i.e., the Company has historically classified its primary system as 100% demand. The electric ECOS study the Company filed in this case abandons this approach, and instead introduces customer-related components for primary FERC Accounts 364, 365, 366, and 367 (respectively, poles, towers, and fixtures; overhead conductors; underground conduit; and underground conductors and devices).[94]

The Company has not provided adequate justification for why it chose to introduce a customer-related component to its primary system. (The Company does not, for example, argue that the factors that caused it to incur the embedded costs of that system have retroactively changed, as this new ECOS approach would suggest.) The Demand Analysis and Cost of Service (DAC) Panel's initial filing articulates three reasons: "the Company is [1] paralleling its methodology applied to secondary distribution assets and is [2] also recognizing the increased emphasis on fixed-cost recovery. [3] The incorporation of a customer component has been adopted by a number of New York State utilities as part of their cost allocation procedures."[95] None of these explanations sustain the Company's new approach.

The DAC Panel's first explanation assumes, without explaining why, that a "parallel[]" methodology applied to both primary and secondary distribution plants is appropriate. This

alloction factors used to allocate the costs of all equipment of that type in order to assure that minimum use customers and the residential class were not charged twice. In many cases this would mean calculating several allocation factors for each FERC distribution account, since more than one type of equipment is used in the account." *Id.* at 32. However, there is no evidence that the Company has undertaken this additional layer of analysis or made corresponding adjustments to its cost allocators.

93 The primary distribution system constitutes 36% of the Company's total rate base.

94 See DAC Panel prefiled Direct Testimony at 17-18

95 DAC Panel prefiled Direct Testimony at 18.

assumption is belied by the Company's history of non-parallel treatment of primary and secondary plant, which indicates that the Company has traditionally considered those systems to be fundamentally different. Indeed, the primary distribution system operates at a much higher voltage (or "tension") then secondary plant, and thus serves a much different function vis-à-vis individual customers. Unlike secondary plant, "[p]rimary systems exist because they are a more efficient way to carry significant loads than are secondary systems. They reduce line losses."[96]

The DAC Panel's second explanation, that the new treatment of primary distribution plant "recogniz[es] the increased emphasis on fixed-cost recovery," is too vague to even be understood. This statement does not identify the origin or rationale behind this "increased emphasis on fixed-cost recovery," nor describes why such "increased emphasis" is desirable from a ratemaking perspective.

Finally, in support of its third explanation, the DAC Panel refers to New York State Electric and Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E"), stating, "the PSC's September 21, 2010 *Order Establishing Rate Plan* in Cases 09-E-0715 and 09-E-0717 adopts the Joint Proposal requirement that NYSEG and RG&E classify distribution plant as 50/50 demand and customer in their next rate cases."[97] This statement is misleading. The Joint Proposal adopted in those proceedings did instruct the NYSEG and RG&E to file ECOS studies classifying distribution plant as 50% demand and 50% customer in their next rate filings; however, that classification did not actually govern the utilities' revenue allocations. To the contrary: the Joint Proposal ultimately approved in cases 15-E-0283 *et. al.* explicitly provides that "no single ECOS study forms the basis for revenue allocation in these proceedings,"[98] and "the revenue allocation determined in these proceedings does not use or otherwise reflect any one ECOS study sponsored by any party".[99] Thus, if these recent NYSEG/RG&E cases stand for any ECOS principle at all, they represent an example in which the parties and the Commission did **not** accept a 50/50 customer/demand classification of electric distribution plant.

The Company does not articulate a good reason for modifying its primary system classification because there is no such reason. Even the Company's own responses to information requests suggest that primary distribution plant should not be included in the "minimum system."

[96] UIU Electric Rate Panel prefiled Direct Testimony at 13.
[97] DAC Panel prefiled Direct Testimony at 18.
[98] Cases 15-E-0283 *et. al.*, Joint Proposal at 33.
[99] *Id.* at Appendix W.

In its response to UIU-19-263, the DAC Panel wrote, "**The minimum system represents the cost of the smallest secondary system** theoretically needed to physically connect all of the existing service points if the system was not required to supply any load."[100] This is entirely consistent with the UIU Electric Rates Panel's observation in its direct testimony that "[i]f a utility were actually to build the least expensive system needed to provide a very minimal amount of electricity to customers (i.e., a 'minimum system'), it could simply install secondary lines."[101]

The Company has failed to identify a factual or legal basis for adding a portion of primary distribution plant to its minimum system (and, by its own words, appears to support the opposite). This lack of grounds for expanding the minimum system, coupled with the cost-misallocation impacts such expansion would yield, strongly militate against its adoption. Furthermore, the unsupported and harmful nature of this proposed ECOS study modification represents yet additional reasons that the Company's electric ECOS study should not serve as the sole basis of revenue allocations.

2) *Even Accepting the "Minimum System" Method Arguendo, the Company's ECOS Study Suffers from Significant Defects That Favor Larger Customers.*

Even if the Commission were to accept the "minimum system" methodology in this case, it should still reject the Company's electric ECOS study on the basis of that study's flaws.

a. <u>The ECOS Components Included in the Company's "Minimum System" Are Much Larger than Minimum, Which Distorts Cost Responsibility.</u>

The Company's electric ECOS study estimates a minimum secondary distribution system that is actually much larger than minimum and therefore amplifies the cost-misallocation impacts inherent to the minimum system methodology. As discussed above, a "minimum system" based on actual distribution plant components is not truly "minimum," as such a system will still have load-carrying capacity. This minimum system methodology thus mischaracterizes this load-carrying capacity of the "minimum system" as "customer-related" costs. Rather than seeking to minimize the extent of this cost mischaracterization, the Company's electric ECOS goes in the

[100] Exhibit__(UERP-JP-9) Company Response to UIU-19-263 (emphasis added).
[101] UIU Electric Rate Panel prefiled Direct Testimony at 13.

opposite direction, and employs a larger "minimum system" that correspondingly inflates this defect.

i. Secondary Conductor (Overhead and Underground)

The Company's electric ECOS study uses a "minimum" conductor cost that is three times more expensive than the actual embedded costs of conductor in the Company's secondary system. The Company's various sizes of conductor are represented as American Wire Gauge (AWG) sizes 1 through 600.[102] The Company has several miles of 1 AWG wire, the smallest of these conductor sizes, currently installed in its distribution system – 16,875 feet in its overhead system (FERC Account 365), and 8,863 feet in the underground system (FERC Account 366).[103] All of this conductor, presumably, connects customers to the electric grid (and accommodates their demand) – otherwise, it would not have been installed in the first place. The Company's average cost of 1 AWG wire is 8 cents per foot.[104]

The Company's electric ECOS study, however, employs a "minimum" size conductor cost of $0.247 per foot, or over 3 times more expensive than 1 AWG wire. This cost is not based on the actual cost of a specific conductor size; rather, it represents "the weighted average unit cost of installed wire sizes from 1 to 10."[105] This "weighted average unit cost" thus reflects the costs of conductor far larger than the minimum size that actually connects customers to the Company's system.

The Company does not deny that this conductor-cost calculation does not, in fact, represent a "minimum system." The DAC Panel has acknowledged that "[t]he minimum system represents the cost of the smallest secondary system theoretically needed to physically connect all of the existing service points if the system was not required to supply any load."[106] In response to UIU-19-260, the Company's Electric Infrastructure and Operations Panel further admitted that the Company can still achieve such no- or minimum-load connections using 1 AWG conductor: "If current load can be satisfied with 1 Awg cable, it will be replaced with new

[102] Electric Work papers for Exhibit ___ (DAC-2), Schedule 1.
[103] Electric Work papers for Exhibit ___ (DAC-2), Schedule 1
[104] Exhibit__(UERP-JP-6) Company response to UIU-10-205.
[105] DAC Panel Rebuttal Testimony at 24-25
[106] Exhibit__(UERP-JP-6) UIU-19-263 (emphasis added).

1 Awg cable." Thus, the larger-than-minimum conductor sizes reflected in the Company's "weighted average unit cost" scheme are a function of demand, not the number of customers.

The Company has offered two explanations for using this non-minimum "minimum" secondary conductor cost: first, that the approach is required under a Memorandum of Understanding developed in 2005 following the Company's 2004 electric rate case (Case 04-E-0572) ("2005 MOU"); and second, that 1 AWG conductor constitutes a small proportion of the system's total embedded conductor, and should therefore not a "representative minimum system."[107] Far from justifying the Company's conductor-cost selection, both "explanations" actually demonstrate the opposite; namely, that the Company's method is inappropriate.

The 2005 MOU is not a ground upon which the Commission should rely for the purposes of making rates. First, the MOU does not reflect a balanced cross-section of party interests. Eight parties signed the MOU: the Company, Staff, and six other parties who either represent large energy consumers or are themselves large energy consumers.[108] No party representing the interests of consumers generally (such as the Consumer Protection Board, UIU's predecessor entity) or the interests of small customers specifically, signed this MOU. Furthermore, of MOU's signatories, half had further overlapping interests, as customers of NYPA, to shift costs away from their supplier.[109] It is not surprising, then, that the MOU is biased toward those large-customer and NYPA interests – and it even acknowledges as much: "It should be noted that the use of these methodologies [prescribed in the MOU] will affect the overall surpluses and deficiencies of the customer classes. For example, NYPA will continue to have a deficiency, **albeit a smaller one**."[110]

The 2005 MOU also provides no justification for the "minimum" conductor cost that it adopted. The MOU instead offers only the conclusory statement that this methodology "does not depend on a large degree of judgment and produces reasonable results."[111] While application of the methodology itself may "depend upon a large degree of judgment," the means by arriving at

[107] DAC Panel Rebuttal Testimony at 24-25.
[108] 2005 MOU at 1. The six other signatories are: the City of New York, CPA, NYPA, NYECC, the Port Authority of New York and New Jersey, and the MTA.
[109] In addition to NYPA itself, these parties comprise the City of New York, the Port Authority of New York and New Jersey, and the MTA, which are each customers of NYPA.
[110] 2005 MOU at 2 (emphasis added). The benefits to larger customer (and harm to smaller customers) of such smaller deficiencies resulting from the MOU have thus been accumulating for over 11 years.
[111] 2005 MOU at ¶2.

it did (or should have), and as demonstrated above, its results are not reasonable because they do not reflect reality.

Furthermore, insofar as signatories to the MOU support or do not oppose its application in this case, the Commission should note that the MOU to a large extent compels such support/non-opposition.[112] Except in specific, limited circumstances, the MOU prohibits its signatories from opposing (or even proposing modifications to) its "minimum" conductor methodology in any Con Edison electric rate case.[113] This MOU thus stifled party opposition to this "minimum" conductor methodology 11 years before the Company even proposed it in this case.

The Company's second rationalization of its "minimum" conductor methodology, that cheaper conductor does not reflect a "representative minimum system,"[114] implies a requirement of the minimum system methodology that does not exist. First, the term "representative minimum system" is inherently contradictory – the word "minimum" is superlative,[115] so "representative minimum" means, by definition, "not minimum." The Company's use of this term also conflicts with its own statements, as discussed above, in which the Company acknowledges that a "minimum system" represents the "**smallest** secondary system theoretically needed . . . ."[116] Furthermore, the Company has admitted that its "smallest secondary system theoretically needed" could be based on a smaller conductor, such as 1 AWG: "If current load can be satisfied with 1 Awg cable, it will be replaced with new 1 Awg cable."[117] Thus, to the extent the Company chooses not to install larger, more expensive wire, it does so not because such larger wire is required to connect customers to the grid – rather, it does so because of the larger wire's capacity to carry more demand.

ii. Transformer Accounts

[112] 2005 MOU at ¶1.
[113] *Id.* at ¶¶4-5.
[114] DAC Panel prefiled Rebuttal Testimony at 24-25.
[115] *See* Oxford English Dictionary, "minimum": "The least or smallest amount or quantity possible, attainable, or required."
[116] Exhibit__(UERP-JP-6) UIU-19-263 (emphasis added).
[117] Exhibit__(UERP-JP-6) Company's Electric Infrastructure and Operations Panel response to UIU-19-260

The Company's electric ECOS study makes a similar mistake by including in its "minimum" system costs of transformers that far exceed the minimum theoretically necessary to connect customers. As an initial matter, UIU notes that transformers need not be included in a "minimum" system at all. Transformers exist to step down voltage. If the Company were to build a theoretical "minimum" system that carried no load, it would not need to build any transformers at all, because there would be no voltage for which modulation would be required

Nevertheless, even *arguendo* including some portion of transformer costs in a "minimum system", the Company's electric ECOS study clearly includes too large a portion:

> The Company's proposed minimum system for [overhead] transformers includes all transformers up to 25Kva, although in reality it has much smaller transformers in service. Its calculation for [underground] transformers not only goes up to 25Kva in size, but also includes equipment called autotransformers, which are transmission voltage (up to 480,000 Volts), and regenerators, neither of which are installed to serve minimum load.[118]

Such smaller transformers currently in service include 10kVa and 15kVa transformers. These transformers, which can and do serve customers, cost less than the 25kVa transformers the Company chose to include in its "minimum" system.

Furthermore, the autotransformer and regenerator equipment bear no relationship to a minimum system. As noted in the passage quoted above, autotransformers operate at transmission voltage levels, far beyond anything required to serve a "minimum" load. Regenerators, or "regenerative control devices," similarly do not belong in a minimum system because they exist "to absorb power flow being directed back in to the system that is caused by elevator motors when the elevators are descending."[119] Including such purpose-specific equipment in a "minimum system" could only be justifiable if every building in the Company's service territory had an elevator (and a regenerator) – which is clearly not the case. A customer does not require an elevator, or a regenerator, to be connected to electric service.

The Company's electric ECOS study further inappropriately includes "rectifiers" in its "minimum" transformer calculation. "Rectifiers convert AC to DC power. They are installed where customers need DC power. The size is specific to the customer and depends on the

[118] UIU Electric Rates Panel prefiled Direct Testimony at 16.
[119] Exhibit__(UERP-JP-6) Company's DAC Panel response to UIU-10-209

specific customer's load."[120] Like regenerators, rectifiers would not be required in a minimum system, as such equipment is not needed to connect a minimum-load customer to the grid. Rectifiers instead serve a specific function for a very limited subset of customers (as the Company notes, it "no longer provides DC power"[121] at all), and therefore their costs should be excluded from the ECOS study's "minimum system."

The Company has not rebutted the factual bases of UIU's recommendation to remove such extraneous and larger-than-minimum transformer equipment from its "minimum system." The Company's entire defense for its inclusion of such equipment is: "the Company follows a methodology consistent with its approach in the selection of sizes for secondary conductors. That is, the Company selects a range of minimum sizes up to and including 25 KVa transformers which represents the predominant minimum size installed."[122]

(This defense fails here for the same reason it fails with respect to the Company's selection of secondary conductor cost, as discussed above. Indeed, such defense is even weaker in the context of transformer-cost selection because there is no corresponding MOU (fatal flaws of the 2005 MOU notwithstanding) to provide even a superficial basis. Not that such an MOU would justify the Company's approach. Minimum loads simply do not require the level of transformer equipment that the Company has included in its "minimum system." If any transformer plant were reflected in a minimum system, it should be smaller than what the Company has included.

b. The D08 Allocator Does Not Reflect Actual System Planning or Construction, Further Distorting Apparent Cost Responsibility.

The Company's electric ECOS study's D08 allocator, which governs the allocation of secondary distribution plant costs, has long been a contentious aspect of its electric ECOS study. Much of the controversy surrounding this allocator likely springs from the Company's novel – and unsupported – formulation thereof. The Company's calculation of this allocator blends service classes' Non-Coincident Peak Demand (NCP) with their Individual Customer Maximum Demands (ICMD). For SC1, ICMD receives a 25% weight and NCP receives 75% weight; for all other SCs,

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[120] *Id.*
[121] Exhibit__(UERP-JP-6) Company's DAC Panel response to UIU-19-261.
[122] DAC Panel prefiled Rebuttal Testimony at 27. The Company's quote is not true as it implies that the Company includes only transformers, but the transformer plant values they are using include the other plant described above.

ICMD and NCP receive a 50%/50% weighting.[123] This incorporation of ICMD into the D08 allocator is unique to the Company (and its corporate sibling, Orange and Rockland Utilities) among New York utilities, does not reflect actual system planning considerations, and disproportionately shifts costs to smaller customers.

A customer class's NCP represents the maximum demand that all customer classes are projected to place on the distribution system.[124] In contrast, a class's ICMD "represents the actual sum of billing demands for a set of customers"[125] – in other words, ICMD identifies the maximum demand of each individual customer in the class, and sums them up as if they all occurred at the same time. Because all customers in a service class do not hit their maximum demands at the same time, ICMD does not reflect a level of demand that a customer class actually imposes on the secondary distribution system.

NCP therefore instead serves as the traditional, and more accurate, guide for allocation of secondary distribution plant. The major rationale for using NCP is that most local distribution load areas are dominated by single classes. Distribution plant that serves these areas must be of sufficient size to meet the maximum demand on the system. The sum of NCPs is larger than the coincident peak load on the entire system, but it is less than the sum of the individual customer peaks because system planners can count on diversity of load – all of those individual customer peaks rarely if ever occur simultaneously.

Con Edison refers to planning for local load areas. In response to UIU 17-254, the Company states that the "demand in the load area" refers to the coincident peak load in a load area. For an area that is dominated by a single customer class, the class NCP provides an estimate of the coincident load in that area. The secondary distribution system is built to meet the coincident peak loads in all local areas and is the sum of all of these planning and construction determinations.

For an ECOS study to reflect cost causation, the only portion of distribution delivery plant that should be allocated on the basis of ICMDs should be plant that is designed to meet ICMDs (such as service lines that serve a single customer). Factoring ICMD into the D08 allocator implies that much of the cost of the local distribution delivery plant was caused by

[123] Direct Testimony of UIU Rate Panel at 9; ECOS Explanatory Notes in DAC Panel Exhibits and the Workpapers for Exhibit DAC-1
[124] Electric NARUC Manual p. 80
[125] DAC Panel prefiled Rebuttal Testimony at 9.

installing plant to serve the peak loads of individual customers. The Company does not describe how **any** of its secondary lines or transformers have been designed to meet individual customer peak loads. Weighting ICMDs by 50% for a class implies that half of the secondary distribution delivery plant was built to supply that class's individual customer loads. In a residential area, this would suggest that half of the customers would have their own transformer and their own section of secondary conductors. The same would be true of all classes.[126]

The electric ECOS study's incorporation of ICMD into the D08 allocator thus defies the Company's own planning processes. The Company explains how diversity of load is fundamental to the design of the distribution system:

> More diversity of load is taken into consideration when planning investment upstream from the customer. Transmission investment, for example, takes into consideration the coincident loads of groups of customers. Similarly, less diversity of load exists when planning investment closer to the customer. Hence, the service to an individual house is sized to meet the maximum potential demand of that customer or building. The distribution equipment which lies in between has varying degrees of diversity of load and is the subject of this debate.[127]

UIU agrees with the statement that "the service to an individual house is sized to meet the maximum potential demand of that customer or building" – because only one customer or building will use that service line. The allocation of service plant is not in dispute. Services lines are connected to either overhead or underground conductors. For customers who take service at a secondary voltage level, services are connected to secondary level conductors. These secondary conductors usually serve a number of customers[128] – particularly in a system as dense as the Company's – and therefore the maximum loads to be placed on these conductors depend on NCP, not ICMD.[129]

Until 2007, the Company accorded 50% weight to ICMD for all electric service classes. Its current 25% weighting of ICMD for SC1 thus represents some improvement. The Company explains that this 25% weighting for SC1 is based on SC1 customers' load diversity, and cites to

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[126] There may be some large customers who essentially are local load areas, which is why UIU has testified that ICMDs could theoretically have some relevance for classes with larger customers. However, the Company has provided no data suggesting that such large-customer-dominated load areas exist within its service territory
[127] DAC Panel Rebuttal Testimony at 8.
[128] *See* , Exhibit___(UERP-JP-6) UIU-19-268 (Company response confirms that typical small transformers serve 6-10 customers, with a secondary line feeding those customers.
[129] See UIU Electric Rate Panel Testimony on the JP at 8-13.

its DAC Panel's testimony and Load Diversity Study filed in case 13-E-0030. These documents do identify SC1's comparatively high load diversity. For example, the Load Diversity Study found that the peak loads of multifamily buildings were about 60% of the value that would be estimated by using residential ICMD data (that is multiplying average residential ICMD by the number of customers. In other words, multifamily buildings demonstrate that residential customers' peak loads tend not to occur at the same time. The Company accordingly reduced the ICMD assigned to SC1 customers. (Note that the Load Diversity Study did not examine whether other service classes, such as SC2, might also have greater load diversity that could warrant a decrease in their share of ICMD.)

The Company's 2013 testimony and Load Diversity Study support UIU's recommendation that the weighting of ICMD be reduced not just to 25% for some customers, but to 0% for all customers – and instead weight NCP 100%. Those filings did not demonstrate that any distribution plant was incurred solely to meet the maximum demands of individual customers. They simply showed that the coincident load of typical multifamily buildings was less than if it was assumed that all of the residential individual peaks in the building occurred at the same time. For example, the Company's testimony did not demonstrate that either 50%, or 25%, or any other portion of delivery service plant was incurred in order to meet the sum of the loads of individual customers at different times (ICMD). The Company's discovery responses indicate the opposite – this plant was installed to meet peak loads in areas. For example, UIU 15-241 specifically asked what components of distribution plant were planned to meet the ICMDs of multifamily dwelling units. The Company's response refers to its responses to UIU 8-150 and 152, which in turn do not indicate that ICMDs are relevant to the sizing of this plant. Rather, those responses state that the Company matches transformer and cable capacity to the demand in a load area – for which NCP appropriately serves as a proxy.

The Company stands out as among utilities in using this formulation of a D08 allocator. As the UIU Electric Rate Panel observed in its Testimony on the Joint Proposal at p. ###, no other New York utility except for Orange and Rockland Utilities, Inc. (Con Edison's corporate sibling) incorporates ICMD in its D08 allocator. Furthermore, a 2011 Commonwealth Edison "Survey of

Approaches to Distribution Cost Allocation by Voltage" identified only one utility – Con Edison – that incorporated ICMD into its secondary system demand allocator.[130]

The impact of including ICMD in the D08 allocator has a meaningful impact on cost allocation. Because they tend to have a greater disparity between their NCPs and ICMDs, smaller customers – particularly SC1 and SC2 classes – experience the most impact when ICMD is introduced to the secondary system demand allocator. According to the Company's workpapers to Exhibit___(DAC-2), the combined cost allocation to these classes based on NCP alone would be 44% of the Company's total secondary distribution costs. Using the Company's blends of NCP and ICMD in D08 increases the combined allocation to those classes to 50%.

3) UIU's Recommended Approach

a. UIU Recommends a "Minimum System" That Better Reflects Actual Minimum Costs.

In general, UIU does not support the minimum system approach to ECOS for the reasons described above. However, because the Company has traditionally relied on this methodology with respect to its secondary distribution plant, UIU has based its recommended modifications to the electric ECOS study to fit within this methodology. Specifically, UIU recommends that the electric ECOS study remove larger-than-minimum components the Company has included in the "minimum system." A minimum-system ECOS study should employ the Company's DAC Panel's stated formulation of "minimum system:" "The minimum system represents the cost of the smallest secondary system theoretically needed to physically connect all of the existing service points if the system was not required to supply any load."[131] This would require removing from the "minimum system:" (1) primary distribution plant (FERC Accounts 364-367); (2) conductor larger than 1 AWG; and (3) all overhead and underground transformers in the secondary distribution plant (FERC Account 369) (or, in the alternative, all transformers larger than 10kVa and all extraneous transformer-related equipment such as autotransformers, rectifiers, and regenerators). This approach would still not eliminate the cost-misallocation impacts of the

[130] Exhibit___(UERP-JP-6) Response to UIU 18-257 Attachment 1, Commonwealth Edison Company, "Survey of Approaches to Distribution Cost Allocation by Voltage" (October 28, 2011) at 15 (finding only one utility among the sample group –which included Con Edison – that used ICMD in its secondary system demand allocator).
[131] Exhibit___(UERP-JP-6) UIU-19-263 (emphasis added).

minimum system methodology, because even this improved "minimum system" would still retain considerable load-carrying capability, but it would lessen such harmful impacts and would more closely align the Company's hypothetical "minimum system" with the theory underlying that approach.

b. UIU Recommends a D08 Allocator Based Entirely on Non-Coincident Peak.

UIU recommends the Commission modify the D08 allocator (applied to demand-related secondary delivery plant) to be based on 100% NCP for each service class. In addition to reflecting the Company's actual system planning and construction practices, this modification would align the Company's D08 allocator with well-established utility practice (including among New York utilities).

C. Gas Cost of Service (Joint Proposal Sec. H(1))

The JP relies on the results of the Company's gas ECOS study, to the exclusion of all other considerations, to allocate gas costs.[132] This aspect of the JP is similar to the analogous electric provisions in the JP, and it suffers from many of the same flaws. For example, the JP's gas revenue rates would be inconsistent with rate gradualism and proportionality, and would ignore other relevant factors. This shortsighted approach is particularly striking in the gas context because the Company has failed to justify – or even defend – its flawed gas ECOS study in prefiled testimony. UIU's Gas Rates Panel submitted detailed prefiled testimony demonstrating that the Company's gas ECOS study does not accurately reflect system planning or engineering considerations, and would inappropriately shift apparent cost responsibility onto smaller customers. The Company offered no prefiled rebuttal testimony in response.

To avoid redundancy, the following comments provide only a limited discussion of those defects of the Company's gas ECOS study that are analogous to those of its electric ECOS study. For a fuller discussion of the flaws of the Company's gas ECOS study, please see the UIU Gas Rates Panel's Testimony on the JP (especially pages 28 through 67).

[132] *See* JP § H(1).

1) The ECOS Study Underlying the JP is Based on a Subjective Choice of "Minimum System" Methodology, Which Tends to Favor Larger Customers.

The primary defect of the minimum system methodology – namely, that it mischaracterizes the latent demand-accommodating capacity of the "minimum system" as a customer-related cost – applies to gas mains just as much as electric distribution plant. Each of UIU's objections to this method, as discussed in Part (I)(B)(1)(a) above, are thus reaffirmed with respect to the Company's gas distribution system as if restated here.

The results of the Company's minimum-system analysis demonstrate the infirmities of the methodology as applied to gas mains. The Company's minimum system approach would allocate 54% of distribution main costs on a per-service basis, despite the fact that those costs do not vary according to the number of service lines.[133] This approach would allocate this same share of "minimum system" main costs – comprising more than half of the total costs of the mains – to a large department store as to the tiny bodega across the street. Such illogical results illuminate the failure of the minimum system approach.

2) Even Accepting the "Minimum System" Method Arguendo*, the Company's Gas ECOS Study Suffers from Significant Calculation Flaws That Misallocate Apparent Cost Responsibility.*

To an even greater extent than its electric ECOS study, the Company's gas ECOS study incorrectly employs a "minimum system" that is far more expensive than the minimum actually needed to serve customers under the minimum system methodology. The Company based its gas "minimum system" upon pipes that are significantly more costly than smaller pipes currently embedded in its system.[134] The choice of such plant has momentous consequences – for example, basing a "minimum system" on the Company's cheaper 1.5-inch steel and 2-inch plastic mains would decrease the apparent "customer related" share of distribution main costs from 46% to

[133] UIU Gas Rate Panel Testimony on the JP at 29.

[134] *See* UIU Gas Rate Panel Direct Testimony on the JP at 31 Note that there is no basis for ignoring smaller or less-expensive embedded pipe simply because it was not installed recently. One would reasonably expect the Company to install larger, more expensive pipes today than in the past – but such increase in size is not because today's customers each somehow require a larger pipe solely to be connected to the distribution system. Rather, the Company lays larger pipe today than in the past because larger pipe accommodates more *demand* – and, correspondingly, represents a demand-related cost.

18%.[135] The Company's gas ECOS model thus relies on inputs that are not consistent with the minimum system methodology.[136]

3) UIU's Recommended Approach

a. UIU Recommends Classifying Gas Distribution Mains as 100% Demand-Related.

UIU recommends the Commission employ the NARUC Manual's "basic system approach"[137] to classifying gas distribution mains, i.e., classify mains as 100% demand-related. This recommended approach would better reflect the Company's system planning and construction methods,[138] be more consistent with the NARUC manual (which notes that the minimum system method – but not the basic system method – can be "controversial"),[139] mitigate the misallocation of latent "minimum system" capacity on a customer-related basis,[140] support more progressive rate

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[135] UIU Gas Rates Panel Direct Testimony on the JP at 31

[136] Gas NARUC Manual at 22-23 "Under the minimum size main theory, all distribution mains are priced out at the historic unit cost of the smallest main installed in the system, and assigned as customer costs. The remaining book cost of distribution mains is assigned to demand."

[137] Gas NARUC Manual at 23.

[138] UIU Gas Rates Panel Testimony on the JP at 30-31 "The Company's methodology is tied to embedded cost data for different size mains, but those data are influenced by many extraneous factors that are not adequately "held constant" in the Company's analysis, including the location where the gas main was installed and the difficulties that were encountered along its installation route." Overall, it is fair to say that the Minimum System Approach is not universally accepted by either utilities or regulators. Where it has been discussed, it has often been very controversial. The NARUC manual notes at p. 22 "A portion of the costs associated with the distribution system may be included as customer costs. However, the inclusion of such costs can be controversial."

[139] The NARUC manual notes at p. 22 "A portion of the costs associated with the distribution system may be included as customer costs. However, the inclusion of such costs can be controversial."

[140] *Id.* at 31 (For instance, 1.5 inch and 2.5 inch steel mains both show lower costs per foot than 2.0 inch steel mains,which is the size used in the Company's minimum system analysis. (Work papers for Exhibit ___ (GRP-1) Schedule 1 - Revised.xls, Tab TRB, Rows 561-661). In some cases, these sorts of cost discrepancies might be attributable to weak data, but not in all cases. For instance, the data set includes cost information for more than a million feet of 2.00 inch plastic main, which cost of $107 per linear foot, installed (Id., Row 645). However, the Company chose to instead focus on 1.25 inch plastic mains, which cost $148 per linear foot. (Id., Row 643). By choosing the more costly size, the Company shifted more costs into the "customer-related" category. To appreciate how sensitive the minimum system analysis on distribution main costs is to the methodology used by the Company, consider what would have happened if it had focused on 1.50 inch steel mains and 2.00 inch plastic mains, rather than 2.00 inch steel mains and 1.25 inch plastic mains: with just these two minor changes, it could have developed a "customer-related" share of 18%, rather than 46%.)

design,[141] and align cost recovery and cost causation.[142] This "basic system" approach is also well-founded in New York precedent – Orange and Rockland has implemented 100%-demand gas main classifications in a recent case.[143] NYSEG and RG&E have also traditionally classified mains as 100% demand-related (though, as discussed in Part I(A)(1)(b) above, their most recent rate plan was implemented through a Joint Proposal that does not endorse any one ECOS methodology).[144] Finally, as described in the UIU Gas Rate Panel Testimony on the JP, an ECOS study applying this treatment of mains would yield a more balanced allocation of revenues that, compared to the JP, would mitigate the significant rate shock residential customers stand to experience in Rate Year 2.

b. In the Alternative, UIU Recommends a "Minimum System" That Better Reflects Actual Minimum Costs.

Should the Commission apply the "minimum system" methodology in this case, it should modify the Company's gas ECOS to more closely resemble "minimum" costs of distribution plant. Under this alternative recommendation, the gas ECOS study should employ a "minimum system" based on the actual minimum pipe embedded in the Company's system, consistent with the recommendation of UIU Gas Rate Panel.[145]

D. Recommended Revenue Allocation

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[141] *Id.* at 32 ("The key point to realize is that "minimum system" calculations may help identify fixed costs, but these costs do not vary as a function of the number of customers – even in the long run. Rather, in the long run, the minimum cost of the distribution system varies as a function of the number of miles of streets served by the system, and the remaining cost (in excess of the minimum) primarily varies with the anticipated peak load that each main is expected to accommodate over its useful life (which can be 40 or more years).") "

[142] *Id.* at 32 ("Because these facilities are engineered on the basis of maximum peak load, the costs in Account 376 are often allocated entirely on the basis of peak load data for the various customer classes.")

[143]*See* Case 14-G-0494, Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan Attachment A Joint Proposal 45 (filed October 16, 2015) ("The gas Embedded Cost of Service ("ECOS") in this case has been modified to allocate the distribution mains system on a 100% demand and 0% customer basis. ") In addition, in Case 06-G-1185 Direct Testimony of Aric Rider p. 15, Staff proposes a 100% demand allocation

[144] *See e.g.*, Cases 09-G -0718, Direct Testimony of the Embedded Cost of Service Panel for the (New York State Electric & Gas Corporation for Electric Service) 36 (filed September 17, 2009) (noting "Distribution Mains is classified as entirely Demand-related consistent with the Company's last filing and allocated to service classes based on a design day allocator.")

[145] UIU Gas Rate Panel Testimony on the JP at 30 "The Company's approach is not in any way tied to an analysis the number of customers served by the system, nor is it based upon a "clean slate" engineering analysis of what it would cost to build a "minimum size" system under today's conditions."

UIU recommends that the Commission modify the JP's allocation of electric and gas revenues to provide more equitable treatment of small customers. Especially in light of their shortcomings, the company's ECOS studies should not form the sole basis of revenue allocations in these cases. A broader perspective supports mitigating rate impacts on lower-use customers. However, we urge the Commission to give significant weight to the ECOS studies submitted by UIU and our recommendations concerning the appropriate allocation of the AMI-related portion of the incremental revenue requirements. Please see Exhibit___(UERP-JP-7) Schedules 1-5 and Exhibit___(UGRP—JP-7)[146] . UIU's ECOS study results, the evidence concerning the AMI-related portion of the revenue requirement, the application of other revenue-allocation considerations, and Commission precedent suggest the JP revenue allocation is heavily biased against small customers. In particular, the Commission should reduce the deficiency allocated to residential customers in both electric and gas systems, and assign those customers a rate increase no greater than the system average.

II. The Joint Proposal Does Not Satisfy the Commission's Settlement Guidelines.

In addition to considering whether the Joint Proposal is in the public interest, the Commission's Settlement Guidelines provide that in determining whether to approve a Joint Proposal, the Commission should consider:

> (1) the settlement's consistency with law and with the regulatory, economic, social, and environmental policies of the Commission and the State; (2) whether the result compares favorably with the likely result of full litigation and is within the range of reasonable outcomes; (3) whether the settlement strikes a fair balance among the interests of ratepayers and investors and the long-term soundness of the utility; (4) the existence of a rational basis for decision; (5) the completeness of the record; and (6) whether the settlement is contested.[147]

The JP fails to satisfy these six factors with respect to revenue allocation, and the Commission should therefore modify those aspects of the JP.

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[146] See Exhibit___(UGRP—JP-7) at PDF pages 19, 34, 49, 64, 79, and 94.
[147] *See* Case 92-M-0138 *supra*, Opinion 92-2 at 30.

1) *The JP Is Not Consistent with the Regulatory, Economic, Social, and Environmental Policies of the Commission and the State.*

The JP's revenue allocations would ignore or contravene several important Commission and/or State policy objectives.

First, as discussed in Parts (I)(B) and (C) above, the JP's revenue allocations would be based solely on ECOS studies that improperly shift apparent cost responsibility onto small customers. Because these ECOS studies lack bases in theory of fact, their acceptance in these cases would be inconsistent with the Commission's duty to set just and reasonable rates.[148]

Second, as discussed in Part (I)(A), the JP's revenue allocations would ignore the Commission's policy of ensuring rate affordability.[149] By imposing above-average rate increases on the Company's residential customers, the JP would exacerbate the unaffordability crisis already faced by those customers. This is particularly severe with respect to impacts on gas SC1 customers, which under the JP, would receive nearly **double** the rate increase of other firm customer classes in Rate Year 1.[150] The JP disregards the growing inability of the Company's residential customers (including non-low-income customers) to afford their utility bills, and therefore is not consistent with sound economic or social policy.

Third, the Commission's acceptance of the ECOS studies embodied in this JP would harm its policy efforts to achieve environmentally- and socially-progressive rate design. As discussed in Parts (I)(B) and (C) above, the Company's ECOS studies would classify a greater proportion of distribution costs as "customer-related." The proportion classified as "demand-related" would correspondingly decrease. This would make it appear as if the portion of embedded costs to be recovered through volumetric delivery rates should also decrease, and that such costs should instead be recovered through customer-related (i.e., fixed) charges. For example, see UIU Electric Rate Panel Testimony on the JP at 16-23, which compares the disparate fixed-cost implications of the Company's and UIU's electric ECOS methodologies.

[148] Pub. Serv. L. 65

[149] Case 14-M-0565, *Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers*, Order Adopting Low Income Program Modifications and Directing Utility Filings 7-8 (issued May 20, 2016) (noting "The Commission's policy to maintain universal, affordable service is a critical driver of the REV initiative… The Commission therefore adopts a policy that an energy burden at or below 6% of household income shall be the target level for all low income customers.")

[150] See Exhibit__(UGRP-JP-2) Schedule 1 Page 2 of 4 which shows for Rate Year 1 the overall rate increase for SC-1 gas customers is 5.44% which is nearly double the 3.08% system average increase.

Higher fixed charges are undesirable for a variety of policy reasons – they reduce conservation incentives, send inappropriate price signals, and impose regressive cost burdens on poorer customers – all of which run contrary to State policy objectives.[151] Except for gas SC1 customers, the JP would not increase fixed customer charges during this rate plan. But to endorse the Company's ECOS methodology here would set up significant increases in fixed charges in future rate cases.

Fourth, the JP's treatment of AMI costs is contrary to the objectives of REV. The JP's proposal to recover the costs of AMI as if it were a traditional utility program would "ignore changing circumstances and set policies based solely on the rear view mirror."[152] As discussed in Part (I)(A)(XXX) above, the same policy objectives that led the Commission to approve AMI – namely, AMI's projected benefits and ability to advance REV – should also bear on the recovery of AMI costs. By failing to take AMI's projected benefits into account, this aspect of the JP is inconsistent with REV.

2) *The JP's Revenue Allocations Do Not Compare Favorably with the Likely Result of Full Litigation.*

With very few exceptions, the JP's revenue allocations would track the Company's proposed approaches in its initial rate filing.[153] This does not mean, however, that the Commission would be likely to approve such approaches in a fully-litigated proceeding. The opposite is the case: the serious flaws of the Company's ECOS studies, as described in detail in Part (I)(B) and (C) above, would not survive scrutiny in a litigated case. Even notwithstanding those studies' defects, precedent in past litigated Con Edison rate cases suggests that the Commission is not inclined to apply the JP's approach to allocate revenues.[154]

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[151] See REV Track Two Order at 10 noting "(w)ith this direction we begin a new turn toward a modernized utility business model, developing earnings opportunities for utilities that are aligned with consumer value and with a more efficient and resilient distributed low-carbon electric system. More effective value signals to provide incentive and reward for customers to manage their bills and usage will be essential."
[152] REV Track Two Order at 36.
[153] One such exception is the significant discount the JP would give to non-firm gas customer in SC12 Rate II and SC9 Rate (c) (Off-Peak Firm) compared to the Company's initial filing. The Company had recommended that these customers' rates increase to 11.5 cents per therm (for one, two, and three terms of service). *See* Company Gas Rate Panel prefiled Direct Testimony at 47. The JP cuts that increase to 0.00, 0.25, and 0.50 cents per respective rate year. JP at70. This significantly increases the gas revenues that must instead be recovered from firm customers, such as SC1. *See* UGRP Direct Testimony on the JP at 87-90.
[154] *See* Part (I)(A)(1) *supra*.

Furthermore, with respect to gas revenues and rates, the JP's signatories nearly failed to offer even a superficial rebuttal of UIU's litigation position. The Company, for example, made no effort to defend its gas ECOS study in prefiled testimony. The Company's Gas Rates Panel barely addressed the allocation of distribution mains at all in prefiled direct testimony,[155] and not at all in rebuttal testimony (it offered none). Only the City of New York submitted any prefiled testimony disagreeing with UIU's gas ECOS and revenue allocation proposals. The relative strength of parties' litigation positions – and the likely outcome of a fully-litigated proceeding – thus favored UIU from the outset of the case.[156]

Proponents of the JP's revenue allocations may argue that the number of parties supporting the JP's revenue allocations outnumber those parties who oppose them, which would have favored the proponents' chances of succeeding on these issues were the case to have been fully litigated. This argument would fail for several reasons. First, the number of parties does not correspond to the factual or legal merit of their shared position. Second, many proponents share overlapping – or identical – interests with respect to revenue allocation. One such overlapping interest is the interest of large energy consumers, who make up a minority of the Company's ratepayers. The convergence of revenue-allocation interests among JP proponents undermines the implication that they are "correct" in proportion to their numbers.

3) *The JP's Revenue Allocations Do Not Strike a Fair Balance Among the Interests of Ratepayers.*

The JP reflects a one-sided approach to revenue allocations that favors a select group of larger customers at the expense of all other customers. The many ways in which the Company's revenue allocation proposals are unfair to smaller customers have been demonstrated at length above and need not be repeated here. Furthermore, as noted above, the JP only deviates from the Company's proposed revenue allocation methodologies to grant **additional** concessions to larger customers (and further harm other customers as a result). It is telling that neither party that represents smaller-customer interests signed the JP – the JP simply does not reflect those interests.

155 The Company's Gas Rates Panel mentioned the treatment of distribution mains in its gas ECOS study in prefiled Exhibit__(GRP-1) at 6. The allocation of distribution mains is not mentioned in the Panel's prefiled direct testimony.

156 Similarly, no party offered prefiled testimony disputing the presence of an unaffordability crisis among the Company's residential customers, as described in the prefiled Direct Testimony of William Yates.

UIU recognizes that revenue allocation will often be contentious in rate cases. It is a zero-sum issue – revenues shifted away from one group of customers must be assigned to some other group(s) of customers. Therefore, in order to resolve rate cases through settlement, all parties with revenue-allocation interests must be willing to make concessions. UIU participated actively in the settlement discussions that resulted in this JP; unfortunately, the JP does not reflect any compromise on matters of revenue allocation. It would instead make a bad allocation even worse, and therefore the Commission should not approve it without modification.

4) The JP's Revenue Allocations Lack a Rational Basis.

As discussed at length in Part (I), the JP's revenue allocations are based entirely on ECOS studies that suffer from critical flaws. These ECOS studies are not grounded in fact, and therefore do not provide a rational basis for the JP's revenue allocations.

5) Pending Submission of Sworn Testimony at an Evidentiary Hearing, the Record is Incomplete.

The factual record in this case remains under development, and unless parties file sworn testimony supporting and/or opposing the JP, there are no factual grounds upon which the JP may be approved. Testimony is currently expected to be admitted into the record at the evidentiary hearing on the JP, as provided for under PSL sec. 65 and the Commission's *Notice of Evidentiary Hearing* issued on October 12, 2016. It is UIU's understanding that because a JP has been filed in this case, many proponents of the JP may decline to submit their witnesses' pre-filed testimony, or may submit such testimony only as exhibits. Such testimony submitted as an exhibit serves only as evidence of the position the sponsoring party took when the testimony was pre-filed. It does not stand for any factual proposition, as no witness swears to its accuracy and no party has the opportunity to test its merits through cross-examination. Parties may, however, choose to submit and attest to supplementary testimony on the JP.

Pending the admission of sworn testimony into the record and testing of such at hearing, the record in this case cannot support a ruling on the JP. Furthermore, the evidentiary hearing will not necessarily cure the record's incompleteness. UIU accordingly reserves its rights to submit comments or motions as may be warranted following the hearing on the JP.

6) The JP Is Contested.

This JP is far from a panacea. Several parties (including Signatory Parties) have indicated disagreement with, and/or reserved rights to except to, aspects of the JP. Of those parties that submitted pre-filed testimony concerning ECOS and/or revenue allocation, UIU actively opposes those aspects of the JP, Pace expressly declined to sign onto those portions of the JP,[157] and PULP does not support the JP.

Note that the fact that more parties support than oppose the JP's revenue allocations is not evidence of a meeting of the minds. Rather, as Pace's signature page observes, the JP adopts the Company's ECOS studies "without modification to any of the allocations," indicating that it does not reflect agreement among normally adversarial parties with respect to ECOS or revenue allocation. Indeed, as discussed above, the JP reflects no compromise on this central issue.

CONCLUSION

The allocation of revenues is a central component of a utility's rate plan, and it is one which this Joint Proposal has failed to properly address. The JP would allocate rate increases among the Company's customers according to a scheme that is neither just, reasonable, nor in the public interest. Furthermore, the JP does not satisfy any of the six prongs of applicable test described in the Commission's *Settlement Procedures and Guidelines*. UIU therefore urges the Commission to modify the JP's ECOS and revenue allocation proposals consistent with UIU's recommendations as described herein.

Respectfully submitted,

s/ Michael Zimmerman

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[157] JP, Pace signature page ("For the reasons set forth in its filed testimony, Pace signs onto this Agreement except for, under sections G.1. and H.1., the use of the Company's Electric and Gas Embedded Cost of Service Studies without modification of any of the allocations, especially as to the use of the alternative demand allocator to the demand portion of low-tension distribution plant (the D08 allocator) and the allocation of primary distribution infrastructure costs to the customer cost category.")

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