STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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 Electric Service.
CASE 16-G-0061 –	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 15-E-0050 –	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-0196 –	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.

JOINT PROPOSAL

September 19, 2016

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JOINT PROPOSAL

THIS JOINT PROPOSAL ("Proposal") is made as of the 19th day of September 2016, by and among Consolidated Edison Company of New York, Inc. ("Con Edison" or "Company"), New York State Department of Public Service Staff ("Staff"), New York Power Authority ("NYPA"), the City of New York ("City" or "NYC"), United States General Services Administration, Consumer Power Advocates ("CPA"), New York Energy Consumers Council, Inc. ("NYECC"), the Pace Energy and Climate Center ("Pace"), the Environmental Defense Fund ("EDF"), Acadia Center, Metropolitan Transportation Authority ("MTA"), Time Warner Cable Inc. ("Time Warner"), Community Housing Improvement Program ("CHIP"), Great Eastern Energy, LLC, Digital Energy Corp., Joint Supporters, the E Cubed Company, LLC, Northeast Clean Heat and Power Initiative, Association for Energy Affordability, Inc., Energy Concepts Engineering, PC, Real Estate Board of New York, Natural Resources Defense Fund

("NRDC") and other parties whose signature pages are or will be attached to this Proposal (collectively referred to herein as the "Signatory Parties").

Procedural Setting

Con Edison is operating under an *Order Adopting Terms of Joint Proposal to Extend Electric Rate Plan* ("2015 Rate Order"),[1] that extended the terms of an electric rate plan established by the *Order Approving Electric, Gas and Steam Rate Plans In Accord With Joint Proposal* ("2014 Rate Order").[2] The 2014 Rate Order established, *inter alia*, electric rates effective January 1, 2014 through December 31, 2015, and gas rates effective January 1, 2014 through December 31, 2016 ("2014 Gas & Electric Rate Plan" or "2014 Gas Rate Plan" or "2014 Electric Rate Plan" as applicable in context). The 2014 Rate Order adopted, with modifications, the Joint Proposal submitted by parties to those proceedings on December 31, 2013 ("2013 Joint Proposal"). The 2015 Rate Order established, *inter alia*, electric rates effective January 1, 2016 through December 31, 2016 ("2015 Electric Rate Plan") and adopted the Joint Proposal submitted by parties to those proceedings on April 20, 2015 ("2015 Joint Proposal").

On January 29, 2016, Con Edison filed new tariff leaves and supporting testimony for new rates and charges for electric and gas service to become effective on January 1, 2017, for the 12-month period ending December 31, 2017. In that filing, the Company

[1] Cases 15-E-0050 and 13-E-0030, Consolidated Edison Company of New York, Inc. – Electric Rates, *Order Adopting Terms of Joint Proposal to Extend Electric Rate Plan* (issued and effective June 19, 2015).

[2] Cases 13-E-0030, *et. al.*, Consolidated Edison Company of New York, Inc. – Electric, Gas and Steam Rates, *Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal* (issued and effective February 21, 2014).

also included financial information for the two succeeding 12-month periods in order to facilitate development of multi-year rate plans through settlement discussions in the event parties elected to do so.

Two administrative law judges were appointed to preside over the rate proceedings. Parties engaged in discovery, with the Company responding to over 1,600 formal discovery requests on the filings. A procedural conference was held in New York City on March 2, 2016, which was immediately followed by a technical presentation by the Company on various aspects of the filing.

On March 11, 2016, the presiding administrative law judges issued a *Ruling on Schedule*, providing dates for certain activities in these cases, including the preliminary Company updates, Staff and intervenor testimony, rebuttal testimony and the start of evidentiary hearings.

On March 25, 2016, the Company provided the parties with preliminary revenue requirement updates and supplemental testimony describing the Company's proposal for a pilot for the existing Structure Inspection and Repair programs.[3]

On April 22, 2016, the Company filed supplemental testimony describing the Company's proposed metrics for its Advanced Metering Infrastructure ("AMI") business plan as required by the Commission in its March 17, 2016 AMI Order.[4]

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[3] See Section I and Appendix 15, which, among other things, set forth a pilot for the Underground Inspection Program under the Electric Safety Standards on an eight-year cycle in lieu of the five-year cycle established in Case 04-M-0159.

[4] Case 15-E-0050, Consolidated Edison Company of New York, Inc. – Electric Rates, *Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions* (issued and effective March 17, 2016) ("AMI Order").

On May 27, 2016, fifteen (15) parties filed testimony in response to the Company's filings.[5] On June 17, 2016, the Company filed update and rebuttal testimony, including the Company's formal revenue requirement update. Eight parties also filed rebuttal testimony on June 17, 2016.[6]

By notice dated June 10, 2016, Con Edison notified all parties of the commencement of settlement negotiations on June 23, 2016.[7] Settlement negotiations began on June 23, 2016, and continued on June 30; July 7,[8] 11, 13-14, 18-21, 25-26, and 28; and August 1-4, 9-11, 15-19, 22, 25, and 31; and September 8-9, 13-16, and 19, 2016.

All negotiations were held either in person or via teleconference. All settlement negotiations were subject to the Commission's Settlement Rules, 16 NYCRR §3.9, and appropriate notices for negotiating sessions were provided.

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[5] Parties filing initial testimony were NYC, CHIP, CPA, Staff, EDF, MTA, NYECC, NYPA, Pace, Public Utility Law Project, Inc. ("PULP"), Solar City, Time Warner, Local 1-2 of the Utility Workers Union of America, the Utility Intervention Unit, Division of Consumer Protection, New York State Department of State ("UIU"), and County of Westchester ("Westchester").

[6] Parties filing rebuttal testimony were NYC, CPA, Staff, EDF, MTA, Pace, PULP and UIU.

[7] This notice was filed with the Secretary to the Commission ("Secretary").

[8] On July 8, 2016, the Company filed a letter with the Secretary agreeing to a one-month extension of the statutory suspension period in these proceedings subject to a "make-whole" provision that would keep the Company and its customers in the same position they would have been absent the extension. On August 8, 2016, the Company agreed to a second one-month extension through February 28, 2017. The second extension raised procedural issues under the Commission's policies and regulations related to subsequent rate filings by the Company absent multi-year rate plans in these proceedings. Accordingly, the Company's agreement to a second extension, as set forth in the letter to the Secretary, was conditioned upon the Commission also waiving the limitations regarding selection of the historical test period in its *Statement of Policy on Test Periods in Major Rate Proceedings* and granting a "make-whole" provision for subsequent rate filings.

The parties' negotiations have been successful and have resulted in this Proposal, which is presented to the Commission for its consideration.

Overall Framework

The Signatory Parties have developed a comprehensive set of terms and conditions for three-year rate plans for Con Edison's electric and gas services. These terms and conditions are set forth below and in the attached Appendices. Specifically, this Proposal addresses the following topics:

A. Term

B. Rates and Revenue Levels

C. Computation and Disposition of Earnings

D Capital Expenditures and Net Plant Reconciliation

E. Reconciliations

F. Additional Accounting Provisions

G. Electric Revenue Allocation/Rate Design

H. Gas Revenue Allocation/Rate Design

I. Performance Metrics

J. Additional Electric Provisions

K. Additional Gas Provisions

L. Customer Operations Provisions

M. Advanced Metering Infrastructure

N. Electric and Gas Low Income Programs

O. Studies and Collaboratives

P. Miscellaneous Provisions

A. Term

The Signatory Parties recommend that the Commission adopt three-year electric and gas rate plans for Con Edison as set forth herein, effective as of January 1, 2017, and continuing through December 31, 2019 ("Electric Rate Plan" and "Gas Rate Plan," respectively, and collectively, both plans will be referred to as "Rate Plans").

For the purposes of this Proposal, Rate Year means the 12-month period starting January 1 and ending December 31; Rate Year 1 ("RY1") means the 12-month period starting January 1, 2017, and ending December 31, 2017; Rate Year 2 ("RY2") means the 12-month period starting January 1, 2018, and ending December 31, 2018; and Rate Year 3 ("RY3") means the 12-month period starting January 1, 2019, and ending December 31, 2019.

B. Rates and Revenue Levels

1. Electric

This Proposal recommends changes to the Company's electric delivery service rates and charges, including the fixed component of the Monthly Adjustment Clause ("MAC"), designed to produce an additional $194.554 million in revenues on an annual basis starting in RY1, an additional $155.315 million increase in revenues on an annual basis starting in RY2, and an additional $155.206 million increase in revenues on an annual basis starting in RY3.[9] The RY1 revenues are in addition to the $47.776 million increase in electric delivery service revenues effective January 1, 2017, as established by

[9] If, as a result of Commission action in Case 16-M-0330, the wireless attachment fees that are reflected in Other Operating Revenues are reduced, the Company may seek recovery in that proceeding of the difference between forecasted revenues at current fees and the new lower fees.

the Commission in the 2015 Rate Order, which is effectuated by the expiration of the temporary credit of $47.776 million (in effect during the 2016 Rate Year) on December 31, 2016.[10]

The Signatory Parties propose that the base rate changes and the $47.776 million increase approved by the Commission in the 2015 Rate Order be implemented on a levelized basis, including interest, to provide rate stability over the term of the Electric Rate Plan. The annual levelized revenue changes associated with Transmission and Distribution ("T&D") delivery revenue, the retained generation component of the MAC and purchased power working capital is $199.034 million, in each of RY1, RY2 and RY3.[11] Revenue changes by service class are shown in Appendix 19.

The annual levelized rate changes would result in higher base rates at the end of the three-year term of the Electric Rate Plan than they would otherwise be under a non-levelized approach. Accordingly, if the Company does not file for new rates to be effective January 1, 2020, the Company will make a compliance filing by December 1, 2019 to set rates effective January 1, 2020 at a level that is designed to produce non-

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[10] This Joint Proposal contains provisions designed to implement certain initiatives addressed in the Commission's Reforming the Energy Vision ("REV") proceeding (Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision) and related proceedings that have been established ("REV Initiatives"). Nothing in this Joint Proposal is intended to preclude or limit the Company's right to seek recovery of any costs, expenses, fees, incentives, etc. associated with its implementation of any REV Initiatives (including REV-related proceedings that may be established after the date of this Proposal) that are incremental to costs, expenses, fees, incentives, etc. associated with REV Initiatives that are already addressed by this Joint Proposal.

[11] The levelized rate changes are inclusive of interest on the deferred rate increase calculated at the 2016 Other Customer-Provided Capital Rate of 2.6 percent. The Company will calculate the change in interest for any change in the Other Customer-Provided Capital Rate in future years, and defer the difference for surcharge or credit to customers, as applicable.

competitive delivery base rate revenues on an annual basis that are lower by $44.25 million. The Revenue Decoupling Mechanism ("RDM") target for the Rate Year commencing January 1, 2020 will be reduced by $44.25 million.[12]

The major components of the electric revenue requirements underlying this Proposal are set forth in Appendix 1.[13] These revenue requirements reflect the amortizations of various customer credits and debits on the Company's books of account that have previously been or are projected to be deferred by the Company. The list of deferred customer credits and debits to be applied during the Electric Rate Plan is attached as Appendix 3.

a. Market Supply Charge, Monthly Adjustment Clause and NYPA Surcharge

The Company will continue to recover all prudently-incurred supply and supply-related costs, including, but not limited to, power purchase costs and the embedded costs of retained generation through the Market Supply Charge ("MSC")[14]/Monthly Adjustment Charge ("MAC") mechanism. In addition, the Company will continue to collect certain charges from NYPA through the Statement of Other Charges and Adjustments ("NYPA OTH Statement"), as set forth under Additional Delivery Charges

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[12] The Company will send to Staff and the parties the rates effective January 1, 2020 and RDM targets within thirty (30) days after the Commission order approving this Proposal.

[13] The electric revenue requirements include an adjustment to reflect a finding in the Management and Operations Audit (conducted in Case 14-M-0001) regarding the Company's procurement procedures.

[14] Costs recovered through the MSC will include costs incurred by the Company pursuant to Commission orders in Cases 15-E-0302 and 16-E-0270 related to the Clean Energy Standard (*e.g.*, Zero Emissions Credits ("ZECs") and Renewable Emissions Credits ("RECs")).

and Adjustments in Section H of the Company's Schedule for PASNY Delivery Service, P.S.C. No. 12 – Electricity ("PASNY Tariff").[15]

The following additional charges will be recovered via the MAC and NYPA OTH Statement:[16]

i. incentives earned under Earning Adjustment Mechanisms ("EAMs"), as set forth in section(s) J.1.e, J.2 and M.3;

ii. Electric's share of up to $4 million of costs to undertake a Climate Change Vulnerability Study, as incurred, as set forth in section O.6;

iii. up to $600,000 of costs to undertake a marginal cost study, as incurred, as set forth in section O.2;

iv. costs and incentives related to Non-Wires Alternatives ("NWA"), as set forth in section D.1.c;

v. bill credits issued under the Reliability Credit program, as incurred, as set forth in section G.6.c.iii; and

vi. bill credits issued under the Optional Bill Credit for Export-Only Buyback Customers program, as incurred, as set forth in section G.6.d.iii.

b. Revenue Decoupling Mechanism ("RDM")

The RDM prescribed by the Commission in Cases 07-E-0523, 08-E-0539, 09-E-0428, 13-E-0030 and 15-E-0050, subject to the modifications described in this section and section G.8, will remain in effect unless and until changed by Commission order, except for restating RDM targets for the Rate Year commencing January 1, 2020, if the

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[15] For costs, charges, and credits covered by the MSC/MAC mechanism and NYPA OTH Statement, the Company will continue to recover such costs and charges, and provide such credits, as incurred, by reflecting these charges, costs and/or credits in monthly statements filed pursuant to these mechanisms.

[16] NYPA will be allocated its share of these charges based on the PASNY allocation, as defined in Additional Delivery Charges and Adjustments – Section H of the PASNY Tariff ("PASNY Allocation"). The balance will be recovered from Con Edison customers through the MAC. See Appendix 19.

Company does not file for new base delivery rates to be effective within fifteen (15) days after the expiration of RY3. The restated RDM targets that go into effect January 1, 2020[17] will remain in effect until the next time base delivery rates are changed (*i.e.*, continuation of the RDM mechanism unless and until changed by the Commission is premised upon the RDM targets being reset each time base delivery rates are changed).

Consistent with the RDM mechanism in effect: (i) any interim charges/credits associated with the RDM reconciliations of actual versus targeted revenues for periods commencing on and after January 1, 2017, will become effective on the first day of the month in which they become effective, and (ii) any RDM deferrals will accrue interest as set forth in section F.2 below. The costs of the Low Income Program will be reconciled through the RDM as set forth in section N.[18]

The currently-effective RDM is modified commencing with the effective date of the Electric Rate Plan as follows: the RDM target for NYPA and Kennedy International Airport Cogeneration Partners ("KIAC") will continue to be forecasted based on pure base revenues ("PBR") and the combined monthly RDM under/over collections for NYPA and KIAC will be allocated between NYPA and KIAC based on respective ratios of their individual actual PBR to the total of their aggregate actual PBRs for the month. These allocated monthly over/under collections will be accumulated during each RDM

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[17] As noted in footnote 12, these targets will be provided within 30 days of the Commission order approving this Proposal.

[18] With a change from a rate discount to a customer credit for the Low Income Program in RY2 and RY3, the RDM targets for SC1 customers will be increased in RY2 and RY3 because the targets will no longer reflect the low income discounts.

reconciliation period and used to calculate the separate RDM Adjustments to be assessed to NYPA and KIAC.

During the course of this Rate Plan, the Company through a tariff filing, or any party by petition to the Commission, may propose an adjustment to the currently-effective RDM targets if the Company or such party, as applicable, believes that circumstances are resulting in anomalous results unduly impacting certain customers. Any proposed changes to RDM targets are to be revenue and earnings neutral to the Company.

c. PJM OATT Charges

The Company will continue to recover all rates and charges associated with the 1000 MW firm transmission service provided pursuant to PJM Interconnection L.L.C.'s ("PJM") Open Access Transmission Tariff ("OATT"). These costs are recovered from Con Edison customers through the MAC and from NYPA through a separate surcharge on the NYPA OTH Statement. The allocation of the monthly PJM OATT rates and charges between Con Edison customers and NYPA shall continue to be based on the percentage allocation of T&D revenues included in the revenue allocation for each Rate Year, as shown in Table 4 of Appendix 19.

Pursuant to the PJM tariff, Con Edison notified PJM in April 2016 that Con Edison was electing not to continue this service beyond April 30, 2017.

NYPA's allocation will continue to be limited to $4.6 million in any full Rate Year. If PJM OATT rates and charges are incurred for less than a full Rate Year, then NYPA's allocation shall be limited to $4.6 million multiplied by the number of months in the partial year divided by twelve months. For example, if the Company receives a final bill from PJM in May 2017 for deliveries through April 30, 2017 (the contract termination date), the limitation in RY1 would be $1.533 million for the NYPA class.

Pursuant to the PJM Tariff, PJM has up to two years to process a billing adjustment for any given month, and FERC can also require retroactive billing adjustments beyond that window in some cases. The Company will process any retroactive PJM billing adjustments through the MAC and, when not in excess of the applicable cap described above, through the NYPA OTH Statement.

Should the allocation to NYPA exceed the applicable limitation in any Rate Year, any excess in that year will instead be collected from Con Edison customers through the MAC.

d. Other Charges

The Signatory Parties agree that whenever the Company is or will be subject to governmental or regional transmission organization ("RTO") transmission and/or generation-related charges, costs or credits (*e.g.*, FERC, NYISO, PJM, EPA[19]) not already listed in or otherwise covered by the then-effective MAC/MSC tariff language, the Company may make a tariff filing with the Commission providing for recovery of such charges/costs, or application of these credits, through the MAC/MSC mechanism and/or comparable adjustment mechanism. The proposed tariff amendment may include charges/costs/credits applicable to the period prior to the effective date of the tariff amendment.

[19] Federal Energy Regulatory Commission ("FERC"), New York Independent System Operator, Inc. ("NYISO"), Environmental Protection Agency ("EPA")

2. **Gas**

This Proposal recommends changes to the Company's retail gas sales and gas transportation service rates and charges, designed to produce a $5.373 million decrease in revenues on an annual basis starting in RY1, a $92.337 million increase in revenues on an annual basis starting in RY2, and an additional $89.453 million increase in revenues on an annual basis starting in RY3.[20] The revenue decrease in RY1 is offset by the $40.856 million increase in gas delivery service revenues effective January 1, 2017, as established by the Commission in the 2014 Rate Order, which is effectuated by the expiration of the temporary credit of $40.856 million (in effect during the 2016 Rate Year) on December 31, 2016.[21]

The major components of the gas revenue requirements underlying this Proposal are set forth in Appendix 2.[22] These revenue requirements reflect the amortizations of various customer credits and debits on the Company's books of account that have previously been or are projected to be deferred by the Company. The list of deferred customer credits and debits to be applied during the Gas Rate Plan is attached as Appendix 3.

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[20] Unless specifically stated otherwise in this Proposal, the terms "customers" and "base rate" with respect to gas service apply to the Company's firm gas customers, excluding interruptible gas customers, CNG, bypass and power generation customers served under SC 9 and off-peak firm customers.

[21] Cases 14-G-0201 and 14-G-0212 are pending. No adjustments to gas delivery rates were made to reflect matters at issue in these proceedings. Nothing in this Joint Proposal is intended to preclude an adjustment to gas delivery rates to implement Commission determinations in these proceedings.

[22] The gas revenue requirements include an adjustment to reflect a finding in the Management and Operations Audit (conducted in Case 14-M-0001) regarding the Company's procurement procedures, plus an annual one (1) percent labor-productivity adjustment applicable only to gas operations labor in addition to the traditional one-percent labor productivity adjustment.

a. Revenue Per Customer Mechanism

The RDM established for gas service in Cases 06-G-1332, 09-G-0795, and 13-G-0031,[23] subject to the modifications described in this section, will remain in effect unless and until changed by Commission order.

Delivery revenues from service provided to the Company's firm customers will be subject to reconciliation pursuant to the RPC Mechanism set forth in Appendix 5. The currently effective RPC Mechanism is modified to change the RDM adjustment period from 11 months to 12 months commencing with the first RDM reconciliation following the effective date of the Gas Rate Plan (*i.e.*, the reconciliation for 2016 to be effective for the period February 2017 through January 2018). Details of the RPC Mechanism are set forth in Appendix 5.

b. Monthly Rate Adjustment/Gas Cost Factor

The Company will recover all supply and supply-related costs through the Monthly Rate Adjustment ("MRA")/Gas Cost Factor ("GCF") mechanisms.[24]

(i) Revenue Neutral Changes to MRA/GCF

(1) The customer share of balancing charge revenues included as part of Non-Firm Revenues (see section B.2.c), which are currently credited through the GCF, will be credited through the MRA once the imputation of $65 million attributable Non-Firm Revenues is exceeded.

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[23] The RDM established for gas customers is a Revenue Per Customer ("RPC") Mechanism.

[24] The Company recovers various costs and charges, and provides certain credits, through the GCF, MRA and Weighted Average Cost of Capacity ("WACOC"). For costs, charges, and credits covered by these adjustment mechanisms, the Company will continue to recover such costs and charges, and provide such credits, as incurred, by reflecting these charges, costs and/or credits in monthly statements filed pursuant to these adjustment mechanisms.

(2) Gas Supplier Refunds,[25] currently credited to firm sales customers through the Gas Cost Factor, will be moved to the MRA consistent with the treatment of Gas Supplier Refunds credited to firm transportation customers.

(3) Nothing in this Gas Rate Plan precludes the Company from submitting a tariff filing to implement additional revenue neutral changes as between and among the GCF, MRA and WACOC during the term of the Gas Rate Plan.[26]

(ii) Additions to the MRA

The following new categories of costs will be included in the MRA:

(1) Safety and Reliability Surcharge Mechanism

The MRA will include a Safety and Reliability Surcharge Mechanism ("SRSM") as a component at the same unit rate for all classes subject to the MRA.

The SRSM will recover the incremental carrying costs associated with incremental capital expenditures for leak prone pipe replacement (*i.e.,* when both the mileage for mains and associated services replaced and the associated cost of replacement on an annual basis exceed the mileage and associated cost of replacement amounts reflected in base rates). Carrying costs for incremental capital expenditures will be capped at a level reflecting the lesser of the target incremental cost for each location or the actual cost per mile (determined on a geographic basis) times the number of miles.[27] The SRSM will also recover any incremental O&M expenses associated with the incremental capital expenditures for leak prone pipe replacement above applicable targets, to the extent that the annual rate allowance for such work is exceeded.

The SRSM will also recover O&M expenses associated with lowering the Company's leak backlog below the applicable target, to the extent that the annual rate allowance for leak repairs is exceeded.

[25] Gas Supplier Refunds in this context pertain to refunds for gas pipeline and/or storage reservation charges.

[26] Such revenue neutral changes may include, for example, changes to the allocation of credits between and among full service customers, firm transportation customers and SC 20 marketers.

[27] The target incremental cost for each location is specified in Appendix 6.

Recovery will be capped at the lesser of the total incremental cost or $5,100 per actual leak repaired below the applicable target.

Recovery under the SRSM for the incremental costs described above will commence on March 1 following the applicable Rate Year (*e.g.*, eligible incremental costs incurred in RY1 to be recovered beginning on March 1, 2018). Appendix 6 describes how the SRSM is calculated and collected. The Company will submit the details of the calculations of any costs recovered through the SRSM, as part of the reporting requirements set forth in Appendix 22.

(2) Gate Station Work on Pipeline-Owned Facilities

The Company has requested Algonquin Gas Transmission Pipeline ("Algonquin") and Tennessee Gas Pipeline Company, LLC ("Tennessee") to upgrade and/or modify their interstate pipeline facilities at the Peekskill and Rye gate stations, respectively, in order to enhance delivery services to the Company. The Company is and/or will be obligated to reimburse the pipelines for these project costs.[28] The Company will recover through the MRA up to $9 million of payments made to Algonquin for work at the Peekskill gate station and up to $9 million of payments made to Tennessee for work at the Rye gate station. Recovery of payments made to Algonquin and Tennessee will commence after each project's in-service date, and shall include interest at the Commission's Other Customer Capital Rate. Any amounts incurred over $9 million for either or both of these projects shall be deferred and addressed in the Company's next base rate filing.

(3) incentives earned under the AMI EAM as set forth in section M.3.

(4) Gas' share of up to $4 million of costs to undertake a Climate Change Vulnerability Study, as incurred, in section O.6.

[28] The Company has executed an agreement with Algonquin for the work at the Peekskill gate station. The Company does not yet have an executed agreement with Tennessee for the work at the Rye gate station.

c. Non-Firm Revenues

The revenue requirement for each Rate Year reflects a base rate revenue imputation of $65 million attributable to Non-Firm Revenues. For each Rate Year, the following revenues constitute "Non-Firm Revenues:"

1. Net base revenues[29] derived from

(i) Customers receiving interruptible service under SC 12 Rate 1 and SC 9 Rates B and D; and

(ii) Power generation customers[30] receiving interruptible or off-peak firm service, including off-peak firm service under SC 9 Rate D(2) or special negotiated contract; the New York Power Authority (in excess of $3.1 million per Rate Year, which is the level reflected in base rates); interruptible or off-peak firm service to Company-owned power generation steam-electric plants; and existing, new, and divested power generation facilities owned by third parties pursuant to, for example, SC 9 Rate D(1); and

2. Net revenues derived from the use of interstate pipeline capacity for capacity releases:[31] for or by customers taking service under off-peak firm SC 12 Rate 2; for or by interruptible or off-peak firm customers taking service under negotiated bypass SC 9 Rate D (1); for SC 19 and bundled sales; and other off-system transactions (*e.g.*, gas supplied to the Company's steam/electric plants); and

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[29] Net base revenues mean total revenues less the following, as applicable: taxes, actual cost of gas (reflecting, for example, hedging costs and gas supplier take-or-pay charges), cash-out charges and credits, and any revenues included in total revenues related to reimbursements for facility costs associated with providing service, including metering and communication equipment, service pipes and lines, service connections, main extensions, measuring and regulating equipment and system reinforcements and other facilities as necessary to render service.

[30] For the purposes of this section B.2.c, power generation customers do not include cogeneration or other customers taking off-peak firm service under SC 12 Rate 2 or SC 9 Rate C.

[31] Net capacity release revenues means the credits afforded the Company from releasing capacity to third parties excluding (i) capacity release revenues applicable to capacity releases to firm customers and/or ESCOs serving firm customers under the Company's capacity release program that became effective November 1, 2001 and any amended, extended, or superseding programs ("Capacity Release Service Program"), and (ii) the demand charges recovered through the Winter Bundled Sales Service ("WBSS").

> 3. Gas balancing revenues derived from gas balancing services provided to SC 9 and 12 interruptible and off-peak firm customers, CNG, bypass and power generation customers, and SC 20 marketers serving SC 9 transportation customers.[32]

The Company will retain 100 percent of the first $65 million of Non-Firm Revenues achieved during each Rate Year of the Gas Rate Plan.

If Non-Firm Revenues are less than $65 million in any Rate Year, the Company will (i) defer on its books of account for future recovery from customers, with interest, the amount by which Non-Firm Revenues are less than $65 million and (ii) surcharge firm customers that amount in the subsequent Rate Year (*i.e.*, for 100 percent of the difference between $65 million and the amount actually achieved).

For Non-Firm Revenues above $65 million in any Rate Year, firm customers will be credited with 85 percent of the amount above $65 million beginning in the subsequent month.

The Company may implement a surcharge or credit to customers at the commencement of any Rate Year for a projected variation in revenues from the target level of revenues (*i.e.*, $65 million), up to $25 million, in order to minimize the annual reconciliation of actual revenues as compared to target revenues in any Rate Year. At least two weeks prior to the Company's implementing such a surcharge or credit, the Company will provide Staff work papers underlying such surcharge or credit in order to afford Staff an opportunity to raise with the Company any concerns that Staff has with

[32] Gas balancing revenues will not include charges for the new DDS service, which is pending Commission approval in Case 16-G-0406.

the size of the surcharge or credit.[33] Any such surcharge or credit will be implemented over a 12-month period.

d. Lost and Unaccounted For Gas

The calculation for Lost and Unaccounted for Gas established by the 2010 Gas Rate Order, as modified effective January 1, 2014, continues for the term of this Gas Rate Plan, as set forth in this section.

During RY1, RY2 and RY3, Line Loss Factor ("LLF") will be calculated in three steps as follows:

1. Losses = metered supplies into the system (Total Pipeline Receipts + LNG Withdrawals + Total Receipts from New York Facilities) less metered deliveries to customers (Retail Sales and Transportation Deliveries + Deliveries to Generation + Gas Used for Company Purposes and CNG + LNG Injections + Total Heater & Compressor Consumption + Total Deliveries to New York Facilities).

2. Adjusted Line Loss = Losses minus the contribution to the system line loss from generators.[34]

3. LLF = Adjusted Line Loss divided by Citygate receipts adjusted for generation.

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[33] The Company will provide notice to interested parties of such a surcharge or credit.

[34] The gas revenue requirements continue to reflect New York Facilities revenues and costs in base delivery rates. The New York Facilities members are currently evaluating an amendment to their cost sharing responsibilities. Following execution of a new or amended New York Facilities Agreement, the Company will reconcile its actual New York Facilities costs and revenues against the amount included in base rates through the MRA and/or LAUF, as applicable, until base gas delivery rates are reset. Any changes will be revenue neutral and earnings neutral to the Company.

In order to determine if the Company receives an incentive/pays a penalty for the annual LLF achieved commencing with the 12-month period ending August 31, 2017, the Company will compare the LLF level for such period to a target derived from the five-year rolling average of LLFs from the five previous September 1 through August 31 periods. If the LLF is within two standard deviations of the rolling prior five-year average target, no incentive/penalty will arise. If the LLF is greater than two but less than four standard deviations above the rolling prior five-year average, then a penalty will be assessed according to the tariff. If the LLF is between two and four standard deviations below the rolling prior five-year average, then an incentive will be provided to the Company according to the tariff. For RY1, the rolling prior five-year average level will be determined in October 2016, once the 12-month period ending August 2016 is completed, and will be filed with the Secretary at that time. The LLF for the 12-month period ending August 31, 2017 will be compared to the target (*i.e.*, five-year average level as of August 2016). For RY2 and RY3, the target will be reset each year based on the average of the preceding five (5) years' LLFs.

The Factor of Adjustment ("FOA") applicable to each Rate Year will be used to determine the monthly Gas Cost Factor applicable to sales customers and the amount of gas to be retained by the Company from SC 9 transportation quantities as an allowance for losses. The FOA is derived from the average of the preceding five (5) years' LLFs and is reset for each Rate Year. The FOA applicable to RY1 will be also be determined in October 2016, and will be included in the five-year average LLF filing with the Secretary.

Appendix 7 provides a sample calculation of the determination of the potential benefit or cost to the Company.

e. Transco Heater/Odorization

Under the 2014 Gas Rate Plan, the Commission approved Company plans to contract with Transcontinental Gas Pipe Line ("Transco") to construct, own and operate new natural gas heaters, including modified piping, and supplemental odorization equipment at Transco's Meadowlands facility ("Transco heater/odorization project"). The 2014 Gas Rate Plan contemplated the Company recovering the costs of this project as FERC-approved charges through the GCF, MRA and/or WACOC. Transco has since advised the Company that it does not intend to seek FERC approval to establish a Con Edison-specific surcharge for these costs and instead seeks direct reimbursement of these costs from the Company. The Transco heater/odorization project is still the preferred alternative for addressing these needs. Consequently, the Company will reimburse Transco for these costs, which Transco is incurring in order to address the Company's need for natural gas heaters and supplemental odorization equipment. The Company will defer the cost as a regulatory asset and recover the cost over 15 years.[35] Recovery begins January 1, 2017, as reflected in Appendix 3.

f. Other Charges

The Signatory Parties agree that whenever the Company is or will be subject to FERC-approved charges, costs or credits not already listed in or otherwise covered by the then-effective tariff language for these adjustment mechanisms, the Company will make a

[35] The regulatory asset for this project is $32.1 million.

tariff filing with the Commission to provide for recovery of these costs or charges, or application of these credits, through the GCF, MRA and/or WACOC. The proposed tariff amendment may include charges/costs/credits applicable to the period prior to the effective date of the tariff amendment.

g. Oil-to-Gas Conversions

(i) Oil to Gas Incentive Program

The Company's program of providing financial incentives to residential and commercial customers to encourage their conversion from oil use to gas use shall continue to be funded through an MRA surcharge up to a maximum of $1.465 million per Rate Year. The gas sales forecast and RDM targets underlying the gas rates in this Proposal reflect sales projected to result from this program.

The Company will submit a report to the Secretary within sixty (60) days of the end of each of RY1, RY2 and RY3, on activities under this program during the prior Rate Year, including program descriptions and the amounts of incentives committed and/or disbursed, and the number of customers and estimated sales in the aggregate by service classification. The Company will maintain a list of recipients who receive $500 or more for inspection by Staff.

(ii) Oil to Gas Conversion and Area Growth

NYC promulgated rules in 2011 requiring buildings in New York City that need a boiler operation permit to operate their heating systems, to phase out the use of heavy heating oil, known as ‘No. 6” and “No. 4” fuel oil by 2015 and 2030, respectively. NYC’s rules allow such buildings to switch to No. 2 heating oil, biodiesel, or natural gas. NYC itself maintains a fuel neutral stance and provides, through its Clean Heat marketing arm, guidance on the selection of fuels to building owners, including the use of No. 2

heating oil or biodiesel as alternates to natural gas. The County of Westchester passed similar legislation in June 2016.

The Company will perform the following activities to foster and further facilitate oil-to-gas conversions.

1. The Company will continue to provide milestones/timelines to each applicant. These milestones are available in general format on the Web portal and specifically available to each applicant by logging into the Web portal ("Project Center") and tracking their respective case, as well as through various pieces of correspondence sent to each applicant that provide further detail unique to their case.
2. The Company will continue to file with the Secretary, on a quarterly basis, a report on aggregated data with respect to conversion activity. The report will redact any customer-identifying data and will include the number of work requests received, the number of cases that are deemed "active" or "progressing," services installed and awaiting customer completion and completed conversions. The report will include only conversion applications within the following counties: New York, Bronx, Queens and Westchester. The Company will report the fuel type as the type of fuel indicated as being used on the premises from the report issued by the New York City Department of Environmental Protection and shared with the Company in April 2011.
3. The Company will continue to provide maps, with appropriate disclaimers, of all the anticipated Area Growth Zones for the duration of the program (which

is expected to conclude no later than 2020 for NYC) and will continue to make it available on its website. The Company already has a map of the Area Growth Zones for RY1 available on www.coned.com/gasconversions. The disclaimers will explain that the Area Growth Zones are subject to change and that maps (other than for the immediately following Rate Year) should not be considered certain and will likely be subject to future amendments. The Company accepts no responsibility for the purchase of gas-burning equipment or work performed in the building by the customer based on the issuance of these projected zones, and maps are not a guarantee of service installation in the respective zones.

4. The Company will review and grant requests in writing by applicants made before the expiration of the 60-day period, for an additional 30 days, or less if requested, to complete the customer commitment portion of the conversion upon the applicant explaining the need for additional time. The Company reserves the right to reject requests that would adversely impact its operations or other customers.

5. Additional detail of the breakdown of costs will be provided to applicants receiving an order of magnitude cost to connect to the Company's gas system. Specifically, the Company will provide details of the footage of main/service required to serve the customer.

The Company will also report on a quarterly basis, to the Secretary and NYC, any permitting issues it encounters that affect the installation of regulators, mains or services to serve the population of customers seeking to convert from heating oil to natural gas.

These permits may be issued by any agency of the City, but will typically include: NYC Department of Transportation, NYC Department of Buildings, NYC Department of Design and Construction, NYC School Construction Authority, NYC Department of Parks and Recreation. Customer identifying data shall be redacted.

C. Computation and Disposition of Earnings

Following each of RY1, RY2 and RY3, Con Edison will compute, separately, the earned rate of return on common equity for its electric and gas businesses for the preceding Rate Year. The Company will file with the Secretary these computations of earnings no later than sixty (60) days after the end of each Rate Year.

1. Earnings Sharing Threshold

If the level of earned common equity return for any Rate Year exceeds 9.5 percent ("Earnings Sharing Threshold"), the amount in excess of the Earnings Sharing Threshold will be deemed "shared earnings" for the purposes of this Proposal. One-half of the revenue requirement equivalent of any shared earnings above 9.5 percent but less than 10.0 percent will be deferred for the benefit of customers and the remaining one-half of any such shared earnings will be retained by the Company; seventy-five (75) percent of the revenue requirement equivalent of any shared earnings equal to or in excess of 10.0 percent but less than 10.5 percent will be deferred for the benefit of customers and the remaining twenty-five (25) percent of any shared earnings will be retained by the Company; and ninety (90) percent of the revenue requirement equivalent of any shared earnings equal to or in excess of 10.5 percent will be deferred for the benefit of customers and the remaining ten (10) percent of any shared earnings will be retained by the Company.

2. <u>Earnings Calculation Method</u>

For each Rate Year, for purposes of determining whether the Company has earnings above the Earnings Sharing Threshold:

a. The calculation of return on common equity capital will be "per books," that is, computed from the Company's books of account for each Rate Year, excluding the effects of (i) Company incentives and performance-based revenue adjustments, including incentives for Non-Wires Alternatives ("NWAs") and under Earnings Adjustment Mechanisms; (ii) the Company's share of property tax refunds earned during the applicable Rate Year; (iii) any other Commission-approved ratemaking incentives and revenue adjustments in effect during the applicable Rate Year; and (iv) the amount of expense for awards under the Company's Executive Incentive Program.

b. Such earnings computations will reflect the lesser of: (i) an equity ratio equal to fifty (50) percent, or (ii) Con Edison's actual average common equity ratio. Con Edison's actual common equity ratio will exclude all components related to "other comprehensive income" that may be required by generally accepted accounting principles; such charges are recognized for financial accounting reporting purposes but are not recognized or realized for ratemaking purposes.

c. If the Company does not file for new base delivery rates to take effect within fifteen (15) days after the expiration of RY3, the Earnings Sharing Threshold and the other earnings sharing thresholds will continue until base delivery rates are reset by the Commission. Such calculation will be performed on an annual basis in the same manner as set forth above. Revenue targets (*e.g.*, revenue per customer factors for gas) and trued-up expenses contained in Appendices 4, 5, 8, 9 and 10 will be based on RY3 levels for electric and gas.

d. The actual average rate base for any stay-out period less than 12 months will be adjusted by an operating income ratio factor. This adjustment to rate base is intended to align operating income to the level of rate base that generated that income. This factor will be calculated as the ratio of operating income during the same partial year period in the previous Rate Year to the total operating income for that Rate Year. This methodology is illustrated in Appendix 12.

3. <u>Disposition of Shared Earnings</u>

For earnings above the related Earnings Sharing Threshold in any Rate Year, the Company will apply fifty (50) percent of its share and the full amount of the customers' share of earnings above the sharing threshold that would otherwise be deferred for the benefit of customers under this Proposal, to reduce respective under-collections of Site Investigation and Remediation costs ("SIR Costs") deferred in the Rate Year (increases to the regulatory asset account less expenditures charged to the liability account).

In the event the amount of shared earnings available to reduce respective deferred under-collections of SIR Costs exceeds the amount of such deferred under-collections, the Company will apply the amount of the excess to reduce other interest bearing deferred costs accumulated in the Rate Year (net change in the other regulatory asset and liability accounts). The Company's annual earnings report will include the amount, if any, of deferred undercollections of SIR Costs written down with the Company's and the customers' respective shares of earnings above the earnings sharing thresholds. If applicable, the Company's annual earnings report will identify any other deferred costs reduced by application of shared earnings and the amount of shared earnings used for that purpose.

D. Capital Expenditures and Net Plant Reconciliation

1. Electric

a. Net Plant Reconciliation

The electric revenue requirements for RY1, RY2 and RY3 reflect the average net electric plant balances set forth in Appendix 8. The average net electric plant balances include T&D, Municipal Infrastructure Support, Distributed System Implementation Plan ("DSIP"), Electric Production and Shared Services allocable to Electric (collectively, "Average Electric Plant In Service Balances").[36] These balances do not reflect net plant balances for AMI, which are addressed in section D.3.

The Average Electric Plant In Service Balances reflect a level of capital expenditures supported by various capital programs and projects. The Company, however, has the flexibility over the term of the Electric Rate Plan to modify the list, priority, nature and scope of its capital programs and projects.

The Company will defer for the benefit of customers the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 8) of the amount by which the Company's actual expenditures for electric capital programs and projects result in actual average net plant (excluding removal costs) that is less than the

[36] DSIP capital costs are those costs shown in Appendix 22. REV Demo Project and BQDM Program costs are not included in these DSIP capital costs and in calculating the Average Electric Plant In Service Balances.

amount included in the Average Electric Plant In Service Balances (excluding removal costs), as set forth in Appendix 8, for RY1, RY2 and RY3.[37]

The reconciliations to Average Electric Plant In Service Balances for RY1, RY2 and RY3 will be cumulative; that is, a revenue requirement impact deferral will be required under this provision only if the actual average net plant balances for the 36-month period covered by the Electric Rate Plan is below the amount included in the Average Electric Plant In Service Balances over such period as shown on Appendix 8.

b. Reporting Requirements

The Company will provide annual reports relating to capital expenditures in the manner set forth in Appendix 22.

c. Non-Wires Alternative Adjustment Mechanism

The costs incurred by the Company for implementation of NWAs during the Electric Rate Plan, including the overall pre-tax rate of return on such costs, will be recovered over ten (10) years.[38] Recovery of NWA costs during this Electric Rate Plan will be through the MAC and NYPA OTH Statement. Unamortized NWA costs, including the return, will be incorporated into the Company's base rates when electric base delivery rates are reset.

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[37] The revenue requirement impact will be calculated by applying an annual carrying charge factor (see Appendix 8) to the amount by which the actual net plant was below the amount included in the Average Electric Plant In Service Balances.

[38] For NWAs begun prior to the commencement of the effective date of the Electric Rate Plan, the Company will recover costs incurred and incentives earned up to the effective date of the Electric Rate Plan through the Targeted Demand Management ("TDM") Program. *See* Case 15-E-0229, Con Edison's Targeted Demand Management Program Incentive Mechanism (filed March 4, 2016) (order pending).

To the extent NWAs result in the Company displacing a capital project reflected in the Average Electric Plant In Service Balances, the balance(s) will be reduced to exclude the forecasted net plant associated with the displaced project. The carrying charge on the reduction of the Average Electric Plant In Service Balances that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NWA in the MAC and the NYPA OTH Statement. In the event the carrying charge on the net plant of any displaced project is higher than the NWA recovery, the difference will be deferred for the benefit of customers.

The Company will earn incentives for NWA implementation on the same terms and conditions as established by the Commission for incentives under the TDM program.[39] Any earned incentives will be recovered through the MAC and NYPA OTH Statement.

Consistent with the Commission's TDM Order,[40] the Company will submit an implementation plan for all NWAs that includes at a minimum, detailed measurement and verification procedures, the portfolio of projects to be completed, a demonstration of whether the costs of NWA program expenditures are incremental to the Company's revenue requirement or will be displacing a project subject to the Net Plant Reconciliation mechanism, and a customer and community outreach plan. The Company will file updates to each implementation plan annually, or more frequently as necessary,

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[39] *See* footnote 38 (*i.e.*, Commission decision on incentives associated with Company investments in TDM projects, which are equivalent to NWAs, is pending in Case 15-E-0229).

[40] Case 15-E-0229, Targeted Demand Management Program, Order Implementing with Modification the Targeted Demand Management Program, Cost Recovery, and Incentives (issued December 17, 2015) ("TDM Order").

by January 31st of each year. The Company will also submit quarterly reports for each NWA project detailing the expenditures and program activities, including all relevant details with respect to project costs, project in-service dates, incremental costs incurred, operational savings, and other benefits.

Once the Company has developed a NWA portfolio and has reasonable certainty regarding NWA costs, a Benefit Cost Analysis ("BCA") will be performed in consultation with Staff in accordance with the BCA Handbook and the Commission's BCA Order. The Company will also develop a final BCA using actual NWA costs and quantities after the completion of the NWA.

2. <u>Gas</u>

a. Net Plant Reconciliation

The gas revenue requirements for RY1, RY2 and RY3 reflect the average net gas plant balances set forth in Appendix 9. The average net plant balances include Transmission and Delivery and Municipal Infrastructure Support (collectively, "Average Gas Plant In Service Balances"). These balances do not reflect net plant balances for AMI, which are addressed in section D.3.

The Average Gas Plant In Service Balances reflect a level of capital expenditures supported by various capital programs and projects. The Company, however, has the flexibility over the term of the Gas Rate Plan to modify the list, priority, nature and scope of its gas capital programs and projects.

The Company will defer for the benefit of customers, the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 9) of the amount by which the Company's actual expenditures for gas capital programs and projects result in average net plant (excluding removal costs) that is less than the amount included in the Average Gas Plant In Service Balances (excluding removal costs), as set forth in Appendix 9, for RY1, RY2 and RY3.[41]

The Company may defer on its books of account for future recovery from customers the carrying charges (including depreciation) on average net plant in service (excluding removal costs) resulting from municipal infrastructure support-related capital costs up to $10 million annually incurred due to: (a) projects of the City of New York or any other governmental entity or entities for the purposes of increasing the resiliency to storms of any form of public facility, machinery, equipment, structure, infrastructure, highway, road, street, or grounds; (b) NYC Department of Environmental Protection ("DEP") Combined Sewer Overflow projects;[42] (c) change in customary practice relating to interference (*e.g.*, responsibility for costs associated with New York City transit projects); and/or (d) all other public works or municipal infrastructure projects with a projected total cost in excess of $100 million, to the extent the Company's capital expenditures up to $10 million related to those activities result in total actual average net plant in service (excluding removal costs) exceeding the Average Gas Plant In Service

[41] The revenue requirement impact will be calculated by applying an annual carrying charge factor (see Appendix 9) to the amount by which actual net plant was below the amount included in the Average Gas Plant In Service Balances.

[42] The DEP is required under a 2005 Order on Consent to reduce combined sewer overflows ("CSOs") from its sewer system to improve the water quality of its surrounding waters, such as Flushing Bay, Jamaica Bay, and tributaries to the East River, Long Island Sound, and Outer Harbor. Under the 2005 Consent Order, the DEP has completed Waterbody/Watershed Facility Plans, which are the initial phase of CSO planning, and are required to construct various grey infrastructure projects, and develop Long-Term Control Plans. In 2011, the New York State Department of Environmental Conservation and DEP identified numerous modifications to the CSO Consent Order, including integration of green infrastructure and substitution of more cost-effective grey infrastructure, and agreed to fixed dates for submittal of the Long-Term Control Plans. (http://www.dec.ny.gov/chemical/77733.html).

Balance in any or all Rate Years. The reconciliations to Average Gas Plant In Service Balances for RY1, RY2 and RY3 will be cumulative; that is, a revenue requirement impact deferral will be required under this provision only if the actual average net plant balances for the 36-month period covered by the Gas Rate Plan is below the amount included in the Average Gas Plant In Service Balances over such period as shown on Appendix 9.

The Average Gas Plant In Service Balances do not reflect any expenditures for the Millennium Pipeline Company, L.L.C. ("Millennium") interconnection project because of uncertainty as to the timing of Millennium's construction of its interstate pipeline facilities. If Millennium commences construction of its facilities during the term of the Gas Rate Plan, the Company may commence construction of its interconnection facilities. If the Company completes construction of its facilities during the term of the Gas Rate Plan, the Company may defer for future recovery from customers carrying charges associated with such capital expenditures up to the estimated cost of this project reflected in the Company's rate filing, from the in-service date until gas base delivery rates are reset (including interest at the Other Customer-Provided Capital Rate).

b. Reporting Requirements

The Company will provide annual reports relating to capital expenditures in the manner set forth in Appendix 22.

3. <u>AMI</u>

a. Net Plant Reconciliation

The AMI Order authorized the Company to implement its AMI Business Plan subject to a $1.285 billion cap on capital expenditures. Net plant reconciliation for AMI capital expenditures will be implemented for a single category of AMI capital expenditures that includes amounts allocated to both electric and gas customers. 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.

At the end of RY3, the Company will defer for the benefit of customers or the Company, the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 10) of the amount by which the Company's actual capital expenditures for AMI results in average net plant (excluding removal costs) that is different from the amount included in the Average AMI Plant In Service Balances (excluding removal costs), as set forth in Appendix 10, for RY1, RY2 and RY3 for the AMI program.

When the Company has completed its installation of electric and gas AMI meters and the AMI backbone system, which is currently projected to take approximately six years, if the aggregate revenue requirement impact for electric and gas (*i.e.*, carrying costs, including depreciation) of the amount by which the Company's actual expenditures for the AMI capital program results in average net plant (excluding removal costs) that is less than $1.285 billion, the Company will defer such amount for credit to customers in the manner thereafter determined by the Commission.[43] See Appendix 10 for examples of how this reconciliation mechanism will operate in situations where, during the multi-year period during which meters are being installed, actual expenditures in a year(s)

[43] Nothing in these Rate Plans is intended to affect in any manner the Company's rights under the AMI Order to petition the Commission in the event that AMI capital expenditures exceed $1.285 billion.

result in actual net plant that are either more or less than amounts reflected in the revenue requirement(s) for such year(s).

b. Reporting Requirements

The Company will include capital expenditures for AMI in the annual reports for electric and gas capital expenditures as set forth in Appendix 22.

E. Reconciliations

The Company will reconcile the following costs and related items to the levels provided in rates, as set forth in Appendices 8 and 9. Variations subject to recovery from or to be credited to customers will be deferred on the Company's books of account over the term of the Rate Plans, and the revenue requirement effects of such deferred debits and credits, as the case may be, will be addressed in future rate proceedings, except as addressed in section C.3 above.

1. Property Taxes (Electric and Gas)

If the level of actual electric or gas expense for property taxes, excluding the effect of property tax refunds (as defined in section F.3), varies in any Rate Year from the projected level provided in rates for that service, which levels are set forth in Appendices 8 and 9, ninety (90) percent of the variation will be deferred and either recovered from or credited to customers, subject to the following cap: the Company's ten (10) percent share of property tax expenses above or below the level in rates is capped at an annual amount equal to ten (10) basis points on common equity in Rate Year 1, seven and half (7.5) basis points on common equity in Rate Year 2, and five (5) basis points on common equity in Rate Year 3. The Company will defer on its books of account, for recovery from or credit to customers, one hundred (100) percent of the variation above or below the level at which the cap takes effect.

The Company will not be precluded from applying for a greater share of lower than forecasted property tax expenses (including the period beyond RY3) if its extraordinary efforts result in fundamental taxation changes and produce substantial net benefits to customers.

2. Municipal Infrastructure Support (Other Than Company Labor) (Electric and Gas)

If actual non-Company labor Municipal Infrastructure Support expenses (*e.g.*, contractors costs) vary from the level provided in electric and/or gas rates for any Rate Year, which levels are set forth in Appendices 8 and 9, one hundred (100) percent of the variation below the target will be deferred on the Company's books of account and credited to customers, and eighty (80) percent of the variation above the target within a band of thirty (30) percent (*e.g.*, for electric a maximum deferral of $22.8 million for RY1)[44] will be deferred on the Company's books of account and recovered from customers. Expenditures above the target plus thirty (30) percent are not recoverable from customers except as follows: if actual electric and/or gas non-Company labor Municipal Infrastructure Support expenses (*e.g.*, contractors costs) vary from the respective level provided in rates above the target plus thirty (30) percent, and such increased expenses are due to (a) projects of the City of New York or any other governmental entity or entities for the purposes of increasing the resiliency to storms of any form of public facility, machinery, equipment, structure, infrastructure, highway, road, street, or grounds, (b) the New York City DEP Combined Sewer Overflow

[44] RY1 rate allowance for interference of $95.1 million x 80 percent x 30 percent = $22.8 million.

projects,[45] and/or (c) all other public works or municipal infrastructure projects with a projected total cost in excess of $100 million, eighty (80) percent of the variation above the target plus thirty (30) percent that is attributable to the above-described projects will be deferred on the Company's books of account for future recovery from electric and/or gas customers as applicable.

In addition, if there is a change in law, rules or customary practice relating to interference (*e.g.*, responsibility for costs associated with New York City transit projects), the Company will have the right to defer such incremental costs pursuant to section P.2.

3. <u>Pensions/OPEBs (Electric and Gas)</u>

Pursuant to the Commission's Pension/OPEB Policy Statement,[46] the Company will reconcile its actual pensions/Other Post-Employment Benefits ("OPEBs") expenses to the level allowed in electric and gas rates as set forth in Appendices 8 and 9.

The Pension/OPEB Policy Statement provides that companies may seek prospective interest accruals or rate base treatment for amounts funded above the cost recoveries included in rates.[47] During the term of the Rate Plans, the Company may be required to fund its pension plan at a level above the rate allowance pursuant to the annual minimum pension funding requirements contained within the Pension Protection Act of 2006. The Company, its actuary and the parties are unable to predict with

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[45] *See supra* n.42.

[46] Case 91-M-0890, In the Matter of the Development of a Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Post-Retirement Benefits Other Than Pensions, *Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Post-Retirement Benefits Other Than Pensions* (issued September 7, 1993) ("Pension/OPEB Policy Statement").

[47] *See* Pension/OPEB Policy Statement, Appendix A, page 16, footnote 3.

certainty if the minimum funding threshold will exceed rate recoveries during the term of the Rate Plans. In lieu of a provision in this Proposal addressing the Company's additional financing requirements should it be required to fund its pension plan above the level provided in rates during the term of these Rate Plans, the Proposal does not preclude the Company from petitioning the Commission to defer the financing costs associated with funding the pension plan at levels above the current rate allowance should funding above the rate allowance be required; the Company's right to obtain authority to defer such financing costs on its books of account will not be subject to requirements respecting materiality.[48]

4. <u>Environmental Remediation (Electric and Gas)</u>

Actual expenditures for site investigation and remediation allocated to Con Edison's electric or gas business,[49] including expenditures associated with former manufactured gas plant sites ("MGP"), Superfund and 1994 DEC Consent Order Appendix B sites (also referred to as SIR Costs), will be deferred on the Company's

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[48] For this provision, the Company will not be subject to the Commission's general materiality threshold for deferral treatment purposes of five percent of net income available for common shareholders. *See, e.g.,* Case 10-M-0473, Petition of Central Hudson Gas & Electric Corporation for Commission Approval to Defer Storm Restoration Expenses, Bad Debt Net Write-off Expenses, and Property Taxes for the Rate Year Ended June 30, 2010, as well as, Authority to Offset These Expenses With Certain Income Tax Benefits, *Order Denying Rehearing in Part and Providing Clarification* (issued November 22, 2011) (reaffirming the Commission's general policy on materiality and noting there are case-by-case exceptions).

[49] These costs are the costs Con Edison incurs to investigate, remediate or pay damages (including natural resource damages, with respect to industrial and hazardous waste or contamination spills, discharges, and emissions) for which Con Edison is deemed responsible. These costs are net of insurance reimbursements (if any); nothing herein will require the Company to initiate or pursue litigation for purposes of obtaining insurance reimbursement, nor preclude or limit the Commission's authority to review the reasonableness of the Company's conduct in such matters.

books of account and amortized as shown on Appendix 3. The deferred balances subject to interest will be reduced by accruals, insurance recoveries, associated reserves, deferred taxes and amounts included in rate base (see Appendices 1 and 2). The amortization period for SIR costs will continue to be five (5) years.

5. <u>Long Term Debt Cost Rate (Electric and Gas)</u>

As set forth in Appendices 1 and 2, the weighted average cost of long term debt during the term of the Rate Plans is 4.93 percent for RY1, 4.88 percent for RY2 and 4.74 percent for RY3. As set forth in Appendices 8 and 9, included in those weighted average cost rates is 1.37 percent in RY1, 1.86 percent in RY2 and 2.34 percent in RY3 for Variable Rate Debt (*i.e.*, the Company's entire tax-exempt portfolio). The Company will be allowed to true-up its actual weighted average cost of Variable Rate Debt during RY1, RY2 and RY3 to the cost rates for Variable Rate Debt reflected in Appendices 8 and 9. In the event the Variable Rate Debt[50] is refinanced with tax-exempt or taxable debt (which may include retiring the Variable Rate Debt) prior to January 1, 2020 (including under circumstances not contemplated by the Commission's *Order Authorizing Issuance of Securities*, issued May 20, 2016, in Case 16-M-0020, and therefore requiring Commission authorization), the Company will include its costs associated with the refinancing of the Variable Rate Debt in the amounts to be reconciled.

[50] The cost of Variable Rate Debt includes the costs of any credit support measures, such as letter of credit or bond insurance.

6. Major Storm Cost Reserve (Electric)

a. Major Storm Reserve Funding

The Company's annual electric revenue requirements provide funding for the major storm reserve of an annual amount of $21.4 million in each of RY1, RY2 and RY3.[51] Except as provided herein, all incremental major storm costs will be charged to the major storm reserve. To the extent that the Company incurs incremental major storm damage costs in excess of $21.4 million in a Rate Year, the Company will defer on its books of account expenses in excess of the $21.4 million for future recovery from customers. To the extent that the Company incurs major storm damage expenses less than $21.4 million in a Rate Year, the Company will defer any variation less than $21.4 million for the benefit of customers.[52] All major storm expenses are subject to Staff review.

b. Costs Chargeable to the Major Storm Reserve

Except as provided herein, the Company will continue its current accounting practices respecting the identification of incremental non-capital major storm costs that are charged to the major storm reserve. These current practices include not charging

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[51] A "major storm" is defined in 16 NYCRR Part 97 as a period of adverse weather during which service interruptions affect at least ten (10) percent of the Company's customers within an operating area and/or results in customers being without electric service for durations of at least twenty-four (24) hours. This definition of major storm will be applied to weather events affecting the Company's overhead system. For the Company's underground network system, major storms are defined as weather event(s) that result in at least 5,000 customer outages and 800 jobs as recorded in the Company's outage management system. This includes one storm event that satisfies these criteria and multiple storm events that are up to two days apart and, in aggregate, satisfies these criteria.

[52] The Company will continue to preserve the variation between the $21.4 million annual major storm reserve established under the 2014 Rate Plan and actual major storm costs incurred during the period 2014-2016.

stores handling, telecommunication and transportation (other than fuel) overheads to the major storm reserve.

The Company will charge to the major storm reserve up to $3.0 million per calendar year for costs incurred to obtain the assistance of contractors and/or utility companies providing mutual assistance in reasonable anticipation that a storm will affect its electric operations to the degree meeting the criteria of a major storm as defined in 16 NYCRR Part 97 but which ultimately does not do so.

The Company will exclude from costs chargeable to the major storm reserve an amount equal to two (2) percent of the costs incurred (net of insurance and other recoveries) due to the occurrence of a major storm.

The Company will be able to charge costs against the major storm reserve for a period up to thirty (30) days following the date on which the Company is able to serve all customers.

Following a major storm for which the Company forecasts a period of more than thirty (30) days following the date on which the Company is able to serve all customers to fully restore the system to normal operation, the Company may file a petition with the Commission that will include: (i) a plan for full system restoration, including restoration milestones ("system restoration plan") and (ii) a request for authorization to defer costs incurred in accordance with the system restoration plan beyond thirty (30) days following the date on which the Company is able to serve all customers (*i.e.*, the costs not automatically chargeable to the major storm reserve) for later recovery from customers. Recovery of costs incurred subsequent to that 30-day period following the date on which the Company is able to serve all customers will not be subject to the requirement that the costs be material under the Commission's guidelines for determining whether the deferral of costs will be authorized ("materiality requirement"). Upon completion of the work necessary to restore the system to normal, the Company may file with the Commission, in the proceeding established to consider the Company's deferral petition, an estimate of the total costs incurred to restore the system to normal operation, broken out between costs during the period that they are chargeable to the major storm reserve and costs incurred during the period that they are the subject of the deferral petition. Costs will be estimated where, for example, costs are subject to final billings from vendors, contractors, and utility companies that provided mutual assistance. If the Company seeks recovery of costs incurred during a time period that exceeds the originally forecasted period of time to restore the system to normal operation (*e.g.*, the Company's system restoration plan contemplated a 60-day period and restoration took ninety (90) days), the Company will include with its cost estimate filed with the Commission a demonstration that such extension was in customers' interests (*e.g.*, more cost-effective) and/or was the result of extenuating circumstances (*e.g.*, circumstances not reasonably foreseeable when the system restoration plan was developed, including for example, an intervening storm or other event).

7. Non-Officer Management Variable Pay (Electric and Gas)

The electric and gas revenue requirements reflect the amounts of expense for the Company's Non-Officer Management Variable Pay Program for each service by Rate Year as shown on Appendices 8, and 9. The Company will defer for future credit to customers, the amount by which the actual expense by service in any Rate Year is less than the amount shown on Appendices 8, and 9 for that service for that Rate Year.

The Company will reflect the changes to safety, reliability and customer service performance metrics adopted within this Proposal in the Safety and Reliability and Customer Service Index portions of the Management Variable Pay Plan.[53]

When the Company undertakes a comparative study of its compensation/benefits to support the next rate case, the Company will conduct the study so as to achieve at least 50 percent matching of positions, or more, to the extent practicable, in a blended peer group of Utilities and New York Metropolitan employers and will describe the process by which the Company matches its positions to the positions of the peer group employers, including an explanation for the exclusion of any Company positions from the analysis in the comparative study. The Company will meet with Staff to discuss the composition of the peer group to be used in the study.

8. East River Major Maintenance Cost Reserve (Electric)

The Company's electric base rates reflect amounts for East River Repowering Project ("East River") Maintenance Costs of $10.704 million for RY1, RY2 and RY3. To the extent that over the term of the Electric Rate Plan, the Company incurs cumulative East River Maintenance Costs more or less than the sum of the amounts provided in rates plus the reserve available as of January 1, 2017, the Company will defer any variation on its books of account for future recovery from or for credit to customers.

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[53] The Company maintains flexibility to modify the Management Variable Pay Plan, including the portions related to the Safety and Reliability and Customer Service Index. For purposes of this reconciliation mechanism, if the Company modifies the Safety, Reliability and/or Customer Service Index portions of the Management Variable Pay Plan, the Company will calculate the downward reconciliation under both the new and the old structure. The Company will defer for future credit to customers the amount by which the actual expense by service is or would have been less than the amount shown on Appendices 8 and 9 for those services.

9. East River Interdepartmental Rent (Electric)

The Electric Rate Plan includes a change to the level of the East River interdepartmental rent expense for electric customers compared to the level set in steam rates for 2016 (the third rate year of the current steam plan). The Company will defer the impact of the change in expense to steam, starting in 2017 and annually thereafter (until steam base rates are reset), whether positive or negative, to continue the "earnings neutral" nature of these revenues to the Company.

10. Other Transmission Revenues (Electric)

The Company's revenue requirements include annual revenue targets for Transmission Congestion Contracts ("TCC") of $75 million; Transmission Service Charges ("TSC") of $5 million; and grandfathered transmission wheeling contracts ("GTWC") of $7 million as shown on Appendix 8. Annual variations between the TCC, TSC and GTWC revenue targets and actual amounts will be passed back or recovered as appropriate through the MAC.

11. Brownfield Tax Credits (Electric)

The Company's electric revenue requirements do not reflect any New York State tax benefits from Brownfield environmental tax credits. The Company will defer on its books of account all Brownfield tax credits received for future credit to customers.

12. NEIL Dividends (Electric)

The Company's electric revenue requirements do not reflect any dividends the Company might receive from the Company's Nuclear Electric Insurance Limited ("NEIL") insurance policy. The Company will credit electric customers with any such dividends received through the MAC.

13. **Proceeds from the Sales of SO_2 Allowances (Electric)**

The Company's electric revenue requirements do not reflect any proceeds that might be received from the sale of SO_2 allowances. With the exception of any proceeds received from the sale SO_2 allowances pursuant to the Environmental Protection Agency's final rule on interstate transport of fine particulate matter and ozone (the "Transport Rule"), any proceeds from the sale of SO_2 allowances will be deferred on the Company's books of account for future credit to customers. The allocation of such proceeds between steam and electric will continue to be computed according to the method established in the *Order Determining Revenue Requirement And Rate Design*, issued September 22, 2006, in Case 05-S-1376. Proceeds from the sale of Transport Rule SO_2 allowances are subject to General Rule 26.1, Monthly Adjustment Clause, of PSC No. 10 – Schedule for Electricity Service, and will be recovered through the MAC as approved by the Commission in Case 14-E-0272 on December 16, 2014.

14. **Adjustments for Competitive Services (Electric and Gas)**

The Company will continue to reconcile competitive service charges in accordance with current tariff provisions. Competitive service charges consist of the supply-related and credit and collections-related components of the MFC, the credit and collections component of the POR discount rate, the Billing and Payment Processing Charge, and Metering Charges (electric only).

15. BQDM Program and REV Demo Project Costs (Electric)

The Company's electric base rates reflect amounts for the Brooklyn Queens Demand Management ("BQDM") program[54] and REV Demo projects[55] in RY1, RY2 and RY3. The Company will defer annually the revenue requirement associated with program expenditures above or below the target levels reflected in base electric rates, subject to the overall cap on expenditures established by the Commission for these programs. Any deferred balance will be addressed in the Company's next rate filing. The target levels for the BQDM Program and the REV Demo Projects are set forth in Appendix 8. The reporting requirements associated with REV Demo projects are included in Appendix 22.

16. AMI Customer Engagement Plan and AMI Rate Pilots (Electric and Gas)

The Company's electric and gas base rates reflect amounts for the AMI Customer Engagement Plan and AMI Rate Pilots[56] in RY1, RY2 and RY3 as shown on Appendices 8 and 9. The Company will reconcile the actual level of costs incurred for the AMI Customer Engagement Plan and AMI Rate Pilots to the three-year cumulative targets and defer any underspending over the term of the Rate Plans for future credit to customers. In the event the Company's actual AMI Customer Engagement Plan and AMI Rate Pilots costs are less than the target level for a particular Rate Year, the Company will defer on

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[54] Case 14-E-0302, Order Establishing Brooklyn/Queens Demand Management Program (issued December 12, 2014).

[55] Case 15-E-0229, Order Implementing with Modification the Targeted Demand Management Program, Cost Recovery, and Incentives (issued December 17, 2015).

[56] Cases 15-E-0050, et al, Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. – AMI Customer Engagement Plan, filed July 29, 2016.

its books of account the amount of such under spending, which amount will be reduced by up to the amount of actual expenditures in any and all subsequent Rate Years that exceeds the target level for that Rate Year(s).

17. Pipeline Integrity Costs – New York Facilities Charges (Gas)

The New York Facilities Agreement is a joint operating agreement among Con Edison, The Brooklyn Union Gas Company d/b/a National Grid NY ("National Grid NY") and KeySpan Gas East Corporation d/b/a National Grid ("National Grid"), which provides for the sharing of certain costs. Among the costs to be shared are the costs that Con Edison, National Grid NY and National Grid incur to comply with federal requirements that require gas companies, like Con Edison, National Grid NY and National Grid, to develop and implement an integrity management program for their affected gas facilities using in-line inspection, hydro or pressure testing, or direct assessment. The Company's projected share of National Grid NY's and National Grid's pipeline integrity costs is reflected in the gas rates for RY1, RY2 and RY3 as shown on Appendix 9. The Company will defer on its books of account, for recovery from or credit to customers, the difference between payments made to National Grid NY and National Grid for pipeline integrity programs and the amount included in gas rates.

18. Research and Development Expense (Gas)

Research and Development ("R&D") expenses reflected in the revenue requirements for each of RY1, RY2 and RY3 for gas are set forth in Appendix 9 ("target levels"). In the event the Company's actual R&D expenses for gas, excluding administrative costs, are less than the target level for a particular Rate Year, the Company will defer on its books of account the amount of such under spending for future credit to customers, subject to any such deferred amount being reduced by up to the amount of actual expenditures in any and all subsequent Rate Years that exceeds the target level for that Rate Year(s) by not more than 20 percent.[57]

The Company has the flexibility over the term of the Gas Rate Plan to modify the list, priority, nature and scope of the R&D projects to be undertaken.[58]

19. Pipeline Safety Act (Gas)

The Company's gas revenue requirements do not reflect costs to comply with new regulations associated with the Pipeline Safety Act of 2011. To the extent that over the term of the Gas Rate Plan, the Company incurs any incremental costs to comply with the new regulations, the Company will defer these costs on its books of account for future recovery from customers.

20. Gas Service Lines (Gas)

The Company's gas revenue requirements do not reflect costs that may result from the implementation of the Commission's recently amended definition of "gas service line." To the extent that cost recovery is not addressed in Case 14-G-0357 and/or Case 15-G-0244 and over the term of the Gas Rate Plan the Company incurs incremental costs associated with complying with the amended definition (*e.g.*, for inspection, repair,

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[57] For example, if actual spending in RY1 is $300,000 below the target level, the Company will defer that amount for future credit to customers. If the target level for RY2 is $1 million, and actual spending in RY2 is $1,150,000, the deferred credit will be reduced by the extra $150,000 spent. However, if the actual spending in RY2 is $1,300,000, the deferred credit will be reduced only by $200,000. A separate, but similar, reconciliation will be performed for RY3, up to the amount of any remaining deferred credit.

[58] The Company will continue to undertake the R&D project to prevent the backflow of water into a gas meter from customer piping during this Rate Plan so long as it continues to be a feasible R&D project.

outreach/communications), the Company will defer these costs on its books of account for future recovery from customers.

21. <u>System Peak Reduction, Energy Efficiency and Electric Vehicle Programs</u>

The Company's electric base rates reflect regulatory asset amounts for the System Peak Reduction, Energy Efficiency above Energy Efficiency Transition Implementation Plan ("ETIP") and Electric Vehicle Programs in RY1, RY2 and RY3. The Company will defer annually the revenue requirement associated with program expenditures below the target levels reflected in base electric rates for credit to customers.

The Company's electric base rates also reflect Electric Vehicle Program expenses in RY1, RY2 and RY3. In the event the Company's actual Electric Vehicle Program expenses are less than the target level for a particular Rate Year, the Company will defer on its books of account the amount of such under spending for future credit to customers.

For each Rate Year, any System Peak Reduction, Energy Efficiency above ETIP, and Electric Vehicle Program spend above the respective annual amounts specified in section J.1.E for each program will not be recoverable from customers.

22. <u>Discontinued Reconciliations</u>

Workers' Compensation

The 2014 Rate Order provided for the Company to defer for later credit to or recovery from customers, the full amount by which changes to the New York State Workers' Compensation insurance laws included in the 2013-2014 New York State Budget and related implementing regulations of the Workers' Compensation Board result in the Company's workers' compensation insurance expense varying from the expense reflected in the revenue requirements. This mechanism is no longer applicable.

23. **Additional Reconciliation/Deferral Provisions**

In addition to the foregoing reconciliation provisions (*i.e.*, sections E.1 through E.21), along with all other provisions of this Proposal embodying the use of a reconciliation and/or deferral accounting mechanism, all other applicable existing reconciliations and/or deferral accounting will continue in effect through the term of these Rate Plans and thereafter until modified or discontinued by the Commission, except for those expressly identified in this Proposal for discontinuation. Continuing reconciliation and/or deferral accounting mechanisms include, but are not limited to, Financial Accounting Standards ("FAS") 109 taxes, Regional Greenhouse Gas Initiative ("RGGI") costs associated with Company-owned generation, System Benefits Charges, Energy Efficiency Portfolio Standard and ETIP charges, Demand Side Management ("DSM") costs, MTA taxes, New York Public Service Law §18-a regulatory assessment, the MSC/MAC, and MRA/GCF mechanisms, as well as the cost of the Low Income customer charge discount (discussed below) as they may be applicable to electric and/or gas operations.

Cases 15-E-0050, 13-E-0030 and 13-G-0031 continued deferral accounting for World Trade Center ("WTC")-related capital costs in excess of insurance and other recoveries. The revenue requirements in these cases do not include any deferrals or amortizations related to World Trade Center costs as the prior amortizations have expired and no additional costs or insurance or other recoveries are projected. When Staff performs its audit of previously recovered costs or recoveries returned to customers, any differences agreed upon or directed by the Commission will be deferred. Although no new recoveries are anticipated, any new recoveries will also be deferred.

F. Additional Accounting Provisions

1. Depreciation Rates and Reserves

a. Depreciation Rates (Electric and Gas)

The average services lives, net salvage factors and life tables used in calculating the depreciation reserve and establishing the revenue requirements for electric and gas service are set forth in Appendix 11.[59]

The average service lives, net salvage factors, life tables and resulting depreciation rates have been agreed to for the purposes of this Proposal, but such agreement does not necessarily imply endorsement of any specific methodology by any Signatory Party.

b. Electric Reserve Deficiency

In addition to the depreciation produced by the application of the rates summarized in Appendix 11, an additional amount of depreciation expense will be realized, beginning in RY1, in connection with the recovery of a portion of the electric depreciation reserve deficiency. The recovery will equal $11,611,000 annually and was determined by applying fifty (50) percent of the reserve deficiency identified in excess of the ten (10) percent tolerance band over a 15-year amortization period.

c. Depreciation of Legacy Meters after AMI Installation

The currently effective depreciation rates for electro-mechanical and solid state electric and gas meters will apply during the AMI deployment period. Any remaining undepreciated investment in the legacy meters will be amortized over a 15-year period.

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[59] Appendix 11 reflects depreciation associated with AMI meters and AMI backbone costs.

2. Interest on Deferred Costs

The Company is required to record on its books of account various credits and debits that are to be charged or refunded to customers. Unless otherwise specified in this Proposal or by Commission order, the Company will accrue interest on these book amounts, net of federal and state income taxes, at the Other Customer-Provided Capital Rate published by the Commission annually. FAS 109 and MTA tax deferrals are either offset by other balance sheet items or reflected in the Company's rate base and will not be subject to interest.

3. Property Tax Refunds and Credits

Prospective Refunds and Credits

Property tax refunds allocated to electric and/or gas that are not reflected in the respective Rate Plans and that result from the Company's efforts, including credits against tax payments or similar forms of tax reductions (intended to return or offset past overcharges or payments determined to have been in excess of the property tax liability appropriate for Con Edison), will be deferred for future disposition, except for an amount equal to fourteen (14) percent of the net refund or credit, which will be retained by the Company. Incremental expenses incurred by the Company to achieve the property tax refunds or credits will be offset against the refund or credit before any allocation of the proceeds is calculated. The deferral and retention of property tax refunds and incentives will be subject to an annual showing in a report to the Secretary by the Company of its ongoing efforts to reduce its property tax burden, in March of each Rate Year. Additionally, the Company is not relieved of the requirements of 16 NYCRR §89.3 with respect to any refunds it receives.

4. **<u>Hudson Avenue</u>**

The electric revenue requirements reflect a transfer of (i) 83 percent of the plant balances (excluding land) and (ii) 100 percent of the land balance for the Hudson Avenue Generating Station ("Hudson Avenue"), from steam rate base to electric rate base as of January 1, 2017. The associated deferred tax balance associated with Hudson Avenue will also be transferred from steam rate base to electric rate base.

For the period commencing January 1, 2017 until steam base delivery rates are reset, the Company will defer for future credit to steam customers: (i) 83 percent of the carrying charges associated with Hudson Avenue plant balances (excluding land) and (ii) the carrying charges for the land balance at 100 percent, currently reflected in steam delivery rates.

5. **<u>Income Tax</u>**

a. Removal Costs

The revenue requirements for electric and gas service reflect the Company's correction of the methodology for the accounting for removal costs determining income tax expense. The correction in methodology increases the electric revenue requirement by $35.0 million and the gas revenue requirement by $35.3 million. In the Company's electric revenue requirement established in Case 15-E-0050, an increase of $93.4 million was provided to correct for this methodology in the calculation of the electric income tax expense.

There are estimated regulatory assets of $1.7 billion for electric and $111.7 million for gas as of September 30, 2015, that reflect the cumulative rate effect of the change from the previous methodology in accounting for removal costs, which understated income tax expense in past periods. In the revenue requirements in this proceeding, the income tax expense provides for an estimated annual amortization of the regulatory asset of approximately $39.5 million for electric and $1.8 million for gas. With respect to the regulatory asset related to this change in methodology and correction, Staff will perform an audit to verify the error in the Company's income tax accounting for ratemaking in previous years, and determine if rate payers received benefits equal to the amount of the regulatory asset reflected in the current revenue requirements for electric and gas.

b. Excess Deferred Federal Income Tax

Staff will also perform an audit of the Company's determination of the electric and gas excess deferred federal income tax liability balances, which are a component of rate base in the electric and gas revenue requirements. The balances are shown in Appendices 1 and 2.

c. Resolution

Staff and the Company will work together to resolve any differences as to the two audits described above, including differences as to the recovery of such amounts from customers.

The income tax expense and excess deferred federal income tax liability balances discussed in (a) and (b) above are subject to reconciliation. Final agreed-upon or Commission-ordered differences resulting from the Staff review will be deferred and any amounts to be refunded or collected from customers will be determined by the Commission.

6. <u>Allocation of Common Expenses/Plant</u>

During the term of the Rate Plans, common expenses and common plant will be allocated according to the percentages reflected in the electric and/or gas revenue requirement calculations, as shown in Appendix 13. Should the Commission approve different common allocation percentages for electric, gas and/or steam service prior to the next base rate case for the electric, gas and/or steam businesses, the resulting annual revenue requirement impacts will be deferred for future recovery from or credit to customers.

7. Allocation of Intercompany Shared Services Expense

During the Rate Plan, expenses for intercompany shared services that are allocated to the Company and its affiliates from Consolidated Edison, Inc. ("CEI") are based on a three-part formula using forecasted 2017 Revenues, Payroll, and Total Assets for each entity. These allocated expenses exclude directly charged services.

G. Electric Revenue Allocation/Rate Design

1. Revenue Allocation

The allocation of the delivery revenue change for each Rate Year is explained in Appendix 19. The 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).

2. Rate Design

This Proposal establishes new competitive and non-competitive electric delivery service rates, including changes to provisions of the MAC.[60] The rates implementing this Proposal will be developed as set forth in Appendix 19.

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[60] If, based on the make whole extension letters referred to in footnote 8, the Commission does not issue an order on this Proposal until January or February 2017, the Company will recover shortfalls and refund over-collections that result from the extension of the suspension period in this proceeding through a "make-whole" provision, as detailed in the Company's July 8, 2016 and

3. **Customer Charges**

With limited exception, customer charges will not be increased and will remain at their current levels. The exceptions are as follows:

a. The existing monthly customer charge in SC 2 will be reduced by $4.41 for customers with unmetered service to reflect the removal of SC2's allocated portion of metering costs in the 2013 ECOS study. Usage charges for all SC 2 customers will be increased to offset the resulting revenue shortfall.

b. Customer charges under standby rates will be set at the customer costs per the ECOS Study, which result in increases or decreases from current levels.

In addition, Special Provision D of SC 2, which provides a reduced customer charge for use of radio transceivers using less than 30 kilowatthours per month and located on street lights or utility distribution poles at 100 or more locations, will be modified to reduce the minimum number of locations to 40 or more. Service will be also permitted for use of devices at other locations that provide free wi-fi services to the public subject to the limitation on monthly kilowatthour use and minimum number of locations described above.

4. **Stand-alone Plug-In Electric Vehicle ("PEV") Charger Rate**

A new Special Provision F in SC 1 will allow customers with separately metered PEV chargers to take service, solely for PEV charging, under a separate account billed under SC 1, Rate III, the voluntary time-of-use ("VTOU") rate. Special Provision F will apply to customers who have an existing SC 1 account or a residential tenant or

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August 8, 2016 letters. The revenue differences will be recovered or credited, with interest, over the remaining months of 2017. The Company will work with Staff to identify and calculate these revenue differences.

residential occupant in a building served under another SC. Customers served under Special Provision F will not be eligible for the price guarantee afforded to SC 1 Rate III customers who register a PEV with the Company under Special Provision E of SC 1. To accommodate the new rate, tariff changes will also be made to the SC 1 Applicability and SC 1 Rate III Applicability provisions.

5. Commercial and Industrial Customer Rate Design

Pursuant to the Track Two Order,[61] the Company will evaluate its Commercial and Industrial ("C&I") customer delivery charges to determine whether they can be improved by making them more peak sensitive and/or by changing the determinants, such as peak-to-off-peak ratios, that influence customer decisions. The Company will file its evaluation report with the Secretary by April 1, 2017.

6. Standby Service and Buyback Rates

The Proposal provides for the following changes to standby rates and SC 11 export-only buyback rates.

a. Minimum Monthly Charge for Customers Exempt from Standby Rates

> The Minimum Monthly Charge ("MMC") applicable to SCs 5, 8, 9, 12, and 13 for standby customers exempt from standby rates will be modified to permit a one-time reduction in the MMC-Contract Demand amount. If a customer installs distributed generation that qualifies as a designated technology exempt from standby service rates and the customer requests and receives that exemption, the customer will receive a one-time reduction, equal to the generator nameplate rating, in the MMC Contract Demand amount applicable to non-standby rates, after the generator commences operation.

[61] 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* (issued May 19, 2016) ("Track Two Order").

b. Exemptions from Standby Rates[62]

(i) Battery Storage up to 1 MW of inverter capability will be defined as a Designated Technology under the Con Edison tariff.

(ii) The NOx emissions standard applicable to exemptions established under the Standby Exemption Order will be reduced from 4.4 lbs/MWh to 1.6 lbs/MWh, except that for currently-exempt customers and customers that have an accepted interconnection application and/or air permit application as of January 1, 2017 4.4 lbs/MWh NOx will continue to be the applicable standard.

c. Reliability Credit

The Company will implement the Reliability Credit directed by the Track Two Order as a replacement for the Standby Performance Credit. The Reliability Credit will be implemented starting with the Measurement Period that commences with the Summer 2017 period on the following terms and conditions:[63]

(i) Application for and Determination of Standby Reliability Credits:

Customers must request Standby Reliability Credits by October 10 of each year for which the credit is sought and, at the same time, specify the Outage Events the Customer requests to be excluded from the Measurement Period.

Outage Events will be up to three time blocks for each Summer Period that, in aggregate, are comprised of no more than five 24-hour periods, excluding weekends and holidays. If a time block contains a period of less than 24 hours, the time period will be rounded up to the next 24 hours (i.e., 24-hour periods cannot be applied on a partial

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[62] Case 14-E-0488, In the Matter of the Continuation of Standby Rate Exemptions**,** *Order Continuing and Expanding the Standby Rate Exemptions* (issued April 20, 2015) ("Standby Exemption Order").

[63] If the Commission modifies the Reliability Credit on rehearing of the Track Two Order, the Reliability Credit as set forth in this Proposal will be modified accordingly.

basis). If a time block encompasses a holiday or weekend, the start time of the 24-hour period on the day prior to the holiday or weekend until the same time the next business day will be considered to be a single 24-hour time period.

The Measurement Period will be the Measurement Hours during the previous two consecutive full Summer Periods; provided, however, that the first year in which a Customer seeks a Standby Reliability Credit, the Measurement Period will be the Measurement Hours during the previous full Summer Period only. For determination of the Standby Reliability Credit, Measurement Hours are defined as follows:

1. For Rate Year 1, the Measurement Hours will be Monday through Friday, except Holidays, 10 AM to 10 PM, June 15 through September 15.

2. For Rate Year 2 and thereafter, the Measurement Hours will be Monday through Friday, except Holidays, 8 AM to 10 PM, June 1 through September 30.

The Standby Reliability Credit for any Measurement Period will be equal to the product of (a) the Reliability Adjustment (defined as the Customer's Contract Demand less the highest kW demand recorded on the meter(s) used for monthly billing (net of generation) during the Measurement Period) and (b) the Delivery Service Contract Demand Charge per kW that is in effect on October 1 of the year in which the Credit is determined. Standby Reliability Credits requested by October 10 will be applied to Customers' successive 12 monthly bills commencing November of the year in which the Standby Reliability Credit is requested and continuing until the following October. If service is taken under the Single Party or Multi-party Offset (see Section G.6.g), the Credit will be applied to each Standby Service account supplied by the generating facility's output.

The Reliability Adjustment will not affect the kW used for purposes (e.g., supply capacity obligations) other than the Standby Reliability Credit. If the customer receives a reduction in Contract Demand Charges for delivery service (e.g., under Business Incentive Rates or the Excelsior Jobs Program), the Contract Demand Charge used to calculate the Standby Reliability Adjustment will be reduced accordingly.

(ii) Eligibility Requirements:

1. The generating facility's output must be separately metered using an Output Meter that the Customer arranges to be furnished and installed at Customer expense;

2. The Customer, at its expense, must provide and maintain the communications service for the Output Meter;

3. The output of the generating facility must be connected at a voltage lower than 100 kV; and

4. The Output Meter must be Commission-approved, revenue grade, interval metering with telecommunications capability, and compatible with the Company's metering infrastructure, including compatibility with the Company's meter reading systems and meter communication systems.

(iii) Recovery of Standby Reliability Credits:

Credits provided to Con Edison standby customers will be recovered from all Con Edison customers, including standby customers, through the MAC. Credits provided to NYPA standby customers will be recovered from NYPA through the NYPA OTH Statement.

d. Optional Bill Credit for Export-Only Buyback Customers

An optional bill credit will be available to SC 11 Export-only Buyback customers.

(i) Customer Eligibility Requirements

The following customer eligibility requirements apply:

1. The bill credit will be available to SC 11 customers that are export-only (*i.e.*, SC 11 customers that do not take service under

another Service Classification through the same service connection);[64]

2. The bill credit will be modeled on the reservation payment rate applicable to the Commercial System Relief Program ("CSRP"), *i.e.*, the credit will be equal to the number of participation months multiplied by the applicable CSRP rate and will be paid as a monthly bill credit, over 12 months, as described below, up to, but not exceeding, the SC 11 monthly Contract Demand per-kW delivery charge;

3. Customers seeking this credit may also participate in the Distribution Load Relief Program ("DLRP") but not the CSRP;

4. The bill credit is only available to a generating facility that is in compliance with air quality criteria established as part of the standby/export rates pilot collaborative (See Appendix 20).

5. The output of a customer's generating facility must be separately metered using Commission-approved, revenue-grade, interval metering with telecommunications capability arranged by customer and installed at customer expense, including communications service for the meter(s) recording the generating facility's output ("output meter").

6. Up to three outages (*i.e.*, zero export) each up to a 24-hour period will be excused under this program during RY1. Up to two outages, each up to a 24-hour period will be excused under this program for each of RY2 and RY3.

(ii) Calculation of Bill Credits

The bill credits will be calculated as follows:

1. The credits will be determined each year in October based on the generating facility's performance during a previous measurement period for which interval data was available from the output meter;

2. The measurement period will be the customer's specified call window, weekdays (M-F, excluding holidays), that would be applicable if it were participating in the CSRP program based on the

[64] For example, a generator that exports power through one service connection and takes station service through a separate service connection would be considered an export-only customer. Alternatively, an on-site generation customer that imports and exports power through the same service connection is not an export-only customer.

distribution network to which the customer is interconnected except that the Company may assign an alternative four-hour CSRP window to SC 11 customers that cannot provide network support (*e.g.*, the generating facility is directly tied into a substation and is not part of a network) based on the peak for the portion of the system for which the customer is providing support;

3. For the first year of a customer's participation, the measurement period will be the previous full summer period (here defined as May 1 through September 30). If the generating facility begins commercial operation after May 1, the customer will be eligible for its first-year credit on a proportional basis, provided that the customer's generating facility shall have been in operation no later than July 1 of that same year;

4. For the second year of a customer's participation and thereafter, the measurement period will be the previous two consecutive full summer periods;

5. The monthly credit will be equal to the product of: (i) The lesser of (a) the lowest kW recorded on the output meter during the measurement period or (b) the customer's SC 11 Contract Demand, and (ii) The lower of (a) the levelized monthly CSRP reservation payment (defined in (6) below) or (b) the Contract Demand delivery charge per kW in effect on October 1 of the year in which the credit is determined;

6. The levelized monthly CSRP reservation payment will be equal to the CSRP reservation payment rate per kW in effect for the network applicable to the customer at the start of the most recent capability period multiplied by five (*i.e.*, the number of months in the CSRP capability period) and divided by 12;

7. The credit will be applied to the customer's successive 12 monthly bills starting in November until the following October, when the credit will be re-determined; and

8. A customer seeking this credit must apply for such credit by October 10 of each year.

(iii) Recovery of Bill Credits

1. Credits provided to SC 11 customers will be recovered from Con Edison customers through the MAC and from NYPA through the NYPA OTH Statement.

2. Charges will be collected under the Electric Rate Schedule and the PASNY Rate Schedule on a pro rata basis, based on forecasted rate year delivery revenues under each rate schedule to total forecasted

rate year delivery revenues under both schedules in effect at the start of the cost recovery period.

3. The credit may be adjusted to reflect DER export compensation from other proceedings (*e.g.*, Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources*). To the extent a change in the credit is appropriate, the Company will make a filing to reflect this change.

e. Changes to Standby and/or Buyback Rates

To the extent that new standby rates/buyback tariff rates are implemented during the term of the Electric Rate Plan,[65] the Company will defer any difference in revenues resulting from such change in rates and/or change between the current and future standby rate/buyback tariff methodology, for recovery from or credit to customers, as applicable.[66]

f. Lump Sum Payment of O&M Expenses and Property Taxes

The Company will offer standby customers the option to pay an up-front non-refundable lump sum charge instead of annual surcharges to cover operation and maintenance expenses and property taxes associated with interconnection costs.[67]

g. Multi-Party Offset Tariff

The Company will implement its multi-party offset tariff proposal pending in Case 16-E-0196, modified to also permit customers in multiple buildings to participate if each of the customers is connected to the generating facility by a thermal loop (delivering

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[65] On October 1, 2016, the Company expects to file the standby matrix, including changes in the standby rates and buyback tariff (SC 11), pursuant to the Track Two Order.

[66]Moreover, any and all rate design and cost allocation changes implemented pursuant to Commission orders issued in the REV or in REV-related proceedings will be implemented on a revenue neutral and earnings neutral basis to the Company.

[67] The formula here is the same as for excess distribution facilities with the change noted in section G.8.(l) of this Proposal.

steam, hot water, or chilled water). For a NYPA Customer, the Customer sponsor and/or its representative will be responsible for coordinating the interconnection and operation of the generating facility with the Company. The Multi-Party Offset Form, available on the Company's website, will be prepared and submitted by the Customer sponsor and/or its representative.[68]

h. Standby/export pilot

The Company will implement the standby export pilot as set forth in Appendix 20.

7. <u>Business Incentive Rate ("BIR")</u>

The BIR program is comprised of 452 MW, allocated both currently and as modified by the Proposal as follows:

Program	Current	Under Joint Proposal
New York City Comprehensive	195 MW (including 5 MW of expired Sandy BIR and 10 MW of expired NYC Business Incubator BIR)	165 MW
Westchester Comprehensive	42 MW (including 2 MW of expired Westchester Business Incubator BIR)	40 MW
New and Vacant	155 MW	155 MW
Biomedical Research	60 MW	80 MW
Business Incubators and Graduates	0 MW	12 MW (10 MW NYC and 2 MW Westchester County)

This Proposal provides for the following:

[68] Commission approval of this Proposal will subsume and resolve the Company's filing made in Case 16-E-0196.

a. Changes to BIR Allocations

(i) Expansion of Biomedical Research Facility Access. The total allocation for biomedical research is increased to 80 MW with the additional 20 MW coming from the NYC Comprehensive Package.

(ii) Reinstatement of BIR for Business Incubators and Business Incubator Graduates. This program, for which the application deadline was March 31, 2015, is being reinstated with 10 MW transferred from the NYC Comprehensive Package and 2 MW transferred from the Westchester Comprehensive Package.

b. Changes to BIR Discounts

The BIR discounts effective for customers who commence BIR service during the term of this Electric Rate Plan are:

SC 9 - 39%

SC 9 TOD - 34%

These percentage rate reductions will also apply to new applicants to the Excelsior Jobs Program (SC 9 – Special Provision H).

8. <u>Tariff Changes</u>

In addition to the tariff changes required to implement various provisions of this Proposal, a number of tariff changes will be made as summarized below. The specific language of the changes will be shown on tariff leaves to be filed with the Commission.

(a) BIR (Rider J): define "retail establishments;"[69] eliminate WTC BIR and Sandy BIR, which are obsolete; and identify the START-UP NY program as an eligible program under the Comprehensive Package of Economic Incentives. Also, on Leaf 177, eliminate SC 2 from the list of applicable SCs under Rider J, because that was only applicable to Sandy BIR.

(b) Increase the amount of compensation payable for losses due to power failures under General Rule 21.1 (Leaf 171).

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[69] The tariff will state that retail establishments are "entities that are included in the sale of goods or services to end users, including without limitation, restaurants; hotels; entertainment-related establishments (unless primarily used for film production); and museums."

(c) Update the percentages used for handling costs and for corporate overheads in the definition of costs associated with Special Services in General Rule 17.3 (Leaf 126) to reflect current costs.

(d) Update Special Services at Stipulated Rates for charges for hi-pot, Megger, and dielectric fluid tests and for the re-inspection charge (Leaf 121 and Leaf 122).

(e) Clarify cost responsibility under General Rule 5.6.1, “Space for Transforming Apparatus” (leaf 56) depending on whether suitable space is provided, and to require elevation of non-submersible transformer enclosures in a 100-year flood zone established by FEMA, plus an additional three feet of flooding along the horizontal plane.

(f) Update SC 6 (Leaf 419) to include LEDs as a type of lamp that can be utilized under SC 6.

(g) Eliminate text in Rider R - Net Metering for Customer-Generators (at Leaf 245) about when detailed, site-specific studies are required and instead refer to the PSC’s Standardized Interconnection Requirements.

(h) Identify in General Rule 25.3, “Merchant Function Charge” (Leaf 335) the monetary amount per kWhr by SC applicable to the supply-related (inclusive of Purchase Power Working Capital) and credit and collections-related components of the MFC.

(i) Eliminate the word “financial” in relation to hedges in Rule 25.2.2, “MSC Adjustment Factor II” (Leaf 333).

(j) Modify text related to the reactive power program described in General Rule 10.11 to eliminate obsolete tariff language about the program’s phase-in and to improve clarity about the applicability of reactive power demand charges.

(k) Clarify on Leaf 495 that the Minimum Charge for SC 13 Rate I is based on the period Monday through Friday, 8:00 AM to 10:00 PM. (The leaf currently refers to the “on-peak period.”)

(l) Correct the formula for the upfront payments for excess distribution facilities on Leaf 373.1 to Lump Sum Value = Cfn/(R - g). Additionally, set R equal to the cost of capital authorized by the Commission in each rate case.

(m) Indicate in the PASNY Tariff:

i) on Leaf 29, that certain public street lighting uses, such as traffic detectors, red light cameras, and municipal parking meters, are types of traffic control signals; and

ii) on Leaf 27, that Special Provision E of SC 6 of the Electric Tariff is not applicable to the PASNY Tariff, to conform to text on PASNY Leaf 32.

(n) Delete, as appropriate, tariff provisions that are now expiring or obsolete or being made for housekeeping purposes.

H. <u>Gas Revenue Allocation/Rate Design</u>

1. <u>Revenue Allocation</u>

The allocation of the delivery revenue change for firm customers for each Rate Year is explained in Appendix 21. The 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. The surplus/deficiency revenue adjustments allocable to each of the Con Edison classes in each Rate Year are shown in Table 1 in Appendix 21. The revenue allocation in Rate Years 2 and 3 also reflects elimination of the SC 1 and SC 3 low income discounts in the base tariff rates.

2. <u>Rate Design</u>

This Proposal establishes new competitive and non-competitive gas delivery service rates.[70] The rates implementing this Proposal will be developed as set forth in Appendix 21, and reflect the following:

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[70] If, based on the make whole extension letters referred to in footnote 8, the Commission does not issue an order on this Proposal until January or February 2017, the Company will recover shortfalls and refund over-collections that result from the extension of the suspension period in this proceeding through a "make-whole" provision, as detailed in the July 8, 2016 and August 8, 2016 letters. The revenue differences will be recovered or credited, with interest, over the

a. Firm Delivery Rates:

(i) Minimum Monthly Charges

The minimum charges for all firm service classes, except for SC 1, will remain at their current levels. The SC 1 minimum charge and the Rider J minimum charge applicable to SC 1 will increase in each Rate Year.

(ii) Low Income Discounts

The low income discount reflected in the minimum charge applicable to SC 1 low income customers will increase from $1.50 to $3.00 in Rate Year 1. For RYs 2 and 3, the SC 1 and SC 3 low income discounts reflected in base tariff rates (*i.e.*, the minimum monthly charge for SC 1 and SC 3 and the 4-90 therm block rate for SC 3) will be eliminated. As discussed in the Low Income Programs section, in RYs 2 and 3, low income discounts will be a credit on the customer's bill.

(iii) SC 2 Rate I and Rate II Applicability

The firm delivery rates reflect the following change in the applicability criteria for the SC 2 Rate I and SC 2 Rate II subclasses of Service Class No. 2. The applicability criteria for the Rate I and Rate II sub-classes of SC No. 2 will be determined by a quantitative test based on the ratio of each SC 2 customer's average billed winter use per day divided by their average billed summer use per day. For this calculation, the winter period is defined as the billing months of the most recently completed January through March and the summer period is defined as the billing months of the prior July through September. The last day of usage in a customer's billing period that occurs in these months will determine the month to which that usage is assigned. The test will be applied annually after the completion of all May billing cycles. As a result of the annual test, any Rate I customers whose ratio is above 2.2 will be transferred to Rate II. Any Rate II customer whose ratio is below 1.8 will be transferred to Rate I. Any such transfers will occur effective with the customer's June bill, beginning June 2018. Any customer with a ratio greater than or equal to 1.8 and less than or equal to 2.2 will remain at its existing rate. This calculation shall apply to all SC 2 customers with the following exceptions:

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remaining months of 2017. The Company will work with Staff to identify and calculate these revenue differences.

1. Customers taking service under Rider H – Distributed Generation Rate will not be subject to the annual review. All Rider H customers would pay the various surcharges and adjustment, as described in Rider H, applicable to SC 2 Rate I.

2. New customers commencing service under SC 2 will initially be placed on Rate I or Rate II based on their load letter and application for service (for new service requests) or based on the previous tenant's rate (for previously occupied premises). Any such new customer will remain at this rate until a subsequent annual review.

3. Customers with limited or incomplete billing history, such as new customers (as described above), will remain at their existing rate until a subsequent annual review.

4. Customers with bills or re-bills spanning several months will be excluded from the annual review, and remain at their existing rate, if the average number of billing days (*i.e.*, total billing days associated with billed usage in the season divided by 3) in either season is greater than 45.

5. Oil-to-gas conversion customers with gas meter turn-on dates later than the October 1 immediately preceding the annual review will be excluded and remain at their existing rate until a subsequent annual review.

6. For the period beginning January 2017, SC 2 customers will be placed on Rate I or Rate II, effective with their January bill, based on the ratio using their billing history for the summer 2014 / winter 2015. Customers will remain on this rate until the annual review to take place in May 2018.

(iv) Weather Normalization Adjustment:

The definition of normal heating degree days in General Information IX will be revised to reflect a thirty-year period. There will be no change in the service classes that are subject to the weather normalization adjustment except references to the term "heating" for SC 2 Rate II will be eliminated.

b. Interruptible Delivery Rates:

(i) SC12 Rate 1/SC9 Rate B:

There is no change to the Rate 1 rates, which will continue to be set each month and consist of the current block rate design with a monthly minimum charge of $100.

The annual revenue reconciliation will continue to be performed on a total bill basis. The annual revenue reconciliation period will be modified so that the reconciliation will be performed after May 31 of each year for the preceding twelve-month period ending May 31 (instead of the twelve month period ending April 30) except for the first year this change goes into effect (*i.e.*, for the reconciliation performed in RY1 after May 31, 2017). For the first year this change goes into effect, the period of the reconciliation will be increased from twelve months to thirteen months and cover the period May 1, 2016 through May 31, 2017.

(ii) SC12 Rate 2/SC9 Rate C:

Rate 2 rates for Rate Year 1 will remain the same at 8.0 cents per therm for one-, two- and three-year contracts. Rates for Rate Years 2 and 3 will be set at 8.25 and 8.75 cents per therm, respectively, for one-, two- and three-year contracts. The existing 1.0 cent per therm reduction for usage in excess of 500,000 therms per month will be retained. An existing customer will be charged the new rate after the expiration of its current contract term.

c. Gas Balancing

The following modifications will be made to gas balancing provisions applicable to SC 9 customers,[71] including power generators, and SC 20 Gas Marketers, effective January 1, 2017:

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[71] For purposes of clarification, the term "customer" included in any tariff or GTOP provision that establishes cashout and/or gas balancing provisions applicable to both or either SC 20 marketers and customers shall mean "Direct Customers," as that term is defined in the tariff, and not customers served by SC 20 marketers.

1. Increase the $4.50 per therm unauthorized use charge applicable to generators under SC 9 and the deficiency imbalance charge/failure to deliver during an OFO charge to marketers under SC 20 to $5.00 per therm.[72]

2. Change the monthly and daily cashout prices that currently utilize a Citygate index price of Transco Z6 NY as the cost basis[73] to a weighted average based on deliveries on Transco, Texas Eastern Transmission ("Tetco") and Iroquois Gas Transmission System ("Iroquois"), using Transco Z6 NY, Tetco M3 and Iroquois Z2 index prices.

3. Cashout prices to utilize fixed percentage weightings for the volumes associated with each of the pipeline indices, based on the previous year's historic weighted average of the total volumes delivered to the Company on each pipeline. These fixed percentages will be recalculated on an annual basis and will be applied to the aforementioned indices to determine the aggregated cashout price.

4. Cashout prices and imbalance charges for all volumes above the first balancing tier (including any unauthorized use of gas during an OFO) will be considered penalty gas and noted as such in the tariff; provided, however, individually negotiated agreements may provide for balancing services that include cashouts where gas used above the first balancing tier is not considered to be penalty gas.

5. The definition of OFO in the tariff will be amended to clarify that it applies to Direct Customers, as follows: "Operational Flow

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[72] The existing SC 9 power generator unauthorized use charge is: the higher of (i) 120% of the applicable wholesale electric market price; (ii) $4.50 per therm; or (iii) $2.50 per therm plus a market gas price, as determined in accordance with the Company's GTOP. The existing SC 20 charges are: (i) A deficiency charge during an Operational Flow Order ("OFO") period equal to the higher of $4.50 per therm or 120% of the cost of gas plus $1.00 per therm; and (ii) a charge for failure to deliver during an OFO period of $4.50 per therm.

[73] The following cashout prices are currently utilizing Transco Z6 NY:
i. Interruptible and Off-Peak Firm Daily Balancing Service - Deficiency Imbalance
ii. Interruptible and Off-Peak Firm Monthly Balancing – Deficiency Imbalance
iii. Power Generation Monthly Cashout– Deficiency and Surplus Imbalances
iv. Power Generation Daily Cashout– Deficiency and Surplus Imbalances
v. Firm Customers Load Following Service - Deficiency and Surplus Imbalances (note – if the Commission approves the Company's proposed DDS service to replace Load Following Service, pending consideration in Case 16-G-0406, this Proposal provides for the cashout prices to utilize the weighted average price based on deliveries on Transco, Tetco and Iroquois, using Transco Z6 NY, Tetco M3 and Iroquois Z2 index prices, effective January 2017).

Order ("OFO") means a directive by the Company to a Direct Customer(s) and/or its gas supplier(s) to adjust Citygate deliveries of gas to alleviate conditions that threaten the integrity of the system."

d. Tariff Changes

In addition to the tariff changes required to implement various provisions of this Proposal, a number of tariff changes will be made as summarized below. The specific language of the changes will be shown on tariff leaves to be filed with the Commission.

1. The uncollectible ("UB") charges related to MRA and MFC (GCF) will be updated based on the system UB rate.

2. The Billing and Payment Processing Charge will remain at its current rate of $1.20.

3. References to heating in relation to SC 2 will be eliminated as well as other tariff changes to effectuate the change in the SC 2 applicability criteria.

4. The Area Growth Program will be expanded to Westchester County.

5. The definition of costs associated with Special Services Performed by the Company in General Information Section IV will be updated to reflect current costs and corporate overheads.

6. Rider D (Excelsior Jobs Program or "EJP") will be modified to: a) require existing customers to have incremental usage of at least 25 percent over their baseline usage in order to receive EJP benefits in any month; and b) to set the EJP rates as a percentage discount from the applicable SC 2 base tariff rates, including the minimum charge. The percentage discounts, which are based on the marginal cost of service study, will be set at 41% for SC 2 Rate I and 0% for SC 2 Rate II, for the term of the Rate Plan.

7. The SC 14 Rate I maximum delivery pressure will be increased from 3,000 to 3,600 psi.

8. The SC 14 Rate II minimum charge will be updated from $55 to $113 per month.

9. The Rider J (Residential DG) rate available to SC 3 and equivalent SC 9 residential customers in buildings with 5 or more dwelling units will be eliminated since they are eligible to take service under Rider H.

10. The Rider H (non-residential DG) factor of 1.3 used to reflect the relationship between the experienced actual Winter Peak Day Gas Usage and the highest Winter Average Daily Gas Usage will be explicitly stated in the tariff.

11. Reference to the allocation of credit and collection ("C&C") targets between their MFC and POR components being established prior to the beginning of each Rate Year will be removed.

12. State in General Information IX. 8. "Merchant Function Charge," the cents per therm rates by SC applicable to the supply-related and credit and collection-related components of the MFC. These rates will be based on the approved targets and exclusive of any prior period reconciliation.

13. Eliminate language on Leaf 316.4, in the "Miscellaneous Provisions" Section (D) of Transportation Service SC 9 since this language only related to the 2004/2005 winter period and is no longer applicable.

14. Add, for clarification purposes, "water heating use" to "cooking" use in section 5 of the "Service is not Available Under this Service Classification" section for SC 1.

15. SC14 has been reorganized for clarity.

16. Amend, as necessary, the gas cashout and balancing sections to clarify to which customers the provision is applicable.

17. Delete, as appropriate, tariff provisions that are now expiring or obsolete or being made for housekeeping purposes.

I. <u>Performance Metrics</u>

Performance metrics designed to measure various activities that are applicable to the Company's Electric,[74] Gas, and Customer Service Operations,[75] and assess negative

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[74] Performance metrics for Electric Safety Standards were established by the Commission in Case 04-M-0159. Upon Commission approval of this Joint Proposal, the Company is authorized to increase the inspection cycle for underground equipment (excluding underground residential distribution ("URD") equipment) from five years to eight years. The modified performance standards are set forth in Appendix 15. The Signatory Parties also note that the performance metrics for Electric set forth in Appendix 14 do not include the Intrusion Detection or System

and/or positive revenue adjustments where performance targets are not met or are exceeded, respectively, are set forth in Appendices 14, 15, 16 and 17. Any negative or positive revenue adjustments incurred by the Company during the Rate Plans will be deferred for credit to or recovery from customers, as applicable, and will be addressed in the Company's next electric and/or gas base rate cases.

J. Additional Electric Provisions

1. System Peak Reduction Programs, Energy Efficiency and Electric Vehicle Programs

The Company will continue or expand existing and implement new energy efficiency, electric vehicle and system peak reduction programs described in this section (collectively, "New Programs"). The New Programs, as well as the associated EAMs also discussed in this section, shall be implemented with the goals of increasing system efficiency as well as decreasing energy use and system peak demand. The New Programs must be cost effective on a portfolio basis, collectively aggregating the New Programs, per the BCA handbook and meet a Societal Cost Test BCA of 1.00 or higher. The Company will file an analysis showing the cost effectiveness (per the BCA handbook) of the New Programs portfolio on an annual basis three months prior to the beginning of each Rate Year. For RY1, the Company will provide the analysis by March 1, 2017.

Restoration metrics included in the existing electric rate plan because the Company has completed the work required by the Intrusion Detection metric and the System Restoration metric has been replaced by a scorecard.

[75] See section L.12 for the Uncollectible/Residential Service Termination positive incentive.

a. System Peak Reduction Program

The System Peak Reduction Program shall consist of two components: (1) the system peak reduction program; and (2) the Electric Vehicle ("EV") Program.

The system peak reduction program will be designed and implemented to reduce system peak demand. The Company will work directly with customers and market partners to offer battery storage systems, thermal storage, building management systems ("BMS")/controls, chiller and Heating, Ventilation and Air Conditioning ("HVAC") upgrades, demand response enablement, and fuel switching to non-electric air conditioning, among others, to reduce peak demand. The Company shall strive to design and implement the system peak reduction program such that one- half of the cumulative target over the three-year term of the Electric Rate Plan is achieved via advanced technologies, including, but not limited to, localized battery storage packaged systems, thermal storage and advanced BMS/controls.

The EV Program will incent existing light-duty electric vehicles in the market to charge during off-peak hours, with the goal of reducing system peak demand. The Company will provide equipment, at no cost to the customer, to measure and verify charging times.

Within 30 days after the issuance of a Commission order in these proceedings, the Company will commence discussions with interested parties on the possible development of a new service classification, new rates within existing service classifications, incentives and/or pilot programs for electric vehicles, including but not limited to cars, light trucks, heavy trucks and buses. The intent of these discussions is to attempt to incentivize the off-peak charging of electric vehicles in a manner that reflects the environmental and other societal benefits of vehicles operating on electricity rather than fossil fuels.

The targeted incremental system peak reduction levels shown below include peak reductions from the System Peak Reduction Program as well as peak reductions resulting from the Energy Efficiency Program and ETIP:

(i) RY1: 43.5 MW for the combined programs; includes 11 MW incremental from the system peak reduction program, 31 MW from the Energy Efficiency Program and ETIP, and 1.5 MW from the EV Program.

(ii) RY2: 65.5 MW for the combined programs; includes 16 MW incremental from the system peak reduction program, 48.5 MW from the Energy Efficiency Program and ETIP, and 1 MW from the EV Program.

(iii) RY3: 94.0 MW for the combined programs; includes 22 MW incremental from the system peak reduction program, 71 MW from the Energy Efficiency Program and ETIP, and 1 MW from the EV Program.

Except as noted above, each year's performance will be judged independently of previous years' performance (*i.e.*, no "carry over" of over- or under-performance from previous years).

b. Energy Efficiency Program

Con Edison will implement a portfolio of energy efficiency programs, the Energy Efficiency Program, with budgets and savings targets above and beyond those currently offered through its ETIP. The Company will develop these programs to increase energy efficiency achievements through a combination of responding to locational needs, bundling offerings through Distributed Energy Resource ("DER") providers, leveraging market-based approaches including market solicitations, time-variant pricing, and other market transformation efforts.

The following energy efficiency targets will apply over the term of the Electric Rate Plan and are inclusive of the ETIP targets. The targeted incremental savings levels shown below include GWh reductions resulting from the Energy Efficiency Program as well as ETIP and the System Peak Reduction Program:

(i) RY1: 178 GWh for the combined programs – 20 GWh above ETIP, including 15 GWh incremental from the Energy Efficiency Program and 5 GWh from the System Peak Reduction Program

(ii) RY2: 270 GWh for the combined programs - 90 GWh above ETIP, including 83 GWh incremental from the Energy Efficiency Program and 7 GWh from the System Peak Reduction Program

(iii) RY3: 391 GWh for the combined programs - 211 GWh above ETIP, including 201 GWh incremental from Energy Efficiency Program and 10 GWh from System Peak Reduction Program

Each year's performance will be judged independently of previous years' performance (*i.e.*, no "carry over" of over- or under-performance from previous years).

c. Program Coordination

The New Programs will be managed as an integrated portfolio. The New Programs will be coordinated with Con Edison's ETIP programs efforts to create a fully integrated portfolio in which programs will not be in competition with each other. To the maximum extent practicable, Con Edison will work with NYSERDA and NYPA to avoid competition over, for example, the same customers or buildings.

d. Earnings Adjustment Mechanisms

The Proposal recommends the following EAMs for the Company's Incremental GWh Savings and Incremental System Peak MW Reductions.

(i) Program-Achievement Based EAMs

1. Incremental GWh Savings– this EAM incentivizes Con Edison to achieve the above-stated energy efficiency savings targets. Con Edison shall only receive incentives for the Incremental GWh Savings EAM for performance incremental to the achievement of the GWh savings set forth in its ETIP filed April 1, 2016, with the ETIP savings for 2018 applicable to RY3. Full achievement of those savings

levels each year shall be a condition precedent to the Company's ability to earn the Incremental GWh Savings incentive.

2 Incremental System Peak MW Reductions – this EAM incentivizes Con Edison to achieve the above-stated system peak reduction targets.

(ii) Outcome-Based EAMs

1. Energy Intensity – this EAM incentivizes Con Edison to help customers reduce total usage on a per customer or other appropriate per unit basis (*e.g.*, GDP, floor space, employment – metric(s) to be defined through the collaborative described below).

2. Customer Load Factor – this EAM incentivizes Con Edison to improve the load factor of poor load factor customers in a manner which is consistent with REV's three environmental goals (metric to be defined through the collaborative described below).

3. DER Utilization – this EAM is intended to encourage Con Edison to work with DER providers and expand the use of DER in its service territory both for the purposes of reducing customer reliance on grid-supplied electricity and for beneficial electrification.

The details of the three Outcome-Based EAMs will be developed in a collaborative to be commenced in September 2016 with the objective of completing work on EAMs for RY1 by November 1, 2016. It is the intent and expectation of the Signatory Parties that the details of the EAMs for RY1, including incentive levels, as appropriate, will be considered by the Commission simultaneously with its consideration of the Joint Proposal. In the event the collaborative reaches agreement on the Outcome-based metrics, the Company, working with collaborative participants, will prepare a consensus report describing that agreement by November 1, 2016 that includes a detailed description of the Outcome-based metrics and associated EAMs. If the collaborative does not reach agreement on the Outcome-based metrics and is unable to agree to a consensus report, the parties may file comments on the collaborative discussion and/or recommendations to the Commission regarding the RY1 EAMs by November 1, 2016 and reply comments/recommendations by November 8, 2016.

As part of the consensus report, the Company will provide a report card showing:

i. Historic normalized system peak (past 10 years) and current normalized system peak (non-coincident and coincident to the New York Control Area ("NYCA") peak).

ii. Historic normalized annual system load factor (past 10 years) and current normalized load factor.

The following dollar amounts associated with each EAM are set forth, at minimum, 100 percent of target and maximum achievement levels. EAMs will be determined linearly between the minimum and 100 percent levels and between the 100 percent and maximum levels:

In Millions	**RY1**	**RY2**	**RY3**	**TOTAL**
Minimum Threshold	**$0.86**	**$2.99**	**$4.94**	**$8.79**
Incremental GWh Savings	$0.58	$2.38	$3.71	$6.67
Incremental System Peak MW Reductions	$0.29	$0.60	$1.24	$2.13
Outcome-based metrics[76]	--	--	--	--
Percent of Outcome-based EAMS	--	--	--	--
At 100% of Target	**$7.41**	**$16.68**	**$27.81**	**$51.90**
Incremental GWh Savings	$4.03	$5.66	$7.73	$17.42
Incremental System Peak MW Reductions	$1.15	$2.68	$3.40	$7.24
Outcome-based metrics	$2.22	$8.34	$16.69	$27.25
Percent of Outcome-based Metrics	**30%**	**50%**	**60%**	**52%**
Maximum	**$18.12**	**$33.34**	**$50.99**	**$102.45**
Incremental GWh Savings	$9.22	$11.31	$14.22	$34.75
Incremental System Peak MW Reductions	$3.46	$5.36	$6.18	$15.00
Outcome-based metrics	$5.43	$16.67	$30.59	$52.70
Percent of Outcome-based Metrics	**30%**	**50%**	**60%**	**51%**

These tables reflect the following incremental GWH savings and system peak reductions:

Incremental GWh Savings			
	RY1	RY2	RY3
Min	158	224	293
Target	178	270	391
Max	198	316	489

[76] To be recommended via collaborative outlined in J(1)(d)(2)(iii).

Incremental System Peak MW Reductions			
	RY1	RY2	RY3
Min	28.3	49.1	70.5
Target	43.5	65.5	94.0
Max	58.7	81.9	117.5

The incremental savings and peak reductions stated above are based upon the following percentage bands:

Incremental GWh Savings as Percent of Target			
	RY1	RY2	RY3
Min	89%	83%	75%
Target	100%	100%	100%
Max	111%	117%	125%

Incremental System Peak MW Reductions as Percent of Target			
	RY1	RY2	RY3
Min	65%	75%	75%
Target	100%	100%	100%
Max	135%	125%	125%

On March 31, 2018, 2019 and 2020, Con Edison shall make a compliance filing to the Commission detailing the savings and other benefits achieved and showing the calculation of incentives earned under each EAM. The Company may begin collecting the calculated amount of incentives forty-five days thereafter, subject to adjustment if the Commission determines that the Company's incentive calculations should be corrected.

To the extent that the Company would otherwise be eligible for a Program-Achievement based EAM in either RY2 or RY3 and the unit cost to deliver the applicable Program is more than 10 percent greater than the annual budget level on a $/GWh or $/MW basis, as applicable, the Company will make a compliance filing ninety (90) days in advance of the surcharge effective date with the Commission, before collecting that year's program-specific incentive. The filing will explain the increase in unit cost compared to budget level, and demonstrate that the applicable Program remains cost-effective. If the variance is less than or equal to 15 percent, the Company may immediately begin collecting the surcharge. If the variance is greater than 15 percent, parties will have forty-five (45) days from the date of the Company filing to submit comments. If the Commission does not take action to the contrary within 90 days, the Company may begin collecting applicable EAMs. EAMs are subject to refund as determined by the Commission.

e. Cost Recovery

The expenditures for the Energy Efficiency Program, which are reflected in the revenue requirements, are as follows:

Energy Efficiency Program

2017: $3.0 million
2018: $23.0 million
2019: $73.0 million

The electric revenue requirements also reflect the following budgets for:

System Peak Reduction Program

2017: $16.0 million
2018: $24.0 million
2019: $32.0 million

EV Program

2017: $1.5 million
2018: $2.0 million
2019: $2.5 million

Electric rates are designed for the Company to recover the costs of the Energy Efficiency Program, system peak reduction program and the equipment portion of the EV Program over ten (10) years, including the overall pre-tax rate of return on such costs.

Electric rates are designed to recover the rate incentive portion of the EV Program through base rates as an expense.

EAMs earned by the Company will be allocated between Con Edison customers and NYPA on the following basis as set forth below. The allocated incentives will be collected through the MAC and NYPA OTH Statement in equal increments over the following 12-month period beginning in April.

NYPA will be required to contribute to, and be eligible for participation in, the System Peak Reduction Program. NYPA will be allocated five (5) percent of the System Peak Reduction Program costs as well as the Program-Achievement based EAMs associated with the System Peak Reduction Program targets. Over the three-year period of the Electric Rate Plan, NYPA will make best efforts, in consultation with its customers, to acquire an additional aggregated 1.35 MW of projected system peak reduction above an annual baseline reduction of 2 MW per year. At the end of the three-year period, the total projected system peak reduction resulting from these efforts would be 7.35 MW.

NYPA will not be required to contribute to, nor will NYPA be eligible to participate in, the Energy Efficiency Program. NYPA will not be required to fund any portion of the Program-Achievement based EAMs associated with the Energy Efficiency targets. NYPA will pay the full class allocation (approximately 11 percent) of the Outcome-Based EAMs.

f. Reporting Requirements

The Company shall file a quarterly report demonstrating the spending, funding, and savings achieved (both MW and MWh) for each program. The reports will include information regarding the use of advanced technologies in the system peak reduction program. For the last report filed under this Electric Rate Plan, the Company will include a back cast analysis of the BCA for the New Programs. The Company and Staff will work together to determine how this analysis should be performed.

The Company shall solicit input and insights from interested stakeholders regarding program innovations and improvements.

g. Post Rate Plan Period

If the Company does not file for new rates to be effective January 1, 2020, the Company may submit a petition to the Commission proposing new Energy Efficiency Program and System Peak Reduction Program budgets, targets and related EAMs for the Post Rate Plan Period.

2. Distributed Generation Interconnection Earnings Adjustment Mechanism

The Company will have the opportunity to earn an EAM for interconnection of Distributed Generation ("DG") larger than 50 kW and up to 5 MW. The EAM will measure three components of DG processing: (1) Standard Interconnection Requirement timeliness; (2) an independent third party customer satisfaction survey; and (3) an independent third party audit of failed applications. The Company may defer for future recovery the combined cost of the independent third party audit and survey if the aggregate cost is greater than $100,000 in any Rate Year. The EAM targets will be based on DG customers that began the application process under the March 2016 revised DG Standard Interconnection Requirements.

a. Rate Year 1 Targets without EAM

The Company will convene a collaborative process soon after September 16, 2016.

This collaborative will seek to reach agreement by December 1, 2016 on the survey plan and instrument, which will include determining which DG applicants will be included in the survey. The collaborative will seek to develop a process that will be used by the independent third party that will conduct the survey so that the participants are anonymous. The Con Edison specific survey plan and instrument will be in effect unless and until the Commission approves a state-wide survey plan and instrument, unless the Commission directs otherwise.

Con Edison will reconvene the collaborative soon after March 31, 2017 and conclude it by May 31, 2017. The parties will discuss and seek agreement upon 2017 targets for the three components of DG processing. There will be no EAM for RY1. Con Edison will develop a baseline for the customer satisfaction survey based on collected information from January 1, 2017 to March 31, 2017 and the collaborative will consider how the audit of failed applications[77] will be used to develop a performance measure. If the collaborative cannot agree upon target(s) by May 31, 2017, DPS Staff will set the target(s).

b. Rate Years 2 and 3 Targets and EAMs

The EAM will be five basis points for RYs 2 and 3,[78] except that parties may seek Commission approval for changes in the basis point amount of up to five basis points. Con Edison will reconvene the collaborative soon after June 30, 2017 to develop RY 2

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[77] The collaborative will define what is meant by failed applications, which may also be referred to as withdrawn and abandoned applications. If a statewide definition is adopted in a Statewide proceeding, that definition will then be applied for failed/withdrawn and abandoned applications.

[78] Such amount is estimated to be $7.95 million in RY2 and $8.25 million in RY3**.**

targets for DG greater than 50 kW and up to 5 MW. Con Edison will develop a baseline for customer satisfaction survey based on information collected in the survey from January 1, 2017 to June 30, 2017 and the collaborative will consider whether to modify the performance measure for the audit of failed applications. If Con Edison is unable to achieve consensus with the collaborative for RY 2 targets by August 31, 2017, parties may file with the Commission request(s) for approval of targets no later than September 27, 2017. Parties will then have two weeks to provide comments on other parties' filing(s).

Con Edison will reconvene the collaborative soon after March 31, 2018, to determine Rate Year 3 targets. Con Edison will develop a baseline for customer satisfaction survey based on information collected in the survey from January 1, 2017 to December 31, 2017 and the collaborative will consider whether to modify the performance measures for the audit of failed applications. If Con Edison is unable to achieve consensus with the collaborative for Rate Year 3 targets by May 31, 2018, parties may file with the Commission a request for approval of targets no later than June 30, 2018.

c. Reporting

On March 31 of 2018, 2019, and 2020, Con Edison will submit a report to the Commission on its previous year's performance in relation to the three targets and include a discussion of its earned EAM, if applicable. The Company will also provide an explanation of targets not achieved, if applicable. The Company may begin collecting the calculated amount of incentives forty-five days thereafter, if there is no Commission action[79] taken within that time. The EAM is subject to adjustment if the Commission determines that the Company's incentive calculations should be corrected. The amount of the incentives earned by the Company will be allocated between Con Edison customers and NYPA based on the PASNY allocation as defined in the Proposal. The allocated incentives will be collected through the MAC and NYPA OTH Statement in equal increments over the following 12-month period.

K. Additional Gas Provisions

1. Methane Reduction Collaborative

A methane reduction collaborative began as a result of the storm hardening process established in the 2014 Gas Rate Plan.[80] As part of this collaborative, there is an ongoing pilot addressing Type 3 leaks. Once Con Edison completes the phase currently scheduled to be completed in 2016, where Con Edison is seeking to prioritize the repair of Type 3 leaks based upon third party testing, and the results are identified, the parties will assess next steps for the collaborative. The Signatory Parties recommend that the next steps will include (a) further consideration of prioritization of Type 3 leak repairs using leak flow rate on an ongoing basis; and (b) consideration of prioritization of pipe replacement activities using leak flow rate as a secondary factor.

2. Residential Methane Detector Program

The Company will work with Staff and other interested parties to develop a residential methane detector program. This program will provide residential methane

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[79] If the Secretary issues a notice of potential Commission action within the 45 day period, unless the Commission takes action within 120 days from the date of the notice, the Company may begin recovery after the end of such 120 day period.

[80] 2014 Rate Order, pp. 70-71.

detectors to residential customers at no charge, on a first-come, first-served basis, for residential customers to install inside their homes.[81] Staff and the Company, with input from interested parties, will determine the specific methane detector to be used. The program will be funded by $1.975 million remaining from a reconciliation of R&D costs in Case 09-G-0795. Of the $1.975 million available to fund this project, approximately one-half will be directed towards providing these detectors to participants in the Company's gas low income program, with a priority focus for customer locations where meter sets are located within customers' apartments. The Company will file a plan with the Commission setting forth selection criteria, timing, reporting status, and administration by December 31, 2016.

If, at the end of the Gas Rate Plan, the Company has not provided $1.975 million (plus applicable interest) of residential methane detectors to customers, the remaining amount will be addressed in the Company's next gas rate proceeding.

3. <u>Inside Gas Meters</u>

The Company will relocate and install gas meters that are located inside a customer's premises outside when performing any planned service line replacements, new service installations, or under other circumstances that offer the customer and the Company the opportunity to relocate meters outside (*e.g.*, major renovation projects), except: (i) where the customer refuses to provide consent to such relocation; (ii) where local building codes or regulations preclude outside meters; (iii) for safety considerations; (iv) where space constraints or physical barriers preclude relocation; and/or (v) when

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[81] This program will be separate from the Company's current residential methane detector R&D programs.

responding to an emergency. The Company may also consider whether and where to relocate meters if the premise is located in a flood plain (*e.g.*, elevating the gas meter to a higher location).

Customers that refuse to move meters outside: 1) will be asked to sign a form explaining the reason(s) for refusal, and 2) will be subject to charges for costs related to survey/inspection of inside piping in accordance with tariff provisions that may be established pursuant to Commission directives in Cases 14-G-0357 and 15-G-0244.

In instances where one or more of the above exceptions apply, the Company will track and document each customer meter it does not relocate outside, as well as the reason(s) the relocation was not performed. The Company will track the incremental costs associated with moving meters outside. These costs will be deferred for future recovery from customers.

The Company will file with the Secretary an annual report that includes: 1) the number of meters relocated outside, 2) the number of meters left inside, and 3) of the meters left inside, the number that involved service replacements by insertion of a new service line in the existing service line.

4. <u>Workforce Development</u>

The Company will continue to work with local schools, local labor unions and other qualified organizations to administer a workforce development program to train future utility workers to meet the Company's increased operational needs in Gas Operations.

5. <u>Fire Department Gas Emergency Training</u>

The Company will enhance its training regarding the appropriate response to gas-related emergencies offered to local fire department first responders throughout its service territory. These enhancements will include more hands-on training, improvements to the training curriculum and an increased frequency of drills and other training targeted at improving the awareness of and response to natural gas leak emergencies. Additionally, the Company will make improvements to the natural gas training facilities at the Westchester County Fire Training Center.

6. American Petroleum Institute Recommended Practice 1173

The Company will commence implementation of the American Petroleum Institute Recommended Practice 1173**,** which is a process to guide pipeline operators in developing and maintaining a pipeline safety management system.

7. Gas Restoration Working Group

Within sixty (60) days of the Commission's issuance of an order approving this Proposal, the Company will initiate discussions with interested parties and work in good faith to identify ways the Company and interested parties can each contribute to improving the process for restoring gas service to customers.

L. Customer Operations Provisions

1. Customer Service System ("CSS") Replacement

During RY2, the Company will begin to implement its plan to replace its current Customer Service System ("CSS"), a suite of systems that support customer service and billing functions, with a new commercial off-the-shelf system. The Company anticipates the following five-year schedule for CSS replacement:[82]

[82] The timeframes for the project phases are preliminary estimates and subject to change as work on the project progresses. Any changes will be submitted for Staff review.

a. Mid 2018 - 2019 – Prepare Phase: Activities include establishing project governance and resourcing, as-is requirements review, Customer Information System ("CIS") and system integrator selection and procurement, updated business case.

b. 2020 – Analyze / Blueprint Phase: Activities include business process analysis, requirements analysis, functional design, and defining project development blueprint, including tasks, activities and resources.

c. 2021 – Mid 2023 Development Phase: Activities include technical design of solutions, build/configuration, data cleanup and conversion, training, and communications, with anticipated deployment in 2023.

2. <u>Data Access</u>

Aggregated Whole Building Data: The Company will add functionality to its current process for providing aggregated whole building data to building owners ("building-level data") in 2017. With this new functionality, the Company will be able to directly upload aggregated whole-building usage data to the EPA's Portfolio Manager using a web service interface. The Company will implement this new functionality by year-end 2017. The fees for providing such data that are currently set forth in General Rule 17.5 of the Electric Tariff and General Rule IV(3)(c) of the Gas Tariff will be eliminated effective January 1, 2017; provided, however, the Company reserves right to seek Commission authorization to charge fees for providing building-level and/or other data consistent with the REV Track Two Order.

Green Button Connect ("GBC"): The Company will implement and deploy GBC functionality with respect to customer usage information, with a target date for implementation of year-end 2017. The Company will consider adding data sets, other than customer usage information, in RYs 2 or 3, consistent with its July 29, 2016 AMI Customer Engagement Plan.

NYPA Customer Usage Information: Each NYPA governmental customer's energy/demand/meter data will be available to such NYPA governmental customer on the same terms as such data are available to Con Edison customers, without any further consent by NYPA.

3. <u>Inactive Gas Accounts</u>

The Company agrees to take the following steps to improve its gas service termination processes with respect to inactive gas accounts:

a. Develop/improve a customer service representative (or equivalent) script attempting to obtain successor or landlord information for contact to establish responsibility for the service.

b. Establish/expand a team of employees whose focus is to make field visits on inactive gas accounts to obtain successor information, or to gain access to lock the meter.

c. Enhance process to prioritize resolution of a meter associated with an inactive gas account that shows consumption through the following measures:

(i) The Company will consider a meter for prioritization when consumption is found upon the second consecutive reading after the service end date, where an advance is identified. Minimum usage thresholds will be established and adjusted, as needed, after coordination with DPS Staff.

(ii) For non AMI meters, the Company will expedite the second field visit and/or replevin process for occupied buildings, and expedite the street cut process for vacant/unoccupied buildings.

(iii) For AMI meters, the Company will implement processes to identify on a more immediate basis, any gas meters advancing and expedite field activity and any subsequent replevin or street cut activity.

d. Develop a voluntary Leave on for Landlord ("LOFLL") program that includes documented confirmation the landlord has accepted responsibility for accounts being transferred to the landlord, and includes notification for each transfer/occurrence through the method requested by the landlord. The LOFLL program will also cover electric accounts.[83]

e. Develop a marketing effort promoting the LOFLL program, which includes incorporating the program into public awareness programs.

f. Engage with New York City and Westchester County and the municipalities in the County to develop modifications to the process for the issuance of permits for street cuts, if and as appropriate.[84]

g. Engage New York City and Westchester County and the municipalities in the County to develop programs to identify buildings where gas service may need to be inspected for termination due to unsafe conditions.

h. Establish a process/program to pursue replevin of meters associated with inactive gas accounts, and implement where appropriate.

4. Forms of Identification for Service Applications

Effective January 1, 2017, the Company will begin accepting Individual Taxpayer Identification Numbers ("ITIN") and the New York City Identification Card ("IDNYC") as acceptable forms of identification for residential service applications, in addition to the currently-accepted forms of identification.

5. Notifications For Resetting Volume Correctors

From time to time, the Company must replace volume correctors on some types of gas meters to appropriately compensate the delivery pressure or temperature coming into the premises. Beginning October 2017, the Company shall notify customers in writing of any resetting of a volume corrector on the customer's gas meter where such resetting results in a back-billing, and will provide the reason for and the details of such resetting.

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[83] Costs associated with the LOFLL program will be allocated 50/50 between gas and electric.

[84] The Company will require a point of contact at Westchester County that will attempt to facilitate discussion with the municipalities in Westchester County.

6. <u>Notifications for Potential Replevin Action</u>

In addition to the notifications and processes currently in place related to the Company's initiation of replevin actions of residential meters, the Company shall provide customers with a letter developed by PULP and the Company, with input from other parties in the form included in Appendix 23, explaining how the customer can respond to legal action that may be initiated by the Company to seize its residential meter and providing information as to customer rights and responsibilities. This letter will be sent to customers approximately 7-10 days prior to the initiation of a replevin action by the Company. The Company shall notify Signatory Parties if the letter in Appendix 23 requires substantial modification (*e.g.*, due to updated court directives, or other legal authority), and to offer PULP and other interested parties the opportunity to provide input to the Company's redrafting of the letter. Within 30 days of the filing of the Joint Proposal, PULP shall notify the Commission in Matter 16-01387 that this resolves the replevin-related concerns set forth in its petition on a going-forward basis because the letter reflects the new replevin process as described in the Chief Clerk's Memorandum 117-A.

7. <u>Digital Customer Experience</u>

As part of the Digital Customer Experience ("DCX") Project, the Company will make available to customers comparative usage information that will allow customers to compare their usage information to other similarly-situated customers. The Company will file quarterly reports with the Secretary on the DCX program that details progress on the re-design of existing digital content and services, and implementation of new digital services/functionality.

8. Landlord Arrearage Working Group

Within sixty (60) days of the Commission's issuance of an order approving this Proposal, the Company will initiate discussions with interested parties and work in good faith to address concerns regarding arrearages associated with landlord/tenant accounts.

9. Outreach and Education

Con Edison will continue to develop and implement outreach and education activities, programs and materials that will aid its customers in understanding their rights and responsibilities as utility customers. The Company will coordinate its outreach and education activities related to DCX, GBC, and AMI implementation to the extent practicable. The Company will continue to survey its customers and to include appropriate questions in the surveys to evaluate its customer outreach program and identify areas where its outreach efforts could be further strengthened or improved. The Company will file with the Secretary by September 30 of each Rate Year a summary and assessment of its customer education efforts, including a description of its efforts to coordinate the DCX, GBC and AMI initiatives.

10. Mandatory Hourly Pricing

The Company will continue its Mandatory Hourly Pricing ("MHP") program "as is" during the Electric Rate Plan (*i.e.*, no change to the threshold kW demand level). The Company will expand its MHP program to include customers with demands over 300 kW after the Company's territory-wide completion of AMI installation.

11. Same Day Electric Service Reconnections

The Company will attempt same day electric service reconnection for residential electric customers whose service was disconnected for non-payment at the meter and who become eligible for reconnection by 5:00 p.m. Monday-Friday (*e.g.*, by making payment). This process does not include customers where the meter was removed or service was cut in the street. The Company will endeavor to restore service to such customers on the same day, to the extent practicable.

The Company will file a report on residential same-day reconnections for each calendar quarter (the "reporting period"). Each report will be filed with the Secretary within thirty (30) days after the end of each reporting period. The report will indicate the number of residential electric customer reconnections issued by 5:00 p.m. Monday-Friday and the number of same-day reconnections attempts made to such customers.

12. Uncollectible/Residential Service Termination Positive Incentive

For each Rate Year, the Company will earn a positive revenue adjustment for achieving the following targets for residential service terminations and bad debt write-offs:

a. A positive revenue adjustment of $6 million if the Company achieves both of the following targets:

   Terminations < or = 62,000
   Bad debt write-offs < or = $45.7 million

b. A positive revenue adjustment of $4 million if the Company achieves both of the following targets:

   Terminations < or = 65,000
   Bad debt write-offs < or = $45.7 million

c. A positive revenue adjustment of $2 million if the Company achieves both of the following targets:

   Terminations < or = 68,000
   Bad debt write-offs < or = $48 million

Any positive revenue adjustment earned will be allocated between electric and gas based on the common cost allocation for Customer Accounting Expenses (84%/16%).

M. Advanced Metering Infrastructure

1. AMI Scorecard

The AMI Order required the Company to develop a set of metrics for AMI "that can be used by the Commission to monitor the success of this AMI project based on Con Edison's purported benefits related to system operation, outage management, and billing errors."[85] Appendix 18 identifies each metric that the Company will track, as well as the specific reporting requirements related to each metric. With the exception of the Customer Awareness AMI metric, there are no EAMs associated with the AMI metrics in Appendix 18.

2. AMI Platform Service Revenues

To the extent the Company identifies an opportunity to generate platform service revenues from the AMI system, the Company shall propose that 80% of the revenues generated should be provided to customers and 20% of the revenues retained by the Company so long as the platform service revenues derive from the Company's monopoly function as per the REV Track Two Order.

3. AMI Customer Awareness Earning Adjustment Mechanism

The Company has the opportunity to earn incentives related to AMI customer awareness for the term of this Rate Plan ("AMI EAM"). The AMI EAM is focused on the Company's efforts to promote customer awareness of AMI technology, features and benefits. The Company's performance will be based on surveys of customers in each deployment region. The Company will conduct an initial survey three months prior to

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[85] AMI Order, p. 47.

the deployment of AMI in each region to establish a baseline of customer awareness related to AMI. Based on the baseline survey results in each region, the Company and Staff will determine appropriate regional target levels for customer awareness of AMI post-deployment.

During AMI roll-out, the Company will conduct progress surveys ("check-in surveys") semi-annually in each region, beginning at least six (6) months after the beginning of deployment, through the end of roll-out in each region. These check-in surveys will include only customers that have had AMI meters installed. The Company will provide the results of the check-in surveys as part of its AMI scorecard metrics reporting.

At the end of deployment in each region, the Company will conduct a post-deployment survey that again measures customers' awareness related to AMI. If the results of the post-deployment survey in a region meet or exceed the established target for that region, the Company will receive an earnings adjustment of $250,000 per region, with a maximum potential earning adjustment of $500,000 during the Rate Plan.[86] All surveys will be conducted by an independent third party.

The Company will provide the post-deployment survey results in the next AMI scorecard metrics report, which will indicate if the Company earned the EAM and the amount of the earned EAM. The Company may begin collecting the calculated amount of incentives forty-five days thereafter if there is no Commission action taken within that

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[86] If the Company does not file for new rates to be effective January 1, 2020, the Company will have the opportunity to receive an earnings adjustment of $250,000 for each additional region in which it completes AMI installation and meets the target levels of the post-deployment survey.

time. The amount of the incentives earned by the Company will be allocated between Con Edison's customers and NYPA based on the PASNY allocation as defined in the Proposal. Any positive revenue adjustment earned will be allocated between electric and gas based on the common cost allocation for Customer Accounting Expenses (84%/16%). The allocated incentives for electric will be collected through the MAC and NYPA OTH Statement and for gas through the MRA in equal increments over the following 12-month period.

N. Electric and Gas Low Income Programs

The Company's Electric and Gas Low Income Programs consist of two components. First, during the terms of the Rate Plans, and continuing thereafter unless and until changed by the Commission, the Company will provide a discount, depending on the program, to eligible and enrolled low income residential customers. Second, during the terms of the Rate Plans, the Company will conduct a waiver of reconnection fee program.

The Electric and Gas Low Income Programs have been designed to recover $54.7 million of discounts for electric and $10.9 million of discounts for gas in each Rate Year.

1. Customer Enrollment

Qualifying Customers may enroll or be enrolled in the Low Income Programs as follows:

First, the Company will continue its existing enrollment procedure for Utility Guarantee ("UG") and Direct Vendor ("DV") customers by the New York City Human Resources Administration ("HRA") or the Westchester County Department of Social Services ("DSS") (the "Agencies"). The Agencies can utilize a Company web application or submit a paper application to enroll a customer on UG or DV. Upon receipt of the electronic or paper application, the Company will update its customer records to indicate that the customer is enrolled in the Low Income Program.

Second, the Company will continue its existing enrollment procedure for Home Energy Assistance Program ("HEAP") recipients whereby the Company enrolls a customer when it receives payment associated with a HEAP grant.

Third, the Company will continue its existing procedure to enroll individual customers upon (a) individual customer application with appropriate documentation and/or (b) receipt of notification from the Agencies of eligibility through any qualifying program. In these cases, the Company will manually update its customer records to indicate that the customer is enrolled in the Low Income Program.

Finally, in April and October, the Company will initiate a semi-annual reconciliation of Company and Agency records by providing the agencies with files for the agencies to compare and advise as to whether the customer(s) qualify for the program.[87] By each June and December during the Rate Plans, the Agencies shall provide the results of a reconciliation of (a) HRA and DSS records of recipients of benefits under Qualifying Programs for which they maintain records with (b) records provided by Con Edison of all SC1 electric residential customers and SC1 and SC3 gas residential customers.

For purposes of this procedure, reconciliation means that each Agency will, in a manner agreed upon by the Company and the Agency, identify those customers on the

[87] The semi-annual reconciliation set to be initiated in October 2016, for customer participation starting in January 2017, will include Medicaid customers.

list provided by the Company that are then participating in any of the Qualifying Programs, except Supplemental Security Income (“SSI”). The Company will notify the parties if the reconciliation has not been completed by June and December, respectively. The Company will take prompt action to enroll or de-enroll customers on the basis of the data provided by the Agencies within thirty (30) days after receiving the data from the Agencies, including data received after the due date.

If the reconciliation with either or both Agencies is not completed within the time frame noted above, or the Company concludes at any time that the annual reconciliation process is impracticable, or one or both of the Agencies impose conditions on the process that impose on Con Edison more than *de minimis* additional administrative costs, the Company will notify the parties of this circumstance. The Company, Staff, UIU, NYC, Westchester, and PULP will work to develop, to the extent necessary, an alternative means to efficiently and effectively identify and enroll Qualifying Customers. If an alternative method is developed, the Company will notify all the parties that an alternative method will be used and will explain the mechanics of the alternative method.

The Company will contribute up to $50,000 in 2017, 2018 and 2019 towards the Agencies’ mailing costs, not recovered in rates, to facilitate the semi-annual reconciliation. The Company will defer for future recovery amounts in excess of $50,000, up to an additional $50,000, that are incurred by the Agencies as part of the semi-annual reconciliation. The Company’s contribution will be applied first to the Agencies’ actual mailing costs. The Agencies will absorb their respective costs, if any, in excess of the aggregate $100,000 provided herein. The Company will also provide, in

2017, up to an additional one-time $50,000, not recovered in rates, for the administration of adding Medicaid as a qualifying program for the Electric Low Income Program.

2. <u>Electric and Gas Customer Qualification</u>

To qualify for the Electric or Gas Low Income Program ("Qualifying Customers"), an Electric Rate I SC1 customer or Gas SC 1 or SC 3 customer must (a) be enrolled in the DV or UG Program; or (b) be receiving benefits under any of the following governmental assistance programs: SSI, Temporary Assistance to Needy Persons/Families, Safety Net Assistance, Medicaid,[88] Supplemental Nutrition Assistance Program; or (c) have received a HEAP grant in the preceding twelve (12) months ("Qualifying Programs"). Customers participating in the Company's electric and gas low income programs at the time these Rate Plans become effective will not be required to re-enroll in the Low Income Programs described herein.

3. <u>Electric and Gas Low Income Discount Program</u>

This Proposal is designed to implement the requirements of the Commission's *Order Adopting Low Income Program Modifications and Directing Utility Filings* (issued May 20, 2016)("Low Income Order") in Case 14-M-0565, in two stages (*i.e.*, certain changes effective January 1, 2017 and additional changes effective January 1, 2018).

Effective January 1, 2017, all customers enrolling in the Electric Low Income Program and continuing participants will receive a $10.00 discount from the otherwise applicable customer charge. Effective January 1, 2017, all SC 1 customers enrolling in the Gas Low Income Program and continuing participants will receive a $3.00 discount

[88] Effective January 1, 2017, Medicaid will be a qualifying electric program.

from the otherwise applicable minimum charge and SC 3 customers enrolling in the Gas Low Income Program and continuing participants will receive a discount of $0.4880 per therm for usage in the 4-90 therm block as well as a $7.25 discount on their otherwise applicable minimum charge.

Effective January 1, 2018, the Company will implement the Tiered discount levels identified in the Low Income Order and in the table below. Tier 1 will include customers enrolled in the Electric and Gas Low Income Programs by virtue of receiving benefits under any of the following governmental assistance programs: SSI, Temporary Assistance to Needy Persons/Families, Safety Net Assistance, Medicaid, Supplemental Nutrition Assistance Program; or have received a standard HEAP grant in the preceding twelve (12) months. Tier 2 will include customers that have received a standard HEAP grant in the preceding twelve (12) months with one adder (currently $25.00). Tier 3 will include customers that have received a standard HEAP grant in the preceding twelve (12) months with two l adders (currently $50.00). Tier 4 customers are customers enrolled in the Electric and Gas Low Income Programs by virtue of being enrolled in a DV or UG Program. Beginning in RY2, all of these discounts will be applied as a credit to the customer's total bill, in lieu of a reduction of the customer charge and/or per therm discount as in RY1.

Income Level	Electric Heating	Electric Non-heating	Gas Heating	Gas Non-heating
Tier 1	$10.00	$10.00	$50.00	$3.00
Tier 2	$10.00	$10.00	$50.00	$3.00
Tier 3	$22.00	$14.00	$50.00	$3.00
Tier 4	$0.00	$0.00	$0.00	$0.00

The target cost of the discount component of the Electric Low Income Program is $54.7 million per Rate Year. The target cost of the discount component of the Gas Low Income Program is $10.9 million per Rate Year.

The Signatory Parties recognize that the Company must submit an Implementation Plan pursuant to the Low Income Order; that the Implementation Plan (which will be consistent with this Proposal) will be subject to comment; and that the Low Income Order is pending rehearing. The Signatory Parties recommend that if the Commission orders any changes to the Low Income Program in this Proposal that such changes be implemented as soon as practical after the order is issued and implemented on a prospective-only basis.[89] The Signatory Parties reserve all of their administrative and judicial rights in connection with the generic low income proceeding.

4. <u>Qualifying Customers</u>

At any time during the terms of the Electric and Gas Rate Plans, the actual number of customers participating in the Low Income Programs may be more or less than the estimated numbers of customers assumed for purposes of establishing the discount targets. All Electric and Gas Qualifying Customers, without limit, will be accepted into the program.

5. <u>Reconnection Fee Waivers</u>

Effective January 1, 2017, the Company will waive its electric and gas service reconnection fees no more than one time per customer each Rate Year during the terms of

[89] For example, the Commission's setting of $0.00 as a discount for Tier 4 customers (*i.e.*, eliminating UG/DV discounts) has been disputed and is the subject of the City's Petition for Rehearing and Clarification of the Low Income Order. To the extent that the Tier 4 discount elimination is modified, a Tier 4 discount should be implemented prospectively.

the Electric and Gas Rate Plans. The target cost of the reconnection fee waiver component is $547,000 each Rate Year of the Electric Rate Plan and $75,000 each Rate Year of the Gas Rate Plan.[90] The Company may grant waivers to individual customers more than once, on a case-by-case basis and for good cause shown, provided that the Company does not forecast that it will exceed the target cost for that Rate Year.

The Company will reflect in its Electric and Gas Tariffs that, if the Company forecasts, based on the quarterly reported data from at least the first six (6) months of a Rate Year, that the yearly program target will be exceeded, the Company will be permitted to make a compliance filing of tariff amendments, on not less than thirty (30) days' notice, which would, over the course of the remainder of the Rate Year, limit the waiver to fifty (50) percent of the total reconnection fee, so that the estimated cost of waived reconnection fees does not exceed the target cost for the Rate Year. The Company's tariff leaves will state that each fee waiver program will end once the cost of these programs equals the target cost for each of the Rate Years. The Company will notify the parties if it projects that the electric and/or gas target cost will be reached during any Rate Year.

6. Budget Billing

As required by the Low Income Order, beginning January 1, 2018, the Company will begin automatically enrolling customers participating in the gas or electric low income program into the Company's existing budget billing program on an opt-out basis.

[90] If the Company does not file to increase rates to become effective after the expiration of either the Electric or Gas Rate Plans, then the reconnection fee waiver program would continue with annual caps of $547,000 and $75,000, respectively.

7. <u>Cost Recovery</u>

The programs will be implemented in a manner that is revenue and earnings neutral to the Company.

a. Electric

All under- and over-recoveries associated with the low income discounts, the waiver of reconnection fees, and up to $50,000 per year for the Agencies' administrative costs above the first $50,000 will be passed through the RDM to all customers subject to the RDM for the Electric Low Income Program. If the Electric Low Income Program continues beyond the term of the Electric Rate Plan, but the RDM as currently structured does not, continuation of the Low Income Program will be contingent upon the implementation of an equivalent mechanism that provides for full recovery of the low income customer charges/discounts, waiver of reconnection fees, and up to $50,000 per year for the Agencies' administrative costs above the first $50,000.

b. Gas

The Company will recover from or credit to all firm customers, through the MRA, any difference between the actual amount of discounts provided to customers during any Rate Year and the $10.9 million per year of discounts assumed for purposes of designing gas rates under this Gas Rate Plan. Any reconnection fees waived will be recovered through the MRA at the end of each Rate Year. If the Gas Low Income Program continues beyond the term of the Gas Rate Plan, but the MRA as currently structured does not, continuation of the Low Income Program will be contingent upon the implementation of an equivalent mechanism that provides for full recovery of the low income customer charges/discounts, and reconnection fee waivers.

8. <u>Reporting Requirements</u>

a. Electric

The Company will file a report on the Electric Low Income Program for each calendar quarter (the “Reporting Period”). Each report will be filed with the Secretary, with copies by email to parties to Case 16-E-0060, within thirty (30) days after the end of each Reporting Period. Beginning January 1, 2017, the following data will be reported as a snapshot of the program as of the last day of each Reporting Period, broken down by Westchester County and New York City participants: (a) the number of customers enrolled; (b) the number of low income customers in arrears; (c) the total amount in arrears; and (d) the average amount in arrears. In addition, the Company will report (i) the aggregate amounts of low income discounts to date for the Rate Year, (ii) the number of reconnections of low income customers for which fees were waived to date for the Rate Year and since the inception of the program, (iii) the aggregate amount of reconnection fees waived to date for the Rate Year and since the inception of the program, and, if applicable, (iv) the aggregate amount of arrears forgiven to date for the Rate Year. Each quarterly report issued during the term of the Electric Rate Plan will also include a summary of this data from all previous quarterly reports.

Beginning January 1, 2018, the Company will begin reporting the data required by the Low Income Order. The reporting template is attached hereto as Appendix 24.

b. Gas

The Company will file a report on the Low Income Program for each calendar quarter (the "Reporting Period"). Each report will be filed with the Secretary, with copies by email to parties to Case 16-G-0061, within thirty (30) days after the end of each Reporting Period. The following data will be reported as a snapshot of the program as of the last day of each Reporting Period, broken down by Westchester County and New York City participants, and by SC1 and SC3 participants: (a) the number of customers enrolled, segregated by (i) Gas Qualifying Customers for whom the Company has received payment in the form of HEAP grants and (ii) all other Gas Qualifying Customers; (b) the number of low income customers in arrears; (c) the total amount in arrears; and (d) the average amount in arrears. In addition, the Company will report (i) the aggregate amounts of low income discounts to date for the Rate Year, (ii) the number of reconnections of low income customers for which fees were waived and (iii) the aggregate amount of reconnection fees waived to date for the Rate Year and since the inception of the program. Each quarterly report issued during the term of the Gas Rate Plan will also include a summary of these data from all previous quarterly reports.

Beginning January 1, 2018, the Company will begin reporting the data required by the Low Income Order. The reporting template is attached hereto as Appendix 24.

O. Studies and Collaboratives

1. Interconnection Procedures Collaborative[91]

Beginning in October 2016, the New York State Distributed Generation Ombudsman ("State Ombudsman") will commence discussions among interested parties to develop improvements to Con Edison's internal process for managing interconnections. As applicable, the modifications to Con Edison's processes resulting

[91] The Company will hold a meeting prior to effective date of the rate plan to review its microgrid interconnection specifications with interested parties and developers to receive their input before issuing revised specifications. If necessary, the Company will hold an additional meeting after the rate plan effective date to receive additional input.

from this collaborative shall be in accordance with the New York State Public Service Commission Standard Interconnection Requirements. As appropriate, and to the extent actions of the Commission and the Department of Public Service to improve DG interconnection related activities are known, the modifications to Con Edison's processes will be harmonized with such actions.

The discussions initially will address the details of the implementation of the following Con Edison interconnection procedures: (1) development of checklists of requirements for customers and/or developers and the Company to provide transparency and an understanding of each party's obligations; (2) improvement to Con Edison's written materials for developers, including explanations of how Con Edison applies the applicable standards; (3) scheduling of business meetings to consider project specific issues; and (4) development of a streamlined internal review process for failed DG inspections where the customer requests a review.

Additional issues may be discussed by the interested parties through this process, such as: (1) procedures and processes for streamlining and improving the interconnection process, including the potential for a single point of contact within Con Edison for each DG project (note - if a single point of contact is established, the parties will discuss that point of contact's responsibilities); (2) procedures for soliciting and submitting information, such as drawings or project plans to and from Con Edison, developers, customers and contractors; (3) timelines for reviews of project information; and (4) Customer requests for estimates of interconnection costs.

The Company agrees to implement changes in its procedures as appropriate following these discussions.

The Company will file an informational report with the Secretary by six (6) months from the initial collaborative meeting, identifying the topics discussed, recommendations developed and the actions taken or to be taken to implement those recommendations. For any recommendation that is not implemented, the Company will explain the reason(s) why the recommendation has not been or will not be implemented.

2. <u>Marginal Cost Study</u>

No later than sixty (60) days after the Commission issues an order approving this Proposal, the Company will initiate discussions with Staff, with input from interested parties, to agree upon an approach for the Company to develop and apply marginal cost studies in future Con Edison electric rate filings. These more granular marginal cost studies may also be used for the Company's BCA required as part of its DSIP and to implement other REV-related initiatives. The Company is authorized to recover the cost of a consultant (up to $600,000) to develop and apply a more granular marginal cost study. As discussed in section B.1.a, the costs will be recovered through the MAC and the NYPA OTH Statement.

3. <u>Gas Peak Demand Reduction Collaborative</u>

The Company will participate with Staff and other interested parties in a collaborative that will (i) examine the potential impact that delays of upstream interstate pipeline construction may have on meeting growing demand associated with oil-to-gas conversions and new business and (ii) explore gas peak demand reduction incentives, including demand response. This collaborative will commence within five months after the Commission issues an order approving this Proposal.

During Phase 1 of this collaborative, the Company will study the feasibility of customers using solar thermal and/or geothermal technologies to reduce gas peak demand

and thereby enable the Company to defer infrastructure investment. The Company may retain a consultant to assist in the performance of this study. The estimated cost of using a consultant for this effort is $50,000, which the Company may defer for future recovery from customers.

For Phase 2 of the collaborative, the Company will convene discussions with Staff and interested parties to consider the results of the Phase 1 analysis and to discuss peak demand reduction incentives including, for example, a peak demand reduction program for firm dual-fuel customers, and opportunities, if any, for interruptible and non-firm customers (including both temperature-interruptible and notification customers) to contribute to peak demand reduction.

The Company will use reasonable efforts to file a collaborative report with the Commission by December 31, 2017 (*i.e.*, the end of RY1).

4. Interruptible Gas Collaborative

The Company will participate with Staff and other interested parties in a collaborative that will examine interruptible gas rates and services in two phases.[92]

During Phase 1, the Company will perform an interruptible gas study, based on input from Staff and interested parties, of the value of interruptible service, any costs incurred to serve interruptible customers,[93] as well as costs incurred by interruptible

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[92] For purposes of this collaborative, the term "interruptible customers" includes SC 12 Rate 1, SC 12 Rate 2 and power generation customers.

[93] The Company asserts that it does not incur infrastructure costs for interruptible customers. The interruptible gas study may consider whether the avoidance of infrastructure costs when a customer takes interruptible service in lieu of firm service provides value to firm customers.

customers to be eligible for interruptible service. The study will include the following elements:[94]

a. O&M costs the Company incurs to maintain facilities used by the interruptible customers and any variable costs, broken down by transmission pressure and distribution pressure facilities;

b. value of service to firm customers from the Company providing service to interruptible customers;

c. costs incurred by interruptible customers to maintain dual-fuel facilities,[95] including replacement fuel, including liquidation cost, storage and inventory costs; regulatory compliance costs *(e.g.*, safety and environmental); carrying cost of dual fuel plant investments; burners, pumps, valves, controls; continuing capital expenditure requirements, including upgrades and replacements; incremental O&M expenses (other than labor), including repairs, cleaning and inspections; incremental labor, including specialized skills, training, overtime and licenses; and internal administration, including internal reporting and risk management;

d. value to interruptible customers of the availability of interruptible gas service versus relying solely on an alternate fuel;

e. evaluation of daily and monthly gas balancing services for both firm and interruptible customers;[96] and

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[94] The parties reserve all of their rights to support or oppose inclusion of some or all of these elements in the analysis.

[95] The Company will work with Staff, interested parties and its consultant to determine the information needed to develop a representative cost of maintaining dual fuel facilities in order to qualify for interruptible gas service, by class or subclass of interruptible customers. Any non-public, customer-specific information provided by any party to the collaborative shall be provided only to the Company and Staff, who shall hold such information on a confidential basis, except that the Company is entitled to share such information with its consultant to the extent necessary to perform the required analyses. The provision of such information to the consultant will be pursuant to an appropriate non-disclosure agreement between the Company and its consultant. If the Company is unable to obtain sufficient customer-specific information that satisfies the representative cost of maintaining dual fuel facilities, the study will note this data deficiency.

[96] Nothing in this Proposal is intended to limit to the Company or other party from proposing changes to gas balancing services provided to interruptible customers and marketers serving interruptible customers during the term of the Gas Rate Plan in accordance with established processes applicable to changes to tariff provisions and/or to the Gas Transportation Operating Procedure ("GTOP").

f. evaluation of negotiated rates with each individual power generator and other non-firm customers (if any), and circumstances for which other customers may seek negotiated rates, including fuel switching (*i.e.*, gas to oil), switching to firm service (including the cost and capability of adding incremental pipeline capacity) and interstate pipeline bypass.[97]

The Company may defer for future recovery from customers up to $100,000 for a consultant to perform the analysis. The Company will endeavor to complete the analysis no later than nine (9) months after the completion of the Gas Peak Demand Reduction Collaborative.

During Phase 2, a collaborative of the Company, Staff and interested parties will seek to develop a report to be submitted to the Commission on the results of the interruptible gas study, including any recommended changes to interruptible rates and/or services. If there are no consensus recommendations, the report may contain individual party(ies) recommendations or parties may separately submit their recommendations to the Commission. The Company will use reasonable efforts to file the collaborative report with the Commission by December 31, 2018 (*i.e.*, the end of Rate Year 2).

5. <u>CNG Access Study</u>

The Company currently has eight (8) compressed natural gas ("CNG") facilities at various locations throughout its service territory. The Company will perform a study, using a consultant, to: (a) review public access, including security concerns, to these CNG facilities to determine if greater access for non-fleet vehicles is feasible; and (b) if it is determined that greater access is feasible, develop a cost structure and process for

[97] Note – any power generator-provided or other customer-provided customer-specific information, including any and all information relating to interstate pipeline by-pass, will be shared on a confidential basis with Staff via the Commission's trade secret rules, and/or with the Company pursuant to a confidentiality agreement, as appropriate.

billing non-fleet vehicles at these facilities. The Company will file this study with the Secretary by September 30, 2017. The cost of the consultant to perform this study is estimated to be $50,000. The Company will defer this cost for future recovery from customers.

6. Climate Change Vulnerability Study

The Company is authorized to spend up to $4 million to complete the Climate Change Vulnerability Study in accordance with the scope of work provided to the Storm Hardening Collaborative and will complete the study by December 31, 2019. The Company will seek alternative sources of funding for the study, including working with NYC and other utilities with service territories in the NYC/Westchester area, and deduct that funding, if obtained, from the cost of the study, which is recoverable through the MAC and the NYPA OTH Statement.[98] Costs for this study will be allocated between electric and gas based on the common cost allocation for Customer Accounting Expenses (84%/16%). The allocated costs for electric will be collected through the MAC and NYPA OTH Statement and for gas through the MRA, as incurred.

7. Building Meter Conversion Study

The Company will retain a consultant to perform a study examining the feasibility and potential costs related to any Company-wide building meter conversion effort, as well as potential incentives that could be offered to building owners to encourage such conversions.[99] The study will include (subject to customer consent) a selected building

[98] See section B.1.a of this Proposal.

[99] Going forward and in accordance with tariff provisions to be added under this Agreement, building meters will be required for oil-to-gas conversions, major renovation projects (which will

conversion to better understand the challenges and costs associated with such an effort. The costs associated with the study, including the consultant, surveys, plumbers, internal and external relocating costs, will be deferred for future recovery from customers. The estimated costs for this initiative are $500,000.

The Company will provide annual reports on the status and results of the study, including the process used to choose the selected building conversion.

P. Miscellaneous Provisions

1. Continuation of Provisions; Rate Changes; Reservation of Authority

Unless otherwise expressly provided herein, the provisions of this Proposal will continue after RY3 for electric and for gas, unless and until electric or gas base delivery service rates, respectively, are changed by Commission order. For any provision subject to RY1, RY2 and RY3 targets, the RY3 target shall be applicable to any additional Rate Year(s).

Nothing herein precludes Con Edison from filing a new general electric rate case or a new general gas rate case prior to January 1, 2020, for rates to be effective on or after January 1, 2020.

Changes to the Company's base delivery service rates during the term of the Electric or Gas Rate Plan will not be permitted, except for (a) changes provided for in this Proposal; and (b) subject to Commission approval, changes as a result of the following circumstances:

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include, but not be limited to, removal of walls, reconfigured building space, or any significant replacement, reconfiguration and/or demolition of internal gas piping) and new construction, except in cases where the Company deems it unsafe or impractical to do so.

a. A minor change in any individual base delivery service rate or rates whose revenue effect is *de minimis*, or essentially offset by associated changes within the same class or for other classes, provided however that the base electric delivery service rates applicable to the NYPA classes will not be increased in total. It is understood that, over time, such minor changes may be necessary and that they may continue to be sought during the term of the Electric and Gas Rate Plans, provided they will not result in a change (other than a *de minimis* change) in the revenues that Con Edison's base delivery service rates are designed to produce overall before such changes.

b. If a circumstance occurs which in the judgment of the Commission so threatens Con Edison's economic viability or ability to maintain safe, reliable and adequate service as to warrant an exception to this undertaking, Con Edison will be permitted to file for an increase in base delivery service rates at any time under such circumstances.

c. The Signatory Parties recognize that the Commission reserves the authority to act on the level of Con Edison's electric and/or gas rates in the event of unforeseen circumstances that, in the Commission's opinion, have such a substantial impact on the range of earnings levels or equity costs envisioned by these Rate Plans as to render Con Edison's electric and/or gas rates unreasonable or insufficient for the provision of safe and adequate service or just and reasonable rates.

d. Nothing herein will preclude any Signatory Party from petitioning the Commission for approval of new services, the implementation of new service classifications and/or cancellation of existing service classifications, or rate design or revenue allocation changes within or among the non-NYPA service classes, which are not contrary to the agreed upon terms and conditions set forth herein. All changes will be implemented on a revenue neutral and earnings neutral basis.

e. The Signatory Parties reserve the right to oppose any filings made under this section.

2. Legislative, Regulatory and Related Actions

a. If at any time the federal government, State of New York, the City of New York and/or other local governments make changes in their tax laws (other than local property taxes, which will be reconciled in accordance with section E.1) that result in a change in the Company's costs[100] in an annual amount, calculated and applied separately for electric and gas, equating to ten (10) basis points of return on common equity or more,[101] and if the Commission does not address the treatment (e.g., through a surcharge or credit) of any such tax law changes, including any new, additional, repealed or reduced federal, State, City of New York or local government taxes, fees or levies, Con Edison will defer on its books of account the full change in expense and reflect such deferral as credits or debits to customers in the next base rate change subject to any final Commission determination in a generic proceeding prescribing utility implementation of a specific tax enactment, including a Commission determination of any Company-specific compliance filing made in connection therewith.[102]

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[100] Costs in this context include current and deferred tax impacts.

[101] For electric, such amounts are estimated to be $15.4 million in RY1, $15.9 million in RY2 and $16.5 million in RY3. For gas, such amounts are estimated to be $4.0 million in RY1, $4.4 million in RY2 and $4.9 million in RY3.

[102] All Signatory Parties reserve all of their administrative and judicial rights in connection with such generic proceeding(s).

b. If at any time any other law, rule, regulation, order, or other requirement or interpretation (or any repeal or amendment of an existing rule, regulation, order or other requirement) of the federal, State, or local government or courts, including a requirement that Con Edison refund its tax exempt debt, results in a change in Con Edison's annual electric or gas costs or expenses not anticipated in the forecasts and assumptions on which the rates in this Proposal are based in an annual amount, calculated and applied separately for electric and gas, equating to ten (10) basis points of return on common equity or more,[103] Con Edison will defer on its books of account the full change in expense, with any such deferrals as credits or debits to be reflected in the next base rate case or in a manner to be determined by the Commission.

c. The Company will retain the right to petition the Commission for authorization to defer on its books of account extraordinary expenditures not otherwise addressed by this Proposal.

3. <u>Financial Protections</u>

Annually, the Company will provide Staff with the five-year earnings forecast for CEI and its business segments, which will include each business segment's major subsidiary. The forecast will include the income statement, balance sheet and cash flow statements for CEI and its business segments. The Company will submit the forecast to Staff no later than thirty (30) calendar days after it is reviewed by the Finance Committee

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[103]For purposes of this Proposal, the ten (10) basis points return on common equity will be applied on a case-by-case basis and not to the aggregate impact of changes of two or more laws, rules, etc.; provided, however, that this threshold will be applied on a Rate Year basis to the incremental aggregate impact of all contemporaneous changes (*e.g.*, changes made as a package even if they occur or are implemented over a period of months) affecting a particular subject area and not to the individual provisions of the new law, rule, etc.

of CEI's Board of Directors. The Company will update Staff when there are material changes to the five-year forecast.

After the completion of the Company's annual audit by its external auditors, the Company will provide Staff with actual financial statements (*i.e.*, income statement, balance sheet, cash flow statement and consolidating adjustments) for CEI and its business segments for the previous year. The Company will submit these statements to Staff no later than thirty (30) calendar days after the completion of the annual audit by its external auditors.

The five-year earnings forecast and actual financial statements will be provided to Staff by filing with the Records Access Officer pursuant to the Commission's trade secret process.

No additional ring-fencing measures will be implemented at this time. If at the end of any calendar year, investments in CEI's non-utility businesses exceed 15 percent of CEI's total consolidated operations as measured by revenues, assets, or cash flow, or if the ratio of holding company debt as a percentage of total consolidated debt rise above 20 percent, the Company shall notify the Commission when this trigger occurs and submit a filing providing a ring-fencing plan to insulate the Company, or, in the alternative, demonstrating why additional ring-fencing measures are not necessary at that time.

4. Trade Secret Protection

Nothing in this document prevents Con Edison from seeking trade secret protection under 16 NYCRR Part 6 for all or any part(s) of any document or report filed (or submitted to Staff) in accordance with the Rate Plans, or prohibits or restricts any other party from challenging any such request.

5. Provisions Not Separable

The Signatory Parties intend this Proposal to be a complete resolution of all the issues in Cases 16-E-0060 and 16-G-0061. It is understood that each provision of this Proposal is in consideration and support of all the other provisions, and expressly conditioned upon acceptance by the Commission. Except as set forth herein, none of the Signatory Parties is deemed to have approved, agreed to or consented to any principle, methodology or interpretation of law underlying or supposed to underlie any provision herein. If the Commission fails to adopt this Proposal according to its terms, then the Signatory Parties to the Proposal will be free to pursue their respective positions in this proceeding without prejudice.

6. Provisions Not Precedent

The terms and provisions of this Proposal apply solely to, and are binding only in, the context of the purposes and results of this Proposal. None of the terms or provisions of this Proposal and none of the positions taken herein by any party may be referred to, cited, or relied upon by any other party in any fashion as precedent or otherwise in any other proceeding before this Commission or any other regulatory agency or before any court of law for any purpose other than furtherance of the purposes, results, and disposition of matters governed by this Proposal.

Concessions made by Signatory Parties on various electric and gas issues do not preclude those parties from addressing such issues in future rate proceedings or in other proceedings.

7. Submission of Proposal

The Signatory Parties agree to submit this Proposal to the Commission and to individually support and request its adoption by the Commission as set forth herein, subject to any reservations expressed by any individual Signatory Party on its signature page. The Signatory Parties hereto believe that the Proposal will satisfy the requirements of Public Service Law §§65(1) and 79(1) that Con Edison provide safe and adequate service at just and reasonable rates.

8. Effect of Commission Adoption of Terms of this Proposal

No provision of this Proposal or the Commission's adoption of the terms of this Proposal shall in any way abrogate or limit the Commission's statutory authority under the Public Service Law. The Parties recognize that any Commission adoption of the terms of this Proposal does not waive the Commission's ongoing rights and responsibilities to enforce its orders and effectuate the goals expressed therein, nor the rights and responsibilities of Staff to conduct investigations or take other actions in furtherance of its duties and responsibilities.

9. Further Assurances

The Signatory Parties recognize that certain provisions of this Proposal require that actions be taken in the future to fully effectuate this Proposal. Accordingly, the Signatory Parties agree to cooperate with each other in good faith in taking such actions.

10. Scope of Provisions

No term or provision of this Proposal that relates specifically to one or more but not all of electric and gas service, limits any rights of the Company or any party to petition the Commission for any purpose with respect to the service(s) not specified in such term or provision.

11. Execution

This Proposal is being executed in counterpart originals, and shall be binding on each Signatory Party when the counterparts have been executed.

IN WITNESS WHEREOF, the Signatory Parties hereto have affixed their signatures below as evidence of their agreement to be bound by the provisions of this Proposal.

CONSOLIDATED EDISON COMPANY
OF NEW YORK, INC.

Dated: ___________________

By_________________________________
Robert Hoglund

IN WITNESS WHEREOF, the Signatory Parties hereto have affixed their signatures below as evidence of their agreement to be bound by the provisions of this Proposal.

CONSOLIDATED EDISON COMPANY
OF NEW YORK, INC.

Dated: 9/19/16

By: Robert Hoglund
Robert Hoglund

NEW YORK STATE DEPARTMENT OF
PUBLIC SERVICE

Dated: 9/19/2016

By: [signature]

METROPOLITAN TRANSPORTATION AUTHORITY ("MTA")

Dated: 9/19/16

By: ______________________ *
Sam Laniado
Counsel to MTA

* The MTA is a signatory to the instant Joint Proposal insofar as it pertains to the electric rate filing in Case 16-E-0060.

NEW YORK POWER AUTHORITY

Dated: 9/19/16

By: [signature]

James F. Pasquale
Senior Vice President
Economic Development & Energy
Efficiency

THE ENVIRONMENTAL DEFENSE FUND

Dated: 9/19/16

By: ______________________

By: James T.B. Tripp

CONSUMER POWER ADVOCATES

Dated: 9/18/2016

By: [signature]

NEW YORK ENERGY CONSUMERS
COUNCIL, INC.

Dated: 9/16/16

By: Phil Skalaski

Philip Skalaski, Co-President

Dated:____________________

By: ____________________________

Peter Febo, Co-President

NEW YORK ENERGY CONSUMERS
COUNCIL, INC.

Dated:______________________ By: ______________________________

Philip Skalaski, Co-President

Dated: 9/16/16 By: ______________________________

Peter Febo, Co-President

ACADIA CENTER

Dated: September 16, 2016 By: Irina Rodina

Cases 16-E-0060 and 16-G-0061

The Association for Energy Affordability (AEA) participated in the rate case discussions on energy efficiency and system peak reduction and the associated earnings adjustment mechanisms. AEA agrees with and supports the energy efficiency and system peak reduction provisions, including the associated earnings adjustment mechanisms and reconciliations, in the Joint Proposal.

For the Association for Energy Affordability,

David Hepinstall
September 19, 2016

COMMUNITY HOUSING
IMPROVEMENT PROGRAM

Dated: September 19, 2016

By: Funk & Zeifer LLP
Its attorneys

By:
Peter V. K. Funk, Jr.
Partner

Funk & Zeifer LLP
260 Madison Avenue
New York, New York 10016
Office: 646.597.6284
Cell: 917.886.6296
Fax: 212.448.0066
peter.funk@funkandzeifer.com

DIGITAL ENERGY CORP.

Dated: September 19, 2016 By: ____________________

Digital Energy Corp is a signatory to the Joint Proposal with the following three exceptions:

1. The Eligibility requirements for the Standby Reliability Credit: Digital Energy does not agree with the requirements that the facility owners will be required to install utility grade meters to measure generation output when the data will not be used for determining the reliability credit, and as explained during the JP discussions, the meter data will be used by Con Edison for internal analysis. Digital submits to the Public Service Commission that if Con Edison wishes to gather the data from the facility for its own use, then Con Edison get the permission of the facility owner and should pay for the cost of the meters and communications.

2. Digital Energy does not support the setting of the new Reliability Credit performance period end date to September 30 for RY2 and RY3. This objection to the September 30 performance period end date is limited to residential facilities which are required to provide heat to residential tenants by October 1. The change in the Reliability Credit performance period end dates in RY2 and RY3 could put residential facility owners in the untenable position of having to shutdown generation to setup for providing heat, thus reducing or eliminating the amount of the reliability credit. Digital submits to the Public Service Commission that Con Edison keep the Reliability Credit performance period end date at September 15 (as in RY1) to avoid this problem RY2 and RY3.

3. Digital Energy does not support the present structure of the SC-11 sell back tariff in regards to the definition of import contract demand, and export capacity contract demand. Energy Concepts submits to the PSC that contract demand for DG sites should be set based primarily on import capacity provided by the utility. Contract demand related to export capacity should be structured based on the specific local Coned dedicated equipment needed for a DG site to deliver such capacity to the utility system. Energy Concepts submits that there are various arrangements for the DG interconnection and configuration of local dedicated equipment at DG sites. (For example DG sites selling capacity back through low to medium voltage systems owned by the utility would have different rates than selling power back directly to high tension systems of 33kv and higher.) The SC-11 tariff needs to be expanded and content added to address these different arrangements. In addition, such rates should reflect the localized value of capacity and bulk power as is reflected in different Coned load pockets such as the Coned BQDM area

THE E CUBED COMPANY, LLC

Dated: September 16, 2016 By: Ruben S. Brown

The E Cubed Company, LLC reserves the right to except on the issue of Standby Reliability Credits

Energy Concepts Engineering PC

Dated: September 19, 2016 By: William Cristafaro

Energy Concepts Engineering PC is a signatory to the Joint Proposal with the following exceptions:

1. The Eligibility requirements for the Standby Reliability Credit: Digital Energy does not agree with the requirements that the facility owners will be required to install utility grade meters to measure generation output when the data will not be used for determining the reliability credit, and as explained during the JP discussions, the meter data will be used by Con Edison for internal analysis. Digital submits to the Public Service Commission that if Con Edison wishes to gather the data from the facility for its own use, then Con Edison get the permission of the facility owner and should pay for the cost of the meters and communications.

2. Energy Concepts does not support the setting of the new Reliability Credit performance period end date to September 30 for RY2 and RY3. This objection to the September 30 performance period end date is limited to residential facilities which are required to provide heat to residential tenants by October 1. The change in the Reliability Credit performance period end dates in RY2 and RY3 could put residential facility owners in the untenable position of having to shutdown generation to setup for providing heat, thus reducing or eliminating the amount of the reliability credit. Energy Concepts submits to the Public Service Commission that Con Edison keep the Reliability Credit performance period end date at September 15 (as in RY1) to avoid this problem RY2 and RY3.

3. Energy Concepts does not support the present structure of the SC-11 sell back tariff in regards to the definition of import contract demand, and export capacity contract demand. Energy Concepts submits to the PSC that contract demand for DG sites should be set based primarily on import capacity provided by the utility. Contract demand related to export capacity should be structured based on the specific local Coned dedicated equipment needed for a DG site to deliver such capacity to the utility system. Energy Concepts submits that there are various arrangements for the DG interconnection and configuration of local dedicated equipment at DG sites. (For example DG sites selling capacity back through low to medium voltage systems owned by the utility would have different rates than selling power back directly to high tension systems of 33kv and higher. The SC-11 tariff needs to be expanded and content added to address these different arrangements. In addition, such rates should reflect the localized value of capacity and bulk power as is reflected in different Coned load pockets such as the Coned BQDM area.

Great Eastern Energy's signing of the Joint Proposal comes with one EXCEPTION- We do not support the changes to Reliability Credit Measurement Hours contained in Section G.6. c (i) "Standby Service and Buy Back Rates," as written.

GREAT EASTERN ENERGY

Dated: 9/19/2016 By: ______________________

UNITED STATES GENERAL SERVICES ADMINISTRATION

Dated: September 20, 2016

By: ______________________

Lariza Sepulveda
Public Utilities Specialist
GSA Energy Division

JOINT SUPPORTERS

Dated: September 16, 2016 By:

JOINT SUPPORTERS reserves the right to except on the issue of Standby Reliability Credits

NORTHEAST CLEAN HEAT AND
POWER INITIATIVE (NECHPI)

Dated: September 19, 2016 By:

Herbert D, Dwyer
Chairman
NECHPI

NECHPI reserves the right to except on the issue of Standby Reliability Credits

The Natural Resources Defense Council (NRDC) participated in negotiations of this Joint Proposal only with regard to discussion of the energy efficiency, system peak reduction, and electric vehicles programs and earnings adjustment mechanisms set forth in Section J.1 of the Joint Proposal. NRDC is therefore agreeing only to those portions of the Joint Proposal pertaining to those provisions (i.e. Section J.1 ("Additional Electric Provisions . . . System Peak Reduction Programs, Energy Efficiency and Electric Vehicles Programs") and E.21 ("Reconciliations . . . System Peak Reduction Programs, Energy Efficiency and Electric Vehicles Programs")). NRDC takes no position regarding the remaining portions of the Joint Proposal.

NATURAL RESOURCES DEFENSE COUNCIL

Dated:____________________ By: ____________________

PACE ENERGY AND CLIMATE
CENTER*

Dated: 09/19/2016

By:

Radina R. Valova
Staff Attorney
Pace Energy and Climate Center

*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.

THE REAL ESTATE BOARD OF NEW YORK

Dated: 9/19/2016

By: ______________________________

TIME WARNER CABLE

Dated: September 19, 2016

By: ______________________