STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

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

ORDER ADOPTING TERMS OF JOINT PROPOSAL AND ESTABLISHING ELECTRIC RATE PLAN

Issued and Effective: October 16, 2015

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At a session of the Public Service Commission held in the City of Albany on October 15, 2015

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Gregg C. Sayre
Diane X. Burman, concurring in part and dissenting in part

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ORDER ADOPTING TERMS OF JOINT PROPOSAL AND ESTABLISHING ELECTRIC AND GAS RATE PLANS

(Issued and Effective October 16, 2015)

BY THE COMMISSION:

I. INTRODUCTION

This order adopts terms set forth in a Joint Proposal (JP) submitted for our review by Orange and Rockland Utilities, Inc. (O&R or the Company), trial staff of the Department of Public Service (Staff), the Utility Intervention Unit of the New York Department of State's Consumer Protection Division (UIU), Pace Energy and Climate Center (Pace), the Sabin Center for Climate Change Law at Columbia Law School (Sabin Center), the Retail Energy Supply Association (RESA), and the Department of Defense and All Other Federal Executive Agencies

(DOD/FEA)(collectively referred to as the signatories).[1] We hereby establish a rate plan and other provisions governing the Company's electric service, to remain in effect for two years starting November 1, 2015, and establish a rate plan and other provisions governing the Company's gas service, to remain in effect for three years starting November 1, 2015.[2]

II. BACKGROUND

O&R is currently operating under an electric rate order that established electric rates effective July 1, 2012,[3] and under a gas rate order that established gas rates effective November 1, 2009.[4] The 2012 Electric Rate Order established rates for the three years ended June 30, 2015 and the 2009 Gas Rate Order established rates for the three years ended October 31, 2012.

On November 14, 2014, O&R filed proposed tariffs for electric and gas rates that would increase the Company's

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[1] Exh. 82. The JP was filed June 5, 2015, and was admitted into the evidentiary record at the hearing as Exhibit 82. It is attached hereto as Attachment A.

[2] The JP defines the term Rate Year as the 12-month period starting November 1 and ending October 31. Rate Year 1 (RY1) is November 1, 2015 through October 31, 2016, Rate Year 2 (RY2) is November 1, 2016 through October 31, 2017, and Rate Year 3 (RY3) is November 1, 2017 through October 31, 2018. JP, pp. 5-6.

[3] Case 11-E-0408, Proceeding as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service, Order Adopting Terms of Joint Proposal, with Modification, and Establishing Electric Rate Plan (issued June 15, 2012) (2012 Electric Rate Order).

[4] Case 08-G-1398, Proceeding as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service, Order Adopting Joint Proposal and Implementing a Three-Year Rate Plan (issued October 16, 2009) (2009 Gas Rate Order).

electric delivery revenues by $33.4 million and its gas delivery revenues by $40.7 million, effective November 1, 2015.[5] On February 13, 2015, the Company submitted a preliminary update that lowered its proposed increase in electric revenues to $25.2 million and lowered its proposed increase in gas revenues to $39.0 million. O&R said these decreases were primarily due to actual net plant additions that were lower than forecast, lower projected interest rates, additional net credits, and actual property taxes that were lower than forecast. The decreases were partially offset by an increase in projections of Other Post Retirement Benefits (OPEB) costs based on actual expenses through December 31, 2014.

Staff, UIU, Pace, and the Sabin Center filed initial testimony on March 20, 2015.[6] In its initial testimony, Staff recommended an electric revenue decrease of $0.595 million and a gas revenue increase of $14.7 million.

On April 10, 2015, the Company filed rebuttal testimony and a second update to its initial filings. The Company raised its proposed increase in electric revenues to $33.9 million, and raised its proposed increase in gas revenues to $44.2 million. Rebuttal testimony was also filed by Staff, UIU, and the Municipal Consortium (MC).[7]

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[5] Notice of the Company’s electric and gas rate filings was published in the New York State Register on February 18, 2015 (PSC SAPA Nos. 14-E-0493SP1 and 14-G-0494SP1, respectively).

[6] The County of Rockland, though a party to this proceeding, elected not to file direct testimony.

[7] The MC is an *ad hoc* group of municipalities formed to participate directly in this proceeding. It includes the Towns of Clarkstown, Orangetown, Ramapo, Stony Point, Wallkill and Warwick, and the Villages of Grandview-on-Hudson, Haverstraw, and Sloatsburg. Exh. 122, Rebuttal Testimony of Christopher P. St. Lawrence, p. 1.

The pre-filed testimony became the basis for settlement discussions, which commenced on April 15, 2015, pursuant to public notice filed April 8, 2015, in compliance with our Rules, 16 NYCRR 3.9. The negotiations continued for several weeks and culminated in the filing, on June 5, 2015, of the JP with Exhibits. Public statement hearings were held in Goshen on June 30, 2015, and in Ramapo on July 1, 2015.[8] At an evidentiary hearing on August 4, 2015, a number of parties actively participated. That hearing resulted in the creation of a transcript with 182 pages of additional testimony and the admission into the record of 125 exhibits.[9]

The JP proposes a two-year electric rate plan, which, if approved, would authorize the Company to increase base electric delivery revenues by $9.3 million, a 3.2 percent increase in delivery rates on an annual basis in RY1, and $8.8 million, a 2.9 percent increase in delivery rates in RY2.[10] The JP proposes a three-year gas rate plan, which, if approved, would authorize the Company to increase base gas delivery rates by $27.5 million in RY1, a 23.9 percent increase in delivery rates on an annual basis, $4.4 million in RY2, a 3.0 percent increase in delivery rates, and $6.7 million in RY3, a 4.5 percent increase in delivery rates. The JP recommends that the rate of these increases be levelized over the three years, which would result in an increase of $16.4 million for each of the three rate years. This would amount to an annual increase

[8] Commissioner Sayre joined the presiding administrative law judge at the June 30, 2015 public statement hearing and Commissioner Burman joined the presiding administrative law judge at the July 1, 2015 public statement hearing.

[9] Exhibits included all the pre-filed testimony and exhibits.

[10] JP, Appendix 18.

of delivery revenues of 13.9 percent in RY1, 12.3 percent in RY2, and 10.9 percent in RY3.[11]

On June 26, 2015, O&R, Staff, UIU, and Pace filed statements in support of the JP. The County of Rockland and the MC filed statements in opposition. O&R, Staff, and the MC filed replies on July 6, 2015.

III. PUBLIC COMMENTS

Throughout the proceeding, the public filed comments in the form of letters, e-mails, telephone calls, and oral presentations made at two public statement hearings held in Goshen, on June 30, 2015, and Ramapo, on July 1, 2015. The public hearings collectively drew 17 commenters. As of September 2, 2015, 112 written comments had been submitted.

Most of the public comments were filed prior to the filing of the JP. The vast majority of commenters opposed O&R's requested rate increases, asserting they would unduly burden customers already facing financial hardship, as well as small businesses and local governments. There was significant concern for the impact of O&R's proposed rate increases on senior citizens and residents on a fixed income. There was also concern about the impact of higher rates on struggling business and industry.

Numerous ratepayers stated their belief that O&R's current rates are excessive. Some questioned why the Company should be permitted to seek another rate increase on top of other recent Commission-approved rate increases. Some expressed

[11] JP, Appendix 19, Schedule 1, p. 2 of 4; Schedule 2, p. 2 of 4; and Schedule 3, p. 2 of 5. In RY3, total delivery bills will increase by 10.9 percent, with 7.1 percent recovered via a temporary surcharge and 3.8 percent recovered in delivery rates.

confusion as to why the Company's delivery rates were higher that its commodity rates.

Many commenters objected to the rate increase because they felt it put an unfair burden on ratepayers without requiring Company shareholders to assume some financial responsibility for the cost increases. Some were upset by the fact that O&R's parent company, Consolidated Edison Inc., (Con Edison) has continued to pay dividends to its shareholders while its subsidiaries have asked for multiple rate increases. Several commenters expressed distrust of the rate-setting process, saying utilities routinely ask for more than needed so the Commission can reduce the increase requested, and thereby appear effective, while still approving significantly increased rates.

State and local government officials unanimously opposed O&R's proposed rate increases. Senator John J. Bonacic expressed strong opposition, saying the last thing New Yorkers need is another O&R rate increase when they are struggling to make ends meet and facing increased energy costs with the newly-created Federal capacity zone. The Senator urged O&R to meet its infrastructure improvement needs through cost-cutting measures. Assemblyman Karl Brabenec strongly opposed the proposed increases, saying residents are experiencing economic hardships even without such unnecessary and significant rate increases. A representative for Senator Carlucci expressed the Senator's firm opposition to O&R's requested rate increase, given the hardship it will impose on Rockland County residents, especially those living on a fixed income. Orange County Executive Steven M. Neuhaus opposed the proposed gas rate increases, saying they would unnecessarily burden residents.

Town of Clarkstown Supervisor Alex Gromack praised O&R for working closely with the Town to eliminate double poles and for helping the Town take control of over 4,000 street lights, expected to lead to annual savings for the Town of approximately $500,000. Supervisor Gromack opposed the JP, however, because he believes O&R can do more, and should be required by the Commission to do more, to reduce its costs. Among other things, he urged the Commission to impose a cap on utility rate increases.

Numerous towns and villages unanimously opposed the rate increases, urged the Commission to deny O&R's requests and instead investigate how to provide customers relief from existing rates, which they described as among the highest in the United States.

Some commenters objected to specific costs O&R sought to recover or defer under its rate proposals. Warwick Town Supervisor Michael Sweeton said deferred property tax costs could be amortized over a longer period to lessen rate impacts, and labor costs associated with new hires could be avoided if O&R and Con Edison shared such costs.[12] Ramapo Town Supervisor St. Lawrence also supported longer amortization of property tax costs and urged us to impose a 2.0 percent cap on utility rate increases, in light of the State-imposed 2.0 percent cap on property taxes. Supervisor St. Lawrence also opposed the

[12] Transcript of Public Statement Hearing, June 30, 2015, 7:00 p.m., p. 6. In rebuttal testimony filed on behalf of the MC, Supervisor St. Lawrence of the Town of Ramapo recommended that O&R amortize deferred property taxes over ten years. Exh. 122, p. 5.

continued deferral of approximately $15 million in accumulated Site Investigation and Remediation (SIR) costs.[13]

IV. STANDARD OF REVIEW

Our obligation in reviewing any joint proposal submitted for our consideration is to ensure that its terms, viewed as a whole, produce a result that is in the public interest. Our Settlement Guidelines describe the factors we take into account in making that assessment.[14]
In general, a desirable settlement should balance protection of consumers, fairness to investors and the long-term viability of the utility. It should be consistent with the environmental, social and economic policies of the Commission and the State; and it should produce results that are within the range of reasonable results that would have likely arisen from a Commission decision in a litigated proceeding.

The parties were provided an opportunity to submit testimony and were provided notification of and an opportunity to participate in settlement negotiations. In addition, as Staff points out, multiple parties having various interests support the JP, including parties that are normally adverse. Although opposition to the JP was filed by the MC and the County of Rockland, we note that the terms of the JP substantially mitigate the rate increases sought by O&R, which was a primary

[13] SIR costs relate to environmental remediation at sites such as those of manufactured gas plants that were polluted due to early activity in the gas and electric industry during the 1800s and 1900s. See Case 11-M-0034, Review and Evaluation of the Treatment of the State’s Regulated Utilities’ Site Investigation and Remediation (SIR) Costs, Order Concerning Costs for Site Investigation and Remediation (issued November 28, 2012) (SIR Order).

[14] Cases 90-M-0255, et al., Procedures for Settlements and Stipulation Agreements, Opinion 92-2 (issued March 24, 1992).

concern of municipal parties. Other terms of the JP are designed to spread the recommended rate increases over a longer period of time, and thereby lessen the impact on customers. These aspects of the JP indicate that the settling parties made genuine efforts to address all parties’ concerns, including those that chose not to sign the JP. No party claims any procedural irregularity or unfairness.

We conclude that the JP in this case was developed fairly with full opportunity for participation by all interested parties. It is, therefore, properly before us for a determination of its consistency with the public interest.

V. SUMMARY OF THE KEY ELEMENTS OF THE JOINT PROPOSAL

This section summarizes key elements of the JP that are significant either because of their impact on base electric or gas rates or because they represent a compromise of heavily contested issues. We include here as well, where helpful, the parties’ explanations of the terms or the parties rationale for their respective positions. The complete proposal accompanies this order as Attachment A.

In addition to the issues discussed below, we note that the JP proposes to continue certain important provisions of the 2009 Gas Rate Order and the 2012 Electric Rate Order. Where appropriate, notable modifications to such provisions are discussed more fully below.

A. Two-Year Electric Rate Plan and Three-Year Gas Rate Plan

The JP would establish electric delivery rates for O&R for a two-year period from November 1, 2015, through October 31, 2017, and gas delivery rates for O&R for a three-year period, from November 1, 2015, through October 31, 2018. The Company would be precluded from filing for new electric or gas rates during the term of the plan, unless circumstances occurred which, in the judgment of the Commission, threatened the Company's economic viability or ability to maintain safe, reliable, and adequate service.

The signatories to the JP have agreed that electric delivery rate increases in the amounts of $9.3 million for RY1 and $8.8 million for RY2, respectively, will enable the Company to provide safe and adequate electric service at just and reasonable rates.

With respect to gas service, the signatories to the JP agreed that gas delivery rate increases in the amounts of $27.5 million for RY1, $4.4 million for RY2, and $6.7 million for RY3 will enable the Company to provide safe and adequate gas service at just and reasonable rates. The signatories propose that the new gas rates be levelized over the three years of the rate plan, in equal increments of $16.4 million per year, to smooth the rate of increase in rates over the three rate years.

Because this levelized approach would leave rates higher at the end of RY3 than if rates were increased on a cost-of-service basis, the JP proposes that $10.6 million of the third year increase be collected as a temporary surcharge, through the Company’s Monthly Gas Adjustment (MGA). The surcharge would expire at the end of RY3. This would ensure that gas rates at the end of RY3 are no higher than they would have been absent levelization.

B. Revenue Allocation and Rate Design

The JP proposes certain revenue allocations based on the Company’s Embedded Cost of Service (ECOS) Study. For electric, the JP’s terms would reallocate delivery revenues, in both RY1 and RY2, to eliminate one-fourth of the class-specific deficiencies and surpluses identified in the ECOS study.[15] For gas service, the rate plan proposed in the JP would address a revenue imbalance between residential and commercial customers, consistent with Staff's adjustments to the Company's ECOS study.[16]

For electric service, the JP proposes no changes in customer charges in RY1 and RY2 for residential Service Class (SC) No. 1, SC No. 19, and commercial SC No. 2 non-demand metered, and SC No. 2 unmetered.[17]

For gas service, monthly customer gas charges would increase in RY1 from $18.63 to $20.00 for residential customers (SC Nos. 1 and 6) and increase from $29.08 to $30.00 for commercial customers (SC Nos. 2 and 6). These charges would remain the same for RY2 and RY3.[18]

C. Cost of Capital

The revenue requirement underlying the rates proposed in the JP is based on an assumed capital structure with 48 percent common equity and a return on common equity (ROE) of 9.0 percent for the two-year term of the electric plan and 9.0 percent for the three-year term of the gas rate plan. These provisions would provide the Company with an after-tax rate of return of 7.10 percent (RY1), 7.06 percent (RY2), and 7.06 percent (RY3).[19]

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[15] Exh. 8, Company Electric Rate Panel, Initial Testimony, pp. 4-5; Exh. 87, Staff SIS, pp. 46-47.

[16] Exh. 87, Staff SIS, p. 54.

[17] JP, App. 18, Schedule 1.

[18] Exh. 118, UIU Statement on the JP, p.2 & n.3; JP, App. 19, p.3.

[19] JP, Appendix 1, pp. 1-2 (Electric); Appendix 2, pp. 1-3 (Gas).

Staff supports the proposed capital structure and cost of capital provisions, noting that the cost of capital has fallen appreciably since O&R's electric rates were last set in 2012 and describing an allowed ROE of 9.0 percent as a fair compromise between Staff's position in its direct pre-filed testimony (8.5 percent) and the Company's position in its original filing (9.75 percent). Staff also notes that the approach under the JP is comparable to what we have allowed for other major utilities operating under multi-year rate plans.[20]

The Company says the provisions of the JP relating to ROE and overall costs of capital were very difficult to accept and were only acceptable in light of all the other provisions of the agreement. The Company says it accepted the 9.0 percent ROE in recognition of the Commission's established policy of setting returns at the lower end of the range experienced within the utility industry.[21] The Company does note, however, that the 48 percent equity ratio is lower than its forecasts of 48.45 percent in RY1, 50.82 percent in RY2, and 52.53 percent in RY3.

D. Earnings Sharing

The JP includes an earnings sharing mechanism (ESM) that, during the respective terms of the Electric and Gas Rate Plans, would establish a sharing threshold at 60 basis points above the recommended ROE of 9.0 percent (the "Earnings Sharing Threshold").[22] Thus, if the Company's earned ROE, calculated as defined in the JP, exceeds 9.6 percent, then the earnings in excess of that threshold would be deemed "Shared Earnings."

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[20] Exh. 87, Staff SIS, at 8 & n. 11 (citing 2015 rate orders affecting Central Hudson and Consolidated Edison).

[21] Exh. 80, O&R SIS, p. 7.

[22] JP, pp. 15-16.

Earnings above 9.6 percent but less than 10.2 percent would be shared equally (50 percent/50 percent) between customers and the Company. Earnings of 10.2 percent and above, but less than 10.8 percent, would be shared 75 percent/25 percent between customers and the Company, respectively. Earnings of 10.8 percent and above would be shared 90 percent/10 percent between customers and the Company, respectively.

Moreover, the terms of the JP specify that, in any Rate Year, the Company would be required to apply one-half of its portion of electric or gas Shared Earnings, and all of the customers' portion of electric or gas Shared Earnings, first to reduce deferred under-collections of SIR costs, and then to reduce other deferred costs.[23]

Under the Gas Rate Plan, the earnings sharing arrangement would continue after the end of RY3, and until the Commission resets the Company's gas base rates.

Under the Electric Rate Plan, the earnings sharing would also continue, with certain modifications. After the end of RY2, the "dead band" would be eliminated, and the Earnings Sharing Threshold would decrease to 9.0 percent until the Commission resets base electric rates. Earnings above 9.0 percent but below 9.6 percent would be shared equally between customers and the Company. Earnings of 9.6 percent and above, up to 10.2 percent, would be allocated 75 percent/25 percent between customers and the Company, respectively. Earnings of 10.2 percent and above would be allocated 90 percent/10 percent between customers and the Company, respectively.

For both the electric and gas ESMs, the provisions relating to the Company's application of shared earnings to SIR costs and other deferred costs would continue after the

[23] JP, p. 17.

expiration of the rate plans, until base rates are reset by the Commission.[24]

E. Advanced Metering Infrastructure

The JP proposes implementation of an Advanced Metering Infrastructure (AMI) system by the Company. AMI systems generally consist of an integrated system of meters, communications networks, and data management systems that enable two-way communication between the Company and its customers.[25] In its initial filing, the Company testified that AMI will provide significant benefits to customers in several areas, including managing their energy use, and participating in energy efficiency and demand response programs.[26] O&R further testified that AMI would also provide system-wide benefits, by reducing operating costs, improving outage detection and restoration, and enhancing system engineering and planning.[27] According to the Company, AMI would also promote integration of new technologies across the electric grid and development of retail market operations. In these and other ways, O&R testified, its proposed AMI program would help the Company achieve policy objectives articulated in the REV proceeding.[28]

The JP proposes that the first phase of O&R's AMI program be implemented in Rockland County, and proposes capital expenditures of $10.8 million in RY1, $8.2 million in RY2, and

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[24] JP, pp. 62-63 (continuation of provisions).

[25] Case 09-M-0074, Advanced Metering Infrastructure, Order Adopting Minimum Functional Requirements For Advanced Metering Infrastructure Systems and Initiating An Inquiry Into Benefit-cost Methodologies, (issued February 13, 2009) p. 6.

[26] Exh. 3, Company AMI Panel, p. 5.

[27] Exh. 3, Company AMI Panel, p. 5-7.

[28] Case 14-M-0101, Proceeding in Regard to Reforming the Energy Vision, Order Instituting Proceeding (issued April 25, 2014) (REV Order).

$9.1 million in RY3.[29] Under Phase One of this program, the Company would install, over a five-year period beginning in 2015, an AMI system in the Rockland County portion of its service territory. This would involve installation of approximately 116,000 electric AMI meters and 91,000 gas AMI meters.[30]

The JP proposes that funding for AMI be tracked and reconciled separately from other capital expenditures. Underspending would be booked as a regulatory liability, and there would be no deferral for overspending. The Company would be required to develop an AMI Business Plan, through a collaborative process with Staff and other interested parties. The Company would, during this collaborative, consider the feasibility of providing near-real-time data access to customers and authorized third parties. The AMI Business Plan would have to include, among other things, a detailed benefit cost analysis, a plan for customer engagement, including privacy principles, and a customer outreach and education plan.[31]

In its direct testimony, Staff had noted that O&R conducted a benefit cost analysis and had estimated a five-year AMI implementation cost of $43.3 million, with net savings of $85.7 million over 20 years, and a payback period of

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[29] The JP, as filed, indicated AMI Phase One capital expenditure levels of $11.7 million in RY1, $8.9 million in RY2, and $8.9 million in RY3. JP, p. 19. During the evidentiary hearing, the Company clarified that those numbers represented capital expenditure levels by calendar year, and testified that rate year amounts would be $10.8 million, $8.2 million, and $9.1 million, respectively, for RY1, RY2, and RY3. See August 4, 2015, Hearing Transcript, p. 81.

[30] Exh. 87, Staff SIS, p. 22 (citing Exh. 3, Company AMI Panel, p. 5).

[31] JP, p. 60.

approximately 9.5-years.[32] Noting that AMI costs and savings may be difficult to quantify, particularly with novel technologies, Staff testified it was satisfied that the Company had exercised best efforts to produce reasonable estimates of costs and savings.[33]

Pace supports the provisions of the JP that call for AMI investments, such as the Company's development of an AMI Business Plan and the AMI collaborative. Such a process, Pace notes, is similar to the collaborative processes we previously approved with respect to Con Edison.[34] Opining that some form of advanced metering will be needed to implement REV, Pace says the AMI collaborative will ensure O&R's AMI investments advance the goals of REV.[35] The collaborative, Pace says, will provide a strong framework for meaningful input from all interested parties during the development of the Company's proposed AMI initiative.[36] Pace asserts that the AMI initiative, in turn, will help to animate distributed energy resource markets, in a manner consistent with our previously-articulated REV goals.

The JP states that the Commission may make a further determination about the AMI proposal when acting on the Commission's final Distributed System Implementation Plan Order and other developments.[37] The Company's DSIP filing is currently due on June 30, 2016. When the Commission acts on the Company's

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[32] Exh. 92, Staff AMI Panel, pp. 6-7.

[33] Exh. 92, Staff AMI Panel, p. 8.

[34] Exh. 121, Pace SIS, p. 5 (citing Cases 13-E-0030 & 15-E-0050).

[35] Exh. 121, Pace SIS, p. 8 (citing Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan, p. 98 (issued February 26, 2015) (REV Framework Order)).

[36] Exh. 121, Pace SIS, pp. 7-8.

[37] JP, p. 20.

DSIP filing, the Commission may further consider the implementation of AMI including deciding to modify or halt the Company's implementation of its proposed AMI system. The JP would provide that, in the event of a determination by the Commission to stop or modify the Company's implementation of its proposed AMI system, all AMI project costs prudently incurred by the Company up to project cancellation would be recoverable by the Company, except for costs such as those for acquiring and/or installing any software, hardware or equipment that is ultimately not needed or cannot meet the required needs as determined at the time the Commission issues its final DSIP Order or earlier.[38]

F. Storm Expense

The JP allows O&R to continue using reserve accounting for its incremental non-capital major storm costs for electric operations. This allows the Company to reconcile actual incremental major storm costs incurred to the levels allowed in rates,[39] and allows the Company to recover prudently incurred costs in responding to major storms.[40] The proposed amounts of $3.77 million in RY1 and $3.85 million in RY2 are based upon the currently-authorized level, adjusted for inflation.[41]

Staff states that it has completed its review of the incremental major storm costs incurred by the Company due to Superstorm Sandy and other major storms prior to November 1, 2014 and charged to the major storm reserve. According to Staff, the JP resolves all outstanding issues relates to those

[38] JP, p. 21.

[39] Exh. 87, Staff SIS, p. 33.

[40] Exh. 80, Company SIS, p. 18.

[41] JP, at 26, and App. 6; Exh. 87, Staff SIS, p. 33.

major storms.[42] Under the JP, the Company would be allowed to recover $59.26 million of such costs over a five-year period, or $11.85 million in each of RY1 and RY2.[43]

Going forward, the JP has provisions protecting ratepayers against certain costs. More specifically, O&R would not charge employee overtime costs to the major storm reserve for overtime occurring more than 60 days after service is restored to all customers, and would not charge certain other overhead costs to the major storm reserve.[44]

Under the terms of the JP, the Company would study and evaluate the feasibility of assigning the costs of mutual aid and other contractors to the individual service territory in which the work was performed.[45]

G. Reforming the Energy Vision

1. Pomona DER Program

In its initial filing, O&R sought to defer construction of a new substation and 138 kV underground transmission line loop, which it estimated would cost $55.7 million, in Pomona, Rockland County.[46] To defer the need for these new facilities and advance REV policy objectives, the Company proposed development of a distributed energy resources

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[42] JP, p. 27.

[43] JP, p. 27.

[44] JP, p. 27.

[45] JP, p. 27.

[46] The Company forecasts that electric load will grow by 4.5 MW over the next seven years in northwest Rockland County. Exh. 39, Company REV Panel, at pp. 14-15.

project (Pomona DER Program), referred in the REV Framework Order as a non-wires alternative (NWA).[47]

The JP states that the definitive nature of projects to be developed in the Pomona area cannot yet be determined because of still-pending developments in the REV Proceeding.[48] However, the Company's benefit/cost analysis assessed the revenue requirement impacts of several categories of non-traditional costs for achieving energy efficiency and demand reduction. These included air-conditioning cycling, battery-based systems, gas-fired distributed generation facilities, solar and energy efficiency initiatives, and substation and transmission investments.[49]

The JP would require the Pomona DER Program to include a commercial and industrial demand response component.[50] The JP would also allow O&R to collaborate with third-parties to create behind-the-meter battery storage solutions.[51] The JP would provide for three positions for the Pomona DER Program, which, based on availability, will also assist in implementing the Company's AMI system.[52]

The Company estimates the Pomona DER Program will cost approximately $9.5 million from 2016 through 2023.[53] Its benefit/cost analysis found the Pomona DER Program would provide

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[47] Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan, (issued February 26, 2015) (REV Framework Order), p. 131, and App. B, p. 3

[48] JP, Appendix 26, p. 2 of 22.

[49] JP, Appendix 26, pp. 4-22 of 22.

[50] JP, p. 39.

[51] JP, p. 39.

[52] JP, p. 39.

[53] Exh. 87, Staff SIS, p. 43.

customer benefits having a net present value of $5.0 million if it could delay the need for the new substation for four years.[54]

The Company's benefit cost analysis (BCA) did not take labor costs into account. However, under the JP, the costs of the three new positions for the Pomona DER Program, not to exceed $950,000 over two years (including fringe benefits), could be recovered through the $9.5 million funding authorization for the Pomona Project.[55] Based on such a funding level for labor costs, the Pomona DER Program would still result in net savings.

In pre-filed testimony, Staff acknowledged the Company's estimate of the benefits of the Pomona DER Program and said the benefits would be even greater if societal benefits had been taken into account.[56] Staff cited potential benefits such as energy and capacity savings, environmental externalities, and benefits realized by owners of distributed energy resources.

The Company would receive base rate funding of $380,000 per year to allow recovery of all Pomona DER Program costs expected to be incurred in RY1 and RY2, and amortized over a ten-year period.[57] Total spending for the Pomona DER Program would be capped at $9.5 million, in 2014 dollars, but O&R would be allowed to request additional funding if it can further delay the need for the Pomona substation and related facilities.[58] The

[54] Exh. 95, Staff REV Panel (Direct) (Redacted), p. 6 (citing the Company's Benefit Cost Analysis (BCA)). The BCA is Appendix 26 to the JP.

[55] JP, App. 22, p. 1 of 2; App. 25, n.1.

[56] Exh. 95, Staff REV Panel (Direct), pp. 6-7.

[57] JP, p. 38 & Appendix 25, p. 2; Exh. 87, Staff SIS, p. 44. This includes funding for three new positions, which, based on their availability, will assist in implementing the Company's AMI system. JP, p. 39.

[58] JP, p. 38.

Company may also earn an incentive if it achieves load reduction above 3.0 MW, or achieves per-MW cost savings, compared to the cost of the proposed Pomona substation.[59]

The Company's ability to own DER assets would be limited to utility-side energy storage and other circumstances described in our REV Framework Order.[60]

The JP calls for a collaborative on the Pomona NWA Program, and would require the Company to provide an implementation Plan and accounting procedures for the Pomona DER Program within 60 days of the Commission's final rate order. The Company would also be required to file quarterly reports on the program.[61]

Pace supports the Pomona DER program and collaborative, saying it is consistent with the goals of REV and will provide valuable information going forward.

2. Demonstration Projects

The JP provides for the filing of a REV Demonstration project in addition to that filed by the Company on July 1, 2015. The timing of the filing would be linked to the Company's implementation plans for AMI and would include the demonstration of time-varying rates integrated with AMI, enabling technologies, and customer interface systems. The filing would be made pursuant to the Commission's REV Framework Order as it relates to REV Demonstration projects.

The Company would establish a surcharge mechanism to recover the costs of Demonstration Projects undertaken pursuant to the REV Framework Order. Specifically, the Company would

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[59] JP, p. 38-39 and Appendix 25; Exh. 87, Staff SIS, p. 44; Exh. 80, Company SIS, p. 23.

[60] REV Framework Order, p. 70.

[61] JP, p. 40.

institute a new component of its existing Energy Cost Adjustment (ECA), subject to a $0.002/kWh maximum rate and semi-annual reconciliation, for recovery of REV Demonstration Project costs only.

H. Street Lighting

In O&R's previous rate case, street lighting was an important issue for the Town of Ramapo and other municipalities.[62] The resulting 2012 Electric Rate Plan included provisions to allow localities greater flexibility in providing street lighting services, while taking into account the Company's cost concerns.

The JP continues provisions to promote municipal upgrades to newer, more energy efficient street lighting technologies. The Company will replace, at no cost to participating municipalities, up to 2.0 percent of its street lights, on a system-wide basis and allocated among requesting municipalities, during each of RY1 and RY2. This approach, similar to the approach under the 2012 Electric Rate Plan, enables municipalities with more ambitious lighting modernization programs to use replacement allocations that are not needed by other localities, without incurring additional cost, and with no increase in the Company's overall replacement obligation.

The terms of the JP would also require the Company to re-examine the costs of light emitting diode (LED) street lights and make a separate tariff filing, within six months of our

[62] 2012 Electric Rate Order, p. 25. At a public statement hearing, Supervisor Gromack of the Town of Clarkstown specifically complimented O&R for its help in reducing the Town's street lighting costs. Transcript of July 1, 2015 Public Statement Hearing, pp. 18-19.

final rate order in this proceeding, to offer municipalities additional LED street lighting options.[63]

I. Reconciliations

The JP includes provisions addressing the reconciliation of certain of the Company's actual costs and revenues to the levels that would be provided for in rates. For example, in addition to a (downward-only) net plant reconciliation mechanism, the JP would allow reconciliation of property taxes, pensions/OPEBs, SIR and major storm costs, and certain other categories of costs.[64] Except for certain reconciliation mechanisms that would be discontinued on the ground that they are no longer needed, the JP proposes continuing reconciliation mechanisms adopted by the Commission in prior rate orders.[65] The reconciliation and deferral provisions under the JP would continue through the term of the proposed electric and gas rate plans and thereafter until rates are reset.[66]

The total amount that could be deferred annually by the Company would be limited, however, by other provisions of the JP governing the disposition of shared earnings. If O&R's earned ROE were to exceed the ESM sharing threshold in any rate year, the Company would be required to apply one-half of its portion of electric or gas Shared Earnings, and all of the customers' portion of electric or gas Shared Earnings, to reduce

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[63] JP, p. 43.

[64] JP, pp. 23-31. The JP proposes discontinuing existing reconciliation mechanisms for long-term debt costs and for deferred income taxes. JP, p. 31.

[65] JP, p. 30; Staff SIS, p. 28.

[66] JP, p. 30. As discussed elsewhere, the reconciliation and deferral mechanisms for long-term debt and income taxes would be discontinued.

deferred under-collections of SIR costs. If any Shared Earnings were to remain after SIR costs were paid down, they would be applied, in like fashion, to pay down other deferred costs.[67] The Company's annual earnings report would be required to describe any such write down(s) of deferred costs through the ESM.

1. Electric – Net Plant Reconciliation

The JP would establish electric revenue requirements for RY1 and RY2 that reflect agreed-upon average net plant in service target balances.[68] The JP would adopt Staff's proposed downward-only net plant reconciliation approach. Actual expenditures would be reconciled against these targets at the end of RY1 and RY2. If, on a cumulative basis at the end of RY2, the Company's actual net plant is lower than the target in the JP, the revenue requirement impact of the shortfall would be deferred for the benefit of ratepayers.[69] If actual net plant exceeds the target, no deferral would be made.[70] This approach ensures that ratepayers are protected from underspending.[71]

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[67] JP, p. 17.

[68] JP, p. 18 & Appendix 9. The net plant in service balances exclude AMI-related capital expenditures, which are to be reconciled separately under the JP.

[69] JP, p. 18.

[70] JP, pp. 18-19, and Appendix 9. These provisions are more stringent than the 2012 Electric Rate Plan, which allowed limited deferral of both underspending and overspending for transmission and distribution plant. 2012 Electric Rate Order, pp.14-15.

[71] Exh. 87, Staff SIS, p. 22.

2. Environmental Remediation

The JP would establish specific funding levels for SIR costs, for both electric and gas operations.[72] It would allow continued deferral accounting for the treatment and recovery of SIR costs and proposes that, if the level of actual expenditures varies in any rate year from the levels provided for in rates, such variations would be deferred and recovered from or credited to customers.[73]

3. Property Taxes

Property taxes are a significant rate driver in both the gas and electric rate cases.[74] For electric services, amortization of deferred property taxes and forecasted future property taxes account for $10.838 million in revenue requirement in RY1.[75] For gas service, amortization of deferred property taxes and forecasts of future property taxes amount to $18.715 million in revenue requirement in rate year 1.[76]

The existing rate plans allowed for deferral and later reconciliation of property taxes, relative to the levels allowed

[72] JP, p. 25, & Appendices 6 and 7.

[73] Exh. 87, Staff SIS, p. 33. Under deferral accounting, deferred SIR cost balances are reduced by, among other things, insurance and third party recoveries, if any, obtained by the Company. JP, p. 25.

[74] Exh. 87, Staff SIS, Attachment A.

[75] Exh. 87, Staff SIS, Attachment A, Page 1 of 2. The RY1 revenue requirement under the JP is less than this amount ($9.3 million) because other costs have decreased.

[76] Exh. 87, Staff SIS, P. 31 and Attachment B, Page 1 of 2. These costs were similarly offset, partially, by decreases in certain categories of costs.

for in rates.[77] Differences due to changes in property tax rates were to be fully reconciled and deferred. Differences due to changes in assessments, however, were shared 86 percent/14 percent between ratepayers and the Company. This sharing mechanism was intended to encourage the Company to challenge excessive property assessments. If property taxes were lower than amounts allowed in rates, due to changes in property assessments, the Company could retain 14 percent of the differential. Conversely, if property taxes were higher due to increased assessments, the Company would be responsible for 14 percent of the resulting increases in property taxes.

During the existing rate plans, the Company experienced significant increases in property taxes. During its review of the Company's filing, Staff took issue with O&R's methodology for calculating the proportion of property tax increases attributable to changes in property tax assessments (as opposed to changes in property tax rates).[78] This dispute was resolved as part of the settlement leading to the JP, whereby the JP proposes to create an electric regulatory asset of $13 million (as opposed to the $15.7 million claimed by the Company) and a gas regulatory asset of $34.034 million (as opposed to the $35 million claimed by the Company).[79] Under the JP, these deferred amounts would be amortized over a five-year period, rather than three years.

In addition, the proposed property tax reconciliation provisions would differ from those of the current rate plans,

[77] Both the 2009 Gas Rate Plan, and the 2012 Electric Rate Plan allowed for deferral and reconciliation of property tax liabilities above the levels allowed for in rates.

[78] The 2009 Gas Rate Plan and the 2012 Electric Rate Plan were silent on this precise point. Staff Statement, p. 31.

[79] Exh. 87, Staff SIS, p. 31.

providing for full and symmetrical reconciliation of property taxes with the amounts allowed for in rates. Staff says this approach is warranted because the Company has experienced significant volatility in its actual property taxes in recent years.[80] For example, under the 2009 Gas Rate Plan, property tax targets for the years ending October 31, 2011 and 2012 reflected a forecasted 5.45 percent annual increase in property taxes, while actual gas property taxes increased by 18.3 percent and 12.5 percent, respectively, during those periods.[81] Under the 2012 Electric Rate Plan, property tax targets reflected a forecasted 5.0 percent annual growth in property taxes, but actual property taxes increased by 14.8 percent and 8.0 percent during the relevant rate years.[82]

Going forward, Staff states that the Company's latest state, county, and town property tax bills for calendar year 2015 reflect a 4.5 percent growth rate from 2014 levels.[83] This information may signal that future growth rates for property taxes may be lower than in recent years. Staff notes that we are now a number of years into the economic recovery from the recession of 2008, and municipalities have now had some experience with the 2.0 percent property tax cap implemented by the State in 2012.[84] However, Staff says, because of continuing uncertainties about future property tax growth rates, the JP would adopt Staff's recommended projections, setting a revenue requirement that reflects projected annual growth rates of 4.5

[80] Exh. 87, Staff SIS, p. 31.

[81] Exh. 87, Staff SIS, p. 31.

[82] Exh. 87, Staff SIS, p. 31.

[83] Exh. 87, Staff SIS, p. 31.

[84] Exh. 87, Staff SIS, p. 32.

percent, 5.3 percent, and 7.1 percent for state, county, and town property tax bills.[85]

J. Gas Programs

The JP includes a several noteworthy programs to enhance gas safety, including a workforce development program and first responders training, and to enhance the gas network.

1. Workforce Development

In testimony, Staff cited several reasons necessitating a workforce development program, including the aging of the workforce, our policy to increase replacement of leak prone gas main among all natural gas utilities, and the need for qualified gas inspectors.[86] Staff proposed that O&R work with local community colleges and other qualified organizations to provide training for future utility workers. This, in turn, will provide the workforce needed going forward to enhance gas safety. The JP would provide funding in gas base rates in the amount of $83,333 in RY1, $166,666 in RY2, and $250,000 in RY3.[87] The Company would be required to provide reports periodically on the progress of this program.[88]

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[85] Staff notes that State, county, and town property taxes account for about 95 percent of the Company's total property taxes. Exh. 87, Staff SIS, p. 32 (citing Exh. 89, Direct Testimony of J. Wang, p. 65).

[86] Staff cited evidence that about 55 percent of the energy industry workforce will need to be replaced in the next 10 years and that, currently, 9.9 percent of the workforce is ready to retire. Staff Gas Safety Panel Testimony (Direct), p. 54-55.

[87] JP, p. 33.

[88] Biannual reports must be filed with the Secretary, no later than June 30, and December 31, of 2016, 2017, and 2018, and continuing until the Company's gas base rates are reset. JP, pp. 33-34.

The International Brotherhood of Electrical Workers Local Union 503 is particularly supportive of the workforce development program under the JP, describing it as critical to training the next generation of utility workers, thereby allowing the Company to continue providing safe and reliable electric and gas service.[89]

2. First Responder Training

The JP includes provisions designed to promote more effective collaboration between the Company and local fire departments during gas emergencies. To this end, the JP would requires O&R to provide enhanced training to local fire department first responders, including more drills, scenarios, and hands-on exercises.[90] The Company would also take steps to enhance radio communications between the Company's first responders and local fire department first responders. Biannual reports must be filed by the Company, detailing progress on the Company's first responder training program.

3. Network Enhancement

The JP contains provisions for a natural gas network enhancement program. For example, the JP would increase the residential conversion rebate, from $500 to $1000, for customers converting to natural gas before June 30, 2016, 2017, and 2018, respectively, and continuing each year until the Commission resets the Company's base gas rates.[91] The JP proposes a 15-year development period for determining the economic feasibility of a

[89] Letter from Scott Jensen, President/Business Manager, I.B.E.W., Local Union 503, to Secretary Burgess, (July 2, 2015).

[90] The Company will also provide training assistance to Orange and Rockland counties.

[91] The rebate would remain at $500 for customers converting during the remainder of the year. JP, p. 35.

proposed expansion of gas service. Thus, a project would be considered economically feasible, for purposes of granting a franchise expansion under Section 68 of the Public Service Law, if it is projected to earn the allowed rate of return by the end of a 15-year development period.[92]

The JP would also require the Company to survey potential customers within targeted gas network expansion areas and analyze penetration rates of past line extension projects, with annual updates. The JP would also require the Company to develop a strategic plan, updated annually, that identifies target areas for gas network expansions based on a number of factors. The strategic plan would include a three-year forecast of line extension and franchise expansion projects, and a list of the gas infrastructure projects needed to support such expansions. The Company would track penetration rates for each project completed pursuant to the strategic plan.[93]

The JP proposes to implement a Customer Addition Incentive Mechanism (CAIM), which would provide the Company an opportunity to earn a positive incentive, in an amount equivalent to up to 10 basis points, based on the number of net

[92] JP, p. 36. The Commission's 1989 Gas Expansion Policy Statement established, among other things, that if a franchise proposal is projected to earn the allowed rate of return by the end of a five-year development period, all investments and revenues related to the expansion will be afforded normal rate treatment. Case 13-G-0092, Petition of NYSEG, Order Amending Certificates of Public Convenience and Necessity and Requiring System Improvements, (Issued June 22, 2015) p. 3 (adopting a ten-year development period); Case 89-G-078, Policy Regarding the Rate Treatment Afforded to Expansion of Gas Service into New Franchise Areas, Statement of Policy Regarding Rate Treatment to be Afforded to the Expansion of Gas Service into New Franchise Areas (issued December 11, 1989).

[93] JP, pp. 35-36.

gas customer additions to SC 1, 2 and 6 during each rate year.[94] For example, if, at the end of the first rate year, the Company experienced a net growth of 2,000 gas customers, it would be entitled to an incentive payment equivalent to 5 basis points.[95]

Staff says the network expansion measures would help increase the availability of natural gas to new customers, lower gas conversion costs, and provide related cost savings for new gas customers. Existing customers would also benefit, Staff explains, from the economic and environmental benefits of the increased availability of natural gas throughout local communities and an increased customer base for the allocation of future shared gas system costs.

4. Leak Prone Pipe

Leaks on underground gas piping can create safety risks to the public.[96] Under the 2009 Gas Rate Plan, the Company was required to replace a minimum of 90,000 feet (approximately 17 miles) of leak prone pipe each calendar year, and replace a total of 330,000 feet (approximately 62.5 miles) over the three-year plan.[97] In its rate filing, O&R proposed replacing 100,000 feet of leak prone pipe each year, of which 10,000 feet would be in low pressure areas. In pre-filed testimony, Staff recommended replacement rates of 115,000 feet (21.8 miles) in CY

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[94] JP, Appendix 24.

[95] Exh. 87, JP, Appendix 24. A single basis point is worth approximately $60,000. Evidentiary Hearing Transcript, p. 140.

[96] Staff testified that leak prone pipe “is generally considered steel pipe that is unprotected, cast iron pipe, and some vintages of plastic pipe that can become brittle.” Exh. 109, Staff Gas Safety Panel, Direct Testimony, p. 6.

[97] Exh. 109, Staff Gas Safety Panel, Direct Testimony, pp. 9-10.

2016, 120,000 feet (22.7 miles) in CY 2017, and 125,000 feet (23.7 miles) in CY 2018.[98]

The JP would establish funding for the removal of 21 miles, 22 miles, and 23 miles of leak prone pipe in RY1, RY2, and RY3, respectively, with annual reporting by O&R on the status of its leak prone pipe replacement efforts. The JP would also allow a negative revenue adjustment if the Company fails to replace at least 20 miles of leak prone pipe in any calendar year.[99] The JP recommends a total negative revenue adjustment of up to eight basis points, rather than continuation of the current level of six basis points, which was initially recommended by Staff in its pre-filed testimony.[100] These metrics bring O&R into alignment with other gas utilities.[101]

The JP also includes a proposed incentive mechanism for incremental replacement of leak prone pipe above the amounts provided for in base rates. The JP would allow a positive revenue adjustment equivalent to two basis points for each whole incremental mile of leak prone main replaced in any calendar year above the targets provided for in base rates, up to a 10 basis point cap.[102] The Company could recover the cumulative incremental revenue requirement for such costs through the

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[98] Mileage amounts are approximate. Exh. 87, Staff SIS, p. 60; Exh. 109, Staff Gas Safety Panel, Direct Testimony, p. 11.

[99] The JP would also include a cast iron sub-target that would require O&R to replace at least 2.0 miles of cast iron main in CY 2016 and in CY 2017, and 7.5 miles total for CY 2016 through CY 2018. Exh. 87, Staff SIS, p. 61.

[100] Exh. 87, Staff SIS, p. 61.

[101] Exh. 87, Staff SIS, p. 61 & n. 196 (citing cases).

[102] Under Staff’s proposal, the incentive would have equaled the revenue requirement effect of an additional basis point on common equity. Exh. 109, Staff Gas Safety Panel, Direct Testimony, pp. 18-19.

Reliability Surcharge Mechanism, provided the Company had also met its other targets for net plant under the JP.[103]

K. Low-Income Programs

The JP proposes to continue low-income customer assistance programs under both the electric rate plan and the gas rate plan.[104] The JP would increase the budget for the electric and gas low-income programs, which would enable the Company to offer higher discounts for both electric heating and non-heating customers as well as gas heating customers.[105] The JP would also decrease the discount for gas non-heating customers from $11.63 per month to $6.00 per month. The JP would allow deferral of low-income program costs above or below the amounts provided for in rates.[106] These low-income program funding levels would continue in effect after the rate plans, until modified by the Commission.[107]

UIU supports these provisions, saying the low-income discount levels specified under the JP would provide a discount of approximately 12 percent on the average bills of heating and non-heating low-income customers.[108] UIU also notes that the JP reflects its proposal for more detailed low-income reports showing a level of detail and information comparable to those filed by other utilities.[109] The JP proposes that the Company

[103] Exh. 87, Staff SIS, pp. 61-62.

[104] JP, p. 55.

[105] Exh. 118, UIU Statement on the JP, p. 5. The monthly discount for electric heating customers would increase from $17.40 to $27.00. For electric non-heating, it would increase from $9.00 to $18.00. For gas heating, it would increase from $11.63 to $17.00.

[106] JP, p. 56.

[107] JP, p. 55.

[108] Exh. 118, UIU Statement on the JP, p. 5.

[109] Exh. 118, UIU Statement on the JP, p. 5.

continue to offer all low-income customers with a one-time waiver of the reconnection fee in any given rate year. UIU states that these provisions of the JP will greatly benefit low-income consumers and will also serve to promote Commission goals.[110]

L. Reporting Requirements

The JP includes reporting requirements for a range of activities. Quarterly reports would be required for electric, gas, and common capital spending. Annual reports would be required for gas sales forecasts and gas reliability forecasts. The Company's annual earnings report would have to report the amounts, if any, of deferred under-collections of SIR costs, or any other costs, written down with the Company's and customers' Shared Earnings. Annual reports of capital expenditures for AMI electric and gas would be required, along with semi-annual reports on the implementation of the Company's AMI system, including the status of various benchmarks under the AMI Business Plan. Biannual reports would be required detailing the status of the Company's Workforce Development and First Responders Training program. The Company would be required to report annually on its strategic plan for gas network expansion, with underlying data provided quarterly.

With respect to the Pomona DER program, the Company would be required to provide, within 60 days of the final rate order, an implementation plan and accounting procedures. The Company would be required to file reports on a quarterly basis, regarding its Pomona DER program activities, including costs incurred for each initiative, in-service dates for capital

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[110] Exh. 118, UIU Statement on the JP, pp. 5-6 (citing Case 14-M-0565, Proceeding to Examine Programs to Address Energy Affordability for Low Income Utility Customers, Staff Report, (filed June 1, 2015).

investments, and participation levels for customer demand reduction and efficiency programs.

The Company would be required to report information annually on natural gas conversions, including the number of inquiries and requests by prospective natural gas customers, and the number of applications submitted for conversion to gas service.

Quarterly reports would be required on the electric and gas low-income assistance programs, and on same-day electric service reconnections.

The Company would be required to file annual reports on the Company’s electric reliability performance mechanism, including the amount of any applicable revenue adjustment and any applicable exclusions. The Company would have to prepare an annual gas safety performance measures report, detailing the Company’s performance on all gas safety performance metrics. An annual report would also be required on the Company’s performance under the customer service performance metrics, identifying the amount of any revenue adjustment as well as any applicable exclusions.

Finally, as of the end of RY2 under the Electric Rate Plan, the Company would review a climate change study to be produced by the Center for Climate Systems Research of Columbia University for Consolidated Edison Company of New York, Inc., and evaluate whether that study suggests a need for adjusted capital expenditures or planning for investment. Thereafter, the Company would provide a written report of its evaluation to the Sabin Center and other interested parties within 120 days of the end of the Electric Rate Plan.[111]

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[111] JP, p. 52.

VI. DISCUSSION

The proposed rate increases are reasonable. The Company has experienced significantly increasing costs. For electric service, the primary rate increase drivers are property taxes (including amortization of deferred property taxes), capital expenses for net plant, depreciation expenses, the amortization of storm reserve costs, and operations and maintenance expenses, including labor.[112] These are offset partially by reductions relating to the amortization of pensions and OPEBs, carrying charges on deferred tax liability, SIR costs, and pollution control debt, as well as a reduction in the rate of return. However, significant cost increases remain. For gas service, the main rate increase drivers are property taxes, significant cost increases related to net plant, property taxes, and operations and maintenance expenses. Again, reductions in other cost categories (in particular the amortization levels of regulatory deferral amounts and rate of return) only partially offset these increases. Increasing revenues for electric and gas to meet the Company’s increasing costs is essential if the Company is to continue meeting its statutory duty to provide safe and adequate electric and service and receive a fair rate of return for shareholders.

One of the largest rate drivers is property taxes. In the electric case, property taxes account for $39.0 million, or 12 percent of electric delivery revenues. The property tax expense in RY1 is $8.238 million higher than it was in the final rate year of the 2012 Electric Rate Order. In addition, property taxes during the previous rate plan exceeded the forecast level by a large amount, resulting in a deferred amount

[112] Exh. 87, Staff SIS, Attachment A, Page 1 of 2.

of over $13.0 million as per the JP.[113] In order for the Company to recover these deferred costs over five years, the revenue requirement includes an amortization of $2.6 million per year. Combined, these two aspects of property taxes account for $10.838 million of revenue requirement, which exceeds the $9.326 million of total RY1 revenue requirement. In other words, absent the large increase in property taxes since 2012, the Company’s electric revenue requirement could have possibly been negative.

In the gas case, property taxes account for $22.8 million, or 15 percent of gas delivery revenues. The property tax expense in RY1 is higher than the final rate year of the 2009 Gas Rate Order by $11.908 million. In addition, a deferral balance of $34.034 million has arisen related to property taxes that exceeded the forecast in that prior case.[114] This has led to a $6.807 million annual amortization of past property tax expenses. Combined, these two rate drivers amount to $18.715 million, accounting for approximately 70% of the large revenue requirement increase required in RY1.

Net plant is another major driver. The Company has invested in its electric and gas systems in order to ensure a safe and reliable system, and such plant has to be paid for through depreciation expense and a rate of return on the higher rate base levels. In the electric case, these cost increases (after reductions related to accumulated deferred federal income taxes) amount to $10.493 million of the RY1 rate increase. In the gas case, they total $13.105 million of the RY1 rate increase.

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[113] Exh. 87, Staff SIS, p. 31.

[114] Exh. 87, Staff SIS, p. 31.

We decline to adopt the recommendation advanced by the MC that we impose a 2.0 percent limit on increases in O&R’s rates on the ground that municipalities are limited to 2.0 percent annual increases in property taxes under State law.[115] Adopting such a limit on utility rate increases would not be consistent with the Public Service Law and could interfere with the Company’s ability to provide safe and adequate electric and gas service. There is no evidence in the record that a delivery rate increase limited to 2.0 percent per year would enable O&R to provide safe and adequate service and earn a reasonable return. On the other hand, as we have discussed, increased property taxes are one of the primary rate drivers in this case. Between 2009 and 2014, the Company’s property taxes increased by an average of 12.9 percent annually.[116] In the 12-month periods ending June 30, 2014 and 2015, the Company’s property taxes for electric operations increased 14.8 percent and 8 percent, respectively.[117] These significant rate pressures are largely outside the Company’s control, and result from a need for increased investment in utility plant, as well as increased tax rates and assessments. Because of this, the MC’s proposal is impractical. For these reasons, the MC’s proposal to limit the rate increases of the Company to 2.0 percent is not adopted. We do, however, take this opportunity to remind the Company to be ever vigilant in its efforts to control its property tax expense in the future, including, where appropriate, challenging assessments and pursuing new, innovative ways to work with taxing jurisdictions to reduce costs.

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[115] Exh. 124, MC SIO, pp. 5-6.

[116] Exh. 113, Staff Rebuttal, p. 7 & n. 24 (citing Exh. 32, Company Property Tax Panel, Initial, p. 11).

[117] Exh. 113, Staff Rebuttal, p. 7 & n. 25 (citing Exh. 89, Wang Direct Testimony, Exhibit JW-3, pp. 22 & 23 of 52).

The JP's recommendations with respect to reconciliation of property taxes are reasonable. We agree with the recommendation of the signatory parties that, in light of remaining uncertainty about the Company's property taxes going forward, a mechanism for full and symmetrical reconciliation of property taxes will be in the best interests of both customers and the Company.

We recognize and appreciate the concerns raised by the public in written comments and at the public statement hearings regarding the burden on customers from increased rates. Ignoring the capital and financial needs of the Company, however, could possibly jeopardize service or deprive the Company of an opportunity to earn a fair rate of return. This could lead to an inability to raise the capital needed to ensure the gas and electric systems are safe and reliable. To balance these concerns, the JP proposes a number of measures to smooth the impact of the rate increases, particularly on low-income customers. For example, levelization of the increase in gas rates over the three-year term of the rate plan will defer some of the rate increase to the later rate years. In addition, use of a surcharge recovered through the MGA will ensure that rates are not artificially high after the end of RY3. Moreover, the multi-year rate plans will provide important rate certainty for ratepayers, as compared to a one-year rate plan.

The proposed revenue reallocations among service classifications are consistent with past rate orders, in that they provide for rates that more closely align cost recovery with cost causation. This approach mitigates customer bill impacts in revenue deficient classes while advancing our stated goal of bringing the Company's service classifications into parity based on cost causation.

The proposed approach to customer charges under the electric rate plan is consistent with our recent Central Hudson Rate Order, in which we rejected proposed increases in fixed customer charges for residential and small commercial customers based on a cost of service study. We did so out of recognition that electric rate design is being re-examined, particularly with respect to mass market classes, as part of the REV proceeding. In this case, Staff testified that innovative rate designs are being considered, which could lead to changes in how fixed costs are recovered from non-demand metered customers.[118] The electric plan proposed under the JP reflects the approach and reasoning we employed in the Central Hudson proceeding, and also the considerations described in Staff's testimony.

On the other hand, the JP proposes modest increases in first block charges under the gas rate plan. In RY1, such gas charges would increase from $18.63 to $20.00 for residential customers (SC Nos. 1 and 6) and from $29.08 to $30.00 for commercial customers (SC Nos. 2 and 6).

Gas rate structures are not expected to undergo the same restructuring anticipated for electric (e.g. the creation of demand charges for mass market customers) rate structures. So, the pause adopted in increasing electric customer charge does not equally apply for gas.

Additionally, in accordance with Commission policy to encourage the expansion of gas to more customers we must recall that gas differs from electric and water utility service in that the customer decision point to use gas for heating versus other often dirtier and less efficient fuels (heating oil or propane) requires that customers see a modest fixed rate coupled with a competitive (on an equivalent BTU basis) volumetric rate.

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[118] Staff Electric Rates Panel, pp. 15-16.

Finally, we note that the percentage increase in the gas customer charge is far less than the overall percentage rate increase that we are adopting. Thus we find it reasonable to increase the customer charge by a modest amount as proposed.

We note that, while the MC opposes other aspects of the JP, it supports the proposed rate design to the extent it would provide for only slight increases in monthly charges for residential gas service, asserting that the JP's provisions will have the effect of mitigating the burden on low-income customers, seniors, and others on fixed incomes.

The capital structure and cost of capital proposed under the JP are also consistent with our recent decisions. More specifically, in the Central Hudson Rate order, we allowed a 48 percent equity share and a 9.0 percent return on equity.[119] Similarly, in a recently-issued Con Edison order, we allowed a 48 percent equity ratio and equity earnings of 9.0 percent.[120] We have found that this level of equity adequately balances the need to maintain a utility's financial strength with the revenue requirement impact of relatively expensive equity capital.

The cost of capital has fallen appreciably since O&R's electric rates were last set in 2012. We have been very consistent in past years in adopting ROE's in JPs based on the expectation that, in any fully litigated case, the ROE would very likely hew closely to the level recommended in Staff's testimony. In this particular case, the JP's 9.0 percent equity return is 50 basis points greater than Staff's litigated

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[119] Case 14-E-0318, *et al.*, Central Hudson Gas & Electric Corporation Electric Rates, Order Approving Rate Plan, (issued June 17, 2015) pp. 55-56.

[120] Case 15-E-0050, *et al.*, Consolidated Edison Company of New York, Inc. Electric Rates, Order Adopting Terms of Joint Proposal to Extend Electric Rate Plan (issued June 19, 2015) pp. 35-36.

position of 8.5 percent.[121] However, this is appropriate in the context of an agreement that provides customers with numerous other material benefits. One of the benefits is a multi-year rate plan, where the Company takes on additional financial and business risks by agreeing not to reset the rate of return or many cost elements. These additional risks are usually recognized by adding a stay-out premium to the ROE. An ROE of 9.0 percent is also comparable to what we have allowed for other major utilities operating under multi-year rate plans.[122] In the context of the entire JP, we adopt as reasonable the JP's proposed capital structure and ROE provisions.

We acknowledge the positions advanced by the MC and some of its members, including Supervisor St. Lawrence, with respect to the proposed rate increases. We are mindful of, and sensitive to, the budgetary constraints faced by local governmental officials. However, our obligation under the Public Service Law is to ensure that O&R continues to provide safe and adequate service at just and reasonable rates. Part of that balancing involves establishing a return on equity that is sufficient to attract needed capital. The return we have provided for is consistent with that purpose.

With respect to environmental remediation costs, the JP would allow continued deferral of SIR costs. MC opposes the proposed level of deferred SIR costs, arguing it should be reduced by approximately $16 million in light of an Appellate Division decision denying insurance coverage for SIR costs on the ground that O&R failed to timely notify its insurance

[121] Exh. 102, Staff Finance Panel, Direct Testimony, p. 6.

[122] Exh. 87, Staff SIS, at 8 & n. 11 (citing 2015 rate orders affecting Central Hudson and Consolidated Edison).

carrier of policy claims.[123] The Company and Staff argued that the SIR costs should continue to be deferred, until the then-still-pending litigation was concluded.

Adopting the approach urged by O&R and Staff, the JP proposes continued deferral of such costs but would require O&R to notify the Commission of all future court decisions. The JP would expressly acknowledge that the Commission may consider and address the amount of any claims denied by O&R's insurance carrier, without having to wait for the Company's next rate filing. The JP would also confirm that SIR costs are "net of insurance reimbursements (if any)" and that "nothing [in the JP would] preclude or limit the Commission's authority to review the reasonableness of the Company's conduct in such matters."[124]

On September 3, 2015, the Court of Appeals denied O&R's motion for leave to appeal the decision of the Appellate Division.[125] The denial of O&R's motion for leave to appeal may have concluded the litigation but, because the Court's decision was rendered so late in this proceeding, the record is not fully developed on the question as to whether O&R should be allowed to recover the disputed SIR costs in rates.

Our stated policy has long been to require utilities to demonstrate that they have pursued insurance compensation and taken other steps to mitigate the ratepayer impacts of SIR

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[123] Exh. 124, MC SIO, p. 3; Travelers Indemnity Co. v. Orange and Rockland Utilities, Inc., 124 A.D.3d 436 (1st Dep't 2015).

[124] JP, p. 25 & n. 14.

[125] Travelers Indemnity Co. v. Orange and Rockland Utilities, Inc., 124 A.D.3d 436 (1st Dep't), leave to appeal denied, 2015 LEXIS 2537 (N.Y. Sept. 3, 2015). Consistent with the terms of the JP, the Company filed notice of the September 3, 2015 decision of the Court of Appeals by a letter dated September 25, 2015.

costs.[126] The courts have apparently finally decided the question of insurance coverage but not the question of rate recovery, which is properly considered by the Commission in the first instance.

The JP's proposed rate allowance for SIR expenses, and its proposed deferral and accounting treatment of SIR costs, are generally consistent with the Commission's established approach in accounting for SIR costs and with the findings reached in the SIR Order. However, because the JP was crafted prior to the Court of Appeals' recent decision, the record is not sufficiently developed on the question of rate recovery of SIR costs. Although we understand the strong desire of the MC to provide ratepayers relief from SIR costs, we decline to adopt its proposed treatment of SIR costs. Further process is needed before the Commission can decide whether such costs can and should be recovered through rates. Because the litigation appears concluded, however, the continued deferral of the SIR costs should only be allowed for a limited time, to allow the Company to make a filing showing why, under the circumstances, it should be allowed rate recovery of the SIR costs in question. Accordingly, we will direct O&R to make a filing, by December 15, 2015, explaining why the SIR costs that were the subject of the litigation over insurance coverage should be recovered through rates.

With respect to the provisions relating to potential excess earnings, we note that the proposed ESM will provide important benefits to ratepayers. In general, an ESM provides a

[126] SIR Order, pp. 7-8. Rate recovery can turn on a variety of factors. A utility's efforts to mitigate costs through various means, including through insurance proceeds or third-party recovery, are relevant but not necessarily dispositive. See SIR Order, at p.2 (describing factors investigated).

utility a financial incentive to control costs while allowing customers to share in efficiency gains. An ESM also provides a significant safeguard against excess earning by a utility if earnings prove significantly higher than what was projected for rate-setting purposes. These benefits are well-recognized, and an ESM has been included in O&R's prior rate plans and in the multi-year rate plans of other utilities.

The characteristics of the ESM proposed under the JP, including the tiered approach, the proposed sharing threshold, and the widths of the various sharing "bands," are all generally consistent with prior decisions of the Commission. Certain of the ESM provisions proposed, however, vary from current electric and gas rate plans in ways significantly favoring customer interests. One example is the period over which earnings are measured. Under current electric and gas rate plans, earnings are measured on a cumulative basis over the full term of the rate plans.[127] Under the JP, earnings are measured each Rate Year, independently of earnings in any other Rate Year. This is advantageous to customers at the risk of the Company because earnings above the Earnings Sharing Threshold in any Rate Year cannot be netted against earnings below the threshold in any other Rate Year.

The Earnings Sharing Threshold under the JP further benefits customers because the "dead band" is only 60 basis points, which is less than the current gas rate plan (100 basis points) and the current electric plan (80 basis points). Customers will also potentially benefit from the proposed

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[127] 2012 Electric Rate Order, Attachment A, JP, p. 13 & n. 6 (The ESM does not prohibit "the netting of under-recoveries and over-recoveries in individual rate years in order to calculate Total Shared Earnings on a cumulative Electric Rate Plan basis.").

requirement that the Company use one-half of its Shared Earnings to reduce deferred SIR costs, because such costs would otherwise remain deferred for future collection from customers. In the 2012 SIR Order,[128] the Commission recognized that a mechanism that obliges a utility to use part of its shared earnings to reduce deferred SIR costs can significantly reduce the deferred SIR cost burden on ratepayers. The JP here would require O&R to use half of its portion of Shared Earnings for such purpose. This is potentially a material benefit to customers.

With regard to the JP provisions that promote municipal upgrades to newer, more energy efficient street lighting technologies, we acknowledge that the Company will replace, at no cost to participating municipalities, up to 2.0 percent of its street lights on a system-wide basis during each of RY1 and RY2. While this approach, similar to the approach under the 2012 Electric Rate Plan, enables certain municipalities to use replacement allocations that are not needed by other localities, without incurring additional cost, and with no increase in the Company's overall replacement obligation, we believe that a more aggressive conversion rate may be appropriate.[129] As such, in conjunction with the required re-examination of the costs of LED lights and separate tariff filing as provided in the JP, we direct the Company to include in that filing an examination of the feasibility and cost

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[128] SIR Order, pp. 12-13 ("[I]n ... negotiations for rate plans where an earnings sharing mechanism is contemplated, we expect Staff and other parties to explore opportunities to allocate some proportion of excess earnings to SIR costs").

[129] The recent Central Hudson LED street lighting order approved an LED conversion rate of no less than 25% annually. Case 15-E-0126, Tariff Filing by Central Hudson Gas and Electric Corporation, Order Adopting the Addition of LED Lighting Options With Modification (issued August 13, 2015).

implications of increasing the conversion rate to 25 percent annually so that more municipalities may avail themselves on the benefits of LED lighting.

The JP also includes a number of provisions that will advance customer interests across a range of areas, such as improved metrics for gas safety performance, electric reliability, and customer service. It would provide for expanded low-income assistance programs, gas network enhancement provisions, incentives for accelerated leak prone pipe replacement, improved emergency first-responder training, and a workforce development program. The changes in the Company's gas safety training efforts, in particular, will enhance coordination among first responders during gas emergencies, and promote public safety.[130] The JP will also promote customer empowerment by establishing collaborative proceedings relating to the Company's advanced metering infrastructure program and the Pomona DER program.

In addition, the JP's provisions relating to the removal of leak prone pipe, including provisions allowing for a positive revenue adjustment for replacement of leak prone pipe above the targets provided for in base rates, are designed to advance long-standing Commission policy objectives.[131] They will encourage the Company to enhance gas safety and promote modernization of the State's natural gas systems.

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[130] Pursuant to a settlement reached in Cases 14-G-0175 and 14-G-0186, the Company contributed $150,000, at shareholders' expense, to fund first responder training, damage prevention awareness, and gas odor awareness.

[131] We recently commenced a proceeding to consider implementing such incentive mechanisms statewide. Case 15-G-0151, Implementation of a Recovery Mechanism to Support Accelerated Replacement of Infrastructure on the Natural Gas System, Order Instituting Proceeding (issued April 17, 2015), p. 2.

Finally, the JP includes provisions which, if adopted, would set deadlines for certain milestones under the AMI collaborative and the Pomona collaborative.[132] To the extent the deadlines established under the JP pre-date the issuance of this order, we recognize those provisions of the JP, but do not adopt them. Instead, we only adopt the deadlines, if any, under Sections M.1 and M.2 of the JP to the extent they will occur on or after the date of issuance of this order.

VII. CONCLUSION

From the comments we have received and the parties' submissions, coupled with the information provided at the evidentiary and public statement hearings, we have a robust record upon which to determine whether the recommendations in the JP are in the public interest and should be adopted. Having reviewed this record, we find that the JP strikes the proper balance between the interests of ratepayers, shareholders and the utility, as described in our Settlement Guidelines. The JP is consistent with Commission and State policies, as indicated in the foregoing discussion of the major issues in these cases. In addition, the rate plans we adopt here are within the range of likely outcomes and compare favorably with the likely result were the matters resolved through fully litigated rate cases. In summary and for these reasons, we adopt the recommendations made in the Joint Proposal, as described or clarified in this Order, and find them to be, in all respects, consistent with the public interest.

The recommended increases in revenue requirement over the two-year term of the electric rate plan and over the three-year term of the gas rate plan are reasonably necessary to meet

[132] JP, Sections M.1 and M.2, pp. 58-61.

increased costs and to support spending for capital improvements and employee additions, which are necessary to improve electric and gas operations and enhance overall electric and gas system integrity. We establish a two-year electric rate plan and a three-year gas rate plan, governing the rates, charges and terms of service of Orange and Rockland Utilities, Inc. for electric and gas service for the rate year commencing November 1, 2015.

The Commission orders:

1. The terms of the Joint Proposal dated June 5, 2015, which is attached as Attachment A, are adopted and incorporated as part of this order, with the exception of Section N, paragraphs 4 through 11, of the Joint Proposal.

2. Orange and Rockland Utilities, Inc. is directed to file cancellation supplements, effective on not less than one day's notice, on or before November 1, 2015, cancelling the tariff amendments and supplements listed in Attachment B to this order.

3. Orange and Rockland Utilities, Inc. is directed to file, on not less than one day's notice, to become effective November 1, 2015, on a temporary basis, such further tariff amendments as are necessary to effectuate the terms of this order. The Company shall serve copies of its filing on all parties to this case. Any comments on the compliance filing must be filed within 14 days of service of the Company's proposed amendments. The amendments specified in the compliance filing shall not become effective on a permanent basis until approved by the Commission.

4. Orange and Rockland Utilities, Inc. is also directed to file such tariff changes, if any, as are necessary to effectuate the terms of this order in subsequent years on not less than 30 days' notice to be effective on a temporary basis.

5. The requirement of Section 66(12)(b) of the Public Service Law that newspaper publication be completed prior to the effective date of the proposed amendments directed in Clause 3 above is waived and the Company is directed to file with the Commission, not later than six weeks following the amendments' effective date, proof that a notice to the public of the changes made by the amendments has been published once a week for four successive weeks in newspapers having general circulation in the areas affected by the amendments.

6. Orange and Rockland Utilities, Inc. is directed to make a filing, not later than December 15, 2015, demonstrating why it should be allowed to recover through rates the SIR costs that have been the subject of litigation between Orange and Rockland Utilities, Inc., and its insurer, Travelers Indemnity Company.[133]

7. In the Secretary's sole discretion, the deadlines set forth in this order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least one day prior to the affected deadline.

8. This proceeding is continued.

By the Commission,

KATHLEEN H. BURGESS
Secretary

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[133] See Travelers Indemnity Co. v. Orange and Rockland Utilities, Inc., 124 A.D.3d 436 (1st Dep't), leave to appeal denied, 2015 LEXIS 2537 (N.Y. Sept. 3, 2015).

Commissioner Diane X. Burman, concurring in part and dissenting in part:

As reflected in my comments made at the public session on October 15, 2015, I concur in part on the overall adoption of the rate plan and dissent in part on the aspects of the Reforming Energy Vision (REV) demonstration projects' delegation of authority and in line with my concerns on the need for more direct oversight by the Commission as a whole in the next steps as it relates to the REV demonstration projects, the AMI rollout, and the Pomona DER program. This opinion is in line with my opinion in the Central Hudson Gas & Electric Corporation, Order Approving Rate Plan, issued June 17, 2015, in Cases 14-E-0318 and 14-G-0319.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

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

JOINT PROPOSAL

June 5, 2015

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

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

JOINT PROPOSAL

THIS JOINT PROPOSAL ("Proposal") is made as of the 5th day of June 2015, by and among Orange and Rockland Utilities, Inc. ("Orange and Rockland" or the "Company"), New York State Department of Public Service Staff ("Staff"), the Utility Intervention Unit, Division of Consumer Protection, New York State Department of State ("UIU"), the Sabin Center for Climate Change at Columbia Law School ("Columbia"), the Pace Energy and Climate Center ("Pace"), the Retail Energy Supply Association ("RESA"), the U.S. Department of Defense and all other Federal Executive Agencies ("DOD/FEA") and other parties whose signature pages are or will be attached to this Proposal (collectively referred to herein as the "Signatory Parties").

Introduction

This Proposal sets forth the terms of an electric rate plan for the period November 1, 2015 through October 31, 2017 ("Electric Rate Plan") and a gas rate plan for the period November 1, 2015 through October 31, 2018 ("Gas Rate Plan"). (Collectively, the Electric Rate Plan and the Gas Rate Plan will be referred to as the "Rate Plans.") The Rate Plans prescribe agreed-upon rate levels and address operational and accounting matters for the term of the Rate Plans, as well as various other rate design and revenue allocation issues. The Rate Plans are designed to support the continued reliability, safety, and security of the Company's electric and gas systems at just and reasonable rates.

Among other things, the Electric Rate Plan reflects a revenue requirement based on the adoption of the electric sales and revenue forecast agreed to by the Signatory Parties, the continuation of a revenue decoupling mechanism ("RDM") and various other reconciliations, including a full and symmetrical property tax reconciliation, reconciliation of net plant balances in the event that actual average net plant is lower than that reflected in rates, continuation of electric performance metrics and continuation of a low income customer assistance program. The Electric Rate Plan also provides for the introduction of the implementation of an Advanced Metering Infrastructure ("AMI") project and a Pomona Distributed Energy Resources Program ("Pomona DER Program").

Among other things, the Gas Rate Plan reflects a revenue requirement based on the adoption of the gas sales and revenue forecast agreed to by the Signatory Parties, updates to the interruptible sales benefit imputation, the continuation of an RDM and various other reconciliations, including a full and symmetrical property tax reconciliation, reconciliation of net plant balances in the event that actual average net plant is lower than that reflected in rates, provision of additional resources to various gas safety initiatives, continuation and/or enhancement of gas performance metrics, continuation of a low income customer assistance program, and implementation of programs to increase residential gas conversions. The Gas Rate Plan also provides for the introduction of the implementation of an AMI project.

Procedural Setting

Orange and Rockland is currently operating under an electric rate order that established electric rates effective July 1, 2012,[1] and under a gas rate order that established gas rates effective November 1, 2009.[2] The 2012 Electric Rate Order established rates for the three years ended June 30, 2015 and the 2009 Gas Rate Order established rates for the three years ended October 31, 2012.

On November 14, 2014, Orange and Rockland filed new tariff leaves and supporting testimony for new rates and charges for electric and gas service effective on November 1, 2015 for the 12-month period ending October 31, 2016. In that filing, the Company 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 850 formal discovery requests on the filings. A procedural conference was held in Albany, New York on January 6, 2015. The procedural conference was immediately followed by a technical presentation by the Company on various aspects of the filing.

On January 23, 2015, a *Ruling on Schedule* was issued, providing dates for certain activities in these cases, including a preliminary update of the Company's filings, other

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[1] Case 11-E-0408, Orange and Rockland Utilities, Inc. – Electric Rates, *Order Adopting Terms of Joint Proposal, with Modification, and Establishing Electric Rate Plan* (issued June 15, 2012) ("2012 Electric Rate Order").

[2] Cases 08-G-1398, Orange and Rockland Utilities, Inc. – Gas Rates, *Order Adopting Joint Proposal and Implementing a Three-Year Rate Plan* (issued October 16, 2009) ("2009 Gas Rate Order").

parties' testimony, rebuttal testimony and a formal update of the Company's filings, and evidentiary hearings.

On February 13, 2015, the Company provided the parties with preliminary revenue requirement updates.

On March 20, 2015, four parties filed testimony in response to the Company's filings. On April 10, 2015, the Company filed update and rebuttal testimony, including the presentation of the Company's formal revenue requirement update. Three other parties also filed rebuttal testimony on April 10, 2015.

By notice dated April 8, 2015, Orange and Rockland notified all parties of the commencement of settlement negotiations on April 15, 2015.[3] Settlement negotiations began on April 15, 2015, and continued on April 21, April 24, April 29, May 1 and May 7, 2015. All settlement negotiations were subject to the Commission's Settlement Rules, 16 NYCRR § 3.9, and appropriate notices for negotiating sessions were provided.

The parties' negotiations have been successful and have resulted in this Proposal, which is presented to the New York Public Service Commission ("Commission") for its consideration.

Overall Framework

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

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

A. Term

B. Rates and Revenue Levels

C. Computation and Disposition of Earnings

D. Capital Expenditures and Net Plant Reconciliation

E. Reconciliations

F. Additional Rate Provisions

G. Reforming the Energy Vision ("REV")

H. Revenue Allocation/Rate Design and Other Tariff Changes

I. Performance Metrics

J. Climate Change

K. Customer Service

L. Electric and Gas Low Income Assistance Program

M. Collaboratives

N. Miscellaneous Provisions

A. Term

The Signatory Parties recommend that the Commission adopt a two-year Electric Rate Plan for Orange and Rockland as set forth herein, effective as of November 1, 2015 and continuing through October 31, 2017. The Signatory Parties also recommend that the Commission adopt a three-year Gas Rate Plan for Orange and Rockland as set forth herein, effective as of November 1, 2015 and continuing through October 31, 2018.

For the purposes of this Proposal, Rate Year means the 12-month period starting November 1 and ending October 31; Rate Year 1 ("RY1") means the 12-month period starting November 1, 2015 and ending October 31, 2016; Rate Year 2 ("RY2") means the

12-month period starting November 1, 2016 and ending October 31, 2017; and Rate Year 3 ("RY3") means the 12-month period starting November 1, 2017 and ending October 31, 2018.

B. <u>Rates and Revenue Levels</u>

1. <u>Electric</u>

This Proposal recommends changes to the Company's electric delivery service rates and charges designed to produce a $9.3 million increase in revenues on an annual basis in RY1 and an $8.8 million increase in revenues on an annual basis in RY2. The electric revenue requirement calculations underlying the Proposal are set forth in Appendix 1. The revenue changes to each service class associated with the proposed additional revenues are shown in Appendix 18.

The proposed revenue changes for each of RY1 and RY2 will be effective on the first day of each Rate Year.

The major components of the electric revenue requirements underlying this Proposal are set forth in Appendix 1. These revenue requirements are net of the amortizations of various deferred customer credits and charges on the Company's books of account that have previously been deferred by the Company, as well as projections of deferred amounts. The list of deferred customer credits and charges to be applied during the Electric Rate Plan is attached as Appendix 3.

a. Market Supply Charge/Energy Cost Adjustment

The Company will continue to recover all prudently-incurred supply and supply-related costs, including, but not limited to, power purchase costs through the Market Supply Charge ("MSC") and Energy Cost Adjustment ("ECA") mechanisms.

b. Revenue Decoupling Mechanism

For the term of the Electric Rate Plan, the Company will continue to implement an RDM, as set forth in the Company's electric tariff, amended to reflect the modifications recommended in this Proposal. The RDM, as modified, will continue thereafter until changed by the Commission.

The currently-effective RDM is modified commencing with the effective date of the Electric Rate Plan as follows: (1) revenues associated with reactive power demand charges will be included in the RDM calculations; (2) the definition in the tariff of the beginning and ending month of the Rate Year will be changed from the 12 months ending June 30 of each year to the 12 months ending October 31 of each year; (3) the period during which total delivery revenue excess/shortfalls for each customer group will be refunded/surcharged to customers will be changed from 12-month periods commencing each August 1 to 12-month periods commencing each December 1; (4) to account for the partial Rate Year period of July 1, 2015 through October 31, 2015, the sum of the monthly delivery revenue excess/shortfalls for those months, for each customer group, will be refunded/surcharged to customers through customer group-specific RDM Adjustments that are applicable during the 12-month period commencing December 1, 2015; (5) if the Company does not file for new base delivery rates to take effect upon the expiration of RY2, the RDM will remain in effect and the delivery revenue targets effective November 1, 2016 will continue; and (6) if new base delivery rates take effect on a date other than November 1, the sum of the monthly delivery revenue excess/shortfalls for each month of the partial year, for each customer group, will be refunded/surcharged to customers through customer group-specific RDM Adjustments applicable during the subsequent 12-month period commencing one month after new base delivery rates take effect. The RDM targets for each Rate Year are detailed in Appendix 18.

During the course of the Electric Rate Plan, the Company through a tariff filing, or any Signatory Party by petition to the Commission, may propose an adjustment to the currently-effective RDM targets if the Company or such Signatory 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 neutral to the Company.

c. 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)[4] not already listed in or otherwise covered by the then-effective MSC or ECA 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 MSC mechanism, ECA 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.

[4] Federal Energy Regulatory Commission ("FERC"), New York Independent System Operator ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), and 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 $27.5 million increase in revenues on an annual basis in RY1, a $4.4 million increase in revenues on an annual basis in RY2, and a $6.7 million increase in revenues on an annual basis in RY3.[5]

The Signatory Parties recommend that the Commission adopt the option to phase in these three base rate changes on a levelized basis to provide rate stability over the term of the Gas Rate Plan. The annual levelized revenue changes would be a $16.4 million increase in each of RY1, RY2 and RY3. Changes in revenues by service class are shown in Appendix 19.

The increases to be implemented and maintained in each Rate Year (*i.e.*, permanently and cumulatively) under the proposed levelization reflect, in part, the application of interest at the Other Customer Provided Capital rate on the variation between the levelized increase, excluding interest, and the rate increase that would have been collected absent the phase-in of the RY1 rate increase. The Company's pension annual rate allowance would be adjusted to bring the calculated revenue requirements in line with the phased-in revenue requirement (see Appendix 7) on an earnings neutral basis.

The Signatory Parties recognize that the phasing-in of the RY1 increase over three years would produce higher base revenues for the Company at the end of RY3 than if the revenues were not phased in. In order to provide so that revenues at the end of RY3 will

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[5] Unless specifically stated otherwise in this Proposal, the terms "customers" and "base rate" with respect to gas apply to the Company's firm gas customers whom are served under SC Nos. 1, 2, and 6.

be no higher than they would have been if the rate increases were not levelized, $10.6 million of the RY3 rate increase will be collected via a temporary surcharge through the Monthly Gas Adjustment ("MGA"). This surcharge component of the MGA will expire at the end of RY3.

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

a. Gas Supply Charge/MGA

The Company will continue to recover all prudently incurred supply and supply-related costs through the Gas Supply Charge ("GSC") and MGA. Costs associated with balancing assets will continue to be recovered from all Service Classification ("SC") Nos. 1, 2, and 6 customers through a common cents per Ccf component in the MGA.[6]

b. Revenue Decoupling Mechanism

The Company will continue to implement an RDM, based on a revenue per customer ("RPC") mechanism, as set forth in the Company's gas tariff, subject to the modifications set forth in this Proposal. The RDM, as modified, will continue thereafter until changed by the Commission, except for restating the RPC targets for the Rate Year

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[6] The Company recovers various costs and charges, and provides certain credits, through the GSC, MGA and Weighted Average Cost of Transportation ("WACOT"). For costs, charges, and credits covered by the language of 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.

commencing November 1, 2018, to reflect the expiration of the temporary surcharge discussed in Paragraph B.2 above, if the Company does not file for new base delivery rates to be effective within 15 days after the expiration of RY3.

The RDM is modified commencing with the effective date of the Gas Rate Plan to: (a) include unbilled revenues in the actual delivery revenues used to compare to RPC targets; and (b) to remove the provision that actual delivery revenues in each Rate Year be adjusted upward to reverse the effect of proration between old and new rates in the actual delivery revenues. The RPC targets for each Rate Year are detailed in Appendix 19.

c. Base Rate Imputations

For RY1, RY2, and RY3, base rate revenue imputations of $3.65 million, $4.15 million, and $4.65 million, respectively, shall be in effect. These revenue imputations reflect (i) imputations for interruptible sales benefits[7] of $3.0 million, $3.5 million, and $4.0 million in RY1, RY2, and RY3, respectively ("Interruptible Benefits Imputation"); and (ii) an imputation of $650,000 for net benefits associated with the delivery of gas to electric generating facilities previously owned by the Company ("Power Generation Imputation") in each Rate Year. Any variances, either positive or negative, between the actual revenue margin and the Interruptible Benefits Imputation, during each Rate Year the Gas Rate Plan is effective, will be shared on an 80% customer/20% Company basis in the manner set forth in Appendix 10, and credited to/recovered from customers as applicable through the MGA. Appendix 10 also illustrates the agreed-upon procedure

[7] Interruptible benefits shall be defined as total interruptible (SC No. 8), firm withdrawable (SC No. 9) and firm dual fuel (SC No. 5) revenues minus any associated gas costs and revenue tax surcharge revenues.

using various assumed levels of actual revenue margin. The 80% customer over/under recovery of the Interruptible Benefits Imputation will be passed back/recovered from customers through the MGA. One hundred percent of any variances, either positive or negative, between the actual revenue margin and the Power Generation Imputation, during each Rate Year the Gas Rate Plan is effective, will be credited to/recovered from customers as applicable through the MGA.

d. Lost and Unaccounted For Gas

The Factor of Adjustment ("FOA") reflecting lost and unaccounted for gas, will be reset every November 1 based on the average of the actual FOAs for the previous five 12-month periods ended August 31.

Actual lost and unaccounted for gas will be calculated as follows:

1. Losses = Total Pipeline Receipts less metered deliveries to customers (Retail Sales and Transportation Deliveries + Deliveries to Generators + Gas Used for Company Purposes).

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

3. Line Loss Factor ("LLF") = Adjusted Line Loss divided by Citygate receipts adjusted for generators.

Wholesale generators served under SC No. 14 that have a capacity that is at least 50 MW are to provide 1% of their consumption to cover losses unless the system average is lower. Wholesale generators that are not on a dedicated line but are on a high pressure transmission line can negotiate a specific LLF, subject to a minimum of 1% of their consumption unless the system average is lower. Wholesale generators that are not served by dedicated lines, and that do not negotiate an LLF, will have the system average LLF applied. The volumes associated with wholesale generators served by dedicated lines shall be excluded from the LAUF factor calculation by deducting the metered in amount from the total send out.

In order to determine if the Company receives an incentive or pays a penalty for the annual LLF achieved commencing with the 12-month period ending August 31, 2016, the Company will compare the LLF level for such period to a targeted dead band based on the FOA set at the beginning of RY 1 (*i.e.*, based on the average of the prior five year factor of adjustments through August 31, 2015) ("Target Dead Band"). The Target Dead Band shall remain in effect until such time as the Commission resets the Company's gas base rates. The Target Dead Band limits are set at minus two standard deviations ("lower limit") and plus two standard deviations ("upper limit") of the FOA set at the beginning of RY1. In the event that two standard deviations below the FOA is below 0%, the lower limit will be 0%, and the upper limit will be 0% plus four standard deviations. If the LLF is within the Target Dead Band, no incentive or penalty will arise. If the LLF is greater than the upper limit of the Target Dead Band, a penalty will be assessed according to the tariff. If the LLF is less than the lower limit of the Target Dead Band, an incentive will be provided to the Company according to the tariff. The Company will not earn an incentive on any portion of an LLF below 0.0%.

Appendix 12 provides a sample calculation of the determination of the potential benefit or cost to the Company. Appendix 12 also details the calculation of the new System Performance Adjustment ("SPA") Mechanism. The SPA Mechanism will be used to refund or surcharge differences in LAUF gas to all firm customers.

If an unforeseeable and uncontrollable event(s) occurs that significantly increases actual line losses, then the Company reserves the right to file a petition with the Commission to modify the annual reconciliation of the GSC in order to reflect such increased line losses. The Company will have the burden of demonstrating the increase in actual line losses and that such increase was not due to the Company's negligent actions or omissions, in the event it makes such a filing.

3. **Common Items**

a. Labor and Productivity

The cost of direct labor included in the revenue requirements reflects a 1% productivity adjustment and the funding of new positions as set forth in Appendix 22.

b. Sales Forecasts

The electric and gas sales and delivery revenue forecasts used to determine the revenue requirements for each of RY1, RY2 and RY3 are set forth in Appendices 4 and 5, respectively. For purposes of this Proposal, the sales and delivery revenue forecasts for electric and gas are each based on the use of a 10-year weather normal for the period through December 2013. The Company shall submit an annual report to the Secretary, by no later than April 30 of each year describing the differences between the methodologies used for its gas sales and reliability forecasts.

C. Computation and Disposition of Earnings

Following each electric and gas Rate Year covered by the Rate Plans, the Company will compute, separately, the earned rate of return on common equity ("ROE") for its electric and gas businesses for the preceding Rate Year. The Company will submit these computations of earnings to the Secretary by no later than February 28 (*i.e.*, within four months after the end of each Rate Year).

1. **Earnings Sharing Threshold**

The ROE reflected in the revenue requirements for electric for RY1 and RY2, and for gas for RY1, RY2 and RY3 are set forth in Appendices 1 and 2 (*i.e.*, 9.0 percent). If the level of the earned electric ROE for RY1 or RY2 and of earned gas ROE for RY1, RY2, or for RY3 exceed 9.6 percent ("Earnings Sharing Threshold"), calculated as set forth below, then the amount in excess of the Earnings Sharing Threshold shall be deemed "shared earnings" ("Shared Earnings") for the purposes of the Rate Plans.

During the terms of the Rate Plans, one-half of the revenue requirement equivalent of any electric or gas Shared Earnings above 9.6 percent but less than 10.20 percent will be deferred for the benefit of customers and the remaining one-half of any Shared Earnings will be retained by the Company; 75 percent of the revenue requirement equivalent of any electric or gas Shared Earnings equal to or in excess of 10.20 percent but less than 10.80 percent will be deferred for the benefit of customers and the remaining 25 percent of any Shared Earnings will be retained by the Company; and 90 percent of the revenue requirement equivalent of any electric or gas Shared Earnings equal to or in excess of 10.80 percent will be deferred for the benefit of customers and the remaining 10 percent of any Shared Earnings will be retained by the Company.

The above described sharing arrangement shall continue after the end of RY3 of the Gas Rate Plan and until such time as the Commission resets the Company's gas base rates.

For the period following the end of RY2 of the Electric Rate Plan, and until such time as the Commission resets the Company's electric base rates, the Earnings Sharing Threshold and allocation of Shared Earnings shall be as follows: one-half of the revenue requirement equivalent of any electric Shared Earnings above 9.0 percent but less than 9.6 percent will be deferred for the benefit of customers and the remaining one-half of any Shared Earnings will be retained by the Company; 75 percent of the revenue requirement equivalent of any electric Shared Earnings equal to or in excess of 9.6 percent but less than 10.20 percent will be deferred for the benefit of customers and the remaining 25 percent of any Shared Earnings will be retained by the Company; and 90 percent of the revenue requirement equivalent of any electric Shared Earnings equal to or in excess of 10.20 percent will be deferred for the benefit of customers and the remaining 10 percent of any Shared Earnings will be retained by the Company.

2. **Earnings Calculation Method**

For each Rate Year, for purposes of determining the actual earned ROE:

a. The calculation of the actual ROE on common equity capital allocated to New York jurisdictional electric and gas utility operations shall be on a "per books" basis, 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; (ii) the Company's share of property tax refunds earned during the applicable Rate Year; and (iii) any other Commission-approved ratemaking incentives and revenue adjustments in effect during the applicable Rate Year.

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

c. To the extent any stay-out period is less than 12 months, the earnings sharing calculation will adjust actual rate base to reflect the effect of seasonal variations of sales on earnings. This approach is illustrated in Appendix 14.

3. **Disposition of Shared Earnings**

For electric and/or gas Shared Earnings in any Rate Year, the Company will apply 50 percent of its share and the full amount of the customers' share of electric and/or gas Shared Earnings that would otherwise be deferred for the benefit of customers under this Proposal, to reduce respective deferred under-collections of site investigation and remediation ("SIR") costs. In the event the amount of Shared Earnings for electric and/or gas 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 deferred costs. The Company's annual earnings report will include the amount, if any, of deferred under-collections of SIR costs written down with the Company's and the customers' respective shares of Shared Earnings. 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

Projected capital expenditures for electric and gas are set forth in Appendix 9.

1. **<u>Electric</u>**

a. Net Plant Reconciliation

The electric revenue requirements for RY1 and RY2 reflect the average net plant balances set forth in Appendix 9 ("Electric Net Plant In Service Balances"). The Electric Net Plant In Service Balances exclude the level of capital expenditures associated with AMI.

The Electric Net 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 9) of the amount by which the Company's actual expenditures for electric capital programs and projects result in actual average net plant that is less than the amount included in the Electric Net Plant In Service Balances, as set forth in Appendix 9, for RY1 and RY2 as provided herein.[8]

The reconciliations to Electric Net Plant In Service Balances for RY1 and RY2 will be cumulative; that is, the carrying charges resulting from the difference (whether representing underspending or overspending) in actual Electric Net Plant In Service Balances and the target levels, which are shown on Appendix 9, will carry forward for each of the Rate Years and will be summed at the end of RY2. If at the end of RY2 the

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

cumulative carrying charges represent underspending, the Company will book a regulatory liability for the cumulative underspent carrying charges. If at the end of RY2 the cumulative carrying charges represent overspending, no deferrals will be made. Examples of how this reconciliation will work are set forth in Appendix 9.

b. Advanced Metering Infrastructure

The Company will begin implementation of an AMI system to, among other things, facilitate the Commission's REV policies and goals, reduce operating costs, assist in more timely identification of customer outages, and improve overall outage response and efficiency. The Company will implement Phase One of its AMI system in Rockland County ("Phase One").[9]

Phase One of the AMI system shall be funded (combined electric and gas) at $11.7 million in RY1, $8.9 million in RY2 and $8.9 million in RY3.[10] The net plant reconciliations of this funding will be performed on a cumulative basis over the terms of the Electric and Gas Rate Plans, and will be performed separate and apart from the net plant reconciliations described in Section D.1.a and D.2.a of this Proposal. The Company will track expenditures on AMI compared with the amounts assumed in net plant targets. Carrying charges on any monies not spent (*e.g.*, due to delays, ultimate decision not to continue the Company's AMI project) will be deferred for future disposition by the Commission. Balances and the target levels, which are shown on Appendix 8, will carry forward for each of the Rate Years and will be summed at the end of RY2 for electric and RY3 for gas. If at the end of RY2 for electric and RY3 for gas the cumulative carrying

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9 The Company will implement Phase Two of its AMI system in Orange County.

10 For RY3, the Phase One capital expenditures for gas only is $3.1 million.

charges represent underspending, the Company will book a regulatory liability for the cumulative underspent carrying charges. If at the end of the last Rate Year the cumulative carrying charges represent overspending, no deferrals will be made. Examples of how this reconciliation will work are set forth in Appendix 9.

Total funding for the implementation of the Phase One AMI system, as proposed by the Company, is $43.3 million ("Funding Level"). The Company will manage cost variations with the ability to seek recovery in future rate cases for actual costs that exceed the Funding Level, including additional costs due to increases in scope to address the Market Design and Platform Technology ("MDPT") Final Report, the Commission's final Distributed System Implementation Plan ("DSIP") Order and other developments. Nothing prohibits or restricts other Signatory Parties from challenging such a request in future rate cases.

Recovery of the Funding Level is tied to completion of Phase One within five years of the Commission's issuance of a final DSIP Order, with consideration for operational/weather emergencies and other external impacts.

The Company shall file an AMI Business Plan relating to Phase One, as described in Section M.1 of this Proposal. The Funding Level includes the cost of developing and implementing such AMI Business Plan. The MDPT Final Report is currently expected to be released on or about August 3, 2015. The Company's AMI Business Plan shall address AMI specific findings contained in the MDPT Final Report. Any AMI Business Plan changes and cost increases required for conformance with such findings will be detailed for discussion and development of necessary solutions, scheduling and cost recovery.

The Company's DSIP filing is currently due on January 15, 2016. When the Commission acts on the Company's DSIP filing, the Commission may further consider the implementation of AMI, including deciding to modify or halt the Company's implementation of its proposed AMI system. In the event of a determination by the Commission to stop or modify the AMI system, all AMI project costs prudently incurred by the Company up to project cancellation, shall be recoverable by the Company. In such an event, recovery will not be provided for costs such as those for acquiring and/or installing any software, hardware or equipment that is ultimately not needed or cannot meet the required needs as determined at the time the Commission issues its final DSIP Order or earlier.

The Company will submit semi-annual reports regarding the implementation of the AMI system, with any data provided on a quarterly basis. These reports will refer to expected benchmarks set forth in the Company's AMI Business Plan.

The Company will implement an AMI savings tracker to evaluate how well Phase One's results compare to the projected savings. The Company will document the reduced O&M costs attributable to savings from reduced meter reading personnel and improved response to outages.

c. Reporting Requirements

The Company will submit annual reports relating to capital expenditures in the manner set forth in Appendix 20.

2. **Gas**

a. Net Plant Reconciliation

The gas revenue requirements for RY1, RY2 and RY3 reflect the average net plant balances set forth in Appendix 9 ("Gas Net Plant In Service Balances"). The Gas Net Plant In Service Balances exclude the level of capital expenditures associated with AMI.

The Gas Net 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 that is less than the amount included in the Gas Net Plant In Service Balances as set forth in Appendix 9, for RY1, RY2 and RY3 for each net plant category as provided herein.[11]

The reconciliations to Gas Net Plant In Service Balances for RY1, RY2 and RY3 will be cumulative; that is, the revenue requirement impact resulting from the difference (whether representing underspending or overspending) in actual Gas Net Plant In Service Balances and the target levels, as shown on Appendix 9, will carry forward each of the Rate Years and will be summed at the end of RY3. If at the end of RY3 the cumulative

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

carrying charges represent underspending, the Company will book a regulatory liability for the cumulative underspent carrying charges. If at the end of RY3 the cumulative carrying charges represent overspending, no deferrals will be made. Examples of how this reconciliation will work are set forth in Appendix 9.

b. Advanced Metering Infrastructure

Section D.1.b of this Proposal will apply to gas as well as electric.

c. Reporting Requirements

The Company will provide annual reports relating to capital expenditures in the manner set forth in Appendix 20.

E. Reconciliations

The Company will reconcile the following costs and revenues to the levels provided in rates, as set forth in Appendices 6, 7, 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 of this Proposal.

1. Capital Expenditures (Electric and Gas)

Please refer to the Section D, Capital Expenditures and Net Plant Reconciliation, of this Proposal.

2. 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 of this Proposal), varies in any Rate Year from the projected level provided in rates for that service, which levels are set forth in Appendices 6 and 7, there will be a full and symmetrical true-up, *i.e.*, 100 percent of the variation will be deferred on the Company's books of account and either recovered from or credited to customers. For electric, this reconciliation will expire at the end of RY2. For gas, this reconciliation will continue for RY3 and thereafter, until such time as the Commission resets the Company's gas base rates. After RY3, the target will remain constant at the RY3 level.

With respect to the electric and gas regulatory deferrals pursuant to the Company's existing reconciliation mechanisms, the Signatory Parties agree that the balances reflected in the columns labeled "Total" on pages 1 and 2 of Appendix 3 are the amounts to be recovered from customers via five year amortizations beginning in RY1.

3. **Pensions/OPEBs (Electric and Gas)**

Pursuant to the Commission's Pension Policy Statement,[12] the Company will reconcile its actual pensions and Other Post-Employment Benefits ("OPEBs") expenses to the level allowed in electric and gas rates as set forth in Appendices 6 and 7.

The Pension Policy Statement provides that companies may seek prospective interest accruals or rate base treatment for amounts funded above the cost recoveries included in rates.[13] 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

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[12] 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 Policy Statement").

[13] See Pension Policy Statement, Appendix A, page 16, footnote 3.

Company, its actuary and the parties are unable to predict with 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.

4. **Environmental Remediation (Electric and Gas)**

If the level of actual SIR expenditures,[14] including expenditures associated with former manufactured gas plant ("MGP") sites, Superfund sites, Spring Valley, West Nyack and other sites allocated to electric and gas operations, varies in any Rate Year from the levels provided in rates, which are set forth in Appendices 6 and 7, such variation shall be deferred and recovered from or credited to customers. Deferred SIR cost balances varying from the level reflected in rate base during each Rate Year will accrue a carrying cost at the pre-tax rate of return, as set forth in Appendices 6 and 7. The deferred cost balances will be reduced by accruals, insurance and third party recoveries, associated reserves and deferred taxes, and other offsets, if any, obtained by the Company.

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[14] SIR expenditures are the costs Orange and Rockland 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 the Company 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.

The Company is currently engaged in litigation with Travelers Indemnity Company ("Travelers") with respect to Travelers' denial of claims filed by Orange and Rockland under third-party liability policies for SIR costs related to seven MGP sites owned and operated by the Company and its predecessors. The Company will notify the Commission of all future court decisions with respect to this ongoing litigation with Travelers. The Commission may consider and address the amount of any claims denied by Travelers related to the seven MGP sites.

5. **Major Storm Cost Reserve (Electric)**

The Company's annual electric revenue requirements provide funding for the major storm reserve of $3.77 million in RY1 and $3.85 million in RY2, as shown in Appendix 6.[15] 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 costs in excess of the annual amounts stated above in either Rate Year, the Company will defer on its books of account expenses in excess of the annual amounts stated above for future recovery from customers. To the extent that the Company incurs major storm costs less than the annual amounts stated above, the Company will defer any variation less than those amounts for the benefit of customers. All major storm costs are subject to Staff audit.

The Company's annual electric revenue requirements provide for $11.85 million in each of RY1 and RY2, reflecting a five-year amortization of previously incurred

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[15] A "major storm" is defined in 16 NYCRR Part 97 as a period of adverse weather during which service interruptions affect at least ten percent of the Company's customers within an operating area and/or results in customers being without electric service for durations of at least 24 hours and exceeds $200,000 in incremental costs.

incremental major storm costs (net of insurance and other recoveries) due to major storms, including Superstorm Sandy, in excess of collections for major storm reserve funding.

Staff has completed its review of the incremental major storm costs (net of insurance proceeds received to date) that the Company incurred due to Superstorm Sandy and other past major storms prior to November 1, 2014 and charged to the major storm reserve. This agreement resolves all outstanding issues related to SuperStorm Sandy and other past major storms prior to November 1, 2014. The Signatory Parties agree that the Company should be allowed to recover $59.26 million of such costs over a five-year period, or $11.85 in each of RY1 and RY2.

The Company will not charge employee overtime to the major storm reserve for overtime work occurring more than 60 days following the date on which the Company is able to restore service to all customers. In addition, the Company will not charge stores handling, engineering, and other overheads costs to the major storm reserve.

Effective November 1, 2015, and during the term of RY1, the Company will commence a pilot program that will collect data and evaluate the feasibility and advisability of directly assigning the costs of mutual aid and other contractors to the individual service territory in which they worked (*i.e.*, Orange and Rockland, Rockland Electric Company, Pike County Light & Power Company) rather than assigning the costs based upon an allocation methodology. The implementation of this pilot program does not invalidate prior allocation methodologies, nor foreclose the use of any such allocation methodologies in future matters. The Company's ability to conduct this pilot program will be contingent on the occurrence of a major storm in the Company's service territory during RY1. In the event that there are no major storm events during RY1, the Company will extend this pilot program into RY2. The Company is conducting this pilot program for informational purposes only and will provide Staff with the results of the pilot program within 60 days after the end of RY1 (or RY2, if extended). The Signatory Parties acknowledge that the Company does not agree to use the results of this pilot program to assign storm costs associated with major storms, however, parties in future rate proceedings may recommend its use and all Signatory Parties reserve their rights regarding allocations of major storm costs in future rate proceedings.

6. **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 6 and 7. 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 6 and 7 for that service for that Rate Year.

7. **Asbestos Workers Compensation Reserve (Electric)**

The Company will reconcile the level of actual asbestos claim payments to the Company's former employees, on a cumulative basis over the term of the Electric Rate Plan, to the level provided in rates, which are set forth in Appendix 6.

8. **Tree Trimming (Electric)**

The Company will defer for the benefit of customers any cumulative shortfall over the term of the Electric Rate Plan between actual expenditures for the Company's transmission and distribution tree trimming program, including the danger tree programs, and the levels provided in rates, which are set forth in Appendix 6. This reconciliation will continue after RY2 on an annual basis or on a pro-rated basis (by month) for any period less than twelve months.

9. **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 Merchant Function Charge ("MFC"), the credit and collections component of the Purchase of Receivables ("POR") discount rate, the Billing and Payment Processing Charge, and Metering Charges (electric only).

10. **Low Income Assistance Program (Electric and Gas)**

The Company will reconcile actual payments (monthly bill credits) to low-income customers to the level allowed in rates as set forth in Appendices 6 and 7. All under- and over-recoveries associated with monthly bill credits will be reconciled.

11. **Research and Development Expense (Electric and Gas)**

The Company will reconcile its actual Research and Development ("R&D") expenses to the level allowed in electric and gas rates as set forth in Appendices 6 and 7. The reconciliation shall be based on a comparison of actual expenses to the level allowed in rates. The Company shall have the flexibility over the term of the Rate Plans to modify the list, priority, nature and scope of the R&D projects to be undertaken. Within 90 days of the date of the Commission's final rate order in this proceeding, the Company will file a plan describing how it will use previously collected but unspent gas Internal R&D and Millennium R&D funds ($142,711 and $2,749,930 respectively, as of December 31, 2014) on gas safety related R&D projects such as methane detection and plastic fusion. The Millennium R&D funds balance has been adjusted to reflect costs incurred that were inadvertently excluded from the surcharge reconciliation.

12. **<u>Tax on Health Insurance Plans (Gas)</u>**

The revenue requirement for RY3 of the Gas Rate Plan includes expected taxes on health plans scheduled to go into effect during RY3 due to provisions of the Affordable Care Act. The Company will reconcile its actual taxes incurred due to this provision with the level allowed in rates, as set forth in Appendix 7.

13. **<u>Additional Reconciliation/Deferral Provisions</u>**

In addition to the foregoing reconciliation provisions, 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 mechanisms 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 termination. Continuing reconciliation and/or deferral accounting mechanisms include, but are not limited to those for, MTA taxes, New York Public Service Law §18-a regulatory assessment, Renewable Portfolio Standard charges, vacation pay accrual pursuant to ASC 980 Regulated Operations, carrying charges for storage gas, the Gas Supply Charge (“GSC”)/MGA, MSC, ECA, and System Benefits Charge (“SBC”) mechanisms. The Company will defer any differences between the Company’s actual revenues and authorized revenues, as determined by the Company’s RDMs. In addition, the Company will defer any carrying costs for projects approved or required by the Commission that are incremental to the Company’s capital additions, such as any expansion of the scope of the Company's proposed AMI project, and participation in regulated backstop solutions or generation as the provider of last resort.

Appendix 3 sets forth the annual amortization of deferred regulatory assets and liabilities included in the annual revenue requirements.

14. **Discontinued Reconciliations**

a. Long Term Debt Cost Rate (Electric and Gas)

The reconciliation of the costs of the Company's long-term taxable and tax-exempt debt to the amounts reflected in rates for such costs will cease effective November 1, 2015. Additionally, the Signatory Parties agree that the balances reflected in the columns labeled "Total" on pages 1 and 2 of Appendix 3 are the amounts to be credited to customers via three-year amortizations beginning in RY1.

b. Deferred Income Taxes – 263A (Electric and Gas)

The deferral of interest on differences between the actual deferred Section 263A tax benefits that result from the Section 263A deduction under the Simplified Service Cost Method and the amount allowed by the Internal Revenue Service ("IRS") will cease effective November 1, 2015. The underlying issue between the Company and the IRS concerning the calculation of the amount of such tax deductions has been resolved and the projections of income tax expense and deferred tax rate base reflected in the electric and gas revenue requirements under this Proposal reflect that resolution.

F. Additional Rate 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 13.

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

b. Gas Net Salvage Caps

With respect to gas, the existing limitations (*i.e.*, caps) on negative net salvage costs that are chargeable to the gas depreciation reserve for both Mains accounts (transmission and distribution) and the Services account will cease. Correspondingly, gas O&M rate allowances providing for negative net salvage costs above the amounts chargeable to the gas depreciation reserve for those accounts will also cease.

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. 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**

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 Orange and Rockland), will be deferred for future disposition, except for an amount equal to 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 14 percent retention will apply to all such property tax refunds and/or credits against future tax payments actually achieved by Orange and Rockland during the term of the Rate Plans.[16] Additionally, the Company is not relieved of the requirements of 16 NYCRR §89.3 with respect to any refunds it receives.

4. **Gas Programs**

a. Workforce Development Program

The Company will 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 needs of the increased leak prone pipe replacement program, network enhancement and to prepare replacement for the potential loss of labor resources due to an aging workforce. The revenue requirement reflects a ramp-up of spending on this program of $83,333 in RY1, $166,666 in RY2, and $250,000 in RY3. The Company will

[16] This includes 14 percent of any property tax refunds, finalized during the term of the Rate Plans, but actually received after the end of the term of the Rate Plans (*e.g.*, November 1, 2017 for electric, and November 1, 2018 for gas).

submit biannual reports to the Secretary detailing progress on this workforce development program. These reports are due no later than June 30 and December 31 of 2016, 2017 and 2018, respectively, and continuing each year until such time as the Commission resets Orange and Rockland's gas base rates.

b. First Responders Training

The Company will improve its training regarding the appropriate response to gas related emergencies offered to local fire department first responders in both Orange and Rockland Counties to include more drills, scenarios and hands-on training. The Company will provide assistance and work with the fire departments to improve and maintain natural gas training facilities at both Orange and Rockland Counties' individual training centers. In addition, the Company will continue to develop the current program to enhance radio communication between Orange and Rockland's first responders and fire department first responders in both Rockland and Orange Counties. The Company will submit biannual reports to the Secretary detailing progress on the First Responders Training program no later than June 30 and December 31 of 2016, 2017 and 2018, respectively, and continuing each year until such time as the Commission resets Orange and Rockland's gas base rates.

c. CNG/NGV Market Development

With regard to the market for compressed natural gas ("CNG") or liquid natural gas ("LNG") fueling in Orange and Rockland's service territory, the Company will meet with Staff and other interested parties within 90 days of the date of the Commission's final rate order in these proceedings. At that meeting, the parties will discuss what market research the Company has done, and what market research the Company believes is necessary to further the development of this market. Further, at that meeting, the parties will discuss and identify what information will be required in a strategic plan for the development of this market beyond the Company's own fleet of vehicles. The Company shall then develop and file the strategic plan with the Secretary within 180 days of the date of the Commission's final rate order in these proceedings.

d. Network Enhancement Program

In order to further natural gas network enhancement, the Company will do the following:

i. The Company will increase the residential conversion rebate from $500 to $1,000 for customers converting to natural gas before June 30, 2016, 2017 and 2018, respectively, and continuing each year until such time as the Commission next resets Orange and Rockland's gas base rates. The rebate amount will remain at $500 for customers converting during the remainder of the year.

ii. When applying to the Commission for new franchises or franchise expansions, the Company will use a 15-year period for its economic feasibility analysis. Line extensions shall also follow the same 15-year economic analysis.

iii. During the term of the Gas Rate Plan, the Company will survey potential customers within targeted gas network expansion areas of the Company's existing gas franchises, as necessary to supplement the Company's existing information regarding customer interest in converting to natural gas. The Company commits to surveying the remaining potential customers within the Company's existing gas franchises as to interest in converting to natural gas no later than October 31, 2020.

iv. In order to develop penetration rates for future projects, the Company will analyze penetration rates of past line extension projects within a 15-year historical period and update the analysis on an annual basis using a rolling 15-year historical period.

v. The Company will develop a strategic plan of target areas for expansions based on customer responses to surveys, location of customers and existing facilities, short-term and long-term construction and planning synergies, location of anchor customers, economic feasibility, alternative fuel cost comparisons and historical penetration rates of line extensions. The strategic plan shall provide a three-year forecast of both line extensions and franchise expansion projects including the needed gas infrastructure project list to support the forecast expansion. This plan will be updated on an annual basis and include a summary for each project within the current and following year of the plan. Each summary will provide a description of the project, location description and available customer potential. For each project executed within the plan, the Company will track the penetration rates and customer attachments on an annual basis.

vi. If additional customer contributions are necessary for the economic feasibility of the project to meet the existing system rate of return by year 15, the Company will collect such contributions through a fixed unit charge in the form of a Contribution in Aid of Construction ("CIAC") over the 15-year development period. The Company shall determine if the unit charge should be different among service classes for each project. The same CIAC shall be applied to all customers within a service class by project.

vii. For projects that include a CIAC charge, if customer commitments and attachments are above the set forecast for the individual project, the Company may elect to reduce or cease the use of the CIAC charge. If the system wide rate of return is reached before the end of the 15-year period, the Company shall discontinue the CIAC charge.

viii. The Company shall provide recommendations on any modifications to the network enhancement program that the Company deems necessary on an on-going basis. The recommendations shall be provided to Staff for discussion prior to seeking formal changes to the program.

ix. Projects that go into service during the term of the Gas Rate Plan and have a revenue shortfall or excess will be rolled into base rates in the next base rate proceeding.

x. Reporting requirements – Annual reports are to be filed with the Secretary by February 28 following the end of the Rate Year (*e.g.*, the 2016 report will be filed by February 28, 2017). The reports shall include the items described above in subpart v. and data shall be provided in quarterly format.

The Company will have the opportunity to earn a positive incentive by adding gas customers in the manner set forth in Appendix 24.

5. **Allocation of Common Expenses/Plant**

During the term of the Rate Plans, common expenses and common plant will be allocated according to the percentages approved by the Commission in Case 99-G-1695 (*i.e.*, 70.75% electric operations, 29.25% gas operations). The Company will address the proper allocation of common expenses and common plant between the Company's electric and gas services in its next base rate filings. Should the Commission approve different common allocation percentages for electric and/or gas service prior to the next base rate case for the electric and/or gas businesses, the resulting annual revenue requirement impacts will be deferred for future recovery from or credit to customers.

6. **Revenue Requirement Presentation**

The electric and gas revenue requirements in this Proposal reflect Staff's proposed reclassification of the amortizations of regulatory deferrals from various cost of service elements to "other operating revenues." The Company will follow this classification in the revenue requirement presentations in its next electric and gas base rate case filings.

7. **Use of Corporate Name**

Upon the date of the Commission's final rate order in these proceedings, the Company's Standards of Competitive Conduct are hereby amended in accordance with Appendix 21, which provides that the Company will not allow any non-affiliate entity to use the name "Orange and Rockland," or trade names, trademarks, service marks or derivatives of the name "Orange and Rockland," subject to the exceptions stated in Appendix 21. The Signatory Parties acknowledge that the Commission, in another proceeding, may modify this limitation in a manner applicable to all utilities. Such modification may be scheduled to take effect during the term of the Rate Plans. The Company reserves all of its administrative and judicial rights to pursue its positions in any such proceeding.

G. Reforming the Energy Vision ("REV")

1. Pomona DER Program

The reconciliation mechanism and incentive calculation approach for the Pomona DER Program are described more fully in Appendix 25. The Company will recover $380,000 per year through electric base rates for its Pomona DER Program, subject to full and symmetrical reconciliation (based on three-year average of escalated revenue requirement, assuming a 10-year amortization of both utility-side and customer-side measures). The Company's total spending on the Pomona DER Program is capped at $9.5 million. The $9.5 million expenditure cap is expressed in 2014 dollars and applies to customer incentive program expenditures and capital investment expenditures and the three positions required for the program. It does not apply to maintenance associated with capital investments nor any potential performance incentives earned by the Company as part of the Pomona DER Program implementation. As shown in the Pomona benefit cost model submitted in response to Staff IR DPS-245, included as Appendix 26, Pomona costs subject to the cap are planned to be spent from 2016 through 2023. The $9.5 million total in 2014 dollars equates to $11.5 million in future escalated dollars. Actual expenditures over the term of the Pomona project will be compared to the $11.5 million cap. The Company may revisit funding levels for the Pomona DER Program if further deferral of the Pomona substation and 138 kV underground loop is possible through additional efforts. The Company shall have the opportunity to earn an incentive of up to 100 basis points of ROE on common equity allocable to the Company's electric operations tied to Company performance as follows:

- Cost Savings (up to 50 basis points) 1.0 basis point for each 1% reduction in cost per MW compared to the cost of the proposed Pomona Substation; and

- Amount of Load Reduction Achieved (up to 50 basis points) 1.0 basis point for each 0.1 MW of load reduction achieved above 3.0 MW (*i.e.*, 0 basis points earned at 3.0 MW, 24 basis points earned at 5.4 MW and 50 basis points earned at 8.0 MW)

In the Pomona DER Program, the Company's ability to own DER assets is limited to utility-side energy storage and in limited other circumstances as defined in the Commission's REV Track One Order.[17] The Company may collaborate with third parties[18] to create behind the meter battery storage solutions. The Pomona DER Program will include a commercial and industrial demand response component. It will also include the three positions for the Pomona DER Program which, based upon their availability, will assist in implementing the AMI system. It is not anticipated that these three positions will be available to assist other REV projects.

Energy efficiency projects undertaken in the Pomona DER Program area may be funded out of either, but not both, the ETIP or Pomona DER Program budgets. Similarly, benefits that accrue from such energy efficiency projects shall count toward only the program through which the project was funded. Thus, the Company may undertake its ETIP projects in the Pomona DER Program area, using funds from within the ETIP budget, however the benefits of such programs, in MW or MWh, shall only count toward

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[17] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision,* Order Adopting Regulatory Policy Framework and Implementation Plan, (issued February 26, 2015) ("REV Track One Order").

[18] As used here, "collaborate" will not involve utility ownership of behind the meter battery storage.

ETIP. Similarly, for any projects the Company funds out of the Pomona DER Program budget, any resulting MW or MWh benefits shall only accrue to the Pomona DER Program.

The Company will provide an implementation plan and accounting procedures within 60 days of the date of the Commission's final rate order in this proceeding. The Company will file quarterly reports on Pomona DER Program activities within 60 days of the end of the relevant three-month period for the report. The first report will cover Pomona DER activities through January 31, 2016 and will be submitted by March 25, 2016. These quarterly reports will include relevant information on the Pomona DER Program including costs incurred by initiative, in-service dates for capital investments, and participation levels for customer demand reduction and efficiency programs. Every fourth quarterly report should include information regarding the Company's progress toward the 100 basis point earning opportunity.

2. **Demonstration Projects**

The Company will file a time-varying rates Demonstration Project (which will explain if and how it will integrate AMI, enabling technologies, and customer interface systems) pursuant to the Commission's REV Track One Order.

The Company will establish a surcharge mechanism to recover the costs of Demonstration Projects undertaken pursuant to the REV Track One Order. Specifically, the Company will institute a new component of its ECA subject to a $0.002/kWh maximum rate and semi-annual reconciliation for recovery of Demonstration Project costs only.

3. **Future REV Proceeding Issues**

The Signatory Parties recognize that Case 14-M-0101 and its companion REV cases are ongoing proceedings which may impact the Company. This Proposal does not limit the Commission's ability to require the Company to take certain actions pursuant to the REV proceedings, and to provide for cost recovery of incremental costs of such actions in separate Orders. The Signatory Parties reserve all of their administrative and judicial rights to take and pursue their respective positions with respect to all issues and Commission proposals and initiatives in the REV proceeding. Nothing herein will preclude the Company from (i) petitioning the Commission to extend, modify or establish programs relating to energy efficiency, demand response (including, for example, but not limited to, direct load control) and demand management (including, for example, but not limited to, targeted demand management), and (ii) filing for approval of programs in response to an order(s) or other issuances in the REV proceeding or otherwise designed to implement REV objectives and principles, including, but not limited to, the Distributed System Platform and demonstration projects.

H. Revenue Allocation/Rate Design and Other Tariff Changes

1. **Electric**

The revenue allocation and rate design changes being made as part of this Proposal are set forth in Appendix 18.

a. Marginal Cost Study

The marginal cost study, originally submitted by the Company, forms the basis for the Excelsior Jobs Program ("EJP") discounts shown below:

SC No. 2 – Secondary	- 63 %
SC No. 2 – Primary	- 66 %
SC No. 3	- 61 %
SC No. 9	- 62 %
SC No. 20	- 64 %
SC No. 21	- 61 %
SC No. 22	- 61 %

The EJP discounts for SC No. 25 customers shall be equal to the EJP discount of the customer's otherwise applicable service classification.

Approximately 120 days after the date of the Commission's final rate order in this proceeding, the Company will initiate discussions with Staff and interested parties to identify an agreed upon methodology for future electric marginal cost studies.

b. Street Light Replacements

The Company will replace up to 2% of its street lights on a system-wide basis ("2% System Threshold") during each of RY1 and RY2 at no cost to participating municipalities in accordance with the requirements and conditions set forth below. Within 90 days of the Commission's final rate order in this proceeding, each municipality wishing to participate in this program during RY1 must notify Orange and Rockland, in writing, of the quantity, location, and types of street lights it would like replaced during RY1 and the types of new street lights it would like installed. Municipalities wishing to participate in RY2 must provide the required notice by November 1, 2016. Within 30 days of the date of the Commission's final rate order in this proceeding, the Company will send a letter to eligible municipalities to notify them of these deadlines.

In each of RY1 and RY2, the Company will allocate a portion of the 2% System Threshold to each municipality that requests replacements by the date established for such requests, based on the quantity of existing street lights in each participating municipality. The Company will not be required to honor any additional requests for installations at no direct charge within the 2% System Threshold during the remainder of RY1 and RY2.

Pursuant to SC No. 4, the Company retains the right to modify any requests based upon operational considerations (*e.g.*, LED lights should not be co-mingled with non-LED lights).

The Company will endeavor to perform replacements requested for RY1 during RY1, and replacements requested for RY2 during RY2. Scheduling replacements will be at the Company's sole discretion. If circumstances beyond the Company's reasonable control prevent the Company from completing the replacement of any street lights included in the 2% System Threshold in any Rate Year, the Company will complete the replacement of any such remaining street lights in the following Rate Year.

c. LED Filing

The Company will make a separate tariff filing, within six months of the date of the Commission's final rate order in this proceeding, that will offer additional LED street light options. As part of this filing, the Company will re-examine the costs in its electric tariff for LED street lights and include its findings as part of the tariff filing. If the Company determines that the costs of LED lights are different than the costs currently contained in the electric tariff, the Company will include in the tariff filing adjustments to the price of the LED street lighting options.

d. Energy Efficiency Tracking Mechanism

The Company will implement an Energy Efficiency Tracking Mechanism ("EE Tracker") that will become a component of the Company's Base ECA Charge. The EE Tracker is meant to recover the costs of any Company-run energy efficiency programs that are approved through the energy efficiency transition implementation plan ("ETIP").[19] The initial target electric EE Tracker costs will be included in the Company's annual base ECA filing that becomes effective March 1, 2016. Every March 1 thereafter, the EE Tracker component of the base ECA will include the coming year's target EE Tracker costs and a reconciliation of actual recoveries to the prior year's target EE Tracker costs.

e. 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. Increase the re-inspection fee contained in General Information Section No. 6, "Wiring, Apparatus, and Inspection" from $51.00 to $80.00;

2. Make changes to the following mechanisms to align with a Rate Year ending October 31 and/or to account for a partial Rate Year: the RDM, the credit and collections component of the POR discount percentage, the Transition Adjustment for Competitive Services ("TACS"), and the reconnection fee waiver;

3. Add reactive power demand charge revenue in the definition of "Actual Delivery Revenue" in General Information Section No. 30, "Revenue Decoupling Mechanism Adjustment;"

4. Make the following changes to the Company's Economic Development Rider, Rider H, applicable to customers with a letter of

[19] REV Track One Order, p. 79.

intent dated on or after November 1, 2015: (1) customers will be required to maintain a metered demand of 65 kW or more in six months of any 12-month period to remain on Rider H; (2) customers can only commence service once their metered demand is 65 kW or more for two consecutive months; (3) customers will be required to submit an energy audit/survey that has been organized through the Company's Customer Energy Services group for customers who purchase, lease, or expand an existing building; and (4) Rider H, which currently expires on December 31, 2016, will be extended for an additional five-year term through December 31, 2021;

5. Add language to Rider C – Excelsior Jobs Program to clarify that this Rider is only applicable to demand-billed customers;

6. Eliminate Riders G and J and all references to these Riders;

7. Eliminate provisions related to the phase-in of Standby Service in SC No. 25 since the phase-in period concluded February 2011; and

8. Add the Village of South Blooming Grove to the list of communities to which the electric tariff applies.

2. <u>**Gas**</u>

The revenue allocation and rate design changes being made as part of this Proposal are set forth in Appendix 19.

a. Embedded Cost of Service Study

The gas Embedded Cost of Service ("ECOS") in this case has been modified to allocate the distribution mains system on a 100% demand and 0% customer basis.

b. Marginal Cost Study

The marginal cost study, originally submitted by the Company, forms the basis for the EJP discounts shown below:

SC Nos. 2 and 6 – RS IB and II - 13.4 %

c. Interruptible Transportation Rates

SC No. 8 rates will consist of a block rate design and a minimum monthly charge. The monthly minimum charge for 100 Ccf will be set at $107.00 in RY1, $117.00 in RY2 and $118.00 in RY3. A Base Charge is used to determine the blocked rates for usage greater than 100 Ccf. The Base Charge will be determined each month and shall not exceed 16.791 cents per Ccf during RY1, 27.014 cents per Ccf during RY2, and 27.864 cents per Ccf during RY3 and thereafter until such time as the Commission resets the Company's gas base rates. The second block is applicable to usage between 100 Ccf and 50,000 Ccf and is priced at the Base Charge plus 5.0 cents per Ccf. The third block is applicable to usage between 50,000 Ccf and 100,000 Ccf and is priced at the Base Charge plus 2.5 cents per Ccf. The fourth block is applicable to usage over 100,000 Ccf and is priced at the Base Charge. A fifth block applicable to usage over 200,000 Ccf is eliminated effective with the commencement of RY1.

The supplemental sales supply charge applicable to SC No. 8 customers who purchase their gas supply from the Company will be equal to the SC No. 9 withdrawable sales service supply charge. Both the SC No. 8 delivery and supplemental sales supply charges will be set forth monthly on the existing "Statement of Interruptible Transportation and Supplemental Sales Charges."

d. Natural Gas Vehicle Service Classification Changes

The Company will amend SC No. 7 to include the following rate options for customers whose end use of gas is to fuel motor vehicles:

1. Firm sales service option to deliver gas to owners of compressed natural gas ("CNG") fueling stations located in the Company's service territory;

2. Firm transportation service option to deliver gas to owners of CNG fueling stations located in the Company's service territory;

3. Gas sales option for all non-Company fleet vehicles, on an emergency basis only, at Orange and Rockland's private CNG facility. An emergency situation is defined as a planned or spontaneous inability to fuel at a third-party operated CNG fueling facility, which may arise

due to circumstances such as, but not limited to, equipment failure, environmental factors, or planned maintenance; and

4. Negotiated interruptible sales/transportation contract option for owners of CNG fueling stations located in the Company's service territory.

The rate for options (1) and (2) will be fixed at the rates for the service classification under which the customer would otherwise be served. The rates for option (3) should be the same as option (1), but the commodity price of gas should be at the highest incremental cost of gas if the emergency situation requires additional, unexpected gas purchases, and at the weighted average cost of gas if no additional gas purchases are required. For customers that do not have their own NGV facility, the commodity price of gas shall always be set at the highest incremental cost of gas. The rates for option (4) will be set forth in the negotiated contract.

e. Energy Efficiency Tracking Mechanism

The Company will implement an EE Tracker that will become a component of the Company's MGA charge. The EE Tracker is meant to recover the costs of any Company-run energy efficiency programs that are approved through the ETIP. The initial target gas EE Tracker costs will be included in the MGA charge that becomes effective January 1, 2016. Every January 1 thereafter, the EE Tracker component of the MGA charge will include the coming year's target EE Tracker costs and a reconciliation of actual recoveries to the prior year's target EE Tracker costs.

f. Reliability Surcharge Mechanism

The Company will implement a Reliability Surcharge Mechanism ("RSM") that will become a component of the Company's MGA charge on the same cents per Ccf basis for all classes subject to the MGA. The RSM will recover the carrying costs (calculated as the incremental revenue requirement) associated with incremental capital expenditures for leak prone pipe replacement not provided for in base rates when both the mileage replaced and the associated cost of replacement exceed the amounts provided for in base rates in aggregate over the term of the Gas Rate Plan. Appendix 23 describes how the RSM is calculated and when it is to be collected.

g. Balancing Provisions

Changes to the gas balancing provisions applicable to SC Nos. 8, 9, 13, and 14, effective November 1, 2015, are set forth in Appendix 11.

h. 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 Company's cost responsibilities associated with main and service line extensions will be modified to indicate that a residential heating customer is entitled to any combination of 200 feet of gas main and service at no charge;

2. The Company's cost responsibilities associated with main and service line extensions will be modified to allow multiple customers to aggregate, or cluster, their entitlements for gas extensions subject to the following rules:

    a. "Clustering" can be used for residential and commercial customers;

    b. "Clustering" can only be used in active main construction projects. Once the Company has completed the main extension/construction, "clustering" will no longer be available to that particular construction project;

    c. "Clustering" can only be used when there are two or more committed customers;

    d. If, based on a revenue test, a customer is entitled to more than 200 feet of entitlement for residential heating applicants or 100 feet of entitlement for residential non-heating and commercial applicants and does not require the use of the entire entitlement, the excess entitlement will become available to the defined “cluster;” and

e. All project entitlements are not to exceed the 200 feet entitlement for residential heating applicants and the 100 feet entitlement for residential non-heating or commercial applicants, multiplied by the total number of customers in the “cluster,” plus any additional entitlements determined from the revenue tests.

3. The calculation of the gas factor of adjustment and line loss incentive/penalty included in the Annual Surcharge or Refund Adjustment will be modified as discussed in Section B.2.d;

4. The normal heating degree days (“NHDD”) contained in the Weather Normalization Adjustment mechanism shall be 4,893 heating degree days (*i.e.*, the October through May average for the 10 calendar years ended December 2013);

5. SC Nos. 3 and 10 and all references to these service classifications have been eliminated;

6. New customers taking service under SC No. 8 who had previously taken firm service from the Company for a period of less than five years

7. will be required, at the Company’s discretion, to pay all or a portion of the facility costs previously paid for by the Company;

8. Customers served under SC No. 14 will pay a monthly Variable Balancing Charge on all volumes delivered and burned. The monthly Variable Balancing Charge will be determined by November 1 of each year based on the allocated costs of assets used to balance customers under SC No. 14;

9. The description of the Winter Bundled Sales (“WBS”) charge contained in SC No. 11 has been modified to remove the language indicating that fixed storage charges are included in the determination of the WBS Charge;

10. The Standard Service Option contained in SC Nos. 6 and 11 has been eliminated;

11. The description of the specific components used to determine the price of WBS gas, annual program volume and terms of capacity release has been removed from SC No. 11 and will be moved to the Company’s Gas Transportation Operating Procedures;

12. For SC No. 11, the points of reference for monthly cash-outs will be removed from the tariff and moved to the Company's Gas Transportation Operating Procedure. These points of reference will be based on the average of daily midpoints of all pipes serving Orange and Rockland. For November 1, 2015, the indexes will be as follows: Tennessee Zone 4 Marcellus, Millennium East Pool, Texas Eastern M3, and Columbia Appalachian Pool;

13. The commodity price of WBS gas will utilize the same storage price used each month for full requirements customers.

14. Housekeeping changes will be made to various other provisions of the gas tariff, including the elimination of obsolete provisions and changes meant to simplify tariff administration as detailed in the direct testimony of the Company Gas Rate Panel.

3. **<u>Tariff Provisions Applicable to Both Electric and Gas</u>**

a. AMI and AMR Opt Out Fees

Customers who opt out of AMI or AMR metering will be subject to the following:

1. A monthly manual meter reading fee will apply to any customer who: refuses to allow the Company to install either an AMI or AMR meter; requests that the transmitter of an AMI meter be disabled; or requests that an AMR meter be removed. Such fee will be $15 for a customer who receives both electric and gas service from the Company, or $10 for a customer who receives only electric or only gas service from the Company;

2. A one-time meter change fee will apply for a customer who requests the change out of an AMI or AMR meter. Such fee will be $90 for a customer who receives both electric and gas service from the Company, $45 for a customer who receives only electric service from the Company, or $55 for a customer who receives only gas service from the Company. The meter change out fee is not applicable to an AMI electric meter that can have its transmitter disabled remotely; and

3. A customer who requests a non-transmitting AMI gas meter, who later elects to switch back to AMI metering, will be charged $55 to reactivate the transmitter.

The Company will send a notification letter to residential customers at least 30 days prior to the date scheduled for installation of an AMI or AMR meter at the customers' premises. The letter shall answer frequently asked questions about such meters and explain how the customer can opt out of receiving such meters. When an unscheduled replacement is made (*e.g.*, replacement of a broken meter), the Company will leave a written notice containing the same information at the customer's premises.

Should a customer fill out the Company's AMI opt-out application within 30 days of being provided with the notification letter described above, such a customer will neither be issued an AMI or AMR meter, nor pay the Company's proposed one-time meter change fee. In such a case, the customer would be allowed to keep its currently installed meter. If an AMI or AMR meter was already installed, it will be replaced with a standard non-communicating meter.

Customers who opt out of AMI or AMR metering must provide reasonable access for meter reading and meter maintenance. If the customer fails to provide access for two months in any 12-month period, then the customer will be required to: (a) pay the Company to relocate the metering equipment to an external location; or (b) permit the Company to reinstall an AMR meter or enable the AMI meter transmitter feature. In addition, the Company will charge any such customers a no access service fee as provided in its tariff.

I. <u>Performance Metrics</u>

Performance metrics designed to measure various activities that are applicable to the Company's Electric, Gas and Customer Service Operations, and assess negative and/or positive revenue adjustments where performance targets are not met or are exceeded, are set forth in Appendices 15, 16 and 17. Any negative or positive revenue adjustments incurred by the Company during the Rate Plans relating to the performance metrics will be deferred for the benefit of customers or shareholders and will be addressed in the Company's next electric and/or gas base rate cases.

J. <u>Climate Change</u>

Orange and Rockland agrees to review the climate change study produced by the Center for Climate Systems Research of Columbia University for Consolidated Edison Company of New York, Inc. ("Con Edison Study") upon its completion, or the completion of components thereof, and any other materials on climate projections furnished to Orange and Rockland by the Sabin Center prior to the release of the Con Edison Study ("Other Materials"). Orange and Rockland will evaluate whether the results of the Con Edison Study or components thereof and the Other Materials suggest a need for an adjustment associated with Orange and Rockland's capital expenditure planning or investment or operational procedures and whether further study may be required. Orange and Rockland's evaluation will be limited to the results of the Con Edison Study or components thereof and the Other Materials that are completed as of the end of the term for the Electric Rate Plan (*i.e.*, October 31, 2017). Orange and Rockland will provide the Sabin Center and other interested parties with a written report of its evaluation results within 120 days of the end of the Electric Rate Plan.

K. Customer Service Issues

1. Outreach and Education

a. Customer Outreach and Education

Orange and Rockland will provide an annual budget of $231,000 for electric and $229,000 for gas for outreach and education, including $75,000 for natural gas safety, and $47,000 for natural gas conversion. Orange and Rockland 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, as well as provide important safety information. Annually, on September 30 of each Rate Year, the Company will file an outreach and education plan with the Secretary, along with a summary and assessment of its customer education efforts in the previous year. The annual plan shall include: the goals of the outreach and education program, detailed budgets, the specific outreach campaign messages to be disseminated, the communication vehicles to be used to disseminate them, and the criteria for measuring the program's achievement.

b. Natural Gas Network Enhancement

The Company will continue to provide increased natural gas-related outreach and education, including attending community events and providing robust website information detailing, among other things, the process for converting to natural gas. The Company will increase education through social media. The Company will track, on a quarterly basis, and report on an annual basis, the number of inquiries and requests by prospective natural gas customers as set forth in Appendix 27.

2. **Mandatory Day Ahead Hourly Pricing**

During the term of the Electric Rate Plan, the threshold for the Company's Mandatory Day Ahead Hourly Pricing ("MDAHP") program shall remain at 300 kW. Prior to October 31, 2016, the Company will complete a study on the impact of lowering the threshold to 100 kW, or another level between 300 and 100 kW. Staff and other interested parties will have the opportunity to provide input into the design of this study. At a minimum, this study will review the types of the Company's customers with demands between 100 kW and 300 kW, their usage profiles, as well as the potential for demand impacts with a range of assumed participation in DER.

3. **Same-Day Electric Service Reconnections**

a. Weekday Same-Day Reconnections

The Company will exercise reasonable efforts, within the Company's existing staffing levels and budgets, in attempting 100% 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 (*e.g.*, by making payment) by 5:00 p.m. Monday-Friday, excluding Company holidays. This process does not include customers whose meter was removed or service was cut in the street.

b. Reporting

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, with copies by email to interested parties, within 30 days after the end of each reporting period. The report will indicate the number of residential electric customer reconnection work orders issued by 5:00 p.m. Monday-Friday, the number of same-day reconnections attempts made to such customers, and the number of completed same-day reconnections.

L. Electric and Gas Low Income Assistance Programs

1. Monthly Bill Credit

The Company will modify its current electric low income assistance program so that any electric space heating customer who receives a Home Energy Assistance Program ("HEAP") grant will receive from the Company a monthly bill credit of $27.00 during each of RY1 and RY2. Any electric non-space heating customer who receives a HEAP grant will receive from the Company a monthly bill credit of $18.00 during each of RY1 and RY2.

The Company will modify its current gas low income assistance program to provide separate bill credits for heating and non-heating customers. Any gas space heating customer who receives a HEAP grant will receive from the Company a monthly bill credit of $17.00 during each of RY1, RY2 and RY3. Any gas non-space heating customer who receives a HEAP grant will receive from the Company a monthly bill credit of $6.00 during each of RY1, RY2 and RY3.

The Company will commence posting such bill credits to the customer's account within 60 days of being notified of the customer's receipt of a HEAP grant. In any month, should the monthly bill credit exceed the charges on the customer's bill, then the bill will be reduced to $0.00 and any remaining credits will be carried over to the following month. These modified electric and gas low income programs will commence on November 1, 2015. The bill credits will remain at the level in effect after the conclusion of RY2 for electric and RY3 for gas until modified by the Commission. The

Rate Plans provide rate allowances for the low income assistance programs as set forth in Appendices 6 and 7. To the extent that expenditures for such low income programs, including the incremental EmPower – NY services program referral costs described below, over the Rate Plans are more or less than the amounts outlined in Appendices 6 and 7, Orange and Rockland shall defer those amounts.

2. **Reconnection Fee Waiver**

During the term of the Rate Plans, the Company will continue its policy of waiving its reconnection fee for any Orange and Rockland electric and/or gas customer who receives a HEAP grant, according to the terms set forth in the Company's electric and gas tariffs.

3. **EmPower Support**

Once during each Rate Year, Orange and Rockland will send a letter to all its low-income customers soliciting the consent of such customers so that they can be referred to the New York State Energy Research and Development Authority ("NYSERDA") for participation in NYSERDA's EmPower-NY services program, or any program approved by the Commission as a successor to the EmPower-NY program during the Rate Plans. For low-income customers that consent, the Company will forward to NYSERDA, through a confidential electronic means, such customers' contact and usage information. Staff will make a good faith effort during the term of the Rate Plans to encourage NYSERDA to promote the EmPower-NY services program in the Company's service territory. Staff also will encourage NYSERDA to provide the Company, Staff, and UIU with a report describing whether, and if so how, the customers referred to NYSERDA by the Company participated in NYSERDA's EmPower-NY services program.

In the final quarterly low income report for each Rate Year, to the extent applicable, the Company will identify the number of referral letters that it sent out to low income customers during the Rate Year and the number of customers that requested that the Company refer them to NYSERDA.

4. **Reporting Requirements**

a. Electric

During each Rate Year, the Company will file a report on the Electric Low Income Assistance Program for each calendar quarter (the "Reporting Period"). Each report will be filed with the Secretary, with copies by email to parties to Case 14-E-0493, within 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: (1) the number of heating and non-heating participants in the Company's low income assistance program; (2) the aggregate amounts of program discounts provided to date for the Rate Year, stated separately for heating and non-heating participants; (3) the number of customers that received waiver of reconnection fees to date for the Rate Year; (4) the aggregate amount of reconnection fees waived to date for the Rate Year; (5) the number of low income assistance program participants who had service terminated; and (6) a brief narrative explaining any significant changes or developments since the last report.

b. Gas

During each Rate Year, the Company will file a report on the Gas Low Income Assistance Program for each calendar quarter (the "Reporting Period"). Each report will be filed with the Secretary, with copies by email to parties to Case 14-G-0494, within 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: (1) the number of heating and non-heating participants in the Company's low income assistance program; (2) the aggregate amounts of program discounts provided to date for the Rate Year, stated separately for heating and non-heating participants; (3) the number of customers that received waiver of reconnection fees to date for the Rate Year; (4) the aggregate amount of reconnection fees waived to date for the Rate Year; (5) the number of low income assistance program customers who had service terminated; and (6) a brief narrative explaining any significant changes or developments since the last report.

5. **Low Income Assistance Proceeding**

The Signatory Parties recognize that Case 14-M-0565[20] is an ongoing proceeding which may impact the Company. The Signatory Parties further recognize that this Proposal does not limit the Commission's ability to require the Company to take certain actions pursuant to the Low Income Assistance Proceeding. All Signatory Parties reserve all of their administrative and judicial rights in connection with the Low Income Assistance Proceeding.

M. Collaboratives

1. **AMI Collaborative**

The Company will provide its proposed AMI Business Plan, and Staff and other interested parties will have the opportunity to comment. The Company will consider in the design and formation of its AMI Business Plan the feasibility of providing access to near real-time data to customers and third parties that are authorized to have access to

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[20] Case 14-M-0565, *Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers*, Order Instituting Proceeding (issued January 9, 2015) ("Low Income Assistance Proceeding").

customer data, including authorized third-party energy services providers *(e.g.*, an energy services company). The Company will also consider experiences by utilities in other states and Canada that have implemented AMI in order to identify benefits, best practices, and impediments experienced and/or identified by these utilities, and how these utilities addressed the impediments. The Company will collaborate with Staff and parties on the development of the Company's AMI Business Plan, and present all costs for AMI.

On or about June 22, 2015, Orange and Rockland will convene a meeting among Staff and other interested parties at which the Company will make a technical presentation regarding its preliminary AMI Business Plan, including its preliminary customer engagement plan (which will explain how the Company will comply with the Home Energy Fair Practices Act [“HEFPA”]) and third-party data access plan. The preliminary AMI Business Plan also will explain how the Company will leverage AMI technology through, for example, dynamic rates and demand response.

On or about June 29, 2015, the Company will provide to Staff and interested parties its preliminary AMI Business Plan, including an updated benefit cost analysis ("BCA"), if applicable.

On or before July 14, 2015, Staff and/or interested parties may submit to the Company written comments and/or proposed modifications to the preliminary AMI Business Plan.

On or about July 29, 2015, the Company will respond to comments and/or proposed modifications submitted by Staff and/or interested parties.

On or about September 8, 2015, the Company will convene a second meeting of Staff and interested parties, at which meeting the Company will provide new information, if any, on the AMI implementation schedule and plan, and further discuss any questions, comments or proposed modifications of Staff and parties or modifications resulting from the MDPT Report of August 3, 2015.

The Company's AMI Business Plan will include the following components:

1. Gas and Electric Meter System ("GEMS"), which will include costs and a schedule for implementation activities in 2016;

2. Meter Data Management System ("MDMS"), which will include costs and a schedule for implementation activities in 2016;

3. System Integration, which will include an estimate of costs and a schedule for implementation of software integration activities in 2016;

4. Meters and Communication Systems, which will include equipment costs;

5. Meter and Communication System Installation, including a high level estimate of costs and a preliminary schedule;

6. An updated and detailed BCA, that will consider, *inter alia,* net remaining plant associated with existing meters and related components to be replaced with AMI meters, and a sensitivity analysis for any potential meter and/or communication cost overruns;

7. A plan for customer engagement, including privacy principles and third-party access to data consistent with the REV proceeding and other proceedings and rules involving access to customer data, and a customer outreach and education plan; and

8. A detailed implementation schedule, including benchmarks.

By mid-November 2015, the Company will provide to Staff and parties updated costs and schedules for (i) System Integration and (ii) Meter and Communication System Installation. Either as part of or at the same time as the Company's DSIP filing (currently due on January 16, 2016), the Company will file the latest version of its AMI Business Plan with the Secretary. If not filed as part of the Company's DSIP, the AMI Business Plan shall be filed in these proceedings.

In addition to the foregoing, throughout this process, Staff and interested parties will have the ability to present questions to the Company about the AMI project, to which the Company will respond within a reasonable timeframe, either in advance of or during the collaborative meetings.

2. **Pomona Collaborative**

On or about May 26, 2015, the Company will convene a meeting among Staff and other interested parties to exchange ideas and information regarding timely, cost-effective potential solutions for load reduction to meet or exceed project goals for the Pomona DER Program.

On or about June 12, 2015, Staff and/or interested parties may submit to the Company suggested solutions or written comments on solutions discussed at the May 26 meeting.

On or about June 26, 2015, the Company will respond to suggested solutions and comments from Staff and/or interested parties.

3. **REV Demonstration Project Outreach**

The Signatory Parties recognize the benefits of an exchange of ideas regarding REV Demonstration Projects.

The Signatory Parties further recognize that there is a NYSERDA website and form through which interested parties may propose Demonstration Projects. This Proposal does not attempt to supersede or modify that existing process.

This Proposal is distinct from the REV Track One Order's requirement that, for Demonstration Projects, the utility "must include a detailed demonstration of outreach that has been performed in any community directly affected by the project."

Regarding Demonstration Projects that may be proposed after July 1, 2015, the Company will commit to the following process as a minimum so as to provide opportunities for engagement with any interested third parties.

Semi-annual meetings will be held (October and April), at which demonstration projects which Orange and Rockland is developing will be discussed and ideas exchanged.

The Company, interested parties and Staff will exchange of information on proposed projects prior to these meetings in order to facilitate productive discussions.

This proposal is not intended to limit the Company's interaction with interested parties, nor to limit the Commission's prerogative to require additional or different processes in the future.

4. **Ongoing Marketer Collaborative**

The Signatory Parties recognize that there is an ongoing Marketer Collaborative between Consolidated Edison Company of New York, Inc. ("Con Edison") and gas marketers operating in its service territory. Through this collaborative Con Edison and gas marketers discuss and seek to resolve operational issues. Similar operational issues raised by gas marketers regarding Orange and Rockland will be considered in this ongoing Marketer Collaborative.

N. Miscellaneous Provisions

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

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

Nothing herein precludes Orange and Rockland from filing a new general electric rate case prior to December 1, 2016, for rates to be effective on or after November 1, 2017, or from filing a new general gas rate case prior to December 1, 2017, for new rates to be effective on or after November 1, 2018. Except pursuant to rate changes permitted by this subparagraph, the Company will not file electric rates to be become effective prior to November 1, 2017 or gas rates to become effective prior to November 1, 2018.

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:

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. It is understood that, over time, such minor changes are routinely made and that they may continue to be sought during the term of the Rate Plans, provided they will not result in a change (other than a *de minimis* change) in the revenues that Orange and Rockland'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 Orange and Rockland's economic viability or ability to maintain safe, reliable and adequate service as to warrant an exception to this undertaking, Orange and Rockland 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 Orange and Rockland'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 Orange and Rockland's electric and/or gas rates unreasonable or insufficient for the provision of safe and adequate service at just and reasonable rates.

d. Nothing herein will preclude Orange and Rockland 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 service classes.

e. The Signatory Parties reserve the right to support or oppose any filings made by the Company under this Section.

2. **Legislative, Regulatory and Related Actions**

a. If at any time the federal government, State of New York and/or other local governments make changes in their tax laws (other than local property taxes, which will be fully reconciled in accordance with Section E.2 of this Proposal) that result in a change in the Company's costs[21] in an annual amount, calculated and applied separately for electric and gas, equating to 10 basis points of return on common equity or more,[22] and if the Commission does not address the treatment (*e.g.*, through a surcharge

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

[22] For electric, such amounts are estimated to be $614,000 in RY1 and $647,000 in RY2. For gas, such amounts are estimated to be $296,000 in RY1, $316,000 in RY2 and $337,000 in RY3.

or credit) of any such tax law changes, including any new, additional, repealed or reduced federal, State, local government taxes, fees or levies, Orange and Rockland 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.[23]

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, results in a change in Orange and Rockland'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 10 basis points of return on common equity or more,[24] Orange and Rockland will defer on its books of account the full change in expense, with any such deferrals 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.

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

[24] For purposes of this Proposal, the ten 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.

3. **Trade Secret Protection**

Nothing in this Proposal prevents Orange and Rockland 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 Signatory Party from challenging any such request.

4. **Provisions Not Separable**

The Signatory Parties intend this Proposal to be a complete resolution of all the issues in Cases 14-E-0493 and 14-G-0494. 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 this Proposal will be free to pursue their respective positions in this proceeding without prejudice.

5. **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 Signatory Party may be referred to, cited, or relied upon by any other Signatory 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 Signatory Parties from addressing such issues in future rate proceedings or in other proceedings.

6. **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. The Signatory Parties hereto believe that the Proposal will satisfy the requirements of Public Service Law §65(1) that Orange and Rockland provide safe and adequate service at just and reasonable rates.

7. **Procedures in the Event of a Disagreement**

In the event of any disagreement over the interpretation of this Proposal or the implementation of any of the provisions of this Proposal, which cannot be resolved informally among the Signatory Parties, such disagreement will be resolved as follows: the Signatory Parties promptly will confer and in good faith will attempt to resolve such disagreement. If any such disagreement cannot be resolved by the Signatory Parties within 15 business days from notification invoking this process, or a longer period if agreed to by the Signatory Parties, any Signatory Party may petition the Commission for a determination on the disputed matter.

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 but not both electric and gas service, limits any rights of the Company or any Signatory Party to petition the Commission for any purpose with respect to the service 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.

ORANGE AND ROCKLAND
UTILITIES, INC.

Dated: June 5, 2015

By: John L. Carley

NEW YORK STATE DEPARTMENT OF PUBLIC SERVICE

Dated: June 5, 2015

By: ______________________
Brandon F. Goodrich
Staff Counsel

THE UTILITY INTERVENTION UNIT,
DIVISION OF CONSUMER
PROTECTION, NEW YORK STATE
DEPARTMENT OF STATE

Dated: June 5, 2015

By: ______________________
Erin Hogan
Director, Utility Intervention Unit

The Utility Intervention Unit ("UIU") supports all of the aspects of the Joint Proposal other than those provisions that uniquely pertain to the gas revenue requirement. The UIU neither supports nor opposes those gas-only provisions.

*PACE ENERGY AND CLIMATE CENTER

Dated: 6/5/15

By: David Gahl

*For the reasons set forth in its filed testimony, Pace signs onto this Agreement except for, under section G, the establishment of a surcharge mechanism to recover the costs of Demonstration Projects undertaken pursuant to the REV Track One Order.

THE COLUMBIA CENTER FOR
CLIMATE CHANGE LAW

Dated: June 5, 2015

By: ______________________

THE RETAIL ENERGY SUPPLY
ASSOCIATION

Dated: 6/5/15

By: Usher Fogel, counsel

Usher Fogel, Counsel

THE DEPARTMENT OF DEFENSE AND
ALL OTHER FEDERAL EXECUTIVE
AGENCIES

Dated: June 4, 2015

By: Matthew Dunne

Matthew Dunne

General Attorney
Regulatory Law Office (JALS-RL/IP)
Office of the Judge Advocate General
U.S. Army Legal Services Agency
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Orange and Rockland Utilities, Inc.
Case 14-E-0493
Electric Revenue Requirement
For Twelve Months Ending October 31, 2016
($000's)

	Rate Year 1 Forecast	Rate Change	Rate Year 1 with Rate Change
Operating Revenues			
Sales & Deliveries to Public	$ 441,885	$ 9,326	$ 451,211
Sales for Resale	21,322		21,322
Other Operating Revenues	5,479	64	5,543
Total Operating Revenues	468,686	9,390	478,076
Operating Expenses			
Purchased Power	135,938		135,938
Other Purchased Power (Base Rates)	705		705
Other O&M	171,212	62	171,274
Depreciation	40,695		40,695
Taxes Other than Income Taxes	51,210	167	51,377
Gain or Loss on Disposition of Utility Plant	(106)		(106)
Total Operating Revenue Deductions	399,654	229	399,883
Operating Income Before FIT	69,032	9,161	78,193
Income Taxes			
State Income taxes	3,079	605	3,684
Federal Income taxes	17,331	2,995	20,326
Total Income Taxes	20,410	3,600	24,010
Operating Income	$ 48,622	$ 5,561	$ 54,183
Electric Rate Base			
Electric Rate Base	839,523		839,523
EBCAP Adjustment to Electric Rate Base	(76,361)		(76,361)
Total Electric Rate Base	$ 763,162		$ 763,162
Rate of Return	6.37%		7.10%

Orange and Rockland Utilities, Inc.
Case 14-E-0493
Electric Revenue Requirement
For Twelve Months Ending October 31, 2017
($000's)

	Rate Year 1 with Rate Change	Rate Year 2 Changes	Rate Change	12 Months Ending October 31, 2017 (RY2)
Operating Revenues				
Sales & Deliveries to Public	$ 451,211	$ (7,536)	$ 8,802	$ 452,477
Sales for Resale	21,322	(862)	-	20,460
Other Operating Revenues	5,543	(869)	61	4,735
Total Operating Revenues	478,076	(9,267)	8,863	477,672
Operating Expenses				
Purchased Power	135,938	(3,999)	-	131,939
Other Purchased Power (Base Rates)	705	9	-	714
Other O&M	171,274	(3,977)	58	167,355
Depreciation	40,695	2,675	-	43,370
Taxes Other than Income Taxes	51,377	1,957	158	53,492
Gain or Loss on Disposition of Utility Plant	(106)	-	-	(106)
Total Operating Revenue Deductions	399,883	(3,336)	216	396,763
Operating Income Before FIT	78,193	(5,931)	8,647	80,909
Income Taxes				
State Income taxes	3,684	(497)	562	3,749
Federal Income taxes	20,326	(2,813)	2,830	20,343
Total Income Taxes	24,010	(3,311)	3,392	24,091
Operating Income	$ 54,183	$ (2,620)	$ 5,255	$ 56,818
Electric Rate Base				
Electric Rate Base	839,523	41,617		881,140
EBCAP Adjustment to Electric Rate Base	(76,361)	-		(76,361)
Total Electric Rate Base	$ 763,162	$ 41,617		$ 804,779
Rate of Return	7.10%			7.06%

Orange and Rockland Utilities, Inc.
Case 14-E-0493
Average Electric Rate Base
For Twelve Months Ending October 31, 2016 and October 31, 2017
($000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2
Utility Plant			
Electric Plant in Service	$ 1,242,112	$ 69,916	$ 1,312,028
Electric Plant Held for Future Use	8,399	0	8,399
Common Utility Plant (Electric Allocation)	156,167	14,379	170,546
CWIP Not Taking Interest	20,096	0	20,096
Total Utility Plant	1,426,774	84,295	1,511,069
Utility Plant Reserves:			
Accum. Prov. For Deprec. of Elecrtic Plant In Service (Including Future Use Plant)	(399,025)	(26,479)	(425,504)
Accum. Prov. For Deprec. & Amortization of Common Plant	(70,601)	(6,918)	(77,519)
Total Utility Plant Reserves	(469,626)	(33,397)	(503,023)
Net Plant	957,148	50,898	1,008,046
Working Capital Requirements			
O&M Expenditures	23,331	61	23,392
Materials & Supplies	9,446	196	9,642
Prepayments	13,942	290	14,232
Regulatory Assets & Other Rate Base Additions (net of income taxes)			
DEFERRED UNBILLED REVENUE	5,366	0	5,366
DEFERRED PURCHASED POWER	(1,952)	0	(1,952)
DEFERRED M.T.A. SURTAX	5,266	0	5,266
DEFERRED M.T.A. MOBILITY TAX	63	0	63
DEFERRED MFC - TRANSITION ADJUSTMENT FOR COMPETITIVE SERVICES	708	0	708
DEFERRED STORM RESERVE EXPENDITURES	32,382	(7,170)	25,212
DEFERRED INTEREST ON STORM RESERVE EXPENDITURES	1,215	(487)	728
DEFERRED ENVIRONMENTAL EXPENDITURES	4,679	(1,036)	3,643
DEFERRED POLLUTION CONTROL DEBT	(880)	351	(529)
DEFERRED PROPERTY TAX TRUE UP	7,103	(1,572)	5,531
DEFERRED SMART GRID MAINTENANCE COST	27	(11)	16
DEFERRED RATE CASE COST	115	(46)	69
Regulatory (Liabilities) & Other Rate Base Deductions (net of income taxes)			
DEFERRED LOW INCOME PROGRAM	(726)	290	(436)
DEFERRED R & D EXPENDITURES	(465)	186	(279)
DEFERRED CONSERVATION COST	27	(11)	16
DEFERRED PROPERTY TAX REFUND	(234)	93	(141)
DEFERRED NYS INCOME TAX RATE CHANGE	(1,116)	446	(670)
DEFERRED NET PLANT RECONCILIATION	336	(134)	202
DEFERRED REACTIVE POWER	(359)	143	(216)
DEFERRED CARRYING CHARGE ON TAX LIABILITIES	(4,857)	1,940	(2,917)
DEFERRED INTEREST REPAIR ALLOWANCE	(69)	27	(42)
DEFERRED ENVIRONMENTAL COST CARRYING CHARGE	(872)	348	(524)
DEFERRED STRAY VOLTAGE	(708)	283	(425)
DEFERRED TREE TRIMMING	(908)	363	(545)
DEFERRED SALE OF PROPERTY - WARWICK	(161)	64	(97)
Accum. Deferred Income Taxes			
ACCUM. DEFERRED FIT - ACRS / ADR /MCRS VARIOUS	(122,920)	(1,246)	(124,166)
ACCUM. DEFERRED FIT - MIXED SERVICES COST & 263(A) CAPITALIZED OVERHEADS	(41,979)	(2,075)	(44,054)
ACCUM. DEFERRED FIT - DEFERRED FIT - REPAIR ALLOWANCE	(33,618)	272	(33,346)
ACCUM. DEFERRED SIT VARIOUS	(7,106)	(926)	(8,032)
ACCUM. DEFERRED SIT (MTA)	(1,965)	0	(1,965)
ACCUMULATED DEFERRED INVESTMENT TAX CREDITS	(736)	80	(656)
Electric Rate Base	839,523	41,617	881,140
EBCAP Adjustment to Electric Rate Base	(76,361)	0	(76,361)
Total Electric Rate Base	**$ 763,162**	**$ 41,617**	**$ 804,779**

Orange and Rockland Utilities, Inc.
Case 14-E-0493
Capital Structure & Cost of Money
For Twelve Months Ending October 31, 2016, and October 31, 2017

Rate Year 1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre-Tax Cost @ 60.71%
Long-Term Debt	51.04%	5.42%	2.77%	2.77%
Customer Deposits	0.96%	1.15%	0.01%	0.01%
Total Debt	52.00%		2.78%	2.78%
Common Equity	48.00%	9.00%	4.32%	7.12%
Total Capitalization	100.00%		7.10%	9.89%

Rate Year 2

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre-Tax Cost @ 60.78%
Long-Term Debt	51.06%	5.35%	2.73%	2.73%
Customer Deposits	0.94%	1.15%	0.01%	0.01%
Total Debt	52.00%		2.74%	2.74%
Common Equity	48.00%	9.00%	4.32%	7.11%
Total Capitalization	100.00%		7.06%	9.85%

Orange and Rockland Utilities, Inc.
Case 14-G-0494
Gas Revenue Requirement
For Twelve Months Ending October 31, 2016
($000's)

	Rate Year 1 Forecast	Rate Change	Rate Year 1 with Rate Change
Operating Revenues			
Sales & Deliveries to Public	$ 177,148	$ 27,525	$ 204,673
Sales for Resale (Pike & NYSEG)	1,369		1,369
Delivery Revenues	178,517	27,525	206,042
Other Operating Revenues	707	126	833
Total Operating Revenues	179,224	27,651	206,875
Operating Expenses			
Purchased Gas	59,430		59,430
Deferred Purchased Gas	(2,651)		(2,651)
Other O&M	64,443	181	64,624
Depreciation	16,092		16,092
Amortization of LTD Term Plant	2,037		2,037
Taxes Other than Income Taxes	28,178	550	28,728
Total Operating Revenue Deductions	167,529	731	168,260
Operating Income Before FIT	11,695	26,920	38,615
Income Taxes			
State Income taxes	96	1,776	1,872
Federal Income taxes	1,954	8,800	10,754
Total Income Taxes	2,050	10,576	12,626
Operating Income	$ 9,645	$ 16,344	$ 25,989
Gas Rate Base			
Gas Rate Base	406,149		406,149
EBCAP Adjustment to Gas Rate Base	(40,101)		(40,101)
Total Gas Rate Base	$ 366,048		$ 366,048
Rate of Return	2.63%		7.10%

Orange and Rockland Utilities, Inc.
Case 14-G-0494
Gas Revenue Requirement
For Twelve Months Ending October 31, 2017
($000's)

	Rate Year 1 with Rate Change	Rate Year 2 Changes	Rate Change	12 Months Ending October 31, 2017 (RY2)
Operating Revenues				
Sales & Deliveries to Public	$ 204,673	$ 2,268	$ 4,403	$ 211,344
Sales for Resale (Pike & NYSEG)	1,369	40	-	1,409
Delivery Revenues	206,042	2,308	4,403	212,753
Other Operating Revenues	833	(348)	20	505
Total Operating Revenues	206,875	1,960	4,423	213,258
Operating Expenses				
Purchased Gas	59,430	(95)	-	59,335
Deferred Purchased Gas	(2,651)	2,794	-	143
Other O&M	64,624	(1,520)	29	63,133
Depreciation	16,092	1,266	-	17,358
Amortization of LTD Term Plant	2,037	125	-	2,162
Taxes Other than Income Taxes	28,728	1,261	88	30,077
Total Operating Revenue Deductions	168,260	3,831	117	172,208
Operating Income Before FIT	38,615	(1,871)	4,306	41,050
Income Taxes				
State Income taxes	1,872	(186)	280	1,966
Federal Income taxes	10,754	(685)	1,409	11,478
Total Income Taxes	12,626	(871)	1,689	13,444
Operating Income	$ 25,989	$ (1,000)	$ 2,617	$ 27,606
Gas Rate Base				
Gas Rate Base	406,149	24,967		431,116
EBCAP Adjustment to Gas Rate Base	(40,101)	-		(40,101)
Total Gas Rate Base	$ 366,048	$ 24,967		$ 391,015
Rate of Return	7.10%			7.06%

Orange and Rockland Utilities, Inc.
Case 14-G-0494
Gas Revenue Requirement
For Twelve Months Ending October 31, 2018
($000's)

	Rate Year 2 with Rate Change	Rate Year 3 Changes	Rate Change	12 Months Ending October 31, 2018 (RY3)
Operating Revenues				
Sales & Deliveries to Public	$ 211,344	$ 3,197	$ 6,692	$ 221,233
Sales for Resale (Pike & NYSEG)	1,409	90	-	1,499
Delivery Revenues	212,753	3,287	6,692	222,732
Other Operating Revenues	505	(387)	31	149
Total Operating Revenues	213,258	2,900	6,723	222,881
Operating Expenses				
Purchased Gas	59,335	4,046	-	63,381
Deferred Purchased Gas	143	(1,299)	-	(1,156)
Other O&M	63,133	469	44	63,646
Depreciation	17,358	1,046	-	18,404
Amortization of LTD Term Plant	2,162	313	-	2,475
Taxes Other than Income Taxes	30,077	1,773	134	31,984
Total Operating Revenue Deductions	172,208	6,348	178	178,734
Operating Income Before FIT	41,050	(3,448)	6,545	44,147
Income Taxes				
Current State Income taxes	1,966	(271)	425	2,120
Deferred Federal Income taxes	11,478	(1,055)	2,142	12,565
Total Income Taxes	13,444	(1,326)	2,567	14,685
Operating Income	$ 27,606	$ (2,122)	$ 3,978	$ 29,462
Gas Rate Base				
Gas Rate Base	431,116	26,287		457,403
EBCAP Adjustment to Gas Rate Base	(40,101)	-		(40,101)
Total Gas Rate Base	$ 391,015	$ 26,287		$ 417,302
Rate of Return	7.06%			7.06%

Orange and Rockland Utilities, Inc.
Case 14-G-0494
Average Gas Rate Base
For Twelve Months Ending October 31, 2016 and October 31, 2017
($000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2
Utility Plant			
Gas Plant In Service	$ 675,237	$ 41,564	$ 716,801
Common Utility Plant (Gas Allocation)	58,911	5,760	64,671
CWIP Not Taking Interest	5,816	0	5,816
Total Utility Plant	739,964	47,324	787,288
Utility Plant Reserves:			
Accum. Prov. For Deprec. of Gas Plant In Service (Including Future Use Plant)	(216,810)	(15,071)	(231,881)
Accum. Prov. For Deprec. & Amortization of Common Plant	(24,770)	(2,656)	(27,426)
Total Utility Plant Reserves	(241,580)	(17,727)	(259,307)
Net Plant	498,384	29,597	527,981
Working Capital Requirements			
O&M Expenditures	7,448	(37)	7,411
Materials & Supplies	5,851	121	5,972
Prepayments	8,646	418	9,064
Regulatory Assets & Other Rate Base Additions (Net of income taxes):			
DEFERRED UNBILLED REVENUE	4,758	0	4,758
DEFERRED M.T.A. SURTAX - VARIOUS	1,626	0	1,626
DEFERRED GAS ECONOMIC DEVELOPMENT ENHANCEMENT PILOT PROGRAM	30	0	30
DEFERRED MFC - TRANSITION ADJUSTMENT FOR COMPETITIVE SERVICES	73	0	73
DEFERRED ENVIRONMENTAL EXPENDITURES MGP	2,928	(648)	2,280
DEFERRED POLLUTION CONTROL DEBT	(4,682)	1,870	(2,812)
DEFERRED LOW INCOME PROGRAM	885	(354)	531
DEFERRED PROPERTY TAX TRUE UP	18,597	(4,118)	14,479
DEFERRED RATE CASE COST CASE	69	(27)	42
DEFERRED CASE 05-G-1594 INTEREST ON REVENUE DEFERRAL	26	(11)	15
DEFERRED R & D EXPENDITURES MILLENNIUM FUND	(505)	0	(505)
DEFERRED PERFORMANCE RELIABILITY REVENUE ADJUSTMENT	(13)	5	(8)
DEFERRED CONSERVATION COST	13	0	13
DEFERRED CUSTOMER OUTREACH	(91)	36	(55)
DEFERRED R & D EXPENDITURES	(80)	32	(48)
DEFERRED INTEREST REPAIR ALLOWANCE	(692)	276	(416)
DEFERRED ENVIRONMENTAL COST GAS CARRYING CHARGE	(159)	64	(95)
DEFERRED PROPERTY TAX REFUND	(61)	24	(37)
DEFERRED CARRYING CHARGE ON TAX LIABILITIES	(4,627)	1,848	(2,779)
DEFERRED NYS TAX RATE CHANGE	(523)	210	(313)
Accum. Deferred Income Taxes			
ACCUM. DEFERRED FIT - ACRS / ADR /MCRS VARIOUS	(87,156)	(2,128)	(89,284)
ACCUM. DEFERRED FIT - MIXED SERVICES COST & 263(A) CAPITALIZED OVERHEADS	(23,611)	(1,754)	(25,365)
ACCUM. DEFERRED FIT - DEFERRED FIT - REPAIR ALLOWANCE	(13,298)	98	(13,200)
ACCUM. DEFERRED SIT VARIOUS	(5,797)	(609)	(6,406)
ACCUM. DEFERRED SIT (MTA)	(1,608)	0	(1,608)
ACCUMULATED DEFERRED INVESTMENT TAX CREDITS	(282)	54	(228)
Gas Rate Base	406,149	24,967	431,116
EBCAP Adjustment to Gas Rate Base	(40,101)		(40,101)
Total Gas Rate Base	**$ 366,048**	**$ 24,967**	**$ 391,015**

Orange and Rockland Utilities, Inc.
Case 14-G-0494
Average Gas Rate Base
For Twelve Months Ending October 31, 2017 and October 31, 2018
($000's)

	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Utility Plant			
Gas Plant In Service	$ 716,801	$ 46,464	$ 763,265
Common Utility Plant (Gas Allocation)	64,671	4,139	68,810
CWIP Not Taking Interest	5,816	-	5,816
Total Utility Plant	787,288	50,603	837,891
Utility Plant Reserves:			
Accum. Prov. For Deprec. of Gas Plant In Service			
(Including Future Use Plant)	(231,881)	(16,279)	(248,160)
Accum. Prov. For Deprec. & Amortization of Common Plant	(27,426)	(3,170)	(30,596)
Total Utility Plant Reserves	(259,307)	(19,449)	(278,756)
Net Plant	527,981	31,154	559,135
	-		
Working Capital Requirements			
O&M Expenditures	7,411	66	7,477
Materials & Supplies	5,972	125	6,097
Prepayments	9,064	440	9,504
Regulatory Assets & Other Rate Base Additions (Net of income taxes):			
DEFERRED UNBILLED REVENUE	4,758	-	4,758
DEFERRED M.T.A. SURTAX - VARIOUS	1,626	-	1,626
DEFERRED GAS ECONOMIC DEVELOPMENT ENHANCEMENT PILOT PROGRAM	30	-	30
DEFERRED MFC - TRANSITION ADJUSTMENT FOR COMPETITIVE SERVICES	73	-	73
DEFERRED ENVIRONMENTAL EXPENDITURES MGP	2,280	(651)	1,629
DEFERRED POLLUTION CONTROL DEBT	(2,812)	1,875	(937)
DEFERRED LOW INCOME PROGRAM	531	(354)	177
DEFERRED PROPERTY TAX TRUE UP	14,479	(4,137)	10,342
DEFERRED RATE CASE COST CASE	42	(28)	14
DEFERRED CASE 05-G-1594 INTEREST ON REVENUE DEFERRAL	15	(10)	5
DEFERRED R & D EXPENDITURES MILLENNIUM FUND	(505)	-	(505)
DEFERRED PERFORMANCE RELIABILITY REVENUE ADJUSTMENT	(8)	5	(3)
DEFERRED CONSERVATION COST	13	-	13
DEFERRED CUSTOMER OUTREACH	(55)	37	(18)
DEFERRED R & D EXPENDITURES	(48)	32	(16)
DEFERRED INTEREST REPAIR ALLOWANCE	(416)	277	(139)
DEFERRED ENVIRONMENTAL COST GAS CARRYING CHARGE	(95)	63	(32)
DEFERRED PROPERTY TAX REFUND	(37)	25	(12)
DEFERRED CARRYING CHARGE ON TAX LIABILITIES	(2,779)	1,853	(926)
DEFERRED NYS TAX RATE CHANGE	(313)	209	(104)
Accum. Deferred Income Taxes			
ACCUM. DEFERRED FIT - ACRS / ADR /MCRS VARIOUS	(89,284)	(2,491)	(91,775)
ACCUM. DEFERRED FIT - MIXED SERVICES COST & 263(A) CAPITALIZED OVERHEADS	(25,365)	(1,723)	(27,088)
ACCUM. DEFERRED FIT - DEFERRED FIT - REPAIR ALLOWANCE	(13,200)	101	(13,099)
ACCUM. DEFERRED SIT VARIOUS	(6,406)	(633)	(7,039)
ACCUM. DEFERRED SIT (MTA)	(1,608)	-	(1,608)
ACCUMULATED DEFERRED INVESTMENT TAX CREDITS	(228)	52	(176)
Gas Rate Base	431,116	26,287	457,403
EBCAP Adjustment to Gas Rate Base	(40,101)		(40,101)
Total Gas Rate Base	**$ 391,015**	**$ 26,287**	**$ 417,302**

Orange and Rockland Utilities, Inc.

Case 14-G-0494

Capital Structure & Cost of Money

For Twelve Months Ending October 31, 2016, October 31, 2017 and October 31, 2018

Rate Year 1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre-Tax Cost @ 60.71%
Long-Term Debt	51.04%	5.42%	2.77%	2.77%
Customer Deposits	0.96%	1.15%	0.01%	0.01%
Total Debt	52.00%		2.78%	2.78%
Common Equity	48.00%	9.00%	4.32%	7.12%
Total Capitalization	100.00%		7.10%	9.89%

Rate Year 2

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre-Tax Cost @ 60.78%
Long-Term Debt	51.06%	5.35%	2.73%	2.73%
Customer Deposits	0.94%	1.15%	0.01%	0.01%
Total Debt	52.00%		2.74%	2.74%
Common Equity	48.00%	9.00%	4.32%	7.11%
Total Capitalization	100.00%		7.06%	9.85%

Rate Year 3

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre-Tax Cost @60.78%
Long-Term Debt	51.10%	5.35%	2.73%	2.73%
Customer Deposits	0.90%	1.15%	0.01%	0.01%
Total Debt	52.00%		2.74%	2.74%
Common Equity	48.00%	9.00%	4.32%	7.11%
Total Capitalization	100.00%		7.06%	9.85%

Orange and Rockland Utilities, Inc.

Case 14-G-0494

Levelized Rate Increase

For Twelve Months Ending October 31, 2016, October 31, 2017 and October 31, 2018

($000's)

Other Customer Provided Capital Rate = 2.9% ; reflects rate effective January 1, 2015

	Twelve Months Ending October 31,			Cumulative
Rate Increase	2016	2017	2018	Total
RY - 1	$ 27,525	$ 27,525	$ 27,525	$ 82,575
RY - 2		4,403	4,403	8,806
RY - 3			6,692	6,692
Total	27,525	31,928	38,620	98,073
Annual rate increase without interest				
RY - 1	16,346	16,346	16,346	49,037
RY - 2		16,346	16,346	32,691
RY - 3			16,346	16,346
Total	16,346	32,691	49,037	**98,073**
Variation	11,180	(763)	(10,417)	-
Interest on Variation (Net of Tax)	98	190	92	**380**
Annual rate increase with interest				
RY - 1	16,409	16,409	16,409	49,227
RY - 2		16,409	16,409	32,818
RY - 3			16,409	16,409
Total	**$ 16,409**	**$ 32,818**	**$ 49,227**	**$ 98,453**

Orange and Rockland Utilities, Inc.
Case 14-E-0493
Amortization of Electric Regulatory Deferrals (Credits & Debits)

Electric Operations	Twelve Months Ending October 31, 2016	2017	2018	2019	2020	Total
Regulatory Assets (Debits)						
Interest on Storm Reserve	$ 799,000	$ 799,000	$ 799,000			$ 2,397,000
Smart Grid	18,000	18,000	18,000			54,000
Conservation Cost	18,000	18,000	18,000			54,000
Plant Reconciliation	221,000	221,000	221,000			663,000
Property Taxes	2,600,000	2,600,000	2,600,000	2,600,000	2,600,000	13,000,000
MGP Sites & Environmental Programs	1,713,000	2,605,000	3,609,000	3,609,000	3,609,000	15,145,000
Storm Reserve	11,853,000	11,853,000	11,853,000	11,853,000	11,853,000	59,265,000
Rate Case Costs	76,000	76,000	76,000			228,000
Pensions	2,353,000	2,353,000	2,353,000			7,059,000
Total Regulatory Assets (a)	$19,651,000	$20,543,000	$21,547,000	$18,062,000	$18,062,000	$97,865,000
Regulatory Liabilities (Credits)						
Interest on Pollution Control Debt	$ 580,000	$ 580,000	$ 580,000			$ 1,740,000
Interest Repair Allowance / Bonus Depreciation	46,000	46,000	46,000			138,000
NYSIT Rate Change	735,000	735,000	735,000			2,205,000
Reactive Power	237,000	237,000	237,000			711,000
Deferred Tax Liabilities Carrying Charge	3,200,000	3,200,000	3,200,000			9,600,000
Property Tax Refunds	154,000	154,000	154,000			462,000
Stray Voltage Savings	467,000	467,000	467,000			1,401,000
Tree Trimming	598,000	598,000	598,000			1,794,000
Environmental Carrying Charge	575,000	575,000	575,000			1,725,000
R&D	307,000	307,000	307,000			921,000
Low Income	478,000	478,000	478,000			1,434,000
OPEB	3,622,000	3,622,000	3,622,000			10,866,000
Medicare Part D	28,000	28,000	28,000			84,000
Sale of Warwick	106,000	106,000	106,000			318,000
Total Regulatory Liabilities (b)	$11,133,000	$11,133,000	$11,133,000	$ -	$ -	$33,399,000
Net Debits (a - b)	$ 8,518,000	$ 9,410,000	$10,414,000	$18,062,000	$18,062,000	$64,466,000

Orange and Rockland Utilities, Inc.
Case 14-G-0494
Amortization of Gas Regulatory Deferrals (Credits & Debits)

Gas Operations	Twelve Months Ending October 31, 2016	2017	2018	2019	2020	Total
Regulatory Assets (Debits)						
Gas Economic Development Enhancement Pilot Program	$ 20,000	$ 20,000	$ 20,000			$ 60,000
Case 05-G-1594 interest on revenue deferral	17,000	17,000	17,000			51,000
Property Taxes	6,807,000	6,807,000	6,807,000	6,807,000	6,807,000	34,035,000
MGP Sites & Environmental Programs	1,072,000	1,441,000	1,856,000	1,856,000	1,856,000	8,081,000
Low Income	582,000	582,000	582,000			1,746,000
Rate Case Costs	46,000	46,000	46,000			138,000
Pensions	1,484,000	1,484,000	1,484,000			4,452,000
Medicare Part D	1,358,000	1,358,000	1,358,000			4,074,000
Total Regulatory Assets (a)	$11,386,000	$11,755,000	$12,170,000	$8,663,000	$8,663,000	$52,637,000
Regulatory Liabilities (Credits)						
Interest on Pollution Control Debt	$ 3,085,000	$ 3,085,000	$ 3,085,000			$ 9,255,000
Customer Outreach	60,000	60,000	60,000			180,000
Damage Prevention Penalty	8,000	8,000	8,000			24,000
Interest Repair Allowance / Bonus Depreciation	456,000	456,000	456,000			1,368,000
NYSIT Rate Change	344,000	344,000	344,000			1,032,000
Deferred Tax Liabilities Carrying Charge	3,049,000	3,049,000	3,049,000			9,147,000
Property Tax Refunds	41,000	41,000	41,000			123,000
Environmental Carrying Charge	105,000	105,000	105,000			315,000
R&D	53,000	53,000	53,000			159,000
OPEB	2,452,000	2,452,000	2,452,000			7,356,000
Total Regulatory Liabilities (b)	$ 9,653,000	$ 9,653,000	$ 9,653,000	$ -	$ -	$28,959,000
Net Debits (a - b)	$ 1,733,000	$ 2,102,000	$ 2,517,000	$8,663,000	$8,663,000	$23,678,000

Orange and Rockland Utilities, Inc.
Case 14-E-0493
Forecast of Sales Volume (MWh)
Rate Year 1

	SC 01	SC 19	SC 02 s	SC 20	SC 02 p	SC 03	SC 09	SC 21	SC 22	SC 25	SC 04	SC 05	SC 06	SC 16	PA	Total O&R
Nov-15	104,302	5,118	64,806	5,138	2,596	29,172	30,233	2,961	26,744	496	1,472	247	418	1,242	7,046	281,991
Dec-15	127,960	6,084	68,508	5,877	2,793	32,822	37,709	3,426	28,601	932	1,609	250	451	1,360	7,991	326,373
Jan-16	148,866	6,757	78,913	6,438	3,221	29,930	36,772	3,143	31,591	547	1,553	247	441	1,411	8,757	358,587
Feb-16	126,874	5,834	70,853	6,098	2,970	29,367	32,623	3,035	25,174	685	1,368	259	383	1,276	8,058	314,857
Mar-16	117,464	5,644	68,557	5,789	3,083	28,672	32,088	2,814	27,503	363	1,299	250	367	1,151	7,524	302,568
Apr-16	104,771	5,650	63,339	5,285	2,787	27,652	31,035	2,916	26,016	470	1,094	251	310	1,029	6,991	279,596
May-16	98,063	4,957	61,452	5,916	2,807	26,767	31,798	2,676	25,726	424	986	245	284	946	6,883	269,930
Jun-16	129,457	6,486	72,844	7,367	3,315	33,517	38,845	3,429	33,246	422	881	245	255	940	9,061	340,310
Jul-16	173,414	9,067	81,449	7,246	3,435	36,070	40,655	4,392	30,189	808	1,007	251	274	931	9,837	399,025
Aug-16	189,816	10,462	86,693	7,400	3,617	32,618	39,184	3,241	31,279	214	1,062	241	306	918	9,682	416,733
Sep-16	170,069	9,027	85,228	7,239	3,458	33,342	36,633	4,259	28,444	575	1,188	243	337	1,011	8,953	390,006
Oct-16	115,384	5,963	67,035	6,101	2,983	30,729	36,472	3,261	30,379	765	1,395	248	393	1,166	8,187	310,461
Total Billed	1,606,440	81,049	869,677	75,894	37,065	370,658	424,047	39,553	344,892	6,701	14,914	2,977	4,219	13,381	98,970	3,990,437
Net Unbilled	(7,754)	(423)	(2,676)	(249)	(110)	(3,141)	(1,742)	(350)	(1,004)	-	-	-	-	-	-	(17,449)
RY 1 Total	1,598,686	80,626	867,001	75,645	36,955	367,517	422,305	39,203	343,888	6,701	14,914	2,977	4,219	13,381	98,970	3,972,988

Orange and Rockland Utilities, Inc.
Case 14-E-0493
Forecast of Sales Volume (MWh)
Rate Year 2

	SC 01	SC 19	SC 02 s	SC 20	SC 02 p	SC 03	SC 09	SC 21	SC 22	SC 25	SC 04	SC 05	SC 06	SC 16	PA	Total O&R
Nov-16	103,128	5,054	63,817	5,100	2,573	28,622	29,935	2,887	26,234	471	1,456	245	418	1,230	7,146	278,316
Dec-16	125,743	5,973	67,046	5,797	2,748	29,218	33,872	3,026	25,470	908	1,591	248	451	1,348	7,368	310,807
Jan-17	150,942	6,847	79,577	6,524	3,257	29,859	36,989	3,114	31,574	526	1,520	243	441	1,388	8,841	361,642
Feb-17	128,568	5,906	71,369	6,186	3,008	29,300	32,820	3,014	25,096	666	1,294	246	370	1,212	8,136	317,191
Mar-17	116,141	5,576	67,236	5,720	3,043	27,624	31,219	2,686	26,520	341	1,271	246	367	1,133	7,335	296,458
Apr-17	106,638	5,106	63,822	5,358	2,828	27,524	31,237	2,879	25,925	423	1,079	248	310	1,018	7,042	281,437
May-17	99,652	5,032	62,281	6,037	2,868	29,589	35,549	2,943	28,410	372	972	243	284	935	7,674	282,841
Jun-17	125,066	6,872	69,977	7,152	3,218	29,432	34,455	2,990	29,261	396	869	242	255	930	8,051	319,166
Jul-17	171,125	8,937	80,000	7,166	3,371	33,687	38,328	4,077	28,129	763	999	250	274	925	9,246	387,277
Aug-17	190,074	10,468	86,233	7,407	3,608	34,808	42,212	3,440	33,367	169	1,052	239	306	911	10,378	424,672
Sep-17	174,812	9,271	86,966	7,428	3,520	34,570	38,346	4,402	29,467	520	1,176	241	337	1,004	9,275	401,335
Oct-17	116,182	5,997	66,859	6,128	3,000	30,768	36,882	3,246	30,410	747	1,376	245	393	1,154	8,215	311,602
Total Billed	1,608,071	81,039	865,183	76,003	37,042	365,001	421,844	38,704	339,863	6,302	14,655	2,936	4,206	13,188	98,707	3,972,744
Net Unbilled	(198)	(11)	1,129	105	47	1,498	831	167	479	-	-	-	-	-	-	4,047
RY 2 Total	1,607,873	81,028	866,312	76,108	37,089	366,499	422,675	38,871	340,342	6,302	14,655	2,936	4,206	13,188	98,707	3,976,791

Orange and Rockland Utilities, Inc.
Case 14-E-0493
Sales Revenues*
$ 000's

	RY 1		RY 2	
Delivery	$	268,128	$	269,014
Competitive Services		16,594		16,480
Reactive Power		216		216
Subtotal	$	284,938	$	285,710
MSC		124,232		121,148
SBC		21,101		16,654
Other **		3,731		3,088
Tax Recovery Revenue		7,884		7,749
Total Sales Revenues	$	441,885	$	434,349
Rate Relief (Unlevelized)		9,326		18,128
Total Sales Revenues with Rate Relief	$	451,211	$	452,477

*At July 2014 rates

** Includes MFC accrual, uncollectibles and other purchased power

Orange and Rockland Utilities, Inc.
Case 14-E-0493
Other Operating Revenues
($000's)

	RY1 12 months ending 10/31/2016	RY2 Adjustments	RY2 12 months ending 10/31/2017
Miscellaneous Service & Other Revenues			
Customer Reconnect Fees	$ 118	$ -	$ 118
Collection Charges	102	-	102
Late Payment Charges	3,113	9	3,122
Shared Meter Assessment	7	-	7
Acceller Inc.	14	-	14
NYSERDA	2	-	2
Bad Check Charge	68	-	68
Agency Checks Dishonored	16	-	16
POR Discount	1,573	-	1,573
Other	(2)	-	(2)
Rents			
Joint Operating Rents	5,539	-	5,539
Other Rents	3,617	75	3,692
Regulatory Accounting - Recoveries / Refunds	(8,624)	(892)	(9,516)
	$ 5,543	$ (808)	$ 4,735

Orange and Rockland Utilities, Inc.
Gas Case 14-G-0494
Sales Revenues
$ 000's

	Twelve Months Ending October 31,		
Firm Revenues	2016	2017	2018
Delivery Revenues			
- Non Competitive	110,183	109,963	110,392
- Competitive	2,800	2,810	2,495
Monthly Gas Adjustments	11,329	10,727	10,709
Gas Supply Charge	44,197	47,696	50,349
Revenue Taxes	3,473	3,500	3,551
Subtotal	171,982	174,697	177,496
Interruptible Revenues			
SC 8/13	2,483	2,983	3,483
SC 9	517	517	517
Revenue Taxes	30	35	41
Subtotal	3,030	3,535	4,041
Other Revenues			
System Benefit Charge	2,101	1,165	1,057
Revenue Taxes	35	19	19
Subtotal	2,136	1,184	1,076
Rate Increase	27,525	31,928	38,620
Grand Total	$ 204,673	$ 211,344	$ 221,233

Volumes (MCF)			
Firm Volume - Billed and Unbilled	213,429	228,242	205,671

Orange and Rockland Utilities, Inc.
Case 14-G-0494
Other Operating Revenues
($000's)

	RY1 12 months ending 10/31/2016	RY2 Adjustments	RY2 12 months ending 10/31/2017	RY3 Adjustments	RY3 12 months ending 10/31/2018
Miscellaneous Service & Other Revenues					
Late Payment Charges	$ 941	$ 31	$ 972	$ 46	$ 1,018
Customer Reconnect Fees	11	-	11	-	11
Access Fines	139	-	139	-	139
Shared Meter Assessment	(11)	-	(11)	-	(11)
R&D Ventures	9	-	9	-	9
POR Discount	999	11	1,010	13	1,023
Joint Use Rents	478	-	478	-	478
Regulatory Accounting - Recoveries / Refunds	(1,733)	(369)	(2,102)	(415)	(2,517)
	$ 833	$ (327)	$ 506	$ (356)	$ 150

Orange and Rockland Utilities, Inc.
Case 14-E-0493
True-Up Targets
$ 000's

Expense Items	Twelve Months Ending October 31, 2016	2017
Research and Development	$ 837	$ 854
Contractor Tree Trimming (shortfall true-up only) *	8,400	8,574
Major Storm Cost Reserve	3,773	3,851
Low Income Program	2,564	2,564
Pension Costs - Qualified Plan	18,053	15,743
- Non Qualified Plan	2,075	1,984
OPEB Costs	440	755
Total	20,568	18,482
Property Taxes - State, County & Town	11,554	12,069
Property Taxes - Village	1,893	2,027
Property Taxes - School	25,585	26,934
Total Property Taxes	39,032	41,030
Non-Officer Management Variable Pay	1,875	1,912
Worker's Compensation Claims (Asbestos)	299	305

* Annual tree trimming over / under expenditures may be netted, true up is cumulative.

Rate Base - Environmental and Deferred FIT	2016	2017
Environmental Remediation	4,679	3,643
Accumulated Deferred FIT		
ACRS / MACRS / ADR	(122,920)	(124,166)
Repair Allowance	(33,618)	(33,346)
Deferrred Accumulated Deferred FIT Balances	(156,538)	(157,512)

Orange and Rockland Utilities, Inc.
Case 14-G-0494
True-Up Targets
($000's)

	Twelve Months Ending October 31,		
Gas Operations	2016	2017	2018
Property Taxes - State, County & Town	6,591	6,888	7,197
Property Taxes - Village	1,167	1,250	1,339
Property Taxes - School	15,065	15,863	16,704
Total Property Taxes	22,823	24,001	25,240
Pension Costs - Qualified Plan	7,465	6,576	5,684
- Non Qualified Plan	601	558	547
OPEB Costs	182	315	558
Rate relief phase-in adjustment - levelized rate increase (b)	(11,180)	763	10,417
Total	(2,931)	8,212	17,205
Research and Development	251	251	251
Low Income Program	1,900	1,900	1,900
Non-Officer Management Variable Pay	775	791	807
Tax on Health Insurance Plans			433
Rate Base - Environmental and Deferred FIT (a)			
Environmental Remediation	2,929	2,279	1,628
Accumulated Deferred FIT - ACRS / ADR / MCRS Various	(87,156)	(89,284)	(91,775)
Accumulated Deferred FIT - Repair Allowance	(13,298)	(13,200)	(13,099)
Total Accumulated Deferred FIT	(100,454)	(102,484)	(104,874)

(a) Variations (+/-) from net deferred environmental and deferred taxes included in Rate Base, will accrue interest at the Company's pretax rate of return of 9.89% in RY1 and 9.85% in RY2 and RY3.

(b) The deferral/amortization of pension/OPEB expense to match the rate recoveries is only applicable if rate relief is levelized as set forth in Appendix 2, page 7 of 7.

Orange and Rockland Utilities, Inc.
Case 14-E-0493
Electric Advanced Metering Infrastructure (AMI) Net Plant In Service Target Balances - Included in Rate Base
Effective November 1, 2015 - October 31, 2017
$ 000's

	Rate Year 1		
MONTH ENDED	AMI Elec. Plant In Service Target	AMI Reserve For Depreciation Target	AMI Net Plant Target
October 31, 2015 @ 50%	$ -	$ -	$ -
November	$ -	$ -	$ -
December	$ -	$ -	$ -
January	$ 123	$ -	$ 123
February	$ 303	$ (1)	$ 302
March	$ 501	$ (2)	$ 499
April	$ 792	$ (4)	$ 788
May	$ 1,457	$ (7)	$ 1,449
June	$ 1,748	$ (13)	$ 1,735
July	$ 1,946	$ (21)	$ 1,925
August	$ 2,144	$ (29)	$ 2,115
September	$ 2,342	$ (38)	$ 2,304
October 31, 2016 @ 50%	$ 1,270	$ (24)	$ 1,246
Total	$ 12,625	$ (137)	$ 12,488
13 Point Average	$ 1,052	$ (11)	$ 1,041

	Rate Year 2		
MONTH ENDED	AMI Elec. Plant In Service Target	AMI Reserve For Depreciation Target	AMI Net Plant Target
October 31, 2016 @ 50%	$ 1,270	$ (24)	$ 1,246
November	$ 2,831	$ (58)	$ 2,773
December	$ 8,170	$ (70)	$ 8,101
January	$ 8,395	$ (130)	$ 8,265
February	$ 8,727	$ (191)	$ 8,536
March	$ 9,096	$ (254)	$ 8,842
April	$ 9,646	$ (318)	$ 9,328
May	$ 10,919	$ (385)	$ 10,535
June	$ 11,469	$ (456)	$ 11,012
July	$ 11,838	$ (530)	$ 11,307
August	$ 12,207	$ (606)	$ 11,601
September	$ 12,576	$ (683)	$ 11,893
October 31, 2017 @ 50%	$ 6,472	$ (381)	$ 6,091
Total	$ 113,615	$ (4,085)	$ 109,530
13 Point Average	$ 9,468	$ (340)	$ 9,127

Orange and Rockland Utilities, Inc.
Case 14-G-0494
Gas Advanced Metering Infrastructure (AMI) Net Plant In Service Target Balances - Included in Rate Base
Effective November 1, 2015 - October 31, 2018
$ 000's

	Rate Year 1		
MONTH ENDED	AMI Gas Plant In Service Target	AMI Reserve For Depreciation Target	AMI Net Plant Target
October 31, 2015 @ 50%	$ -	$ -	$ -
November	0	0	0
December	0	0	0
January	92	(0)	91
February	201	(1)	200
March	316	(1)	315
April	461	(2)	459
May	726	(4)	722
June	871	(6)	865
July	986	(8)	979
August	1,102	(10)	1,092
September	1,217	(13)	1,204
October 31, 2016 @ 50%	666	(8)	658
Total	$ 6,636.9	$ (51.2)	$ 6,585.8
13 Point Average	$ 553	$ (4)	$ 549

	Rate Year 2		
MONTH ENDED	AMI Gas Plant In Service Target	AMI Reserve For Depreciation Target	AMI Net Plant Target
October 31, 2016 @ 50%	$ 666	$ (8)	$ 658
November	1,477	(18)	1,459
December	3,558	(22)	3,537
January	3,725	(43)	3,683
February	3,927	(64)	3,863
March	4,140	(85)	4,055
April	4,411	(108)	4,304
May	4,914	(131)	4,783
June	5,185	(155)	5,030
July	5,398	(179)	5,219
August	5,611	(204)	5,407
September	5,824	(229)	5,595
October 31, 2017 @ 50%	3,019	(127)	2,892
Total	$ 51,855	$ (1,371)	$ 50,483
13 Point Average	$ 4,321	$ (114)	$ 4,207

	Rate Year 3		
MONTH ENDED	AMI Gas Plant In Service Target	AMI Reserve For Depreciation Target	AMI Net Plant Target
October 31, 2017 @ 50%	$ 3,019	$ (127)	$ 2,892
November	6,309	(281)	6,028
December	6,579	(307)	6,272
January	6,831	(335)	6,497
February	7,083	(362)	6,721
March	7,335	(391)	6,944
April	7,586	(420)	7,167
May	7,838	(449)	7,389
June	8,090	(479)	7,611
July	8,342	(510)	7,832
August	8,594	(540)	8,053
September	8,845	(572)	8,273
October 31, 2018 @ 50%	4,549	(302)	4,247
Total	$ 90,999	$ (5,075)	$ 85,924
13 Point Average	$ 7,583	$ (423)	$ 7,160

Orange and Rockland Utilities, Inc.
Case 14-E-0493
Electric Net Plant In Service Target Balances - Included in Rate Base*
Effective November 1, 2015 - October 31, 2017
$ 000's

	Rate Year 1				Rate Year 2		
MONTH ENDED	Elec. Plant In Service Target	Reserve For Depreciation Target	Net Plant Target	MONTH ENDED	Elec. Plant In Service Target	Reserve For Depreciation Target	Net Plant Target
October 31, 2015 @ 50%	$ 687,521	$ (232,761)	$ 454,760	**October 31, 2016 @ 50%**	$ 720,368	$ (242,927)	$ 477,441
November	1,364,535	(455,220)	909,315	**November**	1,444,066	(488,752)	955,315
December	1,374,933	(458,186)	916,748	**December**	1,454,221	(491,603)	962,619
January	1,377,558	(460,881)	916,676	**January**	1,455,439	(494,349)	961,090
February	1,378,622	(463,600)	915,022	**February**	1,456,072	(497,111)	958,961
March	1,380,380	(466,306)	914,074	**March**	1,457,333	(499,887)	957,446
April	1,382,821	(468,932)	913,889	**April**	1,459,931	(502,563)	957,368
May	1,393,601	(471,670)	921,931	**May**	1,463,637	(505,356)	958,281
June	1,412,605	(474,420)	938,186	**June**	1,493,830	(508,144)	985,687
July	1,423,595	(477,313)	946,282	**July**	1,501,234	(511,042)	990,192
August	1,433,045	(480,161)	952,884	**August**	1,506,150	(513,919)	992,232
September	1,437,141	(483,024)	954,117	**September**	1,509,078	(516,788)	992,291
October 31, 2016 @ 50%	720,368	(242,927)	477,441	**October 31, 2017 @ 50%**	755,909	(259,813)	496,096
Total	$ 16,766,724	$ (5,635,399)	$11,131,325	**Total**	$17,677,268	$ (6,032,252)	$ 11,645,017
13 Point Average	$ 1,397,227	$ (469,617)	$ 927,610	**13 Point Average**	$ 1,473,106	$ (502,688)	$ 970,418

* excludes AMI

Orange and Rockland Utilities, Inc.
Case 14-E-0493
Capital True-up Rate - Electric Net Plant and AMI Reconciliations
For Twelve Months Ending October 31, 2016, and October 31, 2017

Rate Year 1	
Electric Carrying Charge - Net Plant and AMI	
- Before Tax ROR*	9.89%
- Composite Depreciation Rate	3.19%
	13.09%
Rate Year 2	
Electric Carrying Charge - Net Plant and AMI	
- Before Tax ROR*	9.85%
- Composite Depreciation Rate	3.17%
	13.02%

* See Appendix 1 page 4 Capital Structure

Orange and Rockland Utilities, Inc.
Case 14-G-0494
Gas Net Plant In Service Target Balances - Included in Rate Base*
Effective November 1, 2015 - October 31, 2018
$ 000's

Rate Year 1

MONTH ENDED	Gas Plant In Service Target	Reserve For Depreciation Target	Net Plant Target
October 31, 2015 @ 50%	$ 360,918	$ (118,755)	$ 242,163
November	718,530	(234,231)	484,299
December	723,225	(235,678)	487,547
January	724,386	(237,091)	487,294
February	725,601	(238,509)	487,093
March	727,656	(239,926)	487,730
April	730,514	(241,343)	489,171
May	733,926	(242,765)	491,160
June	738,484	(244,195)	494,289
July	743,005	(245,680)	497,325
August	747,492	(247,129)	500,363
September	751,738	(248,587)	503,151
October 31, 2016 @ 50%	377,665	(125,027)	252,637
Total	$ 8,803,138	$ (2,898,916)	$ 5,904,222
13 Point Average	$ 733,595	$ (241,576)	$ 492,019

Rate Year 2

MONTH ENDED	Gas Plant In Service Target	Reserve For Depreciation Target	Net Plant Target
October 31, 2016 @ 50%	$ 377,665	$ (125,027)	$ 252,637
November	757,917	(251,551)	506,366
December	766,604	(253,054)	513,550
January	767,560	(254,574)	512,986
February	768,716	(256,094)	512,622
March	770,686	(257,615)	513,072
April	774,064	(259,139)	514,925
May	778,009	(260,670)	517,339
June	783,458	(262,209)	521,249
July	788,585	(263,804)	524,782
August	793,566	(265,369)	528,197
September	797,694	(266,945)	530,749
October 31, 2017 @ 50%	401,280	(134,265)	267,014
Total	$ 9,325,803	$ (3,110,315)	$ 6,215,487
13 Point Average	$ 777,150	$ (259,193)	$ 517,957

Rate Year 3

MONTH ENDED	Gas Plant In Service Target	Reserve For Depreciation Target	Net Plant Target
October 31, 2017 @ 50%	$ 401,280	$ (134,265)	$ 267,014
November	804,741	(270,127)	534,614
December	810,097	(271,727)	538,370
January	813,697	(273,355)	540,342
February	817,297	(274,990)	542,307
March	820,897	(276,632)	544,265
April	824,497	(278,282)	546,215
May	828,097	(279,939)	548,157
June	831,952	(281,605)	550,347
July	835,594	(283,281)	552,314
August	839,237	(284,965)	554,272
September	842,879	(286,657)	556,223
October 31, 2018 @ 50%	423,642	(144,178)	279,463
Total	$ 9,893,903	$ (3,340,002)	$ 6,553,901
13 Point Average	$ 824,492	$ (278,333)	$ 546,159

* excludes AMI

Orange and Rockland Utilities, Inc.
Case 14-G-0494
Capital True-up Rate - Gas Net Plant and AMI Reconciliations
For Twelve Months Ending October 31, 2016, October 31, 2017 and October 31, 2018

Rate Year 1	
Gas Carrying Charge - Net Plant and AMI	
- Before Tax ROR*	9.89%
- Composite Depreciation Rate	2.67%
	12.56%
Rate Year 2	
Gas Carrying Charge - Net Plant and AMI	
- Before Tax ROR*	9.85%
- Composite Depreciation Rate	2.56%
	12.41%
Rate Year 3	
Gas Carrying Charge - Net Plant and AMI	
- Before Tax ROR*	9.85%
- Composite Depreciation Rate	2.41%
	12.26%

* See Appendix 2 page 6 Capital Structure

Orange and Rockland Utilities, Inc.
Case 14-E-0493 and 14-G-0494
Calculation of Composite Depreciation Rate for Carrying Charges on Net Plant and AMI Balances
($000's)

	Electric	Gas
Rate Year 1		
Depreciation Expense 11/15-10/16:		
-Depreciation Expense	$ 35,624.8	$ 16,036.3
-Allocated portion of Common	8,293.0	3,231.9
Total	$ 43,917.8	$ 19,268.2
Plant Balance @ 10/31/15:		
-Plant Balance	$ 1,214,624.0	$ 661,053.0
-Allocated portion of Common	160,418.1	60,783.5
Total	$ 1,375,042.1	$ 721,836.5
Composite Rate	3.19%	2.67%
Rate Year 2		
Depreciation Expense 11/16-10/17:		
-Depreciation Expense	$ 37,527.2	$ 16,140.9
-Allocated portion of Common	8,275.7	3,224.3
Total	$ 45,802.9	$ 19,365.2
Plant Balance @ 10/31/16:		
-Plant Balance	$ 1,282,265.1	$ 695,784.8
-Allocated portion of Common	161,009.9	60,876.9
Total	$ 1,443,275.0	$ 756,661.7
Composite Rate	3.17%	2.56%
Rate Year 3		
Depreciation Expense 11/17-10/18:		
-Depreciation Expense		$ 16,253.0
-Allocated portion of Common		3,247.7
Total		$ 19,500.7
Plant Balance @ 10/31/17:		
-Plant Balance		$ 741,684.5
-Allocated portion of Common		66,912.0
Total		$ 808,596.5
Composite Rate		2.41%

Data based on final Net Plant Model (File 212)

Orange and Rockland Utilities, Inc.
Electric Rate Case 14-E-0493
Calculation of Interest on Electric Net Plant
Effective November 1, 2015 - October 31, 2017
($000's)

EXAMPLE 1 - Carrying Charge in October 2017 - end of RY2

As of the end of RY2, the cumulative interest is positive at $477k indicating the actual plant balances are above the target, therefore no interest is accrued to the customer as of the end of the multi-year plan.

	Net Plant						
	Actual (sample)	**PSC Target**	**Variation**	Interest Computed **13.09%**	Interest Computed Cumulative	**Current Month Interest recorded**	**Cumulative Interest Accrued to Customer**
Oct-15	453,000	454,760	(1,760)	(19)			
Nov-15	907,000	909,315	(2,315)	(25)	(44)	(44)	(44)
Dec-15	920,000	916,748	3,252	35	(9)	35	(9)
Jan-16	921,000	916,676	4,324	47	38	9	-
Feb-16	922,000	915,022	6,978	76	114	-	-
Mar-16	922,000	914,074	7,926	86	200	-	-
Apr-16	922,000	913,889	8,111	88	288	-	-
May-16	923,000	921,931	1,069	12	300	-	-
Jun-16	923,000	938,186	(15,186)	(166)	134	-	-
Jul-16	924,000	946,282	(22,282)	(243)	(109)	(109)	(109)
Aug-16	925,000	952,884	(27,884)	(304)	(413)	(304)	(413)
Sep-16	926,000	954,117	(28,117)	(307)	(720)	(307)	(720)
Oct-16	465,000	477,441	(12,441)	(136)	(856)	(136)	(856)
Average	921,083	927,610	(6,527)	(856)		(856)	

	Net Plant						
	Actual (sample)	**PSC/Rates**	**Variation**	**13.02%**			
Oct-16	465,000	477,441	$ (12,441)	(135)			
Nov-16	963,000	955,315	$ 7,685	83	(908)	(52)	(908)
Dec-16	963,000	962,619	$ 381	4	(904)	4	(904)
Jan-17	963,000	961,090	$ 1,910	21	(883)	21	(883)
Feb-17	963,000	958,961	$ 4,039	44	(839)	44	(839)
Mar-17	963,000	957,446	$ 5,554	60	(779)	60	(779)
Apr-17	963,000	957,368	$ 5,632	61	(718)	61	(718)
May-17	970,000	958,281	$ 11,719	127	(591)	127	(591)
Jun-17	1,000,000	985,687	$ 14,313	155	(436)	155	(436)
Jul-17	1,000,000	990,192	$ 9,808	106	(330)	106	(330)
Aug-17	1,020,000	992,232	$ 27,768	301	(29)	301	(29)
Sep-17	1,020,000	992,291	$ 27,709	301	272	29	-
Oct-17	515,000	496,096	$ 18,904	205	477	-	-
Average	980,667	970,418	10,248	1,333		856	

Orange and Rockland Utilities, Inc.
Gas Rate Case 14-G-0494
Calculation of Interest on Gas Net Plant
Effective November 1, 2015 - October 31, 2018
($000's)

EXAMPLE 2 - Carrying Charge in October 2018 - end of RY3

As of the end of RY3, cumulative interest is negative for $ 328k, indicating the actual plant balances are below the target, therefore the cumulative interest of $328k is accrued to the customer as of the end of the multi-year rate plan.

	Net Plant						
	Actual (sample)	**PSC Target**	**Variation**	Interest Computed **12.56%**	Interest Computed Cumulative	**Current Month Interest recorded**	**Cumulative Interest Accrued to Customer**
Oct-15	243,000	242,163	837	9			
Nov-15	486,000	484,299	1,701	18	27	-	-
Dec-15	486,000	487,547	(1,547)	(16)	11	-	-
Jan-16	487,000	487,294	(294)	(3)	8	-	-
Feb-16	487,000	487,093	(93)	(1)	7	-	-
Mar-16	487,000	487,730	(730)	(8)	(1)	(1)	(1)
Apr-16	488,000	489,171	(1,171)	(12)	(13)	(12)	(13)
May-16	489,000	491,160	(2,160)	(23)	(36)	(23)	(36)
Jun-16	496,000	494,289	1,711	18	(18)	18	(18)
Jul-16	498,000	497,325	675	7	(11)	7	(11)
Aug-16	505,000	500,363	4,637	49	38	11	-
Sep-16	506,000	503,151	2,849	30	68	-	-
Oct-16	255,000	252,637	2,363	25	93	-	-
Average	492,750	492,019	732	93		-	

	Net Plant						
	Actual (sample)	**PSC/Rates**	**Variation**	**12.41%**			
Oct-16	255,000	252,637	$ 2,363	24			
Nov-16	510,000	506,385	$ 3,615	37	154	-	-
Dec-16	510,000	513,588	$ (3,588)	(37)	117	-	-
Jan-17	510,000	513,044	$ (3,044)	(31)	86	-	-
Feb-17	510,000	512,699	$ (2,699)	(28)	58	-	-
Mar-17	510,000	513,168	$ (3,168)	(33)	25	-	-
Apr-17	510,000	515,041	$ (5,041)	(52)	(27)	(27)	(27)
May-17	520,000	517,475	$ 2,525	26	(1)	26	(1)
Jun-17	522,000	521,404	$ 596	6	5	1	-
Jul-17	525,000	524,957	$ 44	-	5	-	-
Aug-17	529,000	528,391	$ 609	6	11	-	-
Sep-17	533,000	530,963	$ 2,037	21	32	-	-
Oct-17	270,000	267,131	$ 2,869	30	62	-	-
Average	517,833	518,074	(240)	(31)		-	

	Net Plant						
	Actual (sample)	**PSC/Rates**	**Variation**	**12.26%**			
Oct-17	270,000	267,131	$ 2,869	29			
Nov-17	540,000	534,867	$ 5,133	52	143	-	-
Dec-17	540,000	538,643	$ 1,357	14	157	-	-
Jan-18	540,000	540,634	$ (634)	(6)	151	-	-
Feb-18	540,000	542,620	$ (2,620)	(27)	124	-	-
Mar-18	540,000	544,597	$ (4,597)	(47)	77	-	-
Apr-18	540,000	546,567	$ (6,567)	(67)	10	-	-
May-18	540,000	548,529	$ (8,529)	(87)	(77)	(77)	(77)
Jun-18	545,000	550,738	$ (5,738)	(59)	(136)	(59)	(136)
Jul-18	550,000	552,725	$ (2,725)	(28)	(164)	(28)	(164)
Aug-18	550,000	554,703	$ (4,703)	(48)	(212)	(48)	(212)
Sep-18	550,000	556,673	$ (6,673)	(68)	(280)	(68)	(280)
Oct-18	275,000	279,698	$ (4,698)	(48)	(328)	(48)	(328)
Average	543,333	546,510	(3,177)	(390)		(328)	

ORANGE AND ROCKLAND UTILITIES, INC.
Case No. 14-G-0494
Base Rate Imputations - RY1 (12 ME October 31, 2016)
$000s

Monthly Revenue Imputations	Interruptible Benefits (1),(2)	Power Generation (3)	Total
November	$252.6	$54.2	$306.8
December	306.0	54.2	360.2
January	283.0	54.2	337.2
February	312.2	54.2	366.4
March	322.4	54.2	376.6
April	246.6	54.2	300.8
May	192.0	54.2	246.2
June	204.0	54.2	258.2
July	217.2	54.2	271.4
August	213.6	54.2	267.8
September	204.8	54.2	259.0
October	245.6	53.8	299.4
Total	$3,000.0	$650.0	$3,650.0

(1) Variances between actual revenue margins and the Interruptible Benefits Imputation will be shared on an 80% customer / 20% shareholder basis.

(2) Includes revenues from SC Nos. 5, 8, and 9

(3) 100% of any variances between actual revenue margins and the Power Generation Imputation will be passed back/recovered from customers.

ORANGE AND ROCKLAND UTILITIES, INC.
Case No. 14-G-0494
Base Rate Imputations - RY2 (12 ME October 31, 2017)
$000s

Monthly Revenue Imputations	Interruptible Benefits (1),(2)	Power Generation (3)	Total
November	$294.7	$54.2	$348.9
December	357.0	54.2	411.2
January	330.2	54.2	384.4
February	364.2	54.2	418.4
March	376.2	54.2	430.4
April	287.7	54.2	341.9
May	224.0	54.2	278.2
June	238.0	54.2	292.2
July	253.5	54.2	307.7
August	249.2	54.2	303.4
September	238.9	54.2	293.1
October	286.4	53.8	340.2
Total	$3,500.0	$650.0	$4,150.0

(1) Variances between actual revenue margins and the Interruptible Benefits Imputation will be shared on an 80% customer / 20% shareholder basis.

(2) Includes revenues from SC Nos. 5, 8, and 9

(3) 100% of any variances between actual revenue margins and the Power Generation Imputation will be passed back/recovered from customers.

ORANGE AND ROCKLAND UTILITIES, INC.
Case No. 14-G-0494
Base Rate Imputations - RY3 (12 ME October 31, 2018) (1)
$000s

Monthly Revenue Imputations	Interruptible Benefits (2),(3)	Power Generation (4)	Total
November	$336.8	$54.2	$391.0
December	408.0	54.2	462.2
January	377.4	54.2	431.6
February	416.2	54.2	470.4
March	429.9	54.2	484.1
April	328.9	54.2	383.1
May	256.0	54.2	310.2
June	272.0	54.2	326.2
July	289.7	54.2	343.9
August	284.7	54.2	338.9
September	273.1	54.2	327.3
October	327.3	53.8	381.1
Total	$4,000.0	$650.0	$4,650.0

(1) Should the Company not file for new base rates effective November 1, 2018, these imputations will remain in effect until changed by the Commission.

(2) Variances between actual revenue margins and the Interruptible Benefits Imputation will be shared on an 80% customer / 20% shareholder basis.

(3) Includes revenues from SC Nos. 5, 8, and 9

(4) 100% of any variances between actual revenue margins and the Power Generation Imputation will be passed back/recovered from customers.

ORANGE AND ROCKLAND UTILITIES, INC.
Case No. 14-G-0494
Interruptible Benefits Illustrative Scenarios by Rate Year
$000s

RATE YEAR 1		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
Interruptible Benefits Imputation		$3,000.0	$3,000.0	$3,000.0	$3,000.0	$3,000.0	$3,000.0
Actual Interruptible Benefits		2,700.0	3,000.0	3,500.0	4,000.0	4,500.0	5,000.0
Excess/(Shortfall)		(300.0)	0.0	500.0	1,000.0	1,500.0	2,000.0
Customer Share	80%	(240.0)	0.0	400.0	800.0	1,200.0	1,600.0
Company Share	20%	(60.0)	0.0	100.0	200.0	300.0	400.0
		(300.0)	0.0	500.0	1,000.0	1,500.0	2,000.0
Company Revenues		$2,940.0	$3,000.0	$3,100.0	$3,200.0	$3,300.0	$3,400.0

RATE YEAR 2		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
Interruptible Benefits Imputation		$3,500.0	$3,500.0	$3,500.0	$3,500.0	$3,500.0	$3,500.0
Actual Interruptible Benefits		2,700.0	3,000.0	3,500.0	4,000.0	4,500.0	5,000.0
Excess/(Shortfall)		(800.0)	(500.0)	0.0	500.0	1,000.0	1,500.0
Customer Share	80%	(640.0)	(400.0)	0.0	400.0	800.0	1,200.0
Company Share	20%	(160.0)	(100.0)	0.0	100.0	200.0	300.0
		(800.0)	(500.0)	0.0	500.0	1,000.0	1,500.0
Company Revenues		$3,340.0	$3,400.0	$3,500.0	$3,600.0	$3,700.0	$3,800.0

RATE YEAR 3		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
Interruptible Benefits Imputation		$4,000.0	$4,000.0	$4,000.0	$4,000.0	$4,000.0	$4,000.0
Actual Interruptible Benefits		2,700.0	3,000.0	3,500.0	4,000.0	4,500.0	5,000.0
Excess/(Shortfall)		(1,300.0)	(1,000.0)	(500.0)	0.0	500.0	1,000.0
Customer Share	80%	(1,040.0)	(800.0)	(400.0)	0.0	400.0	800.0
Company Share	20%	(260.0)	(200.0)	(100.0)	0.0	100.0	200.0
		(1,300.0)	(1,000.0)	(500.0)	0.0	500.0	1,000.0
Company Revenues		$3,740.0	$3,800.0	$3,900.0	$4,000.0	$4,100.0	$4,200.0

ORANGE AND ROCKLAND UTILTIES, INC.
CASES 14-E-0493 AND 14-G-0494
BALANCING SERVICES AND CHARGES

Balancing Services and Charges for Customers Served Under SC Nos. 8, 9, 13, and 14

The balancing provisions and charges contained in SC Nos. 8, 9, 13, and 14 will be modified as follows:

(1) Daily Over-Deliveries – SC Nos. 8 and 13

In Rate Year 1, if on any day the customer's over-delivery is greater than 7.5% of a customer's actual Loss Adjusted Usage, the over-delivered volumes in excess of the 7.5% will be cashed out as follows:

For Over-deliveries	Rate
>7.5% up to and including 10%	90% of Index Price
>10% up to and including 20%	80% of Index Price
>20% - Winter	60% of Index Price
>20 - Summer	70% of Index Price

Beginning in Rate Year 2, the first band will change from "over-deliveries greater than 7.5% up to and including 10%" to "over-deliveries greater than 5% up to and including 10%".

(2) Daily Over-Deliveries – SC Nos. 9 and 14

If on any day the customer's over-delivery is greater than 2% of a customer's actual usage, the over-delivered volumes in excess of the 2% will be cashed out as follows:

For Over-deliveries	Rate
>2% up to and including 5%	90% of Index Price
>5% up to and including 10%	80% of Index Price
>10%	70% of Index Price

(3) Daily Under-Deliveries – SC Nos. 8 and 13

In Rate Year 1, if on any day the customer's under-delivery is greater than 7.5% of a customer's actual Loss Adjusted Usage, the under-delivered volumes in excess of the 7.5% will be cashed out as follows:

For Under-deliveries	Rate
>7.5% up to and including 10%	110% of Index Price
>10% up to and including 20%	120% of Index Price
>20% - Winter	140% of Index Price
>20 - Summer	130% of Index Price

Beginning in Rate Year 2, the first band will change from "under-deliveries greater than 7.5% up to and including 10%" to "under-deliveries greater than 5% up to and including 10%".

(4) Daily Under-Deliveries – SC Nos. 9 and 14

If on any day the customer's under-delivery is greater than 2% of a customer's actual usage, the under-delivered volumes in excess of the 2% will be cashed out as follows:

For Under-deliveries	Rate
>2% up to and including 5%	110% of Index Price
>5% up to and including 10%	120% of Index Price
>10%	130% of Index Price

(5) Index Price for Daily Over- or Under-Deliveries for SC Nos. 8, 9, 13, and 14

The Index Price for daily over- or under-deliveries shall be equal to the simple average of the daily Algonquin, city-gates and Millennium-East midpoint price index on the day on which the over- or under-delivery occurs.

(6) Monthly Over- or Under-Deliveries

If there is an over-delivery at the end of the month, the over-delivered volumes will be purchased at a rate equal to the lower of the monthly average of the daily Algonquin, city-gates and Millennium-East midpoint prices or the average of the Algonquin, city-gates and Millennium-East First-of-Month Low Range Price as published in Platt's Gas Daily.

If there is an under-delivery at the end of the month, the over-delivered volumes will be sold at a rate equal to the higher of the monthly average of the daily Algonquin, city-gates and Millennium-East midpoint prices or the average of the Algonquin, city-gates and Millennium-East First-of-Month High Range Price as published in Platt's Gas Daily.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0493

Calculation of Lost and Unaccounted for Gas ("LAUF") and Dead Band Target
Based on 5 Year Period: TME Aug 10 to Aug 14*

		Aug-14	Aug-13	Aug-12	Aug-11	Aug-10
	Citygate Receipts					
1	**Total Pipeline Receipts**	33,604,385	26,556,514	22,296,727	26,773,568	25,090,357
	Deliveries to Customers					
2	Retail Sales and Transportation Deliveries	26,843,866	24,491,245	21,474,466	25,212,707	23,963,946
3	Gas Used for Company Purposes	40,284	31,540	28,620	42,493	47,428
4	Deliveries to Generation	6,247,085	1,489,326	423,947	1,080,536	672,598
5	**Total Deliveries (Line 2 - Line 4)**	33,131,235	26,012,111	21,927,033	26,335,736	24,683,972
6	**Losses (Line 1 - Line 5)**	473,150	544,403	369,694	437,832	406,385
7	**Contribution to system line loss from Generation at 1.0% (Line 4 * 0.01)**	62,471	14,893	4,239	10,805	6,726
8	**Adjusted Line Loss (Line 6 - Line 7)**	410,679	529,509	365,455	427,027	399,659
9	**Citygate Receipts adjusted for Generation (Line 1 - Line 7)**	27,294,829	25,052,295	21,868,541	25,682,227	24,411,033
10	***Annual Line Loss Factor (Line 8 / Line 9)***	1.505%	2.114%	1.671%	1.663%	1.637%

DETERMINE LAUF% TARGET & DEAD BAND
Basis: Target & Dead Band are calculated from 5 years of historical data
Dead Band is equal to +/- 2 standard deviations
No Incentive to Be Earned for LAUF % Target < 0

	5-Year Statistics (Aug 10 - Aug 14)	
11	**Mean LAUF% (Average of Line 10)**	1.718%
12	**Std Deviation (Std Deviation of Line 10)**	0.231%
13	**2 Std Deviation (Line 12 * 2)**	0.462%
	Target & Dead Band	
14	**LAUF% Target**	1.718%
15	**Upper Band (Mean + 2 SD)**	2.180%
16	**Lower Band (Mean - 2 SD)**	1.255%

* The Company will recalculate the dead band based on the five year period: TME Aug 11 to Aug 15.
The Fixed FOA will be reset every November 1 based on the average of the actual FOAs for the previous five twelve-month periods ended August 31

ORANGE AND ROCKLAND UTILITIES, INC.

Case No. 14-G-0494
GAS LOST AND UNACCOUNTED FOR

ILLUSTRATIVE CALCULATION OF LINE LOSS INCENTIVE / PENALTY

1	Total Distribution Sendout		35,848,500	Mcf
2	Customer Metered Volumes		35,670,000	Mcf
3	Actual Line Loss -- [(Line 1 - Line 2) / Line 1]		0.500%	
4	Actual Factor of Adjustment -- [1 / (1 - 0.0050)]		1.0050	
5	If Line 4 is $\geq$ Lower Dead band and $\leq$ Upper Dead band, equal to line 4 If Line 4 is < Lower Dead band, equal to line 12 If Line 4 is > Upper Dead band, equal to line 11		1.0127	
	Calculation of Benefit / (Shortfall):			
6	Total Cost of Gas 12 months Ended August XX		$110,000,000	
7	(Line 5 Above) -------------------------------- Actual Factor of Adjustment (Line 4 above)	1.0127 ---------- 1.0050	1.007662	
8	Net Adjusted Commodity Cost of Gas (Line 6 x Line 7)		$110,842,820	
9	Company Benefit / (Penalty) due to Line Losses (Line 8 - Line 6)		$842,820	

** The Fixed FOA for purposes of calculating incentives / penalties based on 1.718% losses equals:

10 $$\frac{100.0}{(100.0 - 1.718)} = \frac{100.0}{98.282} = 1.0175$$

** The maximum "FOA Before Adjustment" based on 2.18% losses equals:

11 $$\frac{100.0}{(100.0 - 2.18)} = \frac{100.0}{97.82} = 1.0223$$

** The minimum "FOA Before Adjustment" based on 1.255% losses equals:

12 $$\frac{100.0}{(100.0 - 1.255)} = \frac{100.0}{98.745} = 1.0127$$

Note: The Company will recalculate the dead band based on the five year period: TME Aug 11 to Aug 15.
The Fixed FOA will be reset every November 1 based on the average of the actual FOAs for the previous five twelve-month periods ended August 31

ORANGE AND ROCKLAND UTILITIES, INC.

Case No. 14-G-0494
GAS LOST AND UNACCOUNTED FOR

ILLUSTRATIVE CALCULATION OF
SYSTEM PERFORMANCE ADJUSTMENT ("SPA") MECHANISM

1	Total Distribution Sendout		35,848,500	Mcf
2	Customer Metered Volumes		35,670,000	Mcf
3	Actual Line Loss -- [(Line 1 - Line 2) / Line 1]		0.500%	
4	Actual Factor of Adjustment -- [1 / (1 - 0.0050)]		1.0050	
5	If Line 4 is ≥ Lower Dead band and ≤ Upper Dead band, equal to line 4 If Line 4 is < Lower Dead band, equal to line 14 If Line 4 is > Upper Dead band, equal to line 13		1.0127	
	Calculation of Benefit / (Shortfall):			
6	Total Cost of Gas 12 months Ended August XX		$110,000,000	
7	(Line 5 above) -------------------------------- Fixed Factor of Adjustment (Line 13 Below)	1.0127 ---------- 1.0175	0.995283	
8	Net Adjusted Commodity Cost of Gas (Line 6 x Line 7)		$109,481,130	
9	SPA Dollars to (Credit) / Charge Customers through MGA (Line 8 - Line 6)		($518,870)	
10	Forecasted Firm Sales (SC Nos. 1, 2, and 6) (Ccf) for 12 ME Dec 2017		196,770,000	Ccf
11	SPA Mechanism Rate ($/Ccf) in Monthly Gas Adjustment		($0.00264)	

** The Fixed FOA for purposes of calculating incentives / penalties based on 1.718% losses equals:

12 $$\frac{100.0}{(100.0 - 1.718)} = \frac{100.0}{98.282} = 1.0175$$

** The maximum "FOA Before Adjustment" based on 2.18% losses equals:

13 $$\frac{100.0}{(100.0 - 2.18)} = \frac{100.0}{97.82} = 1.0223$$

** The minimum "FOA Before Adjustment" based on 1.255% losses equals:

14 $$\frac{100.0}{(100.0 - 1.255)} = \frac{100.0}{98.745} = 1.0127$$

Note: The Company will recalculate the dead band based on the five year period: TME Aug 11 to Aug 15.
The Fixed FOA will be reset every November 1 based on the average of the actual FOAs for the previous five twelve-month periods ended August 31

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0493

Examples of Incentives/Penalties and SPA Mechanism At Various Actual Factor of Adjustments

		Actual FOA Below Dead band	Actual FOA Between Minimum FOA and Fixed FOA	Actual FOA Between Fixed FOA and Maximum FOA	Actual FOA Above Dead band
1	Actual Line Loss Factor	0.762%	1.489%	2.027%	2.560%
2	Actual Factor of Adjustment	1.0077	1.0151	1.0207	1.0263
3	Lower Dead Band	1.0127	1.0127	1.0127	1.0127
4	Upper Dead Band	1.0223	1.0223	1.0223	1.0223
5	Adjustment to Cost of Gas Formula for Line Loss Incentive Penalty Applied to GSC	= 1.0127 / 1.0077	= 1.0151 / 1.0151	= 1.0207 / 1.0207	= 1.0223 / 1.0263
6	Adjustment to Cost of Gas for Line Loss Incentive Penalty Applied to GSC	1.004962	1.000000	1.000000	0.996103
7	Actual Cost of Gas	$110,000,000	$110,000,000	$110,000,000	$110,000,000
8	Cost of Gas Adjustment Factor for Line Loss Incentive / Penalty Applied to GSC	1.00496	1.00000	1.00000	0.99610
9	Net Adjusted Cost of Gas for Line Loss Incentive / Penalty Applied to GSC	$110,545,820	$110,000,000	$110,000,000	$109,571,330
10	Company Benefit / (Penalty) Due to Line Losses Applied to GSC	$545,820	$0	$0	($428,670)
11	Adjustment to Cost of Gas Formula for Line Loss Incentive Penalty Applied to MGA	= 1.0127 / 1.0175	= 1.0151 / 1.0175	= 1.0207 / 1.0175	= 1.0023 / 1.0175
12	Adjustment to Cost of Gas for Line Loss Incentive Penalty Applied to MGA	0.995283	0.997641	1.003145	1.004717
13	Net Adjusted Cost of Gas for Line Loss Incentive / Penalty Applied to MGA	$109,481,130	$109,740,510	$110,345,950	$110,518,870
14	SPA Dollars to (Credit) / Charge Customers through MGA	($518,870)	($259,490)	$345,950	$518,870

Note: The Company will recalculate the dead band based on the five year period: TME Aug 11 to Aug 15.
The Fixed FOA will be reset every November 1 based on the average of the actual FOAs for the previous five twelve-month periods ended August 31

ORANGE & ROCKLAND UTILITIES
DEPRECIATION RATES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	A S L	NET SALVAGE %	ANNUAL RATE %
ELECTRIC PLANT					
TRANSMISSION PLANT					
350000 01	LAND-EASEMENTS	h3.0	65	-	1.54
350100 01	LAND AND LAND RIGHTS	-	-	-	-
352000 01	STRUCTURES AND IMPROVEMENTS	h2.5	60	(5)	1.75
353000 01	STATION EQUIPMENT	h1.75	45	(15)	2.56
354000 01	TOWERS AND FIXTURES	h2.0	75	(30)	1.73
355000 01	POLES AND FIXTURES-WOOD	h3.0	53	(40)	2.64
355100 01	POLES AND FIXTURES-STEEL	h3.0	53	(40)	2.64
356000 01	OVERHEAD CONDUCTORS & DEVICES	h1.5	65	(10)	1.69
356100 01	OVERHEAD COND & DEVICES-CLEARING	h1.5	65	(10)	1.69
357000 01	UNDERGROUND CONDUIT	h2.5	35	-	2.86
358000 01	UNDERGROUND COND AND DEVICES	h3.5	33	-	3.03
359000 01	ROADS AND TRAILS	h3.5	70	-	1.43
DISTRIBUTION PLANT					
360000 01	LAND-EASEMENTS	h3.0	65	-	1.54
360100 01	LAND AND LAND RIGHTS-FEE	-	-	-	-
361000 01	STRUCTURES AND IMPROVEMENTS	h2.75	55	(15)	2.09
362000 01	STATION EQUIPMENT	h1.75	45	(5)	2.33
364000 01	POLES,TOWERS, AND FIXTURES	h1.5	60	(90)	3.17
365000 01	OVERHEAD CONDUCTOR AND DEVICES	h1.5	75	(80)	2.40
365100 01	O/H COND AND DEVICES-CAPACITORS	h0.75	35	(30)	3.71
366000 01	UNDERGROUND CONDUIT	h3.0	75	(40)	1.87
367000 01	UNDERGROUND CONDUCTOR & DEVICES	h3.0	65	(40)	2.15
367100 01	U.G. COND. & DEVICES - CABLE CURE	(A)	-	-	-
368100 01	LINE TRANSFORMERS-OVERHEAD	h0.75	50	(30)	2.60
368200 01	LINE TRANSFORMERS-O/H INSTALLS	h0.75	50	(30)	2.60
368300 01	LINE TRANSFORMERS-UNDERGROUND	h0.75	50	(30)	2.60
368400 01	LINE TRANSFORMERS-U/G INSTALLS	h0.75	50	(30)	2.60
369100 01	SERVICES-OVERHEAD	h1.0	70	(95)	2.79
369200 01	SERVICES-UNDERGROUND	h2.0	65	(95)	3.00
370100 01	METERS - ELECTRO-MECHANICAL	h1.0	25	-	4.00
370110 01	METERS - SOLID-STATE	h1.0	20	-	5.00
370200 01	METER INSTALLATIONS - ELECTRO-MECHANICAL	h1.0	25	-	4.00
370210 01	METER INSTALLATIONS - SOLID-STATE	h1.0	20	-	5.00
371000 01	INSTALLATION ON CUSTOMER PREMISES	h1.0	50	-	2.00
371100 01	PALISADES MALL METERING	(A)	-	-	-
373100 01	STREET LIGHTS-OVERHEAD	h1.0	40	(50)	3.75
373200 01	STREET LIGHTS-UNDERGROUND	h1.0	40	(50)	3.75
INTANGIBLE PLANT					
303100 01	WMS SOFTWARE	(B)	5	-	20.00
303110 01	DISTRIBUTION MANAGEMENT SYSTEM	(A)	-	-	-
303120 01	DISTRIBUTION ENGINEERING SYSTEM (DEW)	(A)	-	-	-
303130 01	STRAY VOLTAGE SYSTEM	(A)	-	-	-
303140 01	OUTAGE MANAGEMENT SYSTEM (OMS)	(A)	-	-	-
303150 01	WEB WMS PHASE 1	(A)	-	-	-
303170 01	2009 ELECTRIC SOFTWARE ADDITIONS	(A)	-	-	-
303190 01	2011 ELECTRIC SOFTWARE	(B)	5	-	20.00

ORANGE & ROCKLAND UTILITIES
DEPRECIATION RATES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	A S L	NET SALVAGE %	ANNUAL RATE %
ELECTRIC PLANT					
GENERAL PLANT					
389100 01	LAND AND RIGHTS - FEE	-	-	-	-
390000 01	STRUCTURES AND IMPROVEMENTS	h1.75	45	(35)	3.00
391100 01	OFFICE FURN/EQUIP-FURNITURE	(B)	20	-	5.00
391200 01	OFFICE FURN/EQUIP-OFFICE MACHINES	(B)	15	-	6.67
391700 01	OFFICE FURN/EQUIP-P/C EQUIPMENT	(B)	8	-	12.50
391710 01	OFFICE FURN/EQUIP-NON P/C EQUIPMENT	-	-	-	-
391800 01	OFFICE FURN/EQUIP-E.C.C.	(B)	13	-	7.69
392100 01	TRANSP EQUIP-PASSENGER CARS	h2.5	8	10	11.25
392200 01	TRANSP EQUIP-LIGHT TRUCKS	h2.5	8	10	11.25
392300 01	TRANSP EQUIP-HEAVY TRUCKS	h4.0	12	5	7.92
392400 01	TRANSP EQUIP-TRAILERS/TRAILER MTD EQ.	h4.0	12	5	7.92
393000 01	STORES EQUIPMENT	(B)	20	-	5.00
394000 01	TOOLS, SHOP AND WORK EQUIPMENT	(B)	20	-	5.00
395000 01	LABORATORY EQUIPMENT	(B)	20	-	5.00
396000 01	POWER OPERATED EQUIPMENT	h3.5	18	15	4.72
396100 01	POWER OPERATED EQ - NON FLEET	h4.0	18	15	4.72
397000 01	COMMUNICATION EQUIPMENT	(B)	15	-	6.67
397100 01	COMMUNICATION EQUIPT-TELE SYSTEM COMPUTER	(B)	15	-	6.67
397200 01	COMMUNICATION EQUIPT-TELE SYSTEM EQUIPMENT	-	-	-	-
398000 01	MISCELLANEOUS EQUIPMENT	(B)	20	-	5.00
350009 01	LAND AND LAND RIGHTS-EASEMENTS	h3.0	60	-	1.67
355179 01	POLES AND FIXTURES - STEEL - FUTURE USE - DEFERRED	-	-	-	-
PLANT HELD FOR FUTURE USE - DISTRIBUTION					
360009 01	LAND AND LAND RIGHTS-EASEMENTS	h3.0	50	-	2.00
360109 01	LAND AND LAND RIGHTS-EASEMENTS	-	-	-	-

ORANGE & ROCKLAND UTILITIES
DEPRECIATION RATES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	A S L	NET SALVAGE %	ANNUAL RATE %
COMMON PLANT					
INTANGIBLE PLANT					
301000 03	ORGANIZING	-	-	-	-
303180 03	2011 COMMON SOFTWARE ADDITION	(B)	5	-	20.00
303200 03	MAPPING SOFTWARE	(A)	-	-	-
303310 03	EZ VMS SYSTEM	(A)	-	-	-
303320 03	PEOPLESOFT HR/PR SYSTEM	(B)	15	-	6.67
303400 03	CIMS SYSTEM SOFTWARE	(B)	15	-	6.67
303410 03	CUSTOMER BILLING SYSTEM	(A)	15	-	6.67
303500 03	PLUS SYSTEM SOFTWARE	(A)	-	-	-
303510 03	POWERPLAN SOFTWARE	(B)	15	-	6.67
303600 03	WALKER SYSTEM SOFTWARE	(A)	-	-	-
303700 03	BUDGET SYSTEM SOFTWARE	(A)	-	-	-
303800 03	RETAIL ACCESS SOFTWARE	(A)	-	-	-
303810 03	RETAIL ACCESS SOFTWARE PHASE 4	(A)	-	-	-
303840 03	FIELD ORDER ROUTE DESIGN SYSTEM	(A)	-	-	-
303870 03	DATAPIPE SOFTWARE	(A)	-	-	-
303900 03	NEW BUS PROJ MGMT	(B)	5	-	-
303910 03	NEW CONSTRUCTION SERVICES (NUCON)	(A)	-	-	-
GENERAL PLANT EQUIPMENT					
389000 03	LAND-EASEMENTS	h3.0	50	-	2.00
389100 03	LAND AND LAND RIGHTS -FEES	-	-	-	-
389500 03	LAND AND LAND RIGHTS - MOMBASHA	(B)	50	-	2.00
390000 03	STRUCTURES AND IMPROVEMENTS	h1.75	45	(20)	2.67
390100 03	LEASEHOLD IMPROVEMENTS-BLUE HILL	(C)	-	-	-
391100 03	OFFICE FURN/EQUIP-FURNITURE	(B)	20	-	5.00
391200 03	OFFICE FURN/EQUIP-OFFICE MACHINES	(B)	15	-	6.67
391300 03	OFFICE FURN/EQUIP-CASH EQUIPMENT	(B)	8	-	12.50
391700 03	OFFICE FURN/EQUIP-P/C EQUIPMENT	(B)	8	-	12.50
391710 03	OFFICE FURN/EQUIP-NON P/C EQUIPMENT	(B)	8	-	12.50
392100 03	TRANSP EQUIP-PASSENGER CARS	h2.5	8	10	11.25
392200 03	TRANSP EQUIP-LIGHT TRUCKS	h2.5	8	10	11.25
392300 03	TRANSP EQUIP-HEAVY TRUCKS	h4.0	12	5	7.92
392400 03	TRANSP EQUIP-TRAILERS/TRAILER MTD EQ.	h4.0	12	5	7.92
393000 03	STORES EQUIPMENT	(B)	20	-	5.00
394000 03	TOOLS, SHOP AND WORK EQUIPMENT	(B)	20	-	5.00
394200 03	GARAGE EQUIPMENT	(B)	20	-	5.00
395000 03	LABORATORY EQUIPMENT	(B)	20	-	5.00
396000 03	POWER OPERATED EQUIPMENT	h3.5	18	15	4.72
396100 03	POWER OPERATED EQ. - NON FLEET	h3.5	18	15	4.72
397000 03	COMMUNICATION EQUIPMENT	(B)	15	-	6.67
397100 03	COMMUNICATION EQ.-TELE SYS COMPUTER	(B)	15	-	6.67
397200 03	COMMUNICATION EQ.-TELE SYS EQPT	(B)	15	-	6.67
398000 03	MISCELLANEOUS EQUIPMENT	(B)	20	-	5.00

ORANGE & ROCKLAND UTILITIES
DEPRECIATION RATES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	A S L	NET SALVAGE %	ANNUAL RATE %	
GAS PLANT						
TRANSMISSION PLANT						
367002	MAINS	h3.0	70	-	1.43	(*)
367322	MAINS - STEEL - STONY POINT	(A)	-	-	-	
367502	MAINS - LEDERLE	(A)	-	-	-	
DISTRIBUTION PLANT						
374000	LAND - EASEMENTS	h3.0	60	-	1.67	
374100	LAND - FEE	-	-	-	-	
374200	LAND - FEE - CLEVEPAK	(A)	-	-	-	
375000	STRUCTURES & IMPROVEMENTS	h2.5	70	(20)	1.71	
375100	ST. & IMPROV. - STONY POINT MAIN	(A)	-	-	-	
376000	MAINS	h3.0	70	(30)	1.86	
376200	MAINS - CLEVEPAK	(A)	-	-	-	
376330	MAINS - TRANSCO	(A)	-	-	-	
377000	COMPRESSOR STATION EQUIPMENT	h2.0	35	-	2.86	
378000	MEASURING AND REGULATING EQ.	h1.5	30	(10)	3.67	
378100	MEAS. & REG. EQ. - STONY POINT	(A)	-	-	-	
378330	MEAS. & REG. EQ. - TRANSCO	(A)	-	-	-	
378340	MEAS. & REG. EQ. - TRANSCO ORDER 63	(A)	-	-	-	
380000	SERVICES	h3.0	70	(70)	2.43	
381000	METERS	h3.0	38	-	2.63	
381100	METERS - SPECIAL TYPES	h3.0	38	-	2.63	
382000	METER INSTALLATIONS	h3.75	50	(20)	2.40	
382100	METER INST. - SPECIAL TYPES	h3.75	50	(20)	2.40	
382400	METER BAR INSTALLATIONS	h3.75	50	(15)	2.30	
383000	HOUSE REGULATORS	h3.0	38	-	2.63	
384000	HOUSE REGULATOR INSTALLATIONS	h3.75	55	(15)	2.09	
385000	INDUSTRIAL MEAS. & REG. EQ.	h5.0	35	(5)	3.00	
385500	IND. MEAS. & REG. EQ. - LEDERLE	(A)	-	-	-	
386000	OTHER PROP. ON CUSTS.' PREM.	h4.25	20	-	5.00	
GENERAL PLANT EQUIPMENT						
389100	LAND - FEE	-	-	-	-	
390000	STRUCTURES AND IMPROVEMENTS	h1.75	45	(40)	3.11	
391100	OFFICE FURNITURE & EQ. - FURNITURE	(B)	20	-	5.00	
391200	OFFICE FURNITURE & EQ. - MACHINES	(B)	15	-	6.67	
391700	OFFICE FURNITURE & EQ. - EDP EQ.	(B)	8	-	12.50	
391800	OFFICE FURNITURE & EQ. - ECC	(B)	8	-	12.50	
392100	TRANSPORTATION EQ. - PASS. CARS	h2.5	8	20	10.00	
392200	TRANS. EQ. - LIGHT TRUCKS	h2.5	8	20	10.00	
392300	TRANS. EQ. - HEAVY TRUCKS	h4.0	12	10	7.50	
392400	TRANS. - TRAILERS	h4.0	12	10	7.50	
393000	STORES EQUIPMENT	(B)	20	-	5.00	
394000	TOOLS & WORK EQUIPMENT	(B)	20	-	5.00	
395000	LABORATORY EQUIPMENT	(B)	20	-	5.00	
396000	POWER OPERATED EQUIPMENT	h3.5	18	10	5.00	
396100	POWER OPERATED EQUIPMENT - NON FLEET	h3.5	18	10	5.00	
397000	COMMUNICATION EQUIPMENT	(B)	15	-	6.67	
397200	COM. EQ. - TELEPHONES	(B)	15	-	6.67	
398000	MISCELLANEOUS EQUIPMENT	(B)	20	-	5.00	

ORANGE & ROCKLAND UTILITIES

DEPRECIATION RATES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	A S L	NET SALVAGE %	ANNUAL RATE %
INTANGIBLE PLANT					
302100	FRANCHISES AND CONSENTS				
302200	FRANCHISES & CONSENTS - AMORT.	(A)	-	-	-
303210	SOFTWARE - ADVANTICA GAS	(B)	5	-	20.00
303220	GMD AND GIMS 2011	(B)	5	-	20.00
303830	GAS INSPECTION MGT. SYSTEM	(A)	-	-	-
303850	GAS MOBILE DISPATCH SYSTEM	(A)	-	-	-
303880	GIMS - PHASE 2	(A)	-	-	-
303890	GMD - PH2 GIMS-PH3	(A)	-	-	-

(*) Account 367002 - Mains for Gas service will have a 0 net salvage factor in RY1, with a (30) net salvage factor in RY2-3. The resulting rate in RY2-3 is 1.86%.

(A) Account is fully recovered

(B) Amortizable

(C) Account is amortizable over the remaining life of the assets.

Orange & Rockland Utilities, Inc.
Case 14-E-0493
Pro forma Calculation of Earnings
During Stub Period Starting November 1, 2017
(000's)

Assumption: O&R Delays Filing for New Rates for Six Months

Month / Year	Electric Earnings	
November 30, 2017	$ 4,000	
December 31, 2017	5,000	
January 31, 2018	5,000	
February 28, 2018	5,000	
March 31, 2018	4,000	
April 30, 2018	4,000	
Total		$ 27,000

	Electric Rate Base	
Rate Base as of October 31, 2017	$ 800,000	
Rate Base as of April 30, 2018	830,000	
Total	1,630,000	
Divided by Two	50%	
Average Rate Base During Stub Period	$ 815,000	
x ratio of billed sales during stub period to annual sales forecast	45.0%	
Rate Base Subject to Earnings Test		$ 366,750
Overall Rate of Return		7.36%
($ 27,000 / $ 366,750)		
Return on Equity	9.62%	
Earnings Sharing Threshold	9.00%	
Earnings Above / (Under) Threshold	0.62%	
Equity Earnings Base		
($ 366,750 x 48.00%)	$ 176,040	
Equity Earnings Above / (Under) Target		
($ 176,040 x 0.62%)	$ 1,090	

Orange and Rockland Utilities, Inc.
Case 14-E-0493
Capital Structure & Cost of Money
During Stub Period Starting November 1, 2017

	Capital Structure %	Cost Rate %	Cost of Capital %
Long Term Debt	51.06%	5.35%	2.73%
Customer Deposits	0.94%	1.15%	0.01%
Total Debt	52.00%		2.74%
Common Equity	48.00%	9.62%	4.62%
Total	100.00%		7.36%

Orange & Rockland Utilities, Inc.
Case 14-G-0494
Pro forma Calculation of Earnings
During Stub Period Starting November 1, 2018
(000's)

Assumption: O&R Delays Filing for New Rates for Six Months

Month / Year	Gas Earnings	
November 30, 2018	$ 5,000	
December 31, 2018	5,000	
January 31, 2019	5,000	
February 28, 2019	3,000	
March 31, 2019	2,000	
April 30, 2019	1,000	
Total		$ 21,000

	Gas Rate Base	
Rate Base as of October 31, 2018	$ 415,000	
Rate Base as of April 30, 2019	425,000	
Total	840,000	
Divided by Two	50%	
Average Rate Base During Stub Period	$ 420,000	
x ratio of billed sales during stub period to annual sales forecast	75.0%	
Rate Base Subject to Earnings Test		$ 315,000
Overall Rate of Return ($ 21,000 / $ 315,000)		6.67%
Return on Equity	8.18%	
Earnings Sharing Threshold	9.60%	
Earnings Above / (Under) Threshold	-1.42%	
Equity Earnings Base ($ 315,000 x 48.00%)	$ 151,200	
Equity Earnings Above / (Under) Target ($ 151,200 x -1.42%)	$ (2,140)	

Orange and Rockland Utilities, Inc.
Case 14-G-0494
Capital Structure & Cost of Money
During Stub Period Starting November 1, 2018

	Capital Structure %	Cost Rate %	Cost of Capital %
Long Term Debt	51.06%	5.35%	2.73%
Customer Deposits	0.94%	1.15%	0.01%
Total Debt	52.00%		2.74%
Common Equity	48.00%	8.18%	3.93%
Total	100.00%		6.67%

Orange and Rockland Utilities, Inc.
Cases 14-E-0493 & 14-G-0494

Electric Reliability Performance Mechanism

Operation of Mechanism:

The Reliability Performance Mechanism ("RPM") includes targets for the frequency and duration of electric service interruption, defined as:

1. Customer Average Interruption Duration Index ("CAIDI") – the average interruption duration time (hours) for those customers that experience an interruption during the year.
2. System Average Interruption Frequency Index ("SAIFI") – the average number of times that a customer is interrupted during a year.

The SAIFI and CAIDI performance targets for Orange and Rockland are 1.20 and 1.85, respectively, with negative revenue adjustments of 20 basis points for failure to meet each target on a calendar year basis. These targets are currently in effect and will continue until reset by the Commission.

Exclusions:

The following exclusions are applicable to operating performance under this reliability mechanism.

1. Any outages resulting from a major storm, as defined in 16 NYCRR Part 97.
2. Any incident resulting from a strike or a catastrophic event beyond the control of the Company, including but not limited to a plane crash, water main break, or natural disasters (e.g., hurricanes, floods, earthquakes).
3. Any incident where problems beyond the Company's control involving generation or the

bulk transmission system is the key factor in the outage, including, but not limited to, NYISO mandated load shedding. This criterion is not intended to exclude incidents that occur as a result of unsatisfactory performance by the Company.

Reporting:

The RPM will be measured on a calendar year basis. Accordingly, the results of the performance measurements, as measured during the calendar year 2016, 2017, and 2018, respectively, will be applied to Rate Years 1, 2, and 3, respectively.

The Company will prepare an annual report(s) on its performance under this reliability mechanism. The annual report(s) will be filed by March 31st of each year with the Secretary to the Commission (*e.g.*, the annual report for 2016 shall be due by March 31, 2017). The report(s) will state the following:

1. Company's annual system-wide performance under the RPM and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment;
2. Whether any exclusions should apply, the basis for requesting each exclusion, and adequate support for all requested exclusions.

Orange and Rockland Utilities, Inc.
Cases 14-E-0493 & 14-G-0494

Gas Safety Performance Metrics

The gas safety performance measures described herein will be in effect for the term of the Gas Rate Plan. All measurements shall be on a calendar year basis. Accordingly, the results of the performance measurements, as measured during calendar years 2016, 2017 and 2018, respectively, shall be applied to the Rate Years ending on October 31, 2016, 2017 and 2018, respectively. All gas safety measures and targets (and associated revenue adjustments)[1] for calendar year 2018 remain in effect thereafter unless and until changed by the Commission.[2]

a. Leak Management – Workable Leaks

If the workable leak backlog (types 1, 2 and 2A) exceeds the targets set forth below in calendar year 2016, 2017 and 2018, the following negative rate adjustment will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measures noted below are not attained, as directed by the Commission.

2016	
20 or less	No adjustment
greater than 20	6 basis points[3]

2017	
20 or less	No adjustment
greater than 20	6 basis points

[1] Negative revenue adjustments relating to the Gas Safety Performance metrics in this section shall not exceed 100 basis points in RY1, 125 basis points in RY2 or 150 basis points in RY3.

[2] The 66 mile replacement target established below, for the three-year period 2016 to 2018, does not remain in effect beyond 2018. However, the 22 miles of main removal per year will remain in effect beyond 2018, unless and until changed by the Commission.

[3] The basis point negative rate adjustment associated with each measure is stated on a pre-tax basis. The revenue requirement equivalents of a basis point on common equity capital per the gas revenue requirements under this Proposal are estimated to be approximately $30,000.

<u>2018</u>	
20 or less	No adjustment
greater than 20	6 basis points

b. Leak Management - Year-End Total Backlog

If the year-end total leak backlog (types 1, 2, 2A and 3) exceeds the targets set forth below in calendar year 2016, 2017 and 2018, the following negative rate adjustment will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measures noted below are not attained, as directed by the Commission.

<u>2016</u>	
250 or less	No adjustment
Greater than 250	6 basis points
<u>2017</u>	
225 or less	No adjustment
Greater than 225	6 basis points
<u>2018</u>	
200 or less	No adjustment
Greater than 200	6 basis points

c. Emergency Response - 30 Minute Response Time

If Orange and Rockland does not respond to gas leak or odor calls within 30 minutes for at least 75 percent of the calls for calendar years 2016, 2017 and 2018 a negative rate adjustment of six basis points will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measures are not attained, as directed by the Commission.

Gas leak and odor calls resulting from mass area odor complaints, major weather related occurrences, and major equipment failure are excluded from the calculations for the 30-minute response time.

d. Emergency Response - 45 Minute Response Time

If Orange and Rockland does not respond to gas leak or odor calls within 45 minutes for at least 90 percent of the calls for calendar years 2016, 2017 and 2018, a negative rate adjustment of four basis points will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measures are not attained, as directed by the Commission.

Gas leak and odor calls resulting from mass area odor complaints, major weather related occurrences, and major equipment failure are excluded from the calculations for the 45-minute response time.

e. Emergency Response - 60 Minute Response Time

If Orange and Rockland does not respond to gas leak or odor calls within 60 minutes for at least 95 percent of the calls for calendar years 2016, 2017 and 2018, a negative rate adjustment of two basis points will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measures are not attained, as directed by the Commission.

Gas leak and odor calls resulting from mass area odor complaints, major weather related occurrences, and major equipment failure are excluded from the calculations for the 60-minute response time.

f. Damage Prevention

All damages will be tracked, measured and counted following the guidelines for the data reported for the Annual Gas Safety Performance Measures report.

a) Damages to Gas Facilities Resulting from Mismarks

If the total number of damages to Company gas facilities resulting from mismarks made by the Company and its contractors with respect to the location of Company gas facilities exceeds the targets set forth below per 1,000 one-call tickets[4] in calendar year 2016, 2017 and 2018, the negative rate adjustment associated with such target will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measure noted below is not attained, as directed by the Commission.

2016	
0.40 or less	No adjustment
greater than 0.40	10 basis points
2017	
0.35 or less	No adjustment
greater than 0.35	10 basis points
2018	
0.30 or less	No adjustment
greater than 0.30	10 basis points

b) Damages by Company Employees and Company Contractors

If the total number of damages to Company gas facilities made by Company employees and Company contractors exceeds the targets set forth below per 1,000 one-call tickets in calendar year 2016, 2017 and 2018, the negative rate adjustment associated with such target will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measure noted below is not attained, as directed by the Commission.

2016	
0.45 or less	No adjustment
greater than 0.45	4 basis points

[4]For the purposes of this section, one-call tickets are defined as locate requests involving a work area in the Company's service territory.

2017

0.40 or less	No adjustment
greater than 0.40	4 basis points

2018

0.35 or less	No adjustment
greater than 0.35	4 basis points

c) Total Damages

If the number of total damages to Company gas facilities made by any party exceeds the targets set forth below per 1,000 one-call tickets in calendar year 2016, 2017 and 2018, the negative rate adjustment associated with such target will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measure noted below is not attained, as directed by the Commission.

2016

2.75 or less	No adjustment
greater than 2.75	4 basis points

2017

2.50 or less	No adjustment
greater than 2.50	4 basis points

2018

2.25 or less	No adjustment
greater than 2.25	4 basis points

2. **Gas Main Replacement**

The Company will remove from service a minimum of 66 miles of leak-prone gas main during the three calendar year period 2016 to 2018. The Gas Rate Plan establishes replacement targets of 21 miles in 2016, 22 miles in 2017 and 23 miles in 2018, with a minimum of 20 miles replaced each year. Following the term of the Gas Rate Plan, a minimum of 22 miles of leak-prone gas main will be replaced each year. If the Company does not meet the annual 20-mile minimum for removal of leak-prone gas main in 2016, 2017 or 2018, the Company will accrue on the Company's books of account a negative revenue adjustment equivalent to: six basis points for failing to meet the minimum in 2016 and/or 2017; and three basis points for failing to meet the minimum in 2018, which will be applied to the benefit of firm customers, as directed by the Commission. If the Company does not remove from service a total of 66 miles of leak prone pipe over the three-year period, a negative rate adjustment equivalent to three basis points will be accrued on the Company's books for the benefit of firm service customers.

For each of calendar years 2016 and 2017, a minimum of two miles of main removed from service will be cast iron.[5] For the three calendar year period (2016-2018), a minimum of 7.5 miles of main removed from service will be cast iron. Following the term of the Gas Rate Plan, a minimum of 2.5 miles of cast iron main will be replaced each year, unless less than five miles of cast iron main remain on the Company's system, in which case the annual replacement minimum will be reduced to one mile. If the Company does not meet the annual two mile minimum for 2016 and/or 2017, the Company will accrue on the Company's books of account a negative revenue adjustment equivalent to two basis points. If the Company does not remove from service a total of 7.5 miles of cast iron main over the three-year period, a negative revenue adjustment equivalent to two basis points will be accrued on the Company's books for the benefit of firm service customers.

In the event the Company replaces or eliminates leak-prone pipe in excess of 21 miles in calendar year 2016, 22 miles in calendar year 2017, and/or 23 miles in calendar year 2018, for each whole mile in excess of the calendar year target, the Company shall receive a positive revenue

[5] The cast iron replacement minimums are a subset of, not in addition to, the overall leak-prone main replacement minimums.

adjustment of two basis points per additional whole mile, capped at a maximum of ten basis points (five miles) per calendar year.

The Table below shows the basis points available for different mileages of Leak Prone Pipe replaced in each Rate Year. At the conclusion of this rate plan, the RY3 targets will continue to be in effect until the Company's next rate filing.

	Basis Points Incentive If The Miles of LPP Replacement Is:				
Year	2	4	6	8	10
RY1	22-23	23-24	24-25	25-26	26+
RY2	23-24	24-25	25-26	26-27	27+
RY3	24-25	25-26	26-27	27-28	28+

3. **Gas Regulations Performance Measure**

This metric applies to instances of non-compliance (violations) with the gas safety regulations set forth below that are identified during Staff field and records audits. The categorization of violations hereunder as "High" or "Other" Risk is for administrative purposes of this metric only and do not constitute an admission by the Company as to the level of risk associated with any such regulation or the violation thereunder or that there is any risk associated with a violation.

Only violations identified and included in Staff field and record audit letters may be counted for purposes of this metric. The audit letters cite violations as, for example, "1 violation, 20 occurrences", which means one code section has been violated 20 times. For the Gas Regulations Performance Measure, and in practice, this example constitutes 20 violations (the number of occurrences is the number of violations).

At the conclusion of each audit, Staff and the Company will have a compliance meeting where Staff will present its findings to the Company, including which violation(s), if any, that Staff recommends be subject to this metric. The Company will have five business days from the date of the compliance meeting to cure any identified document deficiency. Only official Company records, as defined in the Company's Operating and Maintenance plan, will be considered by Staff as a cure to a document deficiency. Violations that encompass more than one code section shall only count as one occurrence for this metric, except for 16 NYCRR §255.603 violations.[6] In addition, if the Company is found to be in violation of its work procedure, but the work procedure exceeds Code 255 or 261, and the Company is not in violation of the Code requirement, the violation will not be subject to a negative revenue adjustment under this this Safety Violation metric.

Negative revenue adjustments, if any, would be applied as set forth in the following chart:

High Risk	Other Risk
Threshold - 35 RY1, 30 RY2, 25 RY3 RY1 – 0-35 (1/4 BP); 35+ (1/2 BP) RY2 – 0-30 (1/2 BP); 30+ (1 BP) RY3 – 0-25 (1/2 BP); 25+ (1 BP)	Threshold - 35 RY1, 30 RY2, 25 RY3 RY1 – 0-35 (1/9 BP); 35+ (1/3 BP) RY2 – 0-30 (1/9 BP); 30+ (1/3 BP) RY3 – 0-25 (1/9 BP); 25+ (1/3 BP)

Any negative revenue adjustments assessed under this metric shall not exceed 50 basis points for 2016, 75 basis points for 2017 and 100 basis points for 2018 and subsequent calendar years until changed by the Commission.

This metric will be effective as of January 1, 2016, and will be measured on a calendar year basis. With respect to violations, only documentation or actions performed, or required to

[6] However, this is without prejudice to a penalty action under the Public Service Law for any violation not counted under this metric.

be documented or performed, on or after the date of the Commission's approval of the Joint Proposal will constitute an occurrence under the metric.

Staff will submit its final audit reports to the Secretary under Case 14-G-0494. If the Company disputes any of Staff's final audit results, or elects to seek exclusions based on extenuating circumstances, the Company may appeal Staff's finding to the Commission. Similarly, for violations that are due to a systemic problem, resulting in a high number of occurrences, or require long-term corrective action, the Company may petition the Commission to cap the number of occurrences for that violation at ten. The Company will include in any such petition a remediation plan addressing such violations. If the Company elects to dispute any of Staff's findings, the Company will not incur a negative revenue adjustment on those Staff findings until such time as the Commission has issued a final decision on the Company's appeal. Upon Company request, the Commission may in its discretion, provide the Company with an evidentiary hearing prior to any final determination. The Company does not waive its right to seek judicial appeal of any Commission determination regarding a violation or penalty under applicable law.

4. **Reporting**

The Company will report its annual performance in each of the areas set forth in this Appendix to the Secretary no later than 60 days following the end of each calendar year. If a performance metric is not met, the associated negative revenue adjustment will be excused when the Company can demonstrate to the Commission extenuating circumstances that prevented the Company from meeting such performance metric. The determination of whether such circumstances exist will be made on a case-by-case basis by the Commission.

With respect to leak prone pipe replacement, the report shall include material type, mileage, project location, project cost and a summary noting the totals of Aldyl, Cast Iron and Bare Steel that were replaced and what percentage of pipe replaced, in that year, was in the top 5% of riskiest pipe at the start of the calendar year, per the Company's model.

The Company will provide, to pipeline safety staff, a list of the top 5% riskiest pipe yet to be replaced at the start of each calendar year. For any pipe on the list for the calendar year that the Company does not plan to replace in that calendar year, the Company will provide a brief explanation. Along with the list, the Company will identify any pipe on the preceding calendar year's list that was not replaced as planned.

TABLE 1

ORU Natural Gas - Safety Metrics														
			CY16			CY17			CY18			CYs Post Rate Plan		
GAS SAFETY METRIC	Criteria	Unit	Basis Points	Annual Limit	Target	Basis Points	Annual Limit	Target	Basis Points	Annual Limit	Target	Basis Points	Annual Limit	Target
LEAK BACKLOG	Total of Type 1, 2 and 2A	-	6	12	20	6	12	20	6	12	20	6	12	20
	Total of Type 1, 2, 2A and 3	-	6		250	6		225	6		200	6		200
LEAK PRONE PIPE	Total Replacement Min.	miles	6	8	20	6	8	20	3	8	20	6	8	22
	Total Three Year Replacement				-			-	3		66			-
	Cast Iron Replacement Min.	miles	2		2.0	2		2.0	2		-	2		2.5
	Total Three Year Replacement				-			-			7.5			-
EMERGENCY RESPONSE TIME	30 minutes	%	6	12	75	6	12	75	6	12	75	6	12	75
	45 minutes	%	4		90	4		90	4		90	4		90
	60 minutes	%	2		95	2		95	2		95	2		95
SAFETY VIOLATION OCCURRENCES (ANNUAL RECORD AND FIELD AUDIT)	High Risk (for each up to)	-	1/4 per	35	35	1/2 per	55	30	1/2 per	75	25	1/2 per	75	25
	High Risk (for each above)	-	1/2 per			1 per			1 per			1 per		
	Other Risk (for each up to)	-	1/9 per	15		1/9 per	20		1/9 per	25		1/9 per	25	
	Other Risk (for each above)	-	1/3 per			1/3 per			1/3 per			1/3 per		
DAMAGE PREVENTION (PER 1000 ONE-CALL TICKETS)	Overall	-	4	18	2.75	4	18	2.50	4	18	2.25	4	18	2.25
	Mismark	-	10		0.40	10		0.35	10		0.30	10		0.30
	ORU or ORU Contractor	-	4		0.45	4		0.40	4		0.35	4		0.35
Total Annual Limit				100			125			150			150	

Leak Backlog	Backlog must be below target on one of the last three working days of the year.
Leakprone Cast Iron Pipe	Annual replacement minimum goes to 1.0 mile if less than 5.0 miles remain.
Leak Prone Pipe	In the event the company replaces or eliminates leak prone pipe in excess of 21 miles in CY16, 22 miles in CY17, and 23 miles in CY18, for each whole mile in excess of the calendar year target, the company shall receive a positive revenue adjustment of 2 basis points per additional whole mile, capped at a maximum of 10 basis points (5 miles) per calendar year.

HIGH RISK SECTIONS PART 255

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Material - General	255 53(a),(b),(c)	HIGH
Transportation of Pipe	255 65	HIGH
Pipe Design - General	255 103	HIGH
Design of Components - General Requirements	255 143	HIGH
Design of Components - Flexibility	255 159	HIGH
Design of Components - Supports and anchors	255 161	HIGH
Compressor Stations: Emergency shutdown	255 167	HIGH
Compressor Stations: Pressure limiting devices	255 169	HIGH
Compressor Stations: Ventilation	255 173	HIGH
Valves on pipelines to operate at 125 psig or more	255 179	HIGH
Distribution line valves	255 181	HIGH
Vaults: Structural Design requirements	255 183	HIGH
Vaults: Drainage and waterproofing	255 189	HIGH
Protection against accidental overpressuring	255 195	HIGH
Control of the pressure of gas delivered from high pressure distribution systems	255 197	HIGH
Requirements for design of pressure relief and limiting devices	255 199	HIGH
Required capacity of pressure relieving and limiting stations	255 201	HIGH
Qualification of welding procedures	255 225	HIGH
Qualification of Welders	255 227	HIGH
Protection from weather	255 231	HIGH
Miter Joints	255 233	HIGH
Preparation for welding	255 235	HIGH
Inspection and test of welds	255 241(a),(b)	HIGH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255 243(a)-(e)	HIGH
Welding inspector	255 244(a),(b),(c)	HIGH
Repair or removal of defects	255 245	HIGH
Joining Of Materials Other Than By Welding - General	255 273	HIGH
Joining Of Materials Other Than By Welding - Copper Pipe	255 279	HIGH
Joining Of Materials Other Than By Welding - Plastic Pipe	255 281	HIGH
Plastic pipe: Qualifying persons to make joints	255 285(a),(b),(d)	HIGH
Notification requirements	255 302	HIGH
Compliance with construction standards	255 303	HIGH
Inspection: General	255 305	HIGH
Inspection of materials	255 307	HIGH
Repair of steel pipe	255 309	HIGH
Repair of plastic pipe	255 311	HIGH
Bends and elbows	255 313(a),(b),(c)	HIGH
Wrinkle bends in steel pipe	255 315	HIGH
Installation of plastic pipe	255 321	HIGH
Underground clearance	255 325	HIGH
Customer meters and service regulators: Installation	255 357(d)	HIGH
Service lines: Installation	255 361(e),(f),(g),(h),(i)	HIGH
Service lines: Location of valves	255 365(b)	HIGH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255 455(d),(e)	HIGH
External corrosion control: Buried or submerged pipelines installed before August 1, 1971	255 457	HIGH
External corrosion control: Protective coating	255 461(c)	HIGH
External corrosion control: Cathodic protection	255 463	HIGH
External corrosion control: Monitoring	255 465(a),(e)	HIGH
Internal corrosion control: Design and construction of transmission line	255 476(a),(c)	HIGH
Remedial measures: General	255 483	HIGH
Remedial measures: transmission lines	255 485(a),(b)	HIGH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255 505(a),(b),(c),(d)	HIGH
General requirements (UPGRADES)	255 553 (a),(b),(c),(f)	HIGH
Upgrading to a pressure of 125 PSIG or more in steel pipelines	255 555	HIGH
Upgrading to a pressure less than 125 PSIG	255 557	HIGH
Conversion to service subject to this Part	255 559(a)	HIGH
General provisions	255 603	HIGH
Operator Qualification	255 604	HIGH
Essentials of operating and maintenance plan	255 605	HIGH
Change in class location: Required study	255 609	HIGH
Damage prevention program	255 614	HIGH
Emergency Plans	255 615	HIGH
Customer education and information program	255 616	HIGH
Maximum allowable operating pressure: Steel or plastic pipelines	255 619	HIGH
Maximum allowable operating pressure: High pressure distribution systems	255 621	HIGH
Maximum and minimum allowable operating pressure: Low pressure distribution systems	255 623	HIGH
Odorization of gas	255 625(a),(b)	HIGH

Tapping pipelines under pressure	255 627	HIGH
Purging of pipelines	255 629	HIGH
Control Room Management	255 631(a)	HIGH
Transmission lines: Patrolling	255 705	HIGH
Leakage Surveys - Transmission	255 706	HIGH
Transmission lines: General requirements for repair procedures	255 711	HIGH
Transmission lines: Permanent field repair of imperfections and damages	255 713	HIGH
Transmission lines: Permanent field repair of welds	255 715	HIGH
Transmission lines: Permanent field repair of leaks	255 717	HIGH
Transmission lines: Testing of repairs	255 719	HIGH
Distribution systems: Leak surveys and procedures	255 723	HIGH
Compressor stations: procedures	255 729	HIGH
Compressor stations: Inspection and testing relief devices	255 731	HIGH
Compressor stations: Additional inspections	255 732	HIGH
Compressor stations: Gas detection	255 736	HIGH
Pressure limiting and regulating stations: Inspection and testing	255 739(a),(b)	HIGH
Regulator Station Overpressure Protection	255 743(a),(b)	HIGH
Transmission Line Valves	255 745	HIGH
Prevention of accidental ignition	255 751	HIGH
Protecting cast iron pipelines	255 755	HIGH
Replacement of exposed or undermined cast iron piping	255 756	HIGH
Replacement of cast iron mains paralleling excavations	255 757	HIGH
Leaks: Records	255 807(d)	HIGH
Leaks: Instrument sensitivity verification	255 809	HIGH
Leaks: Type 1	255 811(b),(c),(d),(e)	HIGH
Leaks: Type 2A	255 813(b),(c),(d)	HIGH
Leaks: Type 2	255 815	HIGH
Leak Follow-up	255 819(a)	HIGH
High Consequence Areas	255 905	HIGH
Required Elements (IMP)	255 911	HIGH
Knowledge and Training (IMP)	255 915	HIGH
Identification of Potential Threats to Pipeline Integrity and Use of the Threat Identification in an Integrity Program (IMP)	255 917	HIGH
Baseline Assessment Plan(IMP)	255 919	HIGH
Conducting a Baseline Assessment (IMP)	255 921	HIGH
Direct Assessment (IMP)	255 923	HIGH
External Corrosion Direct Assessment (ECDA) (IMP)	255 925	HIGH
Internal Corrosion Direct Assessment (ICDA) (IMP)	255 927	HIGH
Confirmatory Direct Assessment (CDA) (IMP)	255 931	HIGH
Addressing Integrity Issues (IMP)	255 933	HIGH
Preventive and Mitigative Measures to Protect the High Consequence Areas (IMP)	255 935	HIGH
Continual Process of Evaluation and Assessment (IMP)	255 937	HIGH
Reassessment Intervals (IMP)	255 939	HIGH
General requirements of a GDPIM plan	255 1003	HIGH
Implementation requirements of a GDPIM plan	255 1005	HIGH
Required elements of a GDPIM plan	255 1007	HIGH
Required report when compression couplings fail	255 1009	HIGH
Requirements a small liquefied petroleum gas (LPG) operator must satisfy to implement a GDPIM plan	255 1015	HIGH

HIGH RISK SECTIONS PART 261		
Operation and maintenance plan	261 15	HIGH
Leakage Survey	261 17(a),(c)	HIGH
Carbon monoxide prevention	261 21	HIGH
Warning tag procedures	261 51	HIGH
HEFPA Liaison	261 53	HIGH
Warning Tag Inspection	261 55	HIGH
Warning tag: Class A condition	261 57	HIGH
Warning tag: Class B condition	261 59	HIGH

OTHER RISK SECTIONS PART 255		
ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Preservation of records	255.17	OTH
Compressor station: Design and construction	255.163	OTH
Compressor station: Liquid removal	255.165	OTH
Compressor stations: Additional safety equipment	255.171	OTH
Vaults: Accessibility	255.185	OTH
Vaults: Sealing, venting, and ventilation	255.187	OTH
Calorimeter or calorimeter structures	255.190	OTH
Design pressure of plastic fittings	255.191	OTH
Valve installtion in plastic pipe	255.193	OTH
Instrument, control, and sampling piping and components	255.203	OTH
Limitations On Welders	255.229	OTH
Quality assurance program	255.230	OTH
Preheating	255.237	OTH
Stress relieving	255.239	OTH
Inspection and test of welds	255.241(c)	OTH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(f)	OTH
Plastic pipe: Qualifying joining procedures	255.283	OTH
Plastic pipe: Qualifying persons to make joints	255.285(c),(e)	OTH
Plastic pipe: Inspection of joints	255.287	OTH
Bends and elbows	255.313(d)	OTH
Protection from hazards	255.317	OTH
Installation of pipe in a ditch	255.319	OTH
Casing	255.323	OTH
Cover	255.327	OTH
Customer meters and regulators: Location	255.353	OTH
Customer meters and regulators: Protection from damage	255.355	OTH
Customer meters and service regulators: Installation	255.357(a),(b),(c)	OTH
Customer meter installations: Operating pressure	255.359	OTH
Service lines: Installation	255.361(a),(b),(c),(d)	OTH
Service lines: valve requirements	255.363	OTH
Service lines: Location of valves	255.365(a),(c)	OTH
Service lines: General requirements for connections to main piping	255.367	OTH
Service lines: Connections to cast iron or ductile iron mains	255.369	OTH
Service lines: Steel	255.371	OTH
Service lines: Cast iron and ductile iron	255.373	OTH
Service lines: Plastic	255.375	OTH
Service lines: Copper	255.377	OTH
New service lines not in use	255.379	OTH
Service lines: excess flow valve performance standards	255.381	OTH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455(a)	OTH
External corrosion control: Examination of buried pipeline when exposed	255.459	OTH
External corrosion control: Protective coating	255.461(a),(b),(d),(e),(f),(g)	OTH
Rectifier Inspection	255.465(b),(c),(f)	OTH
External corrosion control: Electrical isolation	255.467	OTH
External corrosion control: Test stations	255.469	OTH
External corrosion control: Test lead	255.471	OTH
External corrosion control: Interference currents	255.473	OTH
Internal corrosion control: General	255.475(a),(b)	OTH
Atmospheric corrosion control: General	255.479	OTH
Atmospheric corrosion control: Monitoring	255.481	OTH
Remedial measures: transmission lines	255.485(c)	OTH
Remedial measures: Pipelines lines other than cast iron or ductile iron lines	255.487	OTH
Remedial measures: Cast iron and ductile iron pipelines	255.489	OTH
Direct Assessment	255.490	OTH
Corrosion control records	255.491	OTH
General requirements (TESTING)	255.503	OTH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255.505(e),(h),(i)	OTH

Test requirements for pipelines to operate at less than 125 PSIG	255.507	OTH
Test requirements for service lines	255.511	OTH
Environmental protection and safety requirements	255.515	OTH
Records (TESTING)	255.517	OTH
Notification requirements (UPGRADES)	255.552	OTH
General requirements (UPGRADES)	255.553(d),(e)	OTH
Conversion to service subject to this Part	255.559(b)	OTH
Change in class location: Confirmation or revision of maximum allowable operating pressure	255.611(a),(d)	OTH
Continuing surveillance	255.613	OTH
Odorization	255.625(e),(f)	OTH
Pipeline Markers	255.707(a),(c),(d),(e)	OTH
Transmission lines: Record keeping	255.709	OTH
Distribution systems: Patrolling	255.721(b)	OTH
Test requirements for reinstating service lines	255.725	OTH
Inactive Services	255.726	OTH
Abandonment or inactivation of facilities	255.727(b)-(g)	OTH
Compressor stations: storage of combustible materials	255.735	OTH
Pressure limiting and regulating stations: Inspection and testing	255.739(c),(d)	OTH
Pressure limiting and regulating stations: Telemetering or recording gauges	255.741	OTH
Regulator Station MAOP	255.743 (c)	OTH
Service Regulator - Min.& Oper. Load	255.744 (d),(e)	OTH
Distribution Line Valves	255.747	OTH
Valve maintenance: Service line valves	255.748	OTH
Regulator Station Vaults	255.749	OTH
Caulked bell and spigot joints	255.753	OTH
Reports of accidents	255.801	OTH
Emergency lists of operator personnel	255.803	OTH
Leaks General	255.805(a),(b),(e),(g),(h)	OTH
Leaks: Records	255.807(a),(b),(c)	OTH
Type 2	255.815(b),(c),(d)	OTH
Type 3	255.817	OTH
Interruptions of service	255.823(a),(b)	OTH
Logging and analysis of gas emergency reports	255.825	OTH
Annual Report	255.829	OTH
Reporting safety-related conditions	255.831	OTH
General (IMP)	255.907	OTH
Changes to an Integrity Management Program (IMP)	255.909	OTH
Low Stress Reassessment (IMP)	255.941	OTH
Measuring Program Effectiveness (IMP)	255.945	OTH
Records (IMP)	255.947	OTH
Records an operator must keep	255.1011	OTH

OTHER RISK SECTIONS PART 261		
High Pressure Piping - Annual Notice	261.19	OTH
Warning tag: Class C condition	261.61	OTH
Warning tag: Action and follow-up	261.63(a)-(h)	OTH
Warning Tag Records	261.65	OTH

Orange and Rockland Utilities, Inc.
Cases 14-E-0493 & 14-G-0494

Customer Service Performance Incentive Mechanism

The Customer Service Performance Incentive Mechanism ("CSPIM") described herein will be in effect for the terms of the Rate Plans and thereafter unless and until changed by the Commission.

a) Operation of Mechanism

The CSPIM establishes threshold performance levels for designated aspects of customer service. For all measures, except the Residential Termination metric, the threshold performance levels are detailed on page 5 of this Appendix 17. Failure by the Company to achieve these specified targets will result in a revenue adjustment of up to $2.25 million annually. For residential terminations, the Company has an opportunity to earn a positive revenue adjustment of up to $800,000 annually. All revenue adjustments related to the CSPIM will be deferred for future disposition by the Commission. The CSPIM will be measured on a calendar year basis. Accordingly, the results of the performance measurements, as measured during calendar years 2016, 2017 and 2018, respectively, will be applied to Rate Years 1, 2 and 3, respectively.

b) Exclusions

Except for the Residential Termination metric, for measurement purposes, results from months having abnormal operating conditions will not be considered. Abnormal operating conditions are deemed to occur during any period of emergency, catastrophe, strike, natural disaster, major storm, or other unusual event not in the Company's control affecting more than 10 percent of the customers in an operating area during any month. A "major storm" will have the same definition as set forth in 16 NYCRR Part 97.

c) Reporting

The Company will prepare an annual report on its performance that will be filed with the Secretary by March 1 following each Rate Year (*e.g.*, the annual report for 2016 shall be due by March 1, 2017). Each report will state: (1) the Company's actual performance for the calendar year on each measure; (2) whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment; and (3) whether any exclusions should apply, the basis for requesting each exclusion, and adequate support for all requested exclusions.

d) Threshold Standards

The Company's threshold performance will be measured based on the Company's cumulative monthly performance for each Rate Year for the following three activities, except as otherwise noted.

i. Commission Complaints

The annual Complaint Rate will be calculated in the manner approved by the Commission in its Order Approving Complaint Rate Targets issued August 26, 2005.[1] In calculating the annual Complaint Rate, (i) duplicative rate consultant complaints, (ii) high commodity prices complaints, and (iii) complaints relating to natural disasters, major storms, or other unusual events not in the Company's control, will be excluded. During the Rate Plans, the complaint rate not to exceed targets and associated revenue adjustment levels are set forth in Table 1, below.

ii. Customer Satisfaction

The Company contracts with a third-party vendor to conduct a monthly Customer Contact Satisfaction Survey. The vendor surveys customers utilizing a 10-point scale to rank

[1] Case 02-G-1553, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Orange and Rockland Utilities, Inc. for Gas Service*, and Case 03-E-0797, *In the Matter of Orange and Rockland Utilities, Inc.'s Proposal for an Extension of an Existing Rate Plan, filed in Case 96-E-0900*, Order Approving Complaint Rate Target (issued August 26, 2005).

customer satisfaction with Company performance based upon a series of questions and one overall customer satisfaction index question:

> "*Using a scale from 1 to 10 where 1 means you were very dissatisfied and 10 means you were very satisfied, how satisfied were you the way the Orange and Rockland's Customer Service Representative handled your recent issue/request?"*

The Company reports the percentage of customers surveyed that responded with a score of 7 – 10 to the overall customer satisfaction index question.

iii. Call Answer Rate

"Call Answer Rate" is the percentage of calls answered by a Company representative within 30 seconds of the customer's request to speak to a representative between the hours of 8:00 AM and 4:30 PM Monday through Friday (excluding holidays). The performance rate is the sum of the system-wide number of calls answered by a representative within 30 seconds divided by the sum of the system-wide number of calls where a customer requests to speak with a representative.

iv. Residential Service Terminations

In order to provide a positive financial incentive for the Company to identify and implement new steps to reduce residential service terminations as a result of customer non-payment, while decreasing, or maintaining, the amount of bad debt from residential accounts, the Company will have the ability during each Rate Year to achieve an overall maximum positive revenue adjustment totaling $800,000 if it achieves both of the following targets for the Rate Year:

Goals:

Turn-offs	< or = 7,500
Bad debt write-offs	< or = $3.1 million

The Company will have the ability during each Rate Year to achieve a maximum positive revenue adjustment of $400,000 if it achieves one of the above targets for the Rate Year; provided the other target is at or below the following levels:

Goals:

Turn-offs	< or = 8,000
Bad debt write-offs	< or = $3.3 million

Any positive revenue adjustment earned will be allocated between the Company's electric and gas businesses based on the common cost allocation factor.

Table 1 - Customer Service Performance Incentive Mechanism Targets

Orange and Rockland Customer Service Performance Incentive Mechanism (CSPIM) (Electric and Gas)			
Indicator	**CSPIM (Electric and Gas)**		
	Target	**Electric NRA**	**Gas NRA**
Annual PSC Complaint Rate	<1.0	$0	$0
	>=1.0	$200,000	$100,000
	>=1.1	$400,000	$200,000
	>=1.2	$600,000	$300,000
Customer Contact Satisfaction Survey	>91.0%	$0	$0
	<=91.0%	$200,000	$100,000
	<=89.4%	$400,000	$200,000
	<=87.8%	$600,000	$300,000
Call Answer Rate <30 sec	>57.5%	$0	$0
	<=57.5%	$100,000	$50,000
	<=55.0%	$200,000	$100,000
	<=52.5%	$300,000	$150,000
Total		$1,500,000	$750,000

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ELECTRIC REVENUE ALLOCATION AND RATE DESIGN

1. Revenue Allocation

The incremental revenue requirement for each Rate Year was adjusted by subtracting amounts included for New York State Gross Receipts and Franchise Tax surcharge revenues, Municipal Tax surcharge revenues and Metropolitan Transportation Authority Business Tax surcharge revenues. For each Rate Year, before the adjusted incremental revenue requirement was applied to each customer class, the Rate Year delivery revenues for each class were realigned in a revenue neutral manner to reduce interclass deficiencies and surpluses as indicated by the embedded cost of service ("ECOS") study. In each Rate Year, deficiency and surplus indications have been reduced by one-fourth. The Rate Year delivery revenue increase was then allocated among the service classifications ("SC") in proportion to the relative contribution made by each SC's realigned Rate Year delivery revenue to the total realigned Rate Year delivery revenue. The Rate Year delivery revenue changes by class were mitigated in a manner such that each class did not receive a revenue change that was more than +2.0 times or less than -2.0 times the overall Rate Year delivery revenue change.

2. Rate Design

The rate design process for each Rate Year consists of the following six steps:

- Determine revised customer charges and associated delivery revenue changes;

- Determine revised competitive service charges and associated delivery revenue changes;
- Adjust class-specific delivery revenue increases to determine non-competitive delivery revenue increases excluding customer charges;
- Calculate class-specific non-competitive delivery revenue increases excluding customer charges for a historical period;
- Implement intraclass rate structure changes for certain SCs; and
- Apply non-competitive delivery revenue increases excluding customer charges within each SC.

a. Revised Customer Charges and Associated Delivery Revenue Changes

Customer charges were increased in RY1 for SC No. 2 Secondary Demand Metered, SC No. 3, SC No. 6, SC No. 16, and SC No. 20 to better reflect customer costs, consistent with the ECOS study. Schedule 1 summarizes the customer charges for RY1. Customer charges for SC No. 15 were increased by the overall delivery revenue increase percentage applicable to all SCs. Customer charges for SC No. 25 are described in the Standby Rate Design section of this appendix. SC-specific changes in customer charge revenue for each Rate Year were determined based on the changes in customer charges described above and the forecast of customer bills for each Rate Year.

b. Revised Competitive Service Charges and Associated Delivery Revenue Changes

The competitive delivery components include the billing and payment processing ("BPP") charge; the Merchant Function Charge ("MFC") fixed components, that is the MFC procurement and credit and collections components; the purchase of receivables (“POR”) credit and collections component; and Metering Charges. For each Rate Year, revised revenue levels for the MFC fixed components, POR credit and collections component and Metering Charges were based on percentages of delivery revenue as determined in the ECOS study[1]. The revised competitive service charge revenue levels for each Rate Year were compared with competitive service charge revenues determined based on competitive service charges for the previous Rate Year to determine the change in competitive service revenues.

c. <u>Determination of Class-Specific Non-Competitive Delivery Revenue Increases Excluding Customer Charges</u>.

For each Rate Year, the revenue changes associated with the competitive service charges and customer charges were used to adjust the class-specific delivery revenue increases to determine class-specific non-competitive delivery revenue increases excluding customer charges.

d. <u>Determination of Class-Specific Non-Competitive Delivery Revenue Increases Excluding Customer Charges for a Historical Period.</u>

Class-specific revenue ratios were developed for each Rate Year by dividing (a) non-competitive delivery revenues excluding customer charges for each class based on billing data for the historical period (<u>i.e.</u>, the twelve months ended June 30, 2014) and rates for the previous Rate Year by (b) non-competitive delivery revenues excluding customer charges for each class based on Rate Year billing data and rates for the previous Rate Year. These revenue ratios for each class were applied to each Rate Year's non-competitive delivery revenue increase excluding customer charges for each

[1] There were no revenue changes associated with the BPP Charge since it will remain at its current level during the term of the Electric Rate Plan.

class to determine each class's non-competitive delivery revenue increase excluding customer charges for the historical period.

e. Intraclass Rate Structure Changes

The following rate structure changes were made in a revenue neutral manner before applying the non-competitive delivery revenue increase excluding customer charges within each of the affected SCs.

SC No. 1

The optional electric space and water heating discounts were reduced by 1/3 in RY1 and an additional 1/3 in RY2.

SC No. 2

For SC No. 2 Secondary Demand Metered service in RY1, 5 percent of the first block usage revenues were reallocated to demand rates. For RY2, 10 percent of the first block usage revenues were reallocated to the demand rates. For each Rate Year, SC No 2 Primary service summer and winter usage revenues were reduced by 20 percent and the resulting seasonal changes in revenue were reallocated to demand revenue by increasing the demand charges.

SC No. 3, 9, and 22

For each Rate Year, SC Nos. 3, 9, and 22 usage revenues were reduced by 20 percent and the resulting change in revenue was reallocated to demand revenue on an equal percentage basis.

f. Application of Non-Competitive Delivery Revenue Increase Excluding Customer Charges Within Each SC.

For SC No. 2 Secondary Demand Metered service, SC No. 2 Primary service, SC No. 3, SC No. 9, and SC No. 22, the class specific non-competitive delivery revenue increase excluding customer charges was divided by the total of demand charge revenues at the previous Rate Year's rate levels to establish average class specific percentages by which demand rates were increased. For all other service classes, each class-specific non-competitive delivery revenue increase excluding customer charges, determined as set forth above, was divided by the total of the usage charge, and where applicable, demand charge revenues, at the previous Rate Year's rate levels, to establish average class-specific percentages by which non-competitive delivery rates were increased.

3. Unbundled Charges

a. Merchant Function Charge

For the term of the Electric Rate Plan, the Company will continue to implement the MFC, as set forth in the Company's electric tariff**.** The MFC fixed component monthly targets (commodity procurement and credit and collections) for RY1 and RY2 are set forth in Schedule 4 of this Appendix.

b. Transition Adjustment for Competitive Services

For the term of the Electric Rate Plan, the Company will continue to implement the Transition Adjustment for Competitive Services ("TACS"), as set forth in the Company's electric tariff, modified as follows.

The effective period of the TACS has been changed from the 12-month periods commencing July 1 to the 12-month periods commencing November 1 of each year beginning in November 2016. In addition, to account for the partial rate year July 1, 2015 through October 31, 2015 the TACS targets are $4,344,689 for the MFC fixed components and $372,258 for the credit and collections lost revenue associated with retail access component. These targets are based on the sum of the monthly targets for July through October for Rate Year 3 of the current Electric Rate Plan as contained in Appendix B, Schedule 5, of the Joint Proposal adopted by the Commission in Case 11-E-0408. Any over- or under- collections for this partial period will be collected through a revised TACS that will be in effect for the 12 month period ending October 31, 2016.

c. POR Discount

For the term of the Electric Rate Plan, the Company will continue to implement the POR discount, as set forth in the Company's electric tariff**.**

d. Billing and Payment Processing Charge

The Company's billing and payment processing charge will remain at its current level, $1.02 per bill.

e. Metering Charges

To determine Metering Charges for classes not subject to mandatory day-ahead hourly pricing ("MDAHP") for each Rate Year, the Metering Charges were revised based on the class-specific metering cost percentages of delivery revenue as set forth in the ECOS study. The metering charges for customers subject to MDAHP in SC Nos. 2, 3, 20 and 21 are set to be equal to the metering charges as indicated in the DAC Panel's direct testimony in Exhibit__(DAC-E2), Schedule 4. For SC Nos. 9 and 22, where the entire classes are MDAHP eligible, the meter ownership charge and meter service provider charge were increased based on percentages as indicated in the DAC Panel's Exhibit __

(DAC-E2, Schedule 3), and the combined SC Nos. 9 and 22 proposed delivery revenue to develop common charges for these two classes since metering installations for customers in these subclasses are similar. The meter data service provider charge for SC Nos. 9 and 22 was set equal to that of the MDAHP meter data service provider charge for MDAHP customers in SC Nos. 2, 3, 20, and 21 as indicated in the DAC Panel's direct testimony in Exhibit__(DAC-E2), Schedule 4 since these costs are common among all MDAHP classes.

4. Standby Rate Design

The standby rate design is consistent with the guidelines set forth in the Commission's Opinion 01-04, Opinion and Order Approving Guidelines for the Design of Standby Service Rates, issued and effective October 26, 2001 in Case 99-M-1470. The billing determinants used to design standby rates were based on those used in the formulation of the proposed rates for the otherwise applicable non-standby SCs. The cost allocation matrix contained in Appendix B of the March 11, 2003 Joint Proposal adopted by the Commission in its Order Establishing Electric Standby Rates, issued July 29, 2003, in Case Nos. 02-E-0780 and 02-E-0781 also was used. This matrix shows the percentage allocation of costs between the as-used demand charge and the contract demand charge, at various service levels.

The class revenue requirements to be recovered through the contract demand charges were developed by applying the percentages applicable to the contract demand from the cost allocation matrix to the portions of the revenue requirement applicable to transmission, substation, primary, and secondary costs. The contract demand revenue requirements were divided by the applicable estimated standby contract demand billing determinants, which were developed based on a ratio reflecting the relationship between contract demand and monthly billing demands. This resulted in the contract demand charges.

The class revenue requirements to be recovered through the as-used daily demand charges were developed by applying the percentages applicable to as-used demand charges from the cost allocation matrix to the portions of the revenue requirement applicable to transmission, substation, primary, and secondary costs. The as-used daily demand charge revenue requirements were divided by the applicable estimated as-used daily demand billing determinants to develop the as-used daily demand charges.

The customer charges for standby service were based on the customer's otherwise applicable Service Classification's customer costs as outlined in the ECOS study.

ORANGE AND ROCKLAND UTILITIES, INC.

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Appendix 18 - Electric Revenue Allocation and Rate Design

Index of Schedules

ORANGE AND ROCKLAND UTILITIES, INC.

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Summary of Customer Charges
For Rates Effective November 1, 2015

	Rates Effective 11/1/2015
SC No. 1	$20.00
SC No. 2 - Pri	35.00
SC No. 2 - Sec Demand Metered	21.00
SC No. 2 - Non-Demand Metered	18.00
SC No. 2 - Unmetered	17.00
SC No. 3	120.00
SC No. 6 - Option C	24.00
SC No. 9 (P/S/T)	500.00
SC No. 16 - Option C Metered	24.00
SC No. 16 - Option C Unmetered	17.00
SC No. 19	32.00
SC No. 20	40.00
SC No. 21	163.00
SC No. 22 (P/S/T)	500.00
SC No. 25	530.00

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-E-0493

Impact of Proposed Rate Change on Total Revenue - Rate Year 1*
(Based on Billed Sales and Revenues)

BASED ON NON-LEVELIZED REVENUE REQUIREMENT

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,606,440	192,290	314,663	320,553	5,890	1.9%
SC19	81,049	3,582	14,424	14,682	259	1.8%
Total Res	1,687,489	195,872	329,087	335,236	6,149	1.9%
SC2 Sec Demand Billed	829,673	22,553	138,727	141,049	2,322	1.7%
SC2 Space Htg	24,232	395	3,291	3,363	71	2.2%
SC2 Non Demand Billed	15,772	5,018	4,250	4,169	(81)	-1.9%
SC20	75,894	382	10,480	10,609	129	1.2%
Total Secondary	945,571	28,348	156,748	159,190	2,442	1.6%
SC2 Pri	37,065	155	5,429	5,437	8	0.2%
SC3	370,658	270	48,457	49,014	557	1.2%
SC21	39,553	26	5,166	5,225	59	1.1%
Total Primary	447,276	451	59,051	59,676	624	1.1%
Total Sec & Pri	1,392,847	28,799	215,800	218,866	3,066	1.4%
SC9 (Commercial)	424,047	47	50,238	50,372	134	0.3%
SC22 (Industrial)	351,593	33	39,911	40,225	315	0.8%
Total SC9 & SC22	775,640	80	90,149	90,597	448	0.5%
SC4	14,914	71	5,497	5,353	(144)	-2.6%
SC5	2,977	496	557	545	(12)	-2.2%
SC6	4,219	2	676	685	9	1.4%
SC 16 -dusk-to-dawn	8,471	2,285	4,491	4,328	(163)	-3.6%
SC 16 - energy only	4,911	430	814	822	8	1.0%
SC16 - Total	13,382	2,715	5,305	5,150	(155)	-2.9%
Total Lighting	35,492	3,283	12,035	11,733	(301)	-2.5%
Total	3,891,468	228,034	647,070	656,432	9,362	1.5%

Notes:
* For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-E-0493

Calculation of Incremental Revenue Requirement for Rate Year 1

BASED ON NON-LEVELIZED REVENUE REQUIREMENT

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes	$9,343,987
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (1)	167,000
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$9,176,987
d.	Rate Year Bundled Delivery Revenues Excl. West Point	$285,520,595
e.	Rate Year Overall Percentage Increase in Delivery Revenues (c / d)	3.21412%

Note:

1. GRT/MTA Gross Up Included in Rev Req = 1.79%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-E-0493

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 1

BASED ON NON-LEVELIZED REVENUE REQUIREMENT

Class	Bundled Rate Yr. Delivery Rev. ($)	(Surplus)/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 3.21412% ($)	Rate Yr. Bundled Delivery Rev. at Proposed Rate Level ($)	Proposed Rate Yr. Increase Incl. (Surplus)/Deficiency ($)	Mitigation Adjustment ($)	Adjusted Rate Yr. Increase Incl. Mitigation Adj ($)	Rate Yr. Bundled %
SC1	162,706,500	500,758	163,207,258	5,245,677	168,452,935	5,746,435	40,654	5,787,089	3.6%
SC19	6,885,400	30,250	6,915,650	222,277	7,137,927	252,527	1,723	254,250	3.7%
Total Res	169,591,900	531,008	170,122,908	5,467,954	175,590,862	5,998,962	42,377	6,041,339	3.6%
SC2 Sec Dmd Billed	62,140,716	249,623	62,390,339	2,005,300	64,395,639	2,254,923	15,541	2,270,464	3.7%
SC2 Space Htg	1,079,887	102,250	1,182,137	37,995	1,220,132	140,245	(70,827)	69,418	6.4%
SC2 Non Dmd Billed	2,389,092	(151,750)	2,237,342	71,911	2,309,253	(79,839)	557	(79,282)	-3.3%
SC20	3,497,700	13,608	3,511,308	112,858	3,624,166	126,466	875	127,341	3.6%
Total Sec	69,107,395	213,731	69,321,126	2,228,064	71,549,190	2,441,795	(53,854)	2,387,941	3.5%
SC2 Pri	2,011,300	(55,750)	1,955,550	62,854	2,018,404	7,104	487	7,591	0.4%
SC3	14,504,300	68,022	14,572,322	468,372	15,040,694	536,394	3,630	540,024	3.7%
SC21	1,575,400	7,279	1,582,679	50,869	1,633,548	58,148	394	58,542	3.7%
Total Pri	18,091,000	19,551	18,110,551	582,095	18,692,646	601,646	4,511	606,157	3.4%
Total Sec & Pri	87,198,395	233,282	87,431,677	2,810,159	90,241,836	3,043,441	(49,343)	2,994,098	3.4%
Total SC9 (Com)	11,845,700	(242,750)	11,602,950	372,933	11,975,883	130,183	2,890	133,073	1.1%
Total SC22 (Mfg)	8,330,000	36,710	8,366,710	268,916	8,635,626	305,626	2,084	307,710	3.7%
Total SC 9 & SC 22	20,175,700	(206,040)	19,969,660	641,849	20,611,509	435,809	4,974	440,783	2.2%
SC4	4,036,000	(263,250)	3,772,750	121,261	3,894,011	(141,989)	940	(141,049)	-3.5%
SC5	275,000	(21,000)	254,000	8,164	262,164	(12,836)	63	(12,773)	-4.6%
SC6	274,000	0	274,000	8,807	282,807	8,807	68	8,875	3.2%
SC 16 -dusk-to-dawn	3,650,000	(271,750)	3,378,250	108,581	3,486,831	(163,169)	842	(162,327)	-4.5%
SC 16 - energy only	319,600	(2,250)	317,350	10,200	327,550	7,950	79	8,029	2.5%
SC16 - Total	3,969,600	(274,000)	3,695,600	118,781	3,814,381	(155,219)	921	(154,298)	-3.9%
Total Lights	8,554,600	(558,250)	7,996,350	257,013	8,253,363	(301,237)	1,992	(299,245)	-3.5%
Total	285,520,595	0	285,520,595	9,176,975	294,697,570	9,176,975	0	9,176,975	3.2%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-E-0493

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 1

BASED ON NON-LEVELIZED REVENUE REQUIREMENT

Class	Adj. Rate Yr. Incr. Incl. (Surplus)/Deficiency ($)	Rate Year Incremental Competitive Services Revenues: MFC Supply Related Rev. ($)	MFC PP WC Related Rev. ($)	MFC Credit & Collections Related Rev. ($)	POR Credit & Collections Related Rev. ($)	Competitive Metering Related Rev. ($)	Customer Charge Rev. ($)	Total Rate Yr. Incrmtl Comp. Services Rev. ($)	Non-Competitive Rate Yr. Delivery Revenue Incr. ($)
SC1	5,787,089	(3,171,188)	(67,779)	(983,035)	(188,978)	0	120	(4,410,860)	10,197,949
SC19	254,250	(115,527)	(2,469)	(35,812)	(13,796)	0	88	(167,516)	421,766
Total Res	6,041,339	(3,286,714)	(70,249)	(1,018,847)	(202,774)	0	208	(4,578,376)	10,619,715
SC2 Sec Dmd Billed	2,270,464	(636,494)	(20,270)	(189,152)	(22,903)	85,852	811,906	28,938	2,241,526
SC2 Space Htg	69,418	(10,667)	(340)	(3,170)	(813)	1,373	0	(13,616)	83,034
SC2 Non Dmd Billed	(79,282)	(25,187)	(802)	(7,485)	429	9,526	0	(23,519)	(55,763)
SC20	127,341	(29,229)	(931)	(8,686)	(29)	41,233	22,850	25,208	102,133
Total Sec	2,387,941	(701,577)	(22,343)	(208,493)	(23,316)	137,984	834,756	17,011	2,370,931
SC2 Pri	7,591	(28,495)	(872)	(7,119)	247	12,576	(200)	(23,863)	31,454
SC3	540,024	(162,827)	(4,980)	(40,679)	1,286	(35,854)	64,860	(178,195)	718,219
SC21	58,542	(6,202)	(190)	(1,550)	25	(7,593)	456	(15,054)	73,595
Total Pri	606,157	(197,524)	(6,042)	(49,348)	1,558	(30,871)	65,116	(217,111)	823,268
Total Sec & Pri	2,994,098	(899,101)	(28,385)	(257,841)	(21,758)	107,113	899,872	(200,101)	3,194,199
Total SC9 (Com)	133,073	(212,374)	(6,496)	(53,058)	4,535	9,702	0	(257,691)	390,764
Total SC22 (Mfg)	307,710	(165,255)	(5,055)	(41,286)	3,142	6,814	360	(201,279)	508,989
Total SC 9 & SC 22	440,783	(377,629)	(11,551)	(94,344)	7,677	16,516	360	(458,970)	899,753
SC4	(141,049)	(4,508)	(144)	(1,339)	(861)	0	0	(6,851)	(134,198)
SC5	(12,773)	(1,078)	(34)	(320)	(192)	0	0	(1,624)	(11,149)
SC6	8,875	0	0	0	(281)	0	0	(281)	9,156
SC 16 -dusk-to-dawn	(162,327)	(7,212)	(230)	(2,143)	(334)	0	0	(9,919)	(152,408)
SC 16 - energy only	8,029	(4,181)	(133)	(1,243)	(138)	0	11,828	6,133	1,896
SC16 - Total	(154,298)	(11,394)	(363)	(3,386)	(472)	0	11,828	(3,786)	(150,512)
Total Lights	(299,245)	(16,979)	(541)	(5,045)	(1,806)	0	11,828	(12,543)	(286,702)
Total	9,176,975	(4,580,423)	(110,725)	(1,376,077)	(218,661)	123,629	912,268	(5,249,990)	14,426,965

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-E-0493

Impact of Proposed Rate Change on Total Revenue - Rate Year 2*
(Based on Billed Sales and Revenues)

BASED ON NON-LEVELIZED REVENUE REQUIREMENT

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,608,071	192,850	321,007	326,619	5,612	1.8%
SC19	81,039	3,534	14,682	14,928	245	1.7%
Total Res	1,689,110	196,384	335,690	341,547	5,858	1.7%
SC2 Sec Demand Billed	825,516	22,801	140,636	142,850	2,213	1.6%
SC2 Space Htg	24,320	395	3,366	3,436	69	2.1%
SC2 Non Demand Billed	15,347	5,018	4,125	4,034	(91)	-2.2%
SC20	76,003	387	10,601	10,724	123	1.2%
Total Secondary	941,186	28,600	158,729	161,044	2,315	1.5%
SC2 Pri	37,042	159	5,463	5,466	3	0.1%
SC3	365,001	273	48,340	48,862	522	1.1%
SC21	38,704	26	5,114	5,169	55	1.1%
Total Primary	440,747	458	58,917	59,497	580	1.0%
Total Sec & Pri	1,381,933	29,058	217,646	220,541	2,895	1.3%
SC9 (Commercial)	421,844	47	49,973	50,075	102	0.2%
SC22 (Industrial)	346,165	33	39,586	39,877	291	0.7%
Total SC9 & SC22	768,009	80	89,559	89,952	392	0.4%
SC4	14,655	71	5,260	5,098	(162)	-3.1%
SC5	2,936	491	543	529	(14)	-2.6%
SC6	4,206	2	675	683	8	1.2%
SC 16 -dusk-to-dawn	8,370	2,231	4,308	4,129	(179)	-4.2%
SC 16 - energy only	4,866	432	819	827	8	1.0%
SC16 - Total	13,236	2,663	5,127	4,956	(171)	-3.3%
Total Lighting	35,033	3,226	11,605	11,266	(339)	-2.9%
Total	3,874,085	228,748	654,499	663,306	8,806	1.4%

Notes:

* For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-E-0493

Calculation of Incremental Revenue Requirement for Rate Year 2

BASED ON NON-LEVELIZED REVENUE REQUIREMENT

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes	$8,794,637
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (1)	157,000
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$8,637,637
d.	Rate Year Bundled Delivery Revenues Excl. West Point	$294,608,800
e.	Rate Year Overall Percentage Increase in Delivery Revenues (c / d)	2.93190%

Note:

1. GRT/MTA Gross Up Included in Rev Req = 1.79%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-E-0493

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 2

BASED ON NON-LEVELIZED REVENUE REQUIREMENT

Class	Bundled Rate Yr. Delivery Rev. ($)	(Surplus)/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 2.93190% ($)	Rate Yr. Bundled Delivery Rev. at Proposed Rate Level ($)	Proposed Rate Yr. Increase Incl. (Surplus)/Deficiency ($)	Mitigation Adjustment ($)	Adjusted Rate Yr. Increase Incl. Mitigation Adj ($)	Rate Yr. Bundled %
SC1	168,987,200	500,758	169,487,958	4,969,217	174,457,175	5,469,975	41,333	5,511,308	3.3%
SC19	7,107,100	30,250	7,137,350	209,260	7,346,610	239,510	1,741	241,251	3.4%
Total Res	176,094,300	531,008	176,625,308	5,178,477	181,803,785	5,709,485	43,074	5,752,559	3.3%
SC2 Sec Dmd Billed	64,491,580	249,623	64,741,203	1,898,147	66,639,350	2,147,770	15,788	2,163,558	3.4%
SC2 Space Htg	1,149,671	102,250	1,251,921	36,705	1,288,626	138,955	(71,540)	67,414	5.9%
SC2 Non Dmd Billed	2,304,249	(151,750)	2,152,499	63,109	2,215,608	(88,641)	525	(88,116)	-3.8%
SC20	3,620,700	13,608	3,634,308	106,554	3,740,862	120,162	886	121,048	3.3%
Total Sec	71,566,200	213,731	71,779,931	2,104,515	73,884,446	2,318,246	(54,341)	2,263,904	3.2%
SC2 Pri	2,053,600	(55,750)	1,997,850	58,575	2,056,425	2,825	487	3,312	0.2%
SC3	14,998,700	68,022	15,066,722	441,741	15,508,463	509,763	3,674	513,437	3.4%
SC21	1,581,400	7,279	1,588,679	46,578	1,635,257	53,857	387	54,244	3.4%
Total Pri	18,633,700	19,551	18,653,251	546,894	19,200,145	566,445	4,548	570,993	3.1%
Total Sec & Pri	90,199,900	233,282	90,433,182	2,651,409	93,084,591	2,884,691	(49,793)	2,834,897	3.1%
Total SC9 (Com)	11,756,000	(242,750)	11,513,250	337,557	11,850,807	94,807	2,808	97,615	0.8%
Total SC22 (Mfg)	8,398,000	36,710	8,434,710	247,297	8,682,007	284,007	2,057	286,064	3.4%
Total SC 9 & SC 22	20,154,000	(206,040)	19,947,960	584,854	20,532,814	378,814	4,865	383,679	1.9%
SC4	3,819,000	(263,250)	3,555,750	104,251	3,660,001	(158,999)	867	(158,132)	-4.1%
SC5	267,000	(21,000)	246,000	7,212	253,212	(13,788)	60	(13,728)	-5.1%
SC6	274,000	0	274,000	8,033	282,033	8,033	67	8,100	3.0%
SC 16 -dusk-to-dawn	3,469,000	(271,750)	3,197,250	93,740	3,290,990	(178,010)	780	(177,230)	-5.1%
SC 16 - energy only	331,600	(2,250)	329,350	9,656	339,006	7,406	80	7,486	2.3%
SC16 - Total	3,800,600	(274,000)	3,526,600	103,396	3,629,996	(170,604)	860	(169,744)	-4.5%
Total Lights	8,160,600	(558,250)	7,602,350	222,892	7,825,242	(335,358)	1,854	(333,504)	-4.1%
Total	294,608,800	0	294,608,800	8,637,632	303,246,432	8,637,632	0	8,637,631	2.9%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-E-0493

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 2

BASED ON NON-LEVELIZED REVENUE REQUIREMENT

		Rate Year Incremental Competitive Services Revenues							
Class	Adj. Rate Yr. Incr. Incl. (Surplus)/Deficiency ($)	MFC Supply Related Rev. ($)	MFC PP WC Related Rev. ($)	MFC Credit & Collections Related Rev. ($)	POR Credit & Collections Related Rev. ($)	Competitive Metering Related Rev. ($)	Customer Charge Rev. ($)	Total Rate Yr. Incrmtl Comp. Services Rev. ($)	Non-Competitive Rate Yr. Delivery Revenue Incr. ($)
SC1	5,511,308	77,133	(1,139)	17,415	14,378	0	0	107,787	5,403,521
SC19	241,251	2,786	(41)	629	721	0	0	4,095	237,156
Total Res	5,752,559	79,919	(1,180)	18,044	15,099	0	0	111,882	5,640,677
SC2 Sec Dmd Billed	2,163,558	34,624	(327)	7,496	2,015	81,988	0	125,796	2,037,762
SC2 Space Htg	67,414	580	(5)	126	34	1,420	0	2,155	65,259
SC2 Non Dmd Billed	(88,116)	1,371	(13)	297	80	9,854	0	11,589	(99,705)
SC20	121,048	1,483	(14)	321	86	1,985	0	3,861	117,188
Total Sec	2,263,904	38,057	(360)	8,240	2,215	95,247	0	143,400	2,120,504
SC2 Pri	3,312	(348)	(15)	(111)	189	166	0	(119)	3,431
SC3	513,437	(1,965)	(83)	(628)	1,086	905	0	(685)	514,122
SC21	54,244	(74)	(3)	(24)	45	102	0	46	54,198
Total Pri	570,993	(2,387)	(101)	(763)	1,320	1,173	0	(758)	571,751
Total Sec & Pri	2,834,897	35,670	(460)	7,477	3,535	96,420	0	142,642	2,692,256
Total SC9 (Com)	97,615	(2,796)	(118)	(893)	1,008	1,501	0	(1,298)	98,913
Total SC22 (Mfg)	286,064	(1,990)	(84)	(635)	799	1,053	0	(857)	286,921
Total SC 9 & SC 22	383,679	(4,787)	(202)	(1,528)	1,807	2,554	0	(2,156)	385,834
SC4	(158,132)	205	(2)	44	12	0	0	259	(158,391)
SC5	(13,728)	55	(1)	12	3	0	0	69	(13,797)
SC6	8,100	0	0	0	0	0	0	0	8,100
SC 16 -dusk-to-dawn	(177,230)	408	(4)	89	24	0	0	518	(177,748)
SC 16 - energy only	7,486	238	(2)	52	14	0	0	302	7,184
SC16 - Total	(169,744)	646	(6)	141	38	0	0	819	(170,563)
Total Lights	(333,504)	906	(9)	197	53	0	0	1,147	(334,651)
Total	8,637,631	111,708	(1,851)	24,190	20,494	98,974	0	253,515	8,384,116

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-E-0493

Summary of MFC Monthly Targets
For Rates Effective November 1, 2015 and November 1, 2016

BASED ON NON-LEVELIZED REVENUE REQUIREMENT

For Rates Effective November 1, 2015	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Supply Related Component*	$297,827	$353,689	$405,225	$347,391	$325,568	$293,626	$277,348	$357,145	$460,200	$497,409	$452,255	$321,757	$4,389,441
Credit and Collections Related Component	53,991	64,353	73,822	63,298	59,182	53,266	50,174	64,772	84,235	91,355	82,814	58,269	799,532
POR Discount Related Component	50,034	59,680	69,180	59,795	56,057	50,819	47,893	61,961	79,406	86,691	79,060	55,744	756,319
Total	$401,851	$477,722	$548,226	$470,484	$440,807	$397,711	$375,415	$483,878	$623,842	$675,455	$614,129	$435,770	$5,945,291

For Rates Effective November 1, 2016	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Supply Related Component*	$300,542	$352,983	$420,875	$360,400	$329,350	$304,515	$291,010	$352,956	$465,699	$513,606	$477,621	$332,437	$4,501,993
Credit and Collections Related Component	54,661	64,551	76,921	65,889	60,082	55,422	52,677	64,353	85,579	94,489	87,709	60,391	822,724
POR Discount Related Component	51,155	60,479	72,154	62,308	56,988	52,920	50,222	61,633	80,261	89,154	83,390	57,596	778,260
Total	$406,358	$478,012	$569,950	$488,597	$446,420	$412,857	$393,909	$478,943	$631,539	$697,249	$648,720	$450,424	$6,102,977

* MFC Supply Related Component Includes purchased power working capital.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-E-0493

Summary of RDM Monthly Targets
Revenue Targets for Rate Year ending October 31, 2016 (Thousand $)

BASED ON NON-LEVELIZED REVENUE REQUIREMENT

Billed	**Residential SC 1/19**	**Secondary SC 2/20**	**SC 2p/3/21**	**Primary SC 9**	**SC 22**	**TOTAL Billed**	**Unbilled**	**Total**
Nov-15	$11,531	$4,539	$1,234	$686	$550	$18,540	$57	$18,597
Dec-15	12,929	4,462	1,229	762	538	19,920	(1,885)	18,035
Jan-16	14,062	5,049	1,183	711	498	21,503	(1,548)	19,955
Feb-16	12,862	4,678	1,165	671	439	19,815	204	20,019
Mar-16	12,326	4,501	1,159	695	523	19,204	1,329	20,533
Apr-16	11,592	4,403	1,141	682	539	18,357	1,054	19,411
May-16	11,155	4,314	1,150	710	506	17,835	1,513	19,348
Jun-16	13,280	5,693	2,114	1,364	891	23,342	(1,705)	21,637
Jul-16	18,668	7,356	2,362	1,564	891	30,841	799	31,640
Aug-16	20,185	7,547	2,013	1,445	867	32,057	116	32,173
Sep-16	18,384	7,480	2,188	1,341	814	30,207	(1,233)	28,974
Oct-16	13,392	5,479	1,296	774	567	21,508	777	22,285
RY ending Oct 2016	$170,366	$65,501	$18,234	$11,405	$7,623	$273,129	($522)	$272,607

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-E-0493

Summary of RDM Monthly Targets
Revenue Targets for Rate Year ending October 31, 2017 (Thousand $)

BASED ON NON-LEVELIZED REVENUE REQUIREMENT

Billed	**Residential SC 1/19**	**Secondary SC 2/20**	**SC 2p/3/21**	**Primary SC 9**	**SC 22**	**TOTAL Billed**	**Unbilled**	**Total**
Nov-16	$11,813	$4,625	$1,249	$660	$557	$18,904	$34	$18,938
Dec-16	13,220	4,497	1,141	672	496	20,026	(1,084)	18,942
Jan-17	14,649	5,217	1,208	693	514	22,281	(1,722)	20,559
Feb-17	13,382	4,838	1,186	657	464	20,527	(576)	19,951
Mar-17	12,638	4,544	1,153	652	519	19,506	1,850	21,356
Apr-17	12,039	4,561	1,162	670	543	18,975	845	19,820
May-17	11,600	4,506	1,309	767	566	18,748	1,062	19,810
Jun-17	13,434	5,707	1,980	1,221	826	23,168	(326)	22,842
Jul-17	19,135	7,530	2,329	1,467	873	31,334	1,734	33,068
Aug-17	20,961	7,828	2,275	1,538	990	33,592	(1)	33,591
Sep-17	19,494	7,919	2,394	1,427	886	32,120	(1,975)	30,145
Oct-17	13,962	5,683	1,338	767	579	22,329	725	23,054
RY ending Oct 2017	$176,327	$67,455	$18,724	$11,191	$7,813	$281,510	$566	$282,076

Orange and Rockland Utilities, Inc.
Cases 14-E-0493 & 14-G-0494

GAS REVENUE ALLOCATION AND RATE DESIGN

1. Revenue Allocation

The incremental revenue requirement for each Rate Year was adjusted by subtracting amounts included for New York State Gross Receipts and Franchise Tax surcharge revenues, Municipal Tax surcharge revenues and Metropolitan Transportation Authority Business Tax surcharge revenues. For each Rate Year, before the adjusted incremental revenue requirement was applied to each customer class, the Rate Year delivery revenues for each class were realigned in a revenue neutral manner to reduce interclass deficiencies and surpluses as indicated by the embedded cost of service study ("ECOS"). For each Rate Year, deficiency and surplus indications have been reduced by one-fourth. The Rate Year delivery revenue increase was then allocated among the Service Classifications ("SC") in proportion to the relative contribution made by each SC's realigned Rate Year delivery revenue to the total realigned Rate Year delivery revenue.

2. Rate Design

The rate design process for each rate year consists of the following four steps:

- Determine revised competitive service charges and associated delivery revenue changes;
- Adjust class-specific delivery revenue increases to determine non-competitive delivery revenue increases;
- Determine first block charges and associated changes in delivery revenue;

- Adjust class-specific non-competitive delivery revenue increases for revenue changes associated with increases in first block charges; and apply non-competitive delivery revenue increases, adjusted for revenue changes associated with increases in first block charges, to the per-Ccf charges within each SC.

a. Revised Competitive Service Charges and Associated Delivery Revenue Changes

The competitive delivery components include the billing and payment processing ("BPP") charge; the Merchant Function Charge ("MFC") fixed components, that is the MFC procurement and credit and collections components; and the purchase of receivables ("POR") credit and collections component. For each Rate Year, revised revenue levels for the MFC fixed components and POR credit and collections component were based on percentages of delivery revenue as determined in the ECOS study.[1] The revised competitive service charge revenue levels for each Rate Year were compared with competitive service charge revenues determined based on competitive service charges for the previous Rate Year to determine the change in competitive service revenues.

b. Determination of Class-Specific Non-Competitive Delivery Revenue Increases

For each Rate Year, the revenue changes associated with the competitive service charges were used to adjust the class-specific delivery revenue increases to determine class-specific non-competitive delivery revenue increases.

[1] There were no revenue changes associated with the BPP Charge since it will remain at its current level during the term of the Gas Rate Plan.

c. Revised First Block Charges and Associated Delivery Revenue Changes

In RY1, first block charges (for the first 3 Ccf or less) for SC No. 1 and SC No. 6 – Rate Schedule 1A are increased to $20.00. First block charges (for the first 3 Ccf or less) for SC No. 2 and SC No. 6 – Rate Schedule 1B are increased to $30.00. The first block charge (for the first 100 Ccf or less) for SC No. 6 – Rate Schedule II remains at $255.18. These first block charges will remain fixed at these levels in RY2 and RY3.

d. Application of Delivery Revenue Increase Adjusted for Revenue Associated with First Block Charges Within Each Service Classification

For RY1, the remaining incremental revenue requirement in each class, after subtracting any revenue associated with increases in the first block charges as described above, shall be applied to all rate block charges, except the first block charges, on an equal percentage basis. The revenue impacts of the rate design changes on firm customers are summarized in Schedule 1 of this Appendix.

3. Competitive Service Charges

a. Merchant Function Charge

For the term of the Gas Rate Plan, the Company will continue to implement the MFC, as set forth in the Company's gas tariff. The MFC fixed component monthly targets (commodity procurement and credit and collections) for RY1, RY2 and RY3 are set forth in Schedule 4 of this Appendix.

b. Transition Adjustment for Competitive Services

For the term of the Gas Rate Plan, the Company will continue to implement the Transition Adjustment for Competitive Services ("TACS"), as set forth in the Company's gas tariff.

c. POR Discount

For the term of the Gas Rate Plan, the Company will continue to implement the POR discount, as set forth in the Company's gas tariff**.**

d. Billing and Payment Processing Charge

The Company's billing and payment processing charge will remain at its current level, $1.02 per bill.

4. Distributed Generation Rates

The per Ccf rates and contract demand charges for service under Rider B (non-residential DG rate) and Rider C (residential DG rate) have been increased at the percentage increases in per Ccf delivery service revenues for the otherwise applicable service classification (i.e., SC No. 2 for Rider B and SC No. 1 for Rider C). The initial block charges for Riders B and C have been increased by the overall delivery revenue percentages for the otherwise applicable service classifications.

By November 1, 2015, 2016 and 2017 the Company will file tariff revisions implementing the rate changes for RY1, RY2, and RY3, respectively.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Appendix 19 - Gas Revenue Allocation and Rate Design

Index of Schedules

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Impact of Proposed Rate Change on Total Revenue - Rate Year 1*
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Type of Service	Total Sales (Mcf)	Customers	Revenue At Current Rates ($000's)	Revenue At Proposed Rates ($000's)	Change ($000's)	Percent Change
1 / 6 IA	Residential	13,838,717	121,128	176,581.6	189,558.4	12,976.9	7.3%
1	Non Residential	774,095	5,762	9,604.7	10,322.3	717.7	7.5%
2 / 6 IB	Commercial	4,112,803	6,133	42,597.0	44,654.3	2,057.3	4.8%
6 II	Large Commercial	1,506,734	110	14,678.8	15,330.6	651.8	4.4%
	Total Firm	20,232,348	133,133	243,462.0	259,865.7	16,403.6	6.7%
5	Firm Dual Fuel	0	0	0.0	0.0	0.0	0.0%
7	NGV	0	0	0.0	0.0	0.0	0.0%
8	Interruptible Trans	1,974,196	93	2,098.9	2,098.9	0.0	0.0%
9	Withdrawable Trans	2,248,900	1	798.9	798.9	0.0	0.0%
	Total	24,455,444	133,227	246,359.8	262,763.4	16,403.6	6.7%

* For comparison purposes, an estimated cost of gas supply has been included in the SC No. 6 revenue. This is equivalent on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Calculation of Incremental Revenue Requirement for Rate Year 1

Based on Levelized Revenue Requirement

a.	Incremental Revenue Requirement for the Rate Year Including Gross Receipts/MTA Taxes	$16,403,952
b.	Less Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (1)	$327,091
c.	Incremental Revenue Requirement for the Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$16,076,861
d.	Rate Year Bundled Delivery Revenues for the Rate Year for Firm Service Classification Nos. 1, 2, and 6	$112,612,315
e.	Rate Year Overall Percentage Increase in Delivery Revenues (c / d)	14.27629%

Note:

1. GRT/MTA Gross Up Included in Rev Req = 1.99%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 1

Based on Levelized Revenue Requirement

	(1)	(2)	(3)=(1)+(2)	(4)	(5)=(3)+(4)	(6)=(2)+(4)	(7)
Class	Rate Year Bundled Delivery Rev. ($)	(Surplus)/ Deficiency (a) ($)	Adjusted Rate Year Del Revenue ($)	Rate Increase 14.276% ($)	Adj Delivery Rev incl Rate Incr at Rate Yr Rate Level ($)	Rate Year Increase Incl. (Surplus)/Deficiency ($)	Rate Year % Increase
SC Nos. 1 & 6 RS IA	91,777,915	279,588	92,057,503	13,142,396	105,199,899	13,421,984	14.62%
SC Nos. 2 & 6 RS 1B & II	20,834,400	(279,588)	20,554,812	2,934,465	23,489,277	2,654,877	12.74%
Total	112,612,315	0	112,612,315	16,076,861	128,689,176	16,076,861	

Notes:

(a) Represents 1/4 of the (Surplus)/Deficiency Indications

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 1

Based on Levelized Revenue Requirement

	(1)	(2)	(3)	(4)=(1)-(2)-(3)
		Incremental Competitve Svc Revenues		
Service Class	Adj Rate Year Incr. Incl (Surplus)/Deficiency Incl Mitigation Adj. Delivery Rev. (a) ($)	MFC Fixed Component Related Revenue (b) ($)	POR Credit & Collections Related Revenue (c) ($)	Non-Competitive Rate Year Delivery Revenue Increase ($)
SC Nos. 1 & 6 RS IA	13,421,984	387,946	(232,133)	13,266,171
SC Nos. 2 & 6 RS 1B & II	2,654,877	7,164	2,365	2,645,349
Total	16,076,861	395,110	(229,768)	15,911,520

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Impact of Proposed Rate Change on Total Revenue - Rate Year 2*
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Type of Service	Total Sales (Mcf)	Customers	Revenue At Current Rates ($000's)	Revenue At Proposed Rates ($000's)	Change ($000's)	Percent Change
1 / 6 IA	Residential	13,662,881	121,993	187,844.1	200,780.7	12,936.7	6.9%
1	Non Residential	806,227	5,826	10,709.6	11,483.7	774.1	7.2%
2 / 6 IB	Commercial	4,119,236	6,266	44,809.9	46,847.7	2,037.9	4.5%
6 II	Large Commercial	1,494,622	111	15,207.1	15,863.1	656.0	4.3%
	Total Firm	20,082,966	134,196	258,570.6	274,975.2	16,404.6	6.3%
5	Firm Dual Fuel	0	0	0.0	0.0	0.0	0.0%
7	NGV	0	0	0.0	0.0	0.0	0.0%
8	Interruptible Trans	1,974,196	93	2,098.9	2,098.9	0.0	0.0%
9	Withdrawable Trans	2,248,900	1	798.9	798.9	0.0	0.0%
	Total	24,306,062	134,290	261,468.4	277,873.0	16,404.6	6.3%

* For comparison purposes, an estimated cost of gas supply has been included in the SC No. 6 revenue. This is equivalent on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Calculation of Incremental Revenue Requirement for Rate Year 1

Based on Levelized Revenue Requirement

a.	Incremental Revenue Requirement for the Rate Year Including Gross Receipts/MTA Taxes	$16,403,952
b.	Less Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (1)	$327,091
c.	Incremental Revenue Requirement for the Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$16,076,861
d.	Rate Year Bundled Delivery Revenues for the Rate Year for Firm Service Classification Nos. 1, 2, and 6	$128,068,582
e.	Rate Year Overall Percentage Increase in Delivery Revenues (c / d)	12.55332%

Note:

1. GRT/MTA Gross Up Included in Rev Req = 1.99%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 2

Based on Levelized Revenue Requirement

Class	(1) Rate Year Bundled Delivery Rev. ($)	(2) (Surplus)/ Deficiency (a) ($)	(3)=(1)+(2) Adjusted Rate Year Del Revenue ($)	(4) Rate Increase 12.553% ($)	(5)=(3)+(4) Adj Delivery Rev incl Rate Incr at Rate Yr Rate Level ($)	(6)=(2)+(4) Rate Year Increase Incl. (Surplus)/Deficiency ($)	(7) Rate Year % Increase
SC Nos. 1 & 6 RS IA	104,532,172	279,588	104,811,760	13,157,356	117,969,116	13,436,944	12.85%
SC Nos. 2 & 6 RS 1B & II	23,536,410	(279,588)	23,256,822	2,919,503	26,176,325	2,639,915	11.22%
Total	128,068,582	0	128,068,582	16,076,859	144,145,441	16,076,859	

Notes:

(a) Represents 1/4 of the (Surplus)/Deficiency Indications

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 2

Based on Levelized Revenue Requirement

	(1)	(2)	(3)	(4)=(1)-(2)-(3)
		Incremental Competitve Svc Revenues		
Service Class	Adj Rate Year Incr. Incl (Surplus)/Deficiency Incl Mitigation Adj. Delivery Rev. (a) ($)	MFC Fixed Component Related Revenue (b) ($)	POR Credit & Collections Related Revenue (c) ($)	Non-Competitive Rate Year Delivery Revenue Increase ($)
SC Nos. 1 & 6 RS IA	13,436,944	168,989	93,857	13,174,098
SC Nos. 2 & 6 RS 1B & II	2,639,915	3,119	9,208	2,627,588
Total	16,076,859	172,108	103,065	15,801,686

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Impact of Proposed Rate Change on Total Revenue - Rate Year 3*
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Type of Service	Total Sales (Mcf)	Customers	Revenue At Current Rates ($000's)	Revenue At Proposed Rates ($000's)	Change ($000's)	Percent Change
1 / 6 IA	Residential	13,664,049	123,043	201,077.8	212,981.2	11,903.4	5.9%
1	Non Residential	830,134	5,941	11,806.3	12,534.0	727.7	6.2%
2 / 6 IB	Commercial	4,222,751	6,452	48,036.5	50,840.6	2,804.1	5.8%
6 II	Large Commercial	1,494,420	112	15,862.8	16,832.4	969.5	6.1%
	Total Firm	20,211,354	135,548	276,783.5	293,188.2	16,404.7	5.9%
5	Firm Dual Fuel	0	0	0.0	0.0	0.0	0.0%
7	NGV	0	0	0.0	0.0	0.0	0.0%
8	Interruptible Trans	1,974,196	93	2,098.9	2,098.9	0.0	0.0%
9	Withdrawable Trans	2,248,900	1	798.9	798.9	0.0	0.0%
	Total	24,434,450	135,642	279,681.2	296,085.9	16,404.7	5.9%

* For comparison purposes, an estimated cost of gas supply has been included in the SC No. 6 revenue. This is equivalent on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Calculation of Incremental Revenue Requirement for Rate Year 3

Based on Levelized Revenue Requirement

a.	Incremental Revenue Requirement for the Rate Year Including Gross Receipts/MTA Taxes	$5,783,805
b.	Less Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (1)	$115,328
c.	Incremental Revenue Requirement for the Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$5,668,477
d.	Rate Year Bundled Delivery Revenues for the Rate Year for Firm Service Classification Nos. 1, 2, and 6	$144,804,651
e.	Rate Year Overall Percentage Increase in Delivery Revenues (c / d)	3.91457%

Note:

1. GRT/MTA Gross Up Included in Rev Req = 1.99%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 3

Based on Levelized Revenue Requirement

	(1)	(2)	(3)=(1)+(2)	(4)	(5)=(3)+(4)	(6)=(2)+(4)	(7)
Class	Rate Year Bundled Delivery Rev. ($)	(Surplus)/ Deficiency (a) ($)	Adjusted Rate Year Del Revenue ($)	Rate Increase 12.553% ($)	Adj Delivery Rev incl Rate Incr at Rate Yr Rate Level ($)	Rate Year Increase Incl. (Surplus)/Deficiency ($)	Rate Year % Increase
SC Nos. 1 & 6 RS IA	118,118,953	279,588	118,398,541	4,634,794	123,033,335	4,914,382	4.16%
SC Nos. 2 & 6 RS 1B & II	26,685,698	(279,588)	26,406,110	1,033,686	27,439,796	754,098	2.83%
Total	144,804,651	0	144,804,651	5,668,480	150,473,131	5,668,480	

Notes:

(a) Represents 1/4 of the (Surplus)/Deficiency Indications

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 3

Based on Levelized Revenue Requirement

	(1)	(2)	(3)	(4)=(1)-(2)-(3)
		Incremental Competitve Svc Revenues		
Service Class	Adj Rate Year Incr. Incl (Surplus)/Deficiency Incl Mitigation Adj. Delivery Rev. (a) ($)	MFC Fixed Component Related Revenue (b) ($)	POR Credit & Collections Related Revenue (c) ($)	Non-Competitive Rate Year Delivery Revenue Increase ($)
SC Nos. 1 & 6 RS IA	4,914,382	70,921	38,377	4,805,084
SC Nos. 2 & 6 RS 1B & II	754,098	(304)	3,331	751,072
Total	5,668,480	70,617	41,707	5,556,155

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Temporary Surcharge to Be Recovered thorugh Monthly Gas Adjustment in Rate Year 3

Based on Levelized Revenue Requirement

Temporary Surcharge	$10,620,147	
Less GRT/MTA Tax	211,271	
Net Temporary Surcharg	$10,408,876	
Rate Year Sales (CCF)	202,113,537	
MGA Surcharge	$0.05150	per CCF

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Summary of MFC Monthly Targets
For Rates Effective November 1, 2015, November 1, 2016 and November 1, 2017

Based on Levelized Revenue Requirement

For Rates Effective November 1, 2015	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Supply Related Component	$95,908	$179,564	$263,865	$261,292	$216,959	$146,028	$81,841	$48,765	$34,131	$31,274	$32,270	$40,681	$1,432,577
Credit and Collections Related Component	23,180	43,414	63,810	63,185	52,459	35,300	19,781	11,784	8,250	7,561	7,796	9,822	346,343
POR Discount Related Component	36,705	63,543	89,969	88,348	74,992	50,325	31,432	19,351	13,314	12,328	12,947	17,147	510,403
Total	$155,793	$286,521	$417,644	$412,825	$344,410	$231,654	$133,055	$79,900	$55,695	$51,163	$53,013	$67,650	$2,289,323

For Rates Effective November 1, 2016	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Supply Related Component	$107,685	$197,404	$296,012	$292,441	$242,548	$164,911	$94,015	$54,244	$38,187	$35,514	$37,029	$44,648	$1,604,637
Credit and Collections Related Component	26,025	47,726	71,584	70,718	58,646	39,866	22,724	13,109	9,230	8,586	8,947	10,780	387,940
POR Discount Related Component	41,147	69,929	100,872	98,820	83,743	56,918	36,110	21,485	14,907	14,001	14,882	18,890	571,705
Total	$174,858	$315,059	$468,467	$461,979	$384,936	$261,695	$152,849	$88,837	$62,324	$58,101	$60,858	$74,318	$2,564,282

For Rates Effective November 1, 2017	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Supply Related Component	$110,502	$203,292	$304,979	$317,204	$251,999	$168,911	$99,289	$55,806	$41,069	$37,418	$37,013	$47,595	$1,675,077
Credit and Collections Related Component	26,706	49,149	73,752	76,707	60,931	40,832	24,000	13,487	9,927	9,046	8,942	11,491	404,970
POR Discount Related Component	42,284	71,986	103,926	107,105	86,990	58,382	38,159	22,201	16,069	14,731	14,834	20,136	596,803
Total	$179,492	$324,427	$482,657	$501,016	$399,920	$268,125	$161,448	$91,493	$67,065	$61,196	$60,789	$79,222	$2,676,850

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Summary of Proposed Revenue Per Customer Targets by Rate Year

Based on Levelized Revenue Requirement

	Group A	RY1	RY2	RY3*
LINE 1	Non-Competitive Delivery Revenue	$102,537,710	$115,193,898	$127,867,402
LINE 2	Number of Bills	1,521,421.0	1,532,574.0	1,546,546.0
LINE 3	Number of Customers (LINE 2/12)	126,785.1	127,714.5	128,878.8
LINE 4	**RPC Target (LINE 1/LINE 3)**	**$808.75**	**$901.96**	**$992.15**

	Group B	RY1	RY2	RY3*
LINE 5	Non-Competitive Delivery Revenue	$23,360,049	$26,043,340	$30,258,782
LINE 6	Number of Bills	74,791.0	76,417.7	78,676.4
LINE 7	Number of Customers (LINE 6/12)	6,232.6	6,368.1	6,556.4
LINE 8	**RPC Target (LINE 5/LINE 7)**	**$3,748.04**	**$4,089.66**	**$4,615.15**

* Includes Rate Year 3 Temporary Surcharge Revenue

ORANGE AND ROCKLAND UTILITIES, INC.

Case 14-G-0494

Illustrative Example of Determination of RPC Revenue Target for RY1

Based on Levelized Revenue Requirement

		Actual Customer Counts	
		Group A Customers	**Group B Customers**
	Nov-15	126,700	6,100
	Dec-15	126,750	6,140
	Jan-16	126,800	6,180
	Feb-16	126,850	6,220
	Mar-16	126,900	6,260
	Apr-16	126,950	6,300
	May-16	127,000	6,340
	Jun-16	127,050	6,380
	Jul-16	127,100	6,420
	Aug-16	127,150	6,460
	Sep-16	127,200	6,500
	Oct-16	127,250	6,540
a.	Average Customers (RY1)	**126,975**	**6,320**
b.	RPC Target (RY1)	**$808.75**	**$3,748.08**
c.	Allowed Revenue (a x b)	**$102,691,031**	**$23,687,866**

Orange and Rockland Utilities, Inc.
Cases 14-E-0493 & 14-G-0494

Electric, Gas, Common Capital Program Reporting Requirements

The Company will file a quarterly report within 45 days after the end of each of the first three calendar quarters of each rate year (e.g., the report for the quarter November – January 2016 would be due by March 15, 2016). The annual report would be due 60 days after the end of the last quarter in each rate year (e.g., by December 31, 2016 for Rate Year 1). The quarterly and annual reports will include the following information as outlined below. The quarterly reports will support the capital projects and blankets, and will reflect cumulative expenditures[1] and plant additions[2] during the rate year. The reports will explain any significant changes in project timelines or cost estimates exceeding 15%, as well as an explanation of any new priority capital projects budgeted over $1.0 million for Electric, and $0.5 million for Gas and Common. Reports for illustrative purposes are attached.

Quarterly Reports will include:

- Summary of Capital Expenditures - Blankets, Regular Projects, and All Other
- Summary of Capital Additions - Blankets, Regular Projects, and All Other
- Capital Projects over $1.0 million (Electric); over $0.5 million (Gas and Common)
    - Rate Case – In-service date
    - Projected in-service date
    - Breakdown of expenditures (e.g., payroll, accounts payable, and materials and supplies categories)
    - Comparison of rate year budgeted vs. rate year actual to date
    - Comparison of calendar year vs. calendar year actual to date
    - Narrative on cost delta's exceeding 15%
    - Narrative on project design, permitting and or construction status (including a detailed construction schedule for each project).
    - Inclusion of any new projects exceeding $1.0 million (Electric), $0.5 million (Gas and Common)
    - Capital project authorized documents for any projects exceeding $1.0 million (Electric), $0.5 million (Gas and Common) that were authorized during the previous quarter.

Annual Reports:

- Summary of Capital Expenditures - Blankets, Regular Projects, and All Other
- Summary of Capital Additions - Blankets, Regular Projects, and All Other
- Blankets - individual comparison of actual expenditures vs. rate case expenditures

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[1] Expenditures – this includes all charges to active and on-going construction projects

[2] Plant Additions – the increase in plant-in-service resulting from a transfer of costs from ongoing construction projects to plant-in-service upon completion of the project.

- All Other Projects - individual comparison of actual expenditures vs. rate case expenditures
- Regular Projects – individual comparison of actual expenditures vs. rate case expenditures
- Regular Projects
  - Rate Case – In-service date
  - Projected in-service date
  - Breakdown of expenditures (e.g., payroll, accounts payable, and materials and supplies categories)
  - Comparison of rate year budgeted vs. rate year actual to date
  - Comparison of calendar year vs. calendar year actual to date
  - Narrative on cost delta's exceeding 15%
  - Narrative on project design, permitting and or construction status (including a detailed construction schedule for each project).
  - Inclusion of any new projects exceeding $1.0 million (Electric), $0.5 million (Gas and Common)
  - Capital project authorized documents for any projects exceeding $1.0 million (Electric), $0.5 million (Gas and Common) that were authorized during the previous quarter.

Orange and Rockland Utilities, Inc.
Cases 14-E-0493 and 14-G-0494

Non-Affiliate Use of the Orange and Rockland Corporate Name

Standards of Competitive Conduct

The following standards of competitive conduct shall govern the Delivery Company's relationship with any energy supply and energy service affiliates:

(i)(a) There are no restrictions on affiliates using the same name, trade names, trademarks, service name, service mark or a derivative of a name, of the Holding Company[1] or the Delivery Company, or in identifying itself as being affiliated with the Holding Company or the Delivery Company. However, no non-affiliate, whether or not engaged in the energy supply and/or energy service business, will be allowed to use the same name, trade names, trademarks, service names, service marks, logos or a derivative of a name of Delivery Company except in the following limited circumstances:

(1) In the event an affiliate business, or the assets of that business, is sold or otherwise is no longer an affiliate, such non-affiliated company will be allowed to use the name, trade names, trademarks, service names, service marks or a derivative of a name of Holding Company or Delivery Company in New York State for a period not exceeding six months, provided that such use is restricted to (i) use of the Holding Company or Delivery Company logo during the pendency of the transition to new ownership (*e.g.*, vehicle and facility signage) and (ii) educating customers about the sales transaction and the impacts on customers. During that six-month period, DPS Staff will be given the opportunity to preview any communication using Holding Company or Delivery Company's name or logo that is to be sent from a non-affiliate to Delivery Company's utility customers in New York. Delivery Company shall supply a copy of any such communication to DPS Staff in advance of its actual use. DPS Staff may reject any customer communication it deems not in compliance with this section by providing Delivery Company with written notice of its specific objections. A communication will be deemed acceptable unless DPS Staff objects in a writing received by the Delivery Company within five business days of DPS Staff's receipt of such communication from Delivery Company. DPS Staff and the Delivery Company will work collaboratively to resolve any disagreement as to the content of the communication.

(2) Delivery Company and/or Holding Company may continue to license, in the same manner as has Delivery Company and/or Holding Company have done, the Delivery Company and/or Holding Company name, trade names, trademarks, service names, service marks, logos or a derivative of a name of Delivery Company for use in movie and/or television productions.

(3) Delivery Company and/or Holding Company may allow industry organizations of which Delivery Company, Holding Company, or their affiliates are members to use the

[1] For purposes of this Appendix, the Holding Company shall mean Consolidated Edison, Inc. and the Delivery Company shall mean Orange and Rockland Utilities, Inc.'s New York regulated operations.

Delivery Company name, trade names, trademarks, service names, service marks, logos or a derivative of a name of Delivery Company.
(4) Delivery Company and/or Holding Company may license the use of the Delivery Company name, trade names, trademarks, service names, service marks, logos or a derivative of a name of Delivery Company, to a non-affiliate to assist with the marketing of Commission-approved energy efficiency programs.

(b) The Delivery Company will not provide sales leads for customers in its service territory to any affiliate, including the ESCO, and will refrain from giving any appearance in promotional advertising or otherwise that the Delivery Company speaks on behalf of an affiliate or that an affiliate speaks on behalf of the Delivery Company. If a customer requests information about securing any service or product offered within the service territory by an affiliate, the Delivery Company will provide a list of all companies known to Delivery Company operating in the service territory who provide the service or product, which may include an affiliate, but the Delivery Company will not promote its affiliate.

ORANGE AND ROCKLAND UTILITIES, INC.
Electric Base Rate Case 14-E-0493
Settlement Position - Labor

	Start Date	Rate Year 1 # of positions		Rate Year 1		Rate Year 2 # of positions	Rate Year 2	Total # of positions	Total
Weekly Employees:									
Distribution Equipment Technicians	Jul-15		3	$ 189,479			$ 193,037	3	$ 382,516
Monthly Employees:									
Distribution Equipment Supervisor	Jul-15		1	93,440			95,309	1	188,749
Smart Grid Engineers	Jul-15		1	85,965			87,684	1	89,438
Distributed Generation Resource	Aug-15		1	85,992			87,712	1	173,704
Sr. Specialist - NERC Compliance Program	Oct-15		1	89,027			90,807	1	179,834
Sr. Specialist - Compliance, Substation Operations	Oct-15		1	89,027			90,807	1	179,834
Sr. Specialist - Compliance, Control Center Operations	Oct-15		1	89,027			90,807	1	179,834
Engineering Distributed Generation Analysts	Nov-15		1	59,802			60,998	1	120,800
Engineering Distributed Generation Analysts	Nov-15		1	59,802			60,998	1	120,800
Chief Construction Inspector - Vegetation Mgt.	Jul-15		1	74,752			76,247	1	150,999
Transferred Energy Transition Implementation Plan (ETIPs) Employees	Jan-16	*	8	420,369	**		504,448	8	924,816
			20	$ 1,336,682			$ 1,438,854	20	$ 2,691,324
*** Program Specialist - Outreach & Education	Nov-15		2	171,983			175,423	2	347,406
*** Program Manager - Outreach & Education	Nov-15		1	96,108			98,031	1	194,139
			3	$ 268,091			$ 273,454	3	$ 541,545
			23	$ 1,604,773			$ 1,712,307	23	$ 3,232,869

*The total Labor Expense in RY 1 regarding the ETIPs employees amounts to $594,161; requesting 8 FTEs that were transferred effective 01/01/2016. The Labor was allocated using a common expense allocation, O&R Electric 70.75%, O&R Gas 29.25%.

**The total Labor Expense in RY 2 regarding the ETIPs employees amounts to $713,000 annualized; requesting 8 FTEs that were transferred effective 01/01/2016. The Labor was allocated using a common expense allocation, O&R Electric 70.75%, O&R Gas 29.25%.

***For the term of this agreement, the costs of these positions (not to exceed $950K including finge benefits) will be recovered through the $9.5M Pomona Project.

ORANGE AND ROCKLAND UTILITIES, INC.
Gas Base Rate Case 14-G-0494
Settlement Position - Labor

	Start Date		Rate Year 1 # of positions	Rate Year 1		Rate Year 2 # of positions	Rate Year 2	Rate Year 3 # of positions	Rate Year 3	Total # of positions	Total
Weekly Employees:											
Locator	Nov-15		1	$ 85,833			$ 88,537		$ 90,161	1	$ 264,531
Gas Fitter - Northern Division	Jul-15		1	66,033			67,829		69,073	1	202,935
Gas Fitter - Northern Division	Jul-15		1	66,033			67,829		69,073	1	202,935
Gas Troubleshooter - Northern Division	Jan-16		1	74,672			92,356		94,243	1	261,271
Gas Troubleshooter - Northern Division	Jan-16		1	74,672			92,356		94,243	1	261,271
Monthly Employees:											
Compliance Supervisor - Northern Division	Jul-15		1	101,167			103,190		105,254	1	309,611
Compliance Supervisor - Eastern Divison	Jul-15		1	101,167			103,190		105,254	1	309,611
Gas Marketing Resources Program	Aug-15		1	91,101			92,923		94,781	1	278,805
Gas Marketing Resources Program	Aug-15		1	91,101			92,923		94,781	1	278,805
Transferred Energy Transition Implementation Plan (ETIPs) Employees	Jan-16	*	8	173,792	**		208,553		212,724	8	595,068
			17	$ 925,571			$ 1,009,686		$ 1,029,587	17	$ 2,964,843

*The total Labor Expense in RY 1 regarding the ETIPs employees amounts to $594,161; requesting 8 FTEs that were transferred effective 01/01/2016. The Labor was allocated using a common expense allocation, O&R Electric 70.75%, O&R Gas 29.25%.

**The total Labor Expense in RY 2 regarding the ETIPs employees amounts to $713,000 annualized; requesting 8 FTEs that were transferred effective 01/01/2016. The Labor was allocated using a common expense allocation, O&R Electric 70.75%, O&R Gas 29.25%.

Orange and Rockland Utilities, Inc.

Cases 14-E-0493 & 14-G-0494

Appendix 23: Reliability Surcharge Mechanism (RSM)

The Reliability Surcharge Mechanism (RSM) allows Orange and Rockland Utilities, Inc. (ORU) to recover the carrying costs on incremental capital expenditures associated with the replacement of Leak Prone Pipe (LPP) above the levels established under the Gas Rate Plan, subject to the conditions set forth below.

1.) Both the actual cumulative revenue requirement (CRR) of the costs of LPP replacement incurred by the Company and the actual cumulative LPP footage replaced by the Company as of the end of the prior Rate Year must exceed the targets shown on page 4 of this Appendix 23.
2.) Actual costs are recoverable up to a Cap. The Cap is set as follows:
    a. The Cap is equal to the cumulative adjusted revenue requirement (CARR) plus 1.5 times the percentage by which the actual cumulative LPP footage replaced exceeds the cumulative LLP footage replacement target provided for in rates.
    b. The CARR is the CRR in rates increased by 3%, 6%, and 9% for RY1, RY2, and RY3, respectively.
3.) Recovery of the incremental costs is to begin no earlier than the start of RY2.
4.) All recoveries shall be refunded to ratepayers during the twelve month period ending October 31, 2019 (defined as RY4 although technically not a rate year), if provision 1 above is not met for the cumulative targets for RY3 at the end of RY3.

Pages 3 and 4 of the attachment to this Appendix 23 show the CRR in rates and how the RSM works if the Company meets the targets exactly as designed in rates. The Gas Rate Plan provides $0.945 million, $4.500 million and $10.926 million in CRR and cumulative LPP footage replacement of 110,880, 227,040, and 348,480 through RY1, RY2, and RY3, respectively. The CARR is $0.973 million, $4.770 million, and $11.910 million through RY1, RY2, and RY3, respectively. Since both the footage and the costs are consistent with the amounts reflected in rates, the Company does not require the recovery of any carrying costs through the RSM.

Pages 5 and 6 of the attachment to this Appendix 23 provide an example of how the amount the Company will be allowed to recover through the RSM will be calculated. In the example, ORU exceeds both the LPP footage replacement target and the associated RR allowed for each of the three Rate Years. At the end of RY1, the LPP footage replaced exceeded the target by 4.51%, and had an actual RR of $1.027 million. Since the actual RR is below the Cap of $1.039 million, but above the CARR of $0.945 million, ORU is allowed to recover $0.081 million in RY2, i.e., the difference between the allowed of $1.027 million (allowed is the lower of the actual or the Cap) and the CARR of $0.945 million. The Cap of $1.039 million is determined by increasing the CARR in rates of $0.973 million by 1.5 times the LPP target variance of 4.51% times. As of the end of RY2, ORU would be allowed to recover a total of $0.345 million through the RSM in RY2 and RY3; and as of the end of RY3 ORU would be allowed to recover a total of $0.803 million through the RSM in RY2, RY3, and RY4.

ORU may file at the end of RY1, RY2, and RY3 with actuals for the first 11 months, 23 months, and 35 months, respectively, along with one month forecast for each of those Rate Years, to permit the RSM to go into effect November 1. The final reconciliation for the RSM, however, shall be for the actuals for the 36 months. Inputs shall be the actual monthly plant additions, removal costs, salvage, feet replaced and depreciation. Actual depreciation may be calculated as the actual average monthly plant-in-service balance times 0.00181, the monthly composite depreciation rate used in the Gas Rate Plan, instead of actuals.

If a new gas rate plan does not go into effect at the end of the Gas Rate Plan, incremental costs beyond the three years shall be recovered as determined in Case 15-G-0151.

Orange & Rockland Utilities, Inc.
Case 14-G-0494
Reliability Surcharge Mechanism (RSM)
Revenue Requirement for Leak Prone Pipe Replacement
"In Rates"

	Plant in Service LPP 14-G-0494					Depreciation Reserve LPP 14-G-0494					Net Plant	Replaced
	Start	Add.	Ret.	End	Avg.	Start	Depr.	Ret.+Sal.	End	Avg.	Avg.	Feet
Nov-15	$ -	$ 475.7	$ 26.9	$ 448.8	$ 224.4	$ -	$ 0.4	$ 26.9	$ (26.5)	$ (13.2)	$ 237.6	2,504
Dec-15	448.8	407.1	26.7	829.2	639.0	(26.5)	1.2	26.7	(52.0)	(39.3)	678.2	2,142
Jan-16	829.2	601.6	32.8	1,397.9	1,113.5	(52.0)	2.0	32.8	(82.8)	(67.4)	1,181.0	3,166
Feb-16	1,397.9	780.5	32.8	2,145.6	1,771.7	(82.8)	3.2	32.8	(112.4)	(97.6)	1,869.4	4,108
Mar-16	2,145.6	1,396.3	33.3	3,508.6	2,827.1	(112.4)	5.1	33.3	(140.6)	(126.5)	2,953.6	7,349
Apr-16	3,508.6	2,113.5	33.7	5,588.4	4,548.5	(140.6)	8.2	33.7	(166.1)	(153.3)	4,701.8	11,124
May-16	5,588.4	2,076.5	33.7	7,631.2	6,609.8	(166.1)	12.0	33.7	(187.8)	(176.9)	6,786.7	10,929
Jun-16	7,631.2	2,880.9	34.2	10,477.9	9,054.5	(187.8)	16.4	34.2	(205.6)	(196.7)	9,251.2	15,163
Jul-16	10,477.9	3,067.1	34.2	13,510.8	11,994.3	(205.6)	21.7	34.2	(218.1)	(211.9)	12,206.2	16,143
Aug-16	13,510.8	2,791.5	34.2	16,268.1	14,889.5	(218.1)	26.9	34.2	(225.4)	(221.7)	15,111.2	14,692
Sep-16	16,268.1	2,475.6	34.2	18,709.6	17,488.9	(225.4)	31.7	34.2	(227.9)	(226.6)	17,715.5	13,030
Oct-16	18,709.6	2,000.9	33.7	20,676.8	19,693.2	(227.9)	35.6	33.7	(226.0)	(226.9)	19,920.1	10,531
		21,067.2	**390.4**	**RY 1 Depreciation Expense =**			**164.4**	**RY 1 Average Net Plant**			**7,717.7**	**110,880**
Nov-16	20,676.8	859.2	32.8	21,503.2	21,090.0	(226.0)	38.2	32.8	(220.6)	(223.3)	21,313.3	4,522
Dec-16	21,503.2	569.0	32.5	22,039.7	21,771.5	(220.6)	39.4	32.5	(213.7)	(217.1)	21,988.6	2,995
Jan-17	22,039.7	617.9	33.0	22,624.6	22,332.2	(213.7)	40.4	33.0	(206.3)	(210.0)	22,542.1	3,252
Feb-17	22,624.6	795.2	33.0	23,386.8	23,005.7	(206.3)	41.6	33.0	(197.6)	(201.9)	23,207.6	4,185
Mar-17	23,386.8	1,414.8	33.5	24,768.1	24,077.5	(197.6)	43.6	33.5	(187.5)	(192.6)	24,270.0	7,446
Apr-17	24,768.1	2,181.0	33.9	26,915.1	25,841.6	(187.5)	46.8	33.9	(174.7)	(181.1)	26,022.7	11,479
May-17	26,915.1	2,076.3	33.9	28,957.5	27,936.3	(174.7)	50.6	33.9	(158.0)	(166.3)	28,102.7	10,928
Jun-17	28,957.5	3,024.0	34.4	31,947.1	30,452.3	(158.0)	55.1	34.4	(137.3)	(147.6)	30,600.0	15,916
Jul-17	31,947.1	3,061.6	34.4	34,974.4	33,460.7	(137.3)	60.6	34.4	(111.1)	(124.2)	33,584.9	16,114
Aug-17	34,974.4	2,963.5	34.4	37,903.5	36,438.9	(111.1)	66.0	34.4	(79.6)	(95.3)	36,534.3	15,598
Sep-17	37,903.5	2,484.7	34.4	40,353.8	39,128.6	(79.6)	70.8	34.4	(43.1)	(61.3)	39,190.0	13,077
Oct-17	40,353.8	2,023.2	33.9	42,343.1	41,348.4	(43.1)	74.8	33.9	(2.2)	(22.7)	41,371.1	10,649
		22,070.4	**404.1**	RY 2 Depreciation Expense =			**627.9**	RY 2 Average Net Plant =			**29,060.6**	**116,160**
Nov-17	42,343.1	1,082.5	33.0	43,392.6	42,867.9	(2.2)	77.6	33.0	42.4	20.1	42,847.8	5,697
Dec-17	43,392.6	897.6	32.7	44,257.5	43,825.1	42.4	79.3	32.7	89.0	65.7	43,759.4	4,724
Jan-18	44,257.5	2,109.3	34.7	46,332.2	45,294.8	89.0	82.0	34.7	136.3	112.7	45,182.2	11,102
Feb-18	46,332.2	2,109.3	34.7	48,406.8	47,369.5	136.3	85.7	34.7	187.3	161.8	47,207.6	11,102
Mar-18	48,406.8	2,109.3	34.7	50,481.4	49,444.1	187.3	89.5	34.7	242.1	214.7	49,229.4	11,102
Apr-18	50,481.4	2,109.3	34.7	52,556.1	51,518.7	242.1	93.2	34.7	300.7	271.4	51,247.3	11,102
May-18	52,556.1	2,109.3	34.7	54,630.7	53,593.4	300.7	97.0	34.7	363.0	331.8	53,261.5	11,102
Jun-18	54,630.7	2,109.3	34.7	56,705.3	55,668.0	363.0	100.8	34.7	429.0	396.0	55,272.0	11,102
Jul-18	56,705.3	2,109.3	34.7	58,780.0	57,742.6	429.0	104.5	34.7	498.9	464.0	57,278.7	11,102
Aug-18	58,780.0	2,109.3	34.7	60,854.6	59,817.3	498.9	108.3	34.7	572.4	535.6	59,281.6	11,102
Sep-18	60,854.6	2,109.3	34.7	62,929.2	61,891.9	572.4	112.0	34.7	649.8	611.1	61,280.8	11,102
Oct-18	62,929.2	2,109.4	34.7	65,004.0	63,966.6	649.8	115.8	34.7	730.8	690.3	63,276.3	11,102
		23,073.6	**412.7**	RY 3 Depreciation Expense =			**1,145.7**	RY 3 Average Net Plant =			**52,427.0**	**121,440**

Orange & Rockland Utilities, Inc.
Case 14-G-0494
Reliability Surcharge Mechanism (RSM)
Revenue Requirement for Leak Prone Pipe Replacement
"In Rates"

	Revenue Requirement (RR)		Replaced Feet of LPP	
	RY	Cumulative (CRR)	RY	Cumulative
RY 1 (10.116%** on Avg. Net Plant) =	945.2	**945.2**	110,880	110,880
RY 2 (10.072%** on Avg. Net Plant) =	3,554.8	**4,500.0**	116,160	227,040
RY 3 (10.072%** on Avg. Net Plant) =	6,426.2	**10,926.2**	121,440	348,480

Adjusted Revenue Requirement (CARR):		
RY 1	(RR x 1.03%)	**973.5**
RY 2	(RR x 1.06%)	**4,770.0**
RY 3	(RR x 1.09%)	**11,909.6**

LPP Footage						Cap						
Target Ft.	Exceeds	% Exceeds	1.5x	1+1.5x	CARR	(1+1.5x)xCARR	Actual	Allowed	Rates	Recovery	Amount and Year Recovered	
110,880	0	0.00%	0.0%	100.0%	973.5	973.5	945.2	945.2	945.2	-		RY1
227,040	0	0.00%	0.0%	100.0%	4,770.0	4,770.0	4,500.0	4,500.0	4,500.0	-	-	RY2
348,480	0	0.00%	0.0%	100.0%	11,909.6	11,909.6	10,926.2	10,926.2	10,926.2	-	-	RY3
											-	RY4*
											-	Total

* RY4 represents the twelve months ended October 31, 2019.
**PreTax-Return Grossed up for Revenue Taxes

	PreTax Return	/ Revenue Tax	= PreTax Return
RY 1	9.893%	97.80%	10.116%
RY 2	9.850%	97.80%	10.072%
RY 3	9.850%	97.80%	10.072%

Orange & Rockland Utilities, Inc.
Case 14-G-0494
Reliability Surcharge Mechanism (RSM)
Revenue Requirement for Leak Prone Pipe Replacement
"Example Calculation"

	Plant in Service LPP 14-G-0494					Depreciation Reserve LPP 14-G-0494					Net Plant	Replaced
	Start	Add.	Ret.	End	Avg.	Start	Depr.	Ret.+Sal.	End	Avg.	Avg.	Feet
Nov-15	$ -	$ 500.0	$ 10.0	$ 490.0	$ 245.0	$ -	$ 0.4	$ 14.0	$ (13.6)	$ (6.8)	$ 251.8	2,600
Dec-15	490.0	500.0	11.0	979.0	734.5	(13.6)	1.3	15.0	(27.2)	(20.4)	754.9	2,500
Jan-16	979.0	700.0	15.0	1,664.0	1,321.5	(27.2)	2.4	21.0	(45.8)	(36.5)	1,358.0	3,720
Feb-16	1,664.0	800.0	15.0	2,449.0	2,056.5	(45.8)	3.7	22.0	(64.1)	(55.0)	2,111.5	4,200
Mar-16	2,449.0	1,500.0	31.0	3,918.0	3,183.5	(64.1)	5.8	43.0	(101.4)	(82.7)	3,266.2	7,500
Apr-16	3,918.0	2,200.0	43.0	6,075.0	4,996.5	(101.4)	9.0	60.0	(152.3)	(126.8)	5,123.3	11,520
May-16	6,075.0	2,500.0	51.0	8,524.0	7,299.5	(152.3)	13.2	71.0	(210.1)	(181.2)	7,480.7	14,100
Jun-16	8,524.0	3,200.0	65.0	11,659.0	10,091.5	(210.1)	18.3	90.0	(281.8)	(246.0)	10,337.5	16,520
Jul-16	11,659.0	3,000.0	59.0	14,600.0	13,129.5	(281.8)	23.8	84.0	(342.1)	(311.9)	13,441.4	15,500
Aug-16	14,600.0	2,800.0	57.0	17,343.0	15,971.5	(342.1)	28.9	82.0	(395.2)	(368.6)	16,340.1	14,520
Sep-16	17,343.0	2,500.0	52.0	19,791.0	18,567.0	(395.2)	33.6	72.0	(433.6)	(414.4)	18,981.4	13,200
Oct-16	19,791.0	2,000.0	19.0	21,772.0	20,781.5	(433.6)	37.6	25.0	(420.9)	(427.2)	21,208.7	10,000
		22,200.0	**428.0**	**RY 1 Depreciation Expense =**			**178.1**	**RY 1 Average Net Plant**			**8,388.0**	**115,880**
Nov-16	21,772.0	950.0	19.0	22,703.0	22,237.5	(420.9)	40.2	27.0	(407.7)	(414.3)	22,651.8	3,500
Dec-16	22,703.0	800.0	16.0	23,487.0	23,095.0	(407.7)	41.8	23.0	(388.9)	(398.3)	23,493.3	4,000
Jan-17	23,487.0	600.0	13.0	24,074.0	23,780.5	(388.9)	43.0	18.0	(363.8)	(376.4)	24,156.9	2,500
Feb-17	24,074.0	900.0	17.0	24,957.0	24,515.5	(363.8)	44.4	22.0	(341.5)	(352.7)	24,868.2	4,000
Mar-17	24,957.0	1,500.0	29.0	26,428.0	25,692.5	(341.5)	46.5	40.0	(335.0)	(338.2)	26,030.7	7,460
Apr-17	26,428.0	2,500.0	52.0	28,876.0	27,652.0	(335.0)	50.1	75.0	(359.9)	(347.4)	27,999.4	11,800
May-17	28,876.0	2,500.0	53.0	31,323.0	30,099.5	(359.9)	54.5	70.0	(375.4)	(367.7)	30,467.2	13,000
Jun-17	31,323.0	3,100.0	58.0	34,365.0	32,844.0	(375.4)	59.4	79.0	(395.0)	(385.2)	33,229.2	15,000
Jul-17	34,365.0	3,100.0	62.0	37,403.0	35,884.0	(395.0)	65.0	85.0	(415.0)	(405.0)	36,289.0	15,500
Aug-17	37,403.0	3,000.0	63.0	40,340.0	38,871.5	(415.0)	70.4	74.0	(418.7)	(416.9)	39,288.4	15,400
Sep-17	40,340.0	2,700.0	55.0	42,985.0	41,662.5	(418.7)	75.4	90.0	(433.3)	(426.0)	42,088.5	14,000
Oct-17	42,985.0	2,200.0	46.0	45,139.0	44,062.0	(433.3)	79.8	80.0	(433.5)	(433.4)	44,495.4	10,000
		23,850.0	**483.0**	**RY 2 Depreciation Expense =**			**670.4**	**RY 2 Average Net Plant =**			**31,254.8**	**116,160**
Nov-17	45,139.0	700.0	14.0	45,825.0	45,482.0	(433.5)	82.3	18.0	(369.2)	(401.4)	45,883.4	2,700
Dec-17	45,825.0	1,100.0	23.0	46,902.0	46,363.5	(369.2)	83.9	33.0	(318.3)	(343.7)	46,707.2	4,700
Jan-18	46,902.0	1,200.0	23.0	48,079.0	47,490.5	(318.3)	86.0	30.0	(262.3)	(290.3)	47,780.8	5,000
Feb-18	48,079.0	1,600.0	33.0	49,646.0	48,862.5	(262.3)	88.4	47.0	(220.9)	(241.6)	49,104.1	8,000
Mar-18	49,646.0	2,400.0	47.0	51,999.0	50,822.5	(220.9)	92.0	67.0	(195.9)	(208.4)	51,030.9	11,000
Apr-18	51,999.0	2,800.0	58.0	54,741.0	53,370.0	(195.9)	96.6	76.0	(175.3)	(185.6)	53,555.6	12,500
May-18	54,741.0	3,100.0	66.0	57,775.0	56,258.0	(175.3)	101.8	90.0	(163.5)	(169.4)	56,427.4	14,540
Jun-18	57,775.0	3,200.0	64.0	60,911.0	59,343.0	(163.5)	107.4	91.0	(147.1)	(155.3)	59,498.3	15,000
Jul-18	60,911.0	2,800.0	60.0	63,651.0	62,281.0	(147.1)	112.7	84.0	(118.3)	(132.7)	62,413.7	14,000
Aug-18	63,651.0	2,700.0	50.0	66,301.0	64,976.0	(118.3)	117.6	71.0	(71.7)	(95.0)	65,071.0	12,000
Sep-18	66,301.0	2,600.0	52.0	68,849.0	67,575.0	(71.7)	122.3	69.0	(18.4)	(45.1)	67,620.1	12,000
Oct-18	68,849.0	2,300.0	45.0	71,104.0	69,976.5	(18.4)	126.7	60.0	48.3	14.9	69,961.6	10,000
		26,500.0	**535.0**	**RY 3 Depreciation Expense =**			**1,217.8**	**RY 3 Average Net Plant =**			**56,254.5**	**121,440**

Orange & Rockland Utilities, Inc.
Case 14-G-0494
Reliability Surcharge Mechanism (RSM)
Revenue Requirement for Leak Prone Pipe Replacement
"Example Calculation"

	Revenue Requirement (RR)		Replaced Feet of LPP	
	RY	Cumulative (CRR)	RY	Cumulative
RY 1 (10.116% on Avg. Net Plant) =	1,026.6	**1,026.6**	115,880	115,880
RY 2 (10.072% on Avg. Net Plant) =	3,818.4	**4,845.0**	116,160	232,040
RY 3 (10.072% on Avg. Net Plant) =	6,883.7	**11,728.7**	121,440	353,480

LPP Footage						Cap						
Target Ft.	Exceeds	% Exceeds	1.5x	1+1.5x	CARR	(1+1.5x)xCARR)	Actual	Allowed	Rates	Recovery	Amount and Year Recovered	
110,880	5,000	4.51%	6.8%	106.8%	973.5	1,039.4	1,026.6	1,026.6	945.2	81.4		RY1
227,040	5,000	2.20%	3.3%	103.3%	4,770.0	4,927.6	4,845.0	4,845.0	4,500.0	345.0	81.4	RY2
348,480	5,000	1.43%	2.2%	102.2%	11,909.6	12,165.9	11,728.7	11,728.7	10,926.2	802.5	263.6	RY3
											457.5	RY4*
											802.5	Total

* RY4 represents the twelve months ended October 31, 2019.

Orange and Rockland Utilities, Inc.

Cases 14-E-0493 & 14-G-0494

Customer Addition Incentive Mechanism (CAIM)

The Table below shows the basis points available for net customer additions to SC 1, 2, and 6 during each rate year. At the conclusion of this rate plan, the RY3 targets will continue to be in effect until the Company's next rate filing. This incentive mechanism will not apply to a partial rate year.

Example: RY1 beginning (11/1/15) customer count is 132,000 and ending (10/31/16) customer count is 134,000, it would be a net growth of 2,000 customer and worth 5 basis points.

	Basis Points Incentive If Number of Customer Additions Is:				
Year	1	2	3	4	5
RY1	1140-1339	1340-1539	1540-1739	1740-1939	1940-2039
RY2	1390-1589	1590-1789	1790-1989	1990-2189	2190-2289
RY3	1715-1914	1915-2114	2115-2314	2315-2514	2515-2614
	Basis Points Incentive If Number of Customer Additions Is:				
Year	6	7	8	9	10
RY1	2040-2139	2140-2239	2240-2339	2340-2439	2440+
RY2	2290-2389	2390-2489	2490-2589	2590-2689	2690+
RY3	2615-2714	2715-2814	2815-2914	2915-3014	3015+

Appendix 25 Pomona DER Program Reconciliation

- There will be four types of expenditures related to the Pomona DER Program:
  - Customer Incentive Programs (*e.g.*, demand reduction programs, energy efficiency programs)
  - Capital Investments (*e.g.*, batteries)
  - Maintenance Associated with Capital Investments (ongoing O&M costs associated with, e.g., batteries)
  - Labor (see Appendix 22)

- The following table indicates the components of the revenue requirement related to each type of program expenditure.

	Customer Incentive Programs	**Capital Investments**	**Maintenance Associated with Capital Investments**	**Labor**
Book depreciation / amortization	10 years	10 years	Current period actuals	Current period actuals
Property Taxes	n/a	Plant in Service x 5%	n/a	n/a
Income Tax / Removal Cost (Salvage Value)	n/a	7 Years Tax Life/ 10% Salvage Value	n/a	n/a
Return	Avg Unamortized Balance, Net of Tax x Pre-Tax WACC + Amortization Expense	Net Rate Base x Pre-Tax WACC + Expenses	n/a	n/a
Gross-Up Factor Applied	Yes	Yes	Yes	Yes
Incentive Applied	Up to 100 Basis Points combined		n/a	n/a
Included in cap?	Yes	Yes	No	Yes[1]

- Net Rate Base is calculated as Average Plant in Service less Average Book Depreciation Reserve with Cost of Removal less Average Federal Deferred Tax Balance (Net of Tax) less Average State Deferred Tax Balance.

[1] The salary and associated benefits for the three positions (See Appendix 22) will be capped at $950,000 for the term of this agreement.

- The Company will obtain actual expenditures each month and calculate the monthly revenue requirement associated with those expenditures per the table above.

- To the extent the monthly revenue requirement is more or less that the monthly rate allowance for the Pomona DER Program ($380,000 / 12), the Company will record an entry to defer the difference as a regulatory liability or asset. A carrying charge at the other customer provided capital rate will be booked on the deferred balance.

- The Company will send a summary of program expenditures, revenue requirement calculations, and deferral balances to Staff quarterly.

- To the extent Property Taxes are included in the Pomona DER Program reconciliation process, they will be excluded from the Company-wide Property Tax reconciliation process.

- Determination and application of incentives
    - Load Reduction (up to 50 basis points - 1.0 basis points for each 0.1 MW of load reduction achieved above 3.0 MW)
        - Determination of MW reduction
            - Upon completion of implementation of Pomona Customer-side and Company-side initiatives, total demand reduction attributable to these initiatives will be determined based on engineering estimates of impacts of distributed energy resources and adoption levels of demand reduction and energy efficiency programs.
    - Cost Savings (up to 50 basis points - 1.0 basis points for each 1% reduction in cost per MW compared to cost of station)
        - Calculating cost of station:
        - The net present value ("NPV") unit cost of the traditional T&D solution is $2.2 million per MW (calculated by dividing the NPV of the revenue requirement to build and install the traditional T&D solution ($48,940,000) by the MW of capability that the Substation and underground loop would be built to serve (22 MW)).

        - Calculating cost of reduction per MW
            - As noted above, upon completion and implementation of all Pomona initiatives, total MW reduction will be calculated. Total cost will also be available at that time and cost per MW reduced will be calculated and compared to cost per MW associated with traditional station construction to determine the incentive amount, if any, to be applied.

- o With regards to timing, the calculation and application of any incentives earned will be tied to the completion of Pomona DER program customer incentive programs and non-traditional capital investments, as opposed to the actual in service date of a traditional substation in the Pomona service area.

- To the extent a performance incentive is earned by the Company upon completion of the program, the basis point incentive will be applied to all eligible Pomona DER Program costs (as specified in the table above).

Company Name: O and R Utilities, Inc.
Case Description: Orange and Rockland Electric and Gas Filing 2014
Case: 14-E-0493; 14-G-0494

Response to DPS Interrogatories – Set DPS-8
Date of Response: 01/05/2015
Responding Witness: REV Panel

Question No. : 245

Subject: Pomona Distributed Energy Resources Demonstration Project -

1. Provide a detailed Benefit Cost Analysis demonstrating the cost-effectiveness of the proposed Pomona distributed energy resources (DER) demonstration project (Pomona DSM program) as compared to construction of the Pomona Substation by 2022. Include and separately identify the benefits of the Pomona DSM program (i.e., deferred carrying costs, avoided energy costs, avoided capacity costs, and environmental externalities). Perform the analysis on a Net Present Value basis over the course of the entire useful life of all assets. Submit the analysis in Microsoft Excel format with all cells unlocked, all formulae intact, and all linked files included.

2. Demonstrate, in detail, how any avoided transmission and distribution costs utilized in the benefit cost analysis described above were developed.

3. Describe the extent to which advanced metering infrastructure (AMI) is required in the Pomona area to effectuate the reductions in demand required to defer the building of the proposed Pomona substation. In the event that the Commission declines to approve the Company's plans to roll out AMI into the Pomona area, describe what impacts such a decision would have on the proposed Pomona DER demonstration project.

4. Do the Company's plans for the Pomona DER demonstration project include targeting the distribution automation upgrades described by the Company's Smart Grid panel within the Pomona area?
   A. If so, describe the plans.
   B. If not, explain why such plans were not considered, or why such plans are not feasible for the Pomona area.
   C. To the extent that it is feasible to target the distribution automation projects described by the Company's Smart Grid panel within the Pomona area, include and separately identify the costs and benefits of the projects in the benefit cost analysis described above.

<u>Response</u>

1. The benefit cost model for the Pomona project is included as Attachment DPS8-245 Att-1. This model does not include avoided energy costs, avoided capacity costs or environmental externalities. The costs in the model are driven by the net present value of the full revenue requirement associated with the investments in non-traditional demand reduction solutions. The benefits included in the model are driven by the ability to defer substation capital spending by four years as a result of these demand reduction investments.

2. Avoided transmission and distribution costs have not been included in the benefit cost analysis. As the project is further defined and developed, transmission and distribution costs will be considered.

3. The definitive nature of the projects that will be implemented in the Pomona area cannot be determined at this time because of pending developments in the REV Proceeding, the anticipated identification of multiple potential resource development initiatives and other approaches that may enhance the available energy pool in the Company's service territory, and the Company's belief that its RFI may produce both innovative uses of technology, as well as, new business models. Given these circumstances it is not possible to describe with certainty the extent to which AMI will be required in the Demonstration Project. However, a decision by the Commission not to approve the Company's planned roll-out of AMI will have a significant negative impact as regards the development of demonstration and other REV type projects because it is AMI technology that will enable the collection of granular data that will enhance customers' ability to manage their energy use, the ability of third parties to offer customer-specific solutions, and the Company's ability to improve system modeling. The majority of the load in the Pomona area is residential. Absent AMI, the Company does not have a two way communication platform in place that will provide for the monitoring of demand response program effectiveness or the integration of other resources during peak events. In addition, failure to approve AMI will negatively impact the Company's ability to animate the market in its service territory. As noted in the AMI Panel's direct testimony (p. 9):

    > Providing the tools to manage energy consumption fosters an environment where customers are both engaged and empowered to proactively optimize their energy cost choices in a more dynamic energy market. Customers with access to more granular data are more likely to reduce their energy usage. This was illustrated in a U.S. Department of Energy ("DOE") study release in January 2014, indicating that 3,000 pilot program participants in Central Maine Power's test group who received weekly usage and cost reports, 70% said they took action to reduce usage which resulted in 1.8% reduction in their electricity consumption.

    AMI is a critical tool for animation of the market both as regards customer action to reduce energy usage, as described in the DOE study, and as regards information and a technology platform that will serve as a basis for the development of energy initiatives by other parties.

4. The current average load on the ten circuits that feed into the Pomona load area is 400 Amps and the average length is 5.3 OH Circuit Miles. Although the current growth rate is low (.52%), putting automation on this load and length will provide minimal benefit.

Cost Benefit Summary
Pomona
NPV of Revenue Requirements
($ 000s)

Revenue Requirement

Group	Year	Ref#	Project Component	NPV		2021 Costs	2025 Costs	Benefit of 2025 Delay	Cost to Achieve Delay
	2025	1	A/C Cycling Incentive	$ 317	Incremental Non-Traditional Costs to Achieve Benefits				$ 317
	2025	2	A/C Cycling Thermostat and Install	$ 167					$ 167
	2025	3&4	Battery	$ 2,005					$ 2,005
	2025	5	Energy Efficiency Program	$ 1,315					$ 1,315
	2025	6&7	Gas Fired DG	$ 1,076					$ 1,076
	2025	8	Patrick Farm Home Energy Incentive	$ 667					$ 667
	2025	9&10	Solar	$ 1,087					$ 1,087
Substation / Transmission Investment	2021	11	Pomona Station	$ 14,733	Benefit - Delayed Capital Costs	$ 14,733			
	2025	12	Pomona Station	$ 11,246			$ 11,246	$ 3,487	
	2021	13	138kV UG Exits	$ 2,609	Benefit - Delayed Capital Costs	$ 2,609			
	2025	14	138kV UG Exits	$ 1,992			$ 1,992	$ 618	
	2021	15	138kV UG Transmission	$ 31,256	Benefit - Delayed Capital Costs	$ 31,256			
	2025	16	138kV UG Transmission	$ 23,859			$ 23,859	$ 7,397	
	2021	17	Line 53 structure	$ 343	Benefit - Delayed Capital Costs	$ 343			
	2025	18	Line 53 structure	$ 262			$ 262	$ 81	
	2021	*	TOTAL	$ 48,940					
	2025	*	TOTAL	$ 43,991		**$ 48,940**	**$ 37,358**	**$ 11,582**	**$ 6,633**
									Benefit - CTA = $ 4,949

Revenue Requirement Summary
Pomona
Based on Escalated Dollars
($ 000s)

Revenue Requirement

	Ref#	Project Component	2014	2015	2016	2017	2018	2019	2020	2021	2022
2025	1	A/C Cycling Incentive	$-	$-	$ -	$ 13	$ 29	$ 45	$ 60	$ 76	$ 75
2025	2	A/C Cycling Thermostat and Install	-	-	30	36	35	34	33	10	10
2025	3&4	Battery	-	-	-	-	-	-	-	685	878
2025	5	Energy Efficiency Program	-	-	247	297	285	272	260	62	62
2025	6&7	Gas Fired DG	-	-	-	-	-	89	333	408	385
2025	8	Patrick Farm Home Energy Incentive	-	-	30	55	86	127	170	150	129
2025	9&10	Solar	-	-	-	-	-	-	353	425	401
		TOTAL	**-**	**-**	**307**	**401**	**434**	**566**	**1,208**	**1,816**	**1,940**

Substation / Transmission Investment	2021	11	Pomona Station	-	-	-	-	-	-	2,671	3,735	3,636
	2025	12	Pomona Station	-	-	-	-	-	-	-	-	-
	2021	13	138kV UG Exits	-	-	-	-	-	-	483	670	652
	2025	14	138kV UG Exits	-	-	-	-	-	-	-	-	-
	2021	15	138kV UG Transmission	-	-	-	-	-	-	5,790	8,030	7,812
	2025	16	138kV UG Transmission	-	-	-	-	-	-	-	-	-
	2021	17	Line 53 structure	-	-	-	-	-	-	60	85	83
	2025	18	Line 53 structure	-	-	-	-	-	-	-	-	-
	2021	*	TOTAL	$-	$-	$ -	$ -	$ -	$ -	$ 9,004	$ 12,520	$ 12,184
	2025	*	TOTAL	$-	$-	$ 307	$ 401	$ 434	$ 566	$ 1,208	$ 1,816	$ 1,940

Revenue Requirement Summary
Pomona
Based on Escalated Dollars
($ 000s)

Revenue Requirement

	Ref#	Project Component	2023	2024	2025	2026	2027	2028	2029
2025	1	A/C Cycling Incentive	$ 71	$ 59	$ 47	$ 34	$ 27	$ -	$ 535
2025	2	A/C Cycling Thermostat and Install	10	9	9	9	-	223	-
2025	3&4	Battery	824	780	698	663	628	597	573
2025	5	Energy Efficiency Program	62	62	62	62	-	1,734	-
2025	6&7	Gas Fired DG	367	351	298	283	269	232	113
2025	8	Patrick Farm Home Energy Incentive	102	70	39	39	-	996	-
2025	9&10	Solar	380	364	311	294	280	269	161
		TOTAL	**1,816**	**1,696**	**1,464**	**1,384**	**1,204**	**4,050**	**1,382**

Substation / Transmission Investment	2021	11	Pomona Station	3,543	3,455	3,370	3,290	3,213	3,138	3,063
	2025	12	Pomona Station	-	3,084	4,312	4,199	4,091	3,989	3,891
	2021	13	138kV UG Exits	635	619	603	588	573	559	546
	2025	14	138kV UG Exits	-	558	774	753	733	714	696
	2021	15	138kV UG Transmission	7,606	7,409	7,221	7,041	6,869	6,701	6,534
	2025	16	138kV UG Transmission	-	6,685	9,271	9,020	8,782	8,554	8,337
	2021	17	Line 53 structure	81	79	77	76	74	72	71
	2025	18	Line 53 structure	-	69	98	96	93	91	89
	2021	*	TOTAL	$ 11,865	$ 11,561	$ 11,271	$ 10,994	$ 10,729	$ 10,471	$ 10,214
	2025	*	TOTAL	$ 1,816	$ 12,092	$ 15,920	$ 15,452	$ 14,904	$ 17,399	$ 14,396

Revenue Requirement Summary
Pomona
Based on Escalated Dollars
($ 000s)

Revenue Requirement

		Ref#	Project Component	2030	2031	2032	2033	2034	2035	2036
	2025	1	A/C Cycling Incentive	$ -						
	2025	2	A/C Cycling Thermostat and Install	-						
	2025	3&4	Battery	344	(0)	(0)	(0)	(0)	(0)	(0)
	2025	5	Energy Efficiency Program	-						
	2025	6&7	Gas Fired DG	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2025	8	Patrick Farm Home Energy Incentive	-						
	2025	9&10	Solar	(0)	(0)	(0)	(0)	(0)	(0)	(0)
			TOTAL	**344**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
Substation / Transmission Investment	2021	11	Pomona Station	2,989	2,914	2,840	2,765	2,691	2,616	2,542
	2025	12	Pomona Station	3,798	3,710	3,623	3,537	3,451	3,365	3,279
	2021	13	138kV UG Exits	532	518	504	490	476	462	448
	2025	14	138kV UG Exits	679	662	646	630	614	598	582
	2021	15	138kV UG Transmission	6,367	6,200	6,033	5,866	5,699	5,532	5,365
	2025	16	138kV UG Transmission	8,130	7,931	7,738	7,545	7,352	7,159	6,966
	2021	17	Line 53 structure	69	68	66	65	63	62	60
	2025	18	Line 53 structure	87	85	84	82	80	78	76
	2021	*	TOTAL	$ 9,957	$ 9,700	$ 9,443	$ 9,186	$ 8,928	$ 8,671	$ 8,414
	2025	*	TOTAL	$ 13,038	$ 12,388	$ 12,090	$ 11,794	$ 11,497	$ 11,200	$ 10,903

Revenue Requirement Summary
Pomona
Based on Escalated Dollars
($ 000s)

Revenue Requirement

		Ref#	Project Component	2037	2038	2039	2040	2041	2042	2043
	2025	1	A/C Cycling Incentive							
	2025	2	A/C Cycling Thermostat and Install							
	2025	3&4	Battery	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2025	5	Energy Efficiency Program							
	2025	6&7	Gas Fired DG	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2025	8	Patrick Farm Home Energy Incentive							
	2025	9&10	Solar	(0)	(0)	(0)	(0)	(0)	(0)	(0)
			TOTAL	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
Substation / Transmission Investment	2021	11	Pomona Station	2,467	2,393	2,318	2,254	2,211	2,179	2,147
	2025	12	Pomona Station	3,193	3,107	3,021	2,935	2,849	2,762	2,676
	2021	13	138kV UG Exits	434	420	406	394	386	379	373
	2025	14	138kV UG Exits	565	549	533	517	501	485	469
	2021	15	138kV UG Transmission	5,198	5,031	4,864	4,719	4,619	4,542	4,465
	2025	16	138kV UG Transmission	6,773	6,580	6,387	6,194	6,001	5,809	5,616
	2021	17	Line 53 structure	58	57	55	54	53	53	52
	2025	18	Line 53 structure	75	73	71	69	67	66	64
	2021	*	TOTAL	$ 8,157	$ 7,900	$ 7,643	$ 7,421	$ 7,270	$ 7,154	$ 7,037
	2025	*	TOTAL	$ 10,606	$ 10,309	$ 10,012	$ 9,715	$ 9,418	$ 9,122	$ 8,825

Revenue Requirement Summary
Pomona
Based on Escalated Dollars
($ 000s)

Revenue Requirement

	Year	Ref#	Project Component	2044	2045	2046	2047	2048	2049	2050
	2025	1	A/C Cycling Incentive							
	2025	2	A/C Cycling Thermostat and Install							
	2025	3&4	Battery	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2025	5	Energy Efficiency Program							
	2025	6&7	Gas Fired DG	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2025	8	Patrick Farm Home Energy Incentive							
	2025	9&10	Solar	(0)	(0)	(0)	(0)	(0)	(0)	(0)
			TOTAL	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
Substation / Transmission Investment	2021	11	Pomona Station	2,115	2,083	2,051	2,019	1,987	1,955	1,923
	2025	12	Pomona Station	2,603	2,553	2,516	2,480	2,443	2,406	2,369
	2021	13	138kV UG Exits	366	360	353	347	341	334	328
	2025	14	138kV UG Exits	455	445	438	430	423	416	408
	2021	15	138kV UG Transmission	4,388	4,311	4,233	4,156	4,079	4,002	3,925
	2025	16	138kV UG Transmission	5,449	5,334	5,245	5,155	5,066	4,977	4,888
	2021	17	Line 53 structure	52	51	50	50	49	49	48
	2025	18	Line 53 structure	62	61	61	60	60	59	58
	2021	*	TOTAL	$ 6,921	$ 6,805	$ 6,689	$ 6,573	$ 6,456	$ 6,340	$ 6,224
	2025	*	TOTAL	$ 8,569	$ 8,394	$ 8,260	$ 8,126	$ 7,991	$ 7,857	$ 7,723

Revenue Requirement Summary
Pomona
Based on Escalated Dollars
($ 000s)

Revenue Requirement

		Ref#	Project Component	2051	2052	2053	2054	2055	2056	2057
	2025	1	A/C Cycling Incentive							
	2025	2	A/C Cycling Thermostat and Install							
	2025	3&4	Battery	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2025	5	Energy Efficiency Program							
	2025	6&7	Gas Fired DG	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2025	8	Patrick Farm Home Energy Incentive							
	2025	9&10	Solar	(0)	(0)	(0)	(0)	(0)	(0)	(0)
			TOTAL	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
Substation / Transmission Investment	2021	11	Pomona Station	1,891	1,859	1,827	1,795	1,763	1,731	1,699
	2025	12	Pomona Station	2,332	2,295	2,258	2,221	2,184	2,147	2,110
	2021	13	138kV UG Exits	321	315	308	110	0	0	0
	2025	14	138kV UG Exits	401	393	386	378	371	363	356
	2021	15	138kV UG Transmission	3,848	3,770	3,693	1,320	0	0	0
	2025	16	138kV UG Transmission	4,799	4,710	4,621	4,532	4,443	4,353	4,264
	2021	17	Line 53 structure	48	47	47	46	46	45	44
	2025	18	Line 53 structure	58	57	56	56	55	54	54
	2021	*	TOTAL	$ 6,108	$ 5,992	$ 5,876	$ 3,271	$ 1,809	$ 1,776	$ 1,744
	2025	*	TOTAL	$ 7,589	$ 7,455	$ 7,321	$ 7,187	$ 7,052	$ 6,918	$ 6,784

Revenue Requirement Summary
Pomona
Based on Escalated Dollars
($ 000s)

Revenue Requirement

		Ref#	Project Component	2058	2059	2060	2061	2062	2063	2064
	2025	1	A/C Cycling Incentive							
	2025	2	A/C Cycling Thermostat and Install							
	2025	3&4	Battery	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2025	5	Energy Efficiency Program							
	2025	6&7	Gas Fired DG	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2025	8	Patrick Farm Home Energy Incentive							
	2025	9&10	Solar	(0)	(0)	(0)	(0)	(0)	(0)	(0)
			TOTAL	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
Substation / Transmission Investment	2021	11	Pomona Station	1,667	550	(0)	(0)	(0)	(0)	(0)
	2025	12	Pomona Station	2,073	2,036	1,999	1,962	1,925	635	0
	2021	13	138kV UG Exits	0	0	0	0	0	0	0
	2025	14	138kV UG Exits	127	(0)	(0)	(0)	(0)	(0)	(0)
	2021	15	138kV UG Transmission	0	0	0	0	0	0	0
	2025	16	138kV UG Transmission	1,524	(0)	(0)	(0)	(0)	(0)	(0)
	2021	17	Line 53 structure	44	43	43	42	42	41	41
	2025	18	Line 53 structure	53	53	52	51	51	50	49
	2021	*	TOTAL	$ 1,711	$ 593	$ 43	$ 42	$ 42	$ 41	$ 41
	2025	*	TOTAL	$ 3,777	$ 2,089	$ 2,051	$ 2,013	$ 1,976	$ 685	$ 49

Revenue Requirement Summary
Pomona
Based on Escalated Dollars
($ 000s)

Revenue Requirement

		Ref#	Project Component	2065	2066	2067	2068	2069	2070	2071
	2025	1	A/C Cycling Incentive							
	2025	2	A/C Cycling Thermostat and Install							
	2025	3&4	Battery	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2025	5	Energy Efficiency Program							
	2025	6&7	Gas Fired DG	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2025	8	Patrick Farm Home Energy Incentive							
	2025	9&10	Solar	(0)	(0)	(0)	(0)	(0)	(0)	(0)
			TOTAL	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
Substation / Transmission Investment	2021	11	Pomona Station	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2025	12	Pomona Station	0	0	0	0	0	0	0
	2021	13	138kV UG Exits	0	0	0	0	0	0	0
	2025	14	138kV UG Exits	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2021	15	138kV UG Transmission	0	0	0	0	0	0	0
	2025	16	138kV UG Transmission	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	2021	17	Line 53 structure	40	40	39	38	38	37	37
	2025	18	Line 53 structure	49	48	48	47	46	46	45
	2021	*	TOTAL	$ 40	$ 40	$ 39	$ 38	$ 38	$ 37	$ 37
	2025	*	TOTAL	$ 49	$ 48	$ 48	$ 47	$ 46	$ 46	$ 45

Revenue Requirement Summary
Pomona
Based on Escalated Dollars
($ 000s)

Revenue Requirement

		Ref#	Project Component	2072	2073	2074	2075	2076	2077	2078
	2025	1	A/C Cycling Incentive							
	2025	2	A/C Cycling Thermostat and Install							
	2025	3&4	Battery	(0)	(0)	(0)	(0)	(0)		
	2025	5	Energy Efficiency Program							
	2025	6&7	Gas Fired DG	(0)	(0)	(0)	(0)	(0)		
	2025	8	Patrick Farm Home Energy Incentive							
	2025	9&10	Solar	(0)	(0)	(0)	(0)	(0)		
			TOTAL	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**		
Substation / Transmission Investment	2021	11	Pomona Station	(0)	(0)	(0)	(0)	(0)		
	2025	12	Pomona Station	0	0	0	0	0		
	2021	13	138kV UG Exits	0	0	0	0	0		
	2025	14	138kV UG Exits	(0)	(0)	(0)	(0)	(0)		
	2021	15	138kV UG Transmission	0	0	0	0	0		
	2025	16	138kV UG Transmission	(0)	(0)	(0)	(0)	(0)		
	2021	17	Line 53 structure	36	36	10	(0)	(0)		
	2025	18	Line 53 structure	44	44	43	42	42	41	11
	2021	*	TOTAL	$ 36	$ 36	$ 10	$ (0)	$ (0)	$ -	$ -
	2025	*	TOTAL	$ 44	$ 44	$ 43	$ 42	$ 42	$ 41	$ 11

Revenue Requirement Summary
Pomona
Based on Escalated Dollars
($ 000s)

Revenue Requirement

	Year	Ref#	Project Component	TOTAL	NPV
	2025	1	A/C Cycling Incentive	$ 1,071	$ 317
	2025	2	A/C Cycling Thermostat and Install	$ 445	$ 167
	2025	3&4	Battery	$ 6,670	$ 2,005
	2025	5	Energy Efficiency Program	$ 3,468	$ 1,315
	2025	6&7	Gas Fired DG	$ 3,127	$ 1,076
	2025	8	Patrick Farm Home Energy Incentive	$ 1,992	$ 667
	2025	9&10	Solar	$ 3,238	$ 1,087
			TOTAL		
Substation / Transmission Investment	2021	11	Pomona Station	$ 97,360	$ 14,733
	2025	12	Pomona Station	$ 112,416	$ 11,246
	2021	13	138kV UG Exits	$ 15,632	$ 2,609
	2025	14	138kV UG Exits	$ 18,049	$ 1,992
	2021	15	138kV UG Transmission	$ 187,238	$ 31,256
	2025	16	138kV UG Transmission	$ 216,192	$ 23,859
	2021	17	Line 53 structure	$ 2,911	$ 343
	2025	18	Line 53 structure	$ 3,361	$ 262
	2021	*	TOTAL	$ 303,141	$ 48,940
	2025	*	TOTAL	$ 370,029	$ 43,991

100 Basis Point Incentive Value

Based on Escalated Dollars

($ 000s)

Revenue Requirement

	Ref#	Project Component	2014	2015	2016	2017	2018	2019	2020	2021
Regular ROR										
2025	1	A/C Cycling Incentive	$ -	$ -	$ -	$ 13	$ 29	$ 45	$ 60	$ 76
2025	2	A/C Cycling Thermostat and Install	-	-	30	36	35	34	33	10
2025	3	Battery	-	-	-	-	-	-	-	685
2025	5	Energy Efficiency Program	-	-	247	297	285	272	260	62
2025	6	Gas Fired DG	-	-	-	-	-	89	333	375
2025	8	Patrick Farm Home Energy Incentive	-	-	30	55	86	127	170	150
2025	9	Solar	-	-	-	-	-	-	321	393
ROR + 100 basis point Incentive on ROE										
2025	1	A/C Cycling Incentive	$ -	$ -	$ -	$ 13	$ 30	$ 46	$ 62	$ 78
2025	2	A/C Cycling Thermostat and Install	-	-	30	37	35	34	33	10
2025	3	Battery	-	-	-	-	-	-	-	699
2025	5	Energy Efficiency Program	-	-	251	305	291	278	265	67
2025	6	Gas Fired DG	-	-	-	-	-	90	340	386
2025	8	Patrick Farm Home Energy Incentive	-	-	30	56	88	130	174	154
2025	9	Solar	-	-	-	-	-	-	328	404
100 Basis Point Incentive Value										
2025	1	A/C Cycling Incentive	$ -	$ -	$ -	$ 0	$ 1	$ 1	$ 1	$ 2
2025	2	A/C Cycling Thermostat and Install	-	-	0	1	1	1	1	1
2025	3	Battery	-	-	-	-	-	-	-	13
2025	5	Energy Efficiency Program	-	-	4	8	7	6	5	5
2025	6	Gas Fired DG	-	-	-	-	-	2	8	11
2025	8	Patrick Farm Home Energy Incentive	-	-	0	1	2	3	4	4
2025	9	Solar	-	-	-	-	-	-	6	12
		Total 100 Basis Point Incentive Value	$ -	$ -	$ 5	$ 10	$ 10	$ 12	$ 25	$ 46

100 Basis Point Incentive Value

Based on Escalated Dollars

($ 000s)

Revenue Requirement

	Ref#	Project Component	2022	2023	2024	2025	2026	2027	2028	2029
Regular ROR										
2025	1	A/C Cycling Incentive	$ 75	$ 71	$ 59	$ 47	$ 34	$ 27	$ -	$ 535
2025	2	A/C Cycling Thermostat and Install	10	10	9	9	9	-	223	-
2025	3	Battery	837	782	736	698	663	628	597	573
2025	5	Energy Efficiency Program	62	62	62	62	62	-	1,734	-
2025	6	Gas Fired DG	351	331	314	298	283	269	232	113
2025	8	Patrick Farm Home Energy Incentive	129	102	70	39	39	-	996	-
2025	9	Solar	367	345	327	311	294	280	269	161
ROR + 100 basis point Incentive on ROE										
2025	1	A/C Cycling Incentive	$ 76	$ 73	$ 61	$ 48	$ 36	$ 29	$ -	$ 551
2025	2	A/C Cycling Thermostat and Install	11	10	10	10	9	-	230	-
2025	3	Battery	862	802	754	713	675	637	604	578
2025	5	Energy Efficiency Program	67	67	67	67	67	-	1,791	-
2025	6	Gas Fired DG	360	339	321	303	287	272	234	113
2025	8	Patrick Farm Home Energy Incentive	133	105	73	42	42	-	1,025	-
2025	9	Solar	376	353	334	316	299	283	271	162
100 Basis Point Incentive Value										
2025	1	A/C Cycling Incentive	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ -	$ 15
2025	2	A/C Cycling Thermostat and Install	1	1	1	1	1	-	7	-
2025	3	Battery	25	21	17	14	12	9	7	5
2025	5	Energy Efficiency Program	5	5	5	5	5	-	57	-
2025	6	Gas Fired DG	9	7	6	5	4	3	2	1
2025	8	Patrick Farm Home Energy Incentive	3	3	3	3	3	-	29	-
2025	9	Solar	10	8	7	6	4	3	2	1
		Total 100 Basis Point Incentive Value	$ 54	$ 46	$ 40	$ 35	$ 30	$ 17	$ 105	$ 22

100 Basis Point Incentive Value

Based on Escalated Dollars

($ 000s)

Revenue Requirement

	Ref#	Project Component	2030	TOTAL	NPV
Regular ROR					
2025	1	A/C Cycling Incentive	$ -	$ 1,071	$ 317
2025	2	A/C Cycling Thermostat and Install	-	$ 445	$ 167
2025	3	Battery	344	$ 6,543	$ 1,960
2025	5	Energy Efficiency Program	-	$ 3,468	$ 1,315
2025	6	Gas Fired DG	(0)	$ 2,989	$ 1,024
2025	8	Patrick Farm Home Energy Incentive	-	$ 1,992	$ 667
2025	9	Solar	(0)	$ 3,068	$ 1,019
ROR + 100 basis point Incentive on ROE					
2025	1	A/C Cycling Incentive	$ -	$ 1,102	$ 326
2025	2	A/C Cycling Thermostat and Install	-	$ 460	$ 172
2025	3	Battery	346	$ 6,669	$ 2,001
2025	5	Energy Efficiency Program	-	$ 3,582	$ 1,354
2025	6	Gas Fired DG	(0)	$ 3,047	$ 1,045
2025	8	Patrick Farm Home Energy Incentive	-	$ 2,051	$ 686
2025	9	Solar	(0)	$ 3,127	$ 1,041
100 Basis Point Incentive Value					
2025	1	A/C Cycling Incentive	$ -	$ 31	$ 9
2025	2	A/C Cycling Thermostat and Install	-	$ 14	$ 5
2025	3	Battery	2	$ 126	$ 41
2025	5	Energy Efficiency Program	-	$ 114	$ 39
2025	6	Gas Fired DG	(0)	$ 57	$ 21
2025	8	Patrick Farm Home Energy Incentive	-	$ 59	$ 18
2025	9	Solar	(0)	$ 59	$ 21
		Total 100 Basis Point Incentive Value	$ 2	$ 460	$ 154

Consolidated Edison Company of New York, Inc.
Project Depreciation and Revenue Requirement Factors

Assumptions

No.	Description		Net Book Life	Tax Life	In Service	Book Life	Salvage Factor	Net Book Rate
1	A/C Cycling Incentive	Reg Asset	10	N/A	2016-2022	10	0%	0
2	A/C Cycling Thermostat and Install	Reg Asset	10	N/A	2015-2021	10	0%	0
3&4	Battery	treat as Plant	10	7N	7/12/1905	10	0%	0.1
5	Energy Efficiency Program	Reg Asset	10	N/A	2014/2015	10	0%	0
6&7	Gas Fired DG	treat as Plant	10	7N	2018/2019	10	0%	0.1
8	Patrick Farm Home Energy Incentive	Reg Asset	10	N/A	2016-2019	10	0%	0
9&10	Solar	treat as Plant	10	7N	2019	10	0%	0.1
11	Pomona Station (2021)	treat as Plant	40	20N	2020	40	-10%	0.0275
12	Pomona Station (2025)	treat as Plant	40	20N	2024	40	-10%	0.0275
13	138kV UG Exits (2021)	treat as Plant	35	20N	2020	35	0%	0.028571429
14	138kV UG Exits (2025)	treat as Plant	35	20N	2024	35	0%	0.028571429
15	138kV UG Transmission (2021)	treat as Plant	35	20N	2020	35	0%	0.028571429
16	138kV UG Transmission (2025)	treat as Plant	35	20N	2024	35	0%	0.028571429
17	Line 53 structure (2021)	treat as Plant	55	20N	2020	55	-50%	0.027272727
18	Line 53 structure (2025)	treat as Plant	55	20N	2024	55	-50%	0.027272727

Base		1.0000	
SIT	6.5%	0.0650	4.62%
MTA (25.6% of SIT rate)	1.7%	0.0166	
		0.9184	
FIT	35.0%	0.3214	
Net Retained		0.5970	
Tax Amount		0.4030	

Gross Up Factor (Case 14-E-XXXX) (per draft Revenue Requirement Model as of 10/3/14)

GRT Revenue Taxes	1.780%	1.0181
LPC Revenues	-0.650%	0.9935
Uncollectible Factor	0.540%	1.0054
Total Revenue Gross Up	1.670%	1.0170

Property Tax rate for new Plant in Service	5.00%
Annual Escalation Rate	3.66%

Annual Cash Flow of Various Pomona Scenarios (2014 dollars)

($000s)

		Ref#	Project Component	2014	2015	2016	2017	2018	2019	2020
	2025	1	A/C Cycling Incentive				$ 90	$ 87	$ 87	$ 87
	2025	2	A/C Cycling Thermostat and Install			$ 210		$ 3	$ 3	$ 3
	2025	3	Battery							
	2025	4	Battery Maintenance							
	2025	5	Energy Efficiency Program			$ 1,750				
	2025	6	Gas Fired DG						$ 400	$ 978
	2025	7	Gas Fired DG- Maintenance							
	2025	8	Patrick Farm Home Energy Incentive			$ 210	$ 130	$ 190	$ 240	$ 240
	2025	9	Solar							$ 1,400
	2025	10	Solar Maintenance							$ 25
Substation / Transmission Investment	2021	11	Pomona Station						$ 8,500	$ 8,500
	2025	12	Pomona Station							
	2021	13	138kV UG Exits						$ 1,500	$ 1,500
	2025	14	138kV UG Exits							
	2021	15	138kV UG Transmission							$ 35,300
	2025	16	138kV UG Transmission							
	2021	17	Line 53 structure						$ 200	$ 200
	2025	18	Line 53 structure							
	2021	*	TOTAL	$ -	$ -	$ -	$ -	$ -	$ 10,200	$ 45,500
	2025	*	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Annual Cash Flow of Various Pomona Scenaric

($000s)

		Ref#	Project Component	2021	2022	2023	2024	2025	2026	TOTAL
	2025	1	A/C Cycling Incentive	$ 87	$ 47	$ 40				$ 525
	2025	2	A/C Cycling Thermostat and Install	$ 3	$ 3					$ 225
	2025	3	Battery	$ 2,880						$ 2,880
	2025	4	Battery Maintenance		$ 30	$ 30	$ 30			$ 90
	2025	5	Energy Efficiency Program							$ 1,750
	2025	6	Gas Fired DG							$ 1,378
	2025	7	Gas Fired DG- Maintenance	$ 25	$ 25	$ 25	$ 25			$ 100
	2025	8	Patrick Farm Home Energy Incentive							$ 1,010
	2025	9	Solar							$ 1,400
	2025	10	Solar Maintenance	$ 25	$ 25	$ 25	$ 25			$ 125
										$ 9,483
	2021	11	Pomona Station							$ 17,000
	2025	12	Pomona Station			$ 8,500	$ 8,500			$ 17,000
	2021	13	138kV UG Exits							$ 3,000
Substation / Transmission Investment	2025	14	138kV UG Exits			$ 1,500	$ 1,500			$ 3,000
	2021	15	138kV UG Transmission							$ 35,300
	2025	16	138kV UG Transmission				$ 35,300			$ 35,300
	2021	17	Line 53 structure							$ 400
	2025	18	Line 53 structure			$ 200	$ 200			$ 400
	2021	*	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	**$ 55,700**
	2025	*	TOTAL	$ -	$ -	$ 10,200	$ 45,500	$ -	$ -	**$ 55,700**

Annual Cash Flow of Various Pomona Scenarios (Escalated dollars)

Annual Escalation 3.66%

($000s)		Ref#	Project Component	2014	2015	2016	2017	2018	2019	2020
			Year	0	1	2	3	4	5	6
	2025	1	A/C Cycling Incentive	$ -	$ -	$ -	$ 100	$ 100	$ 104	$ 108
	2025	2	A/C Cycling Thermostat and Install	-	-	226	-	3	4	4
	2025	3	Battery	-	-	-	-	-	-	-
	2025	4	Battery Maintenance	-	-	-	-	-	-	-
	2025	5	Energy Efficiency Program	-	-	1,880	-	-	-	-
	2025	6	Gas Fired DG	-	-	-	-	-	479	1,213
	2025	7	Gas Fired DG- Maintenance	-	-	-	-	-	-	-
	2025	8	Patrick Farm Home Energy Incentive	-	-	226	145	219	287	298
	2025	9	Solar	-	-	-	-	-	-	1,737
	2025	10	Solar Maintenance	-	-	-	-	-	-	31
Substation / Transmission Investment	2021	11	Pomona Station	-	-	-	-	-	10,174	10,546
	2025	12	Pomona Station	-	-	-	-	-	-	-
	2021	13	138kV UG Exits	-	-	-	-	-	1,795	1,861
	2025	14	138kV UG Exits	-	-	-	-	-	-	-
	2021	15	138kV UG Transmission	-	-	-	-	-	-	43,797
	2025	16	138kV UG Transmission	-	-	-	-	-	-	-
	2021	17	Line 53 structure	-	-	-	-	-	239	248
	2025	18	Line 53 structure	-	-	-	-	-	-	-
	2021	*	TOTAL	$ -	$ -	$ -	$ -	$ -	$ 12,208	$ 56,452
	2025	*	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Annual Cash Flow of Various Pomona Scenaric

Annual Escalation 3.66%

($000s)		Ref#	Project Component	2021	2022	2023	2024	2025	2026	TOTAL
			Year	7	8	9	10	11	12	
	2025	1	A/C Cycling Incentive	$ 112	$ 63	$ 55	$ -	$ -	$ -	$ 643
	2025	2	A/C Cycling Thermostat and Install	4	4	-	-	-	-	$ 244
	2025	3	Battery	3,704	-	-	-	-	-	$ 3,704
	2025	4	Battery Maintenance	-	40	41	43	-	-	$ 124
	2025	5	Energy Efficiency Program	-	-	-	-	-	-	$ 1,880
	2025	6	Gas Fired DG	-	-	-	-	-	-	$ 1,692
	2025	7	Gas Fired DG- Maintenance	32	33	35	36	-	-	$ 136
	2025	8	Patrick Farm Home Energy Incentive	-	-	-	-	-	-	$ 1,175
	2025	9	Solar	-	-	-	-	-	-	$ 1,737
	2025	10	Solar Maintenance	32	33	35	36	-	-	$ 167
										$ 11,502
Substation / Transmission Investment	2021	11	Pomona Station	-	-	-	-	-	-	$ 20,720
	2025	12	Pomona Station	-	-	11,747	12,177	-	-	$ 23,924
	2021	13	138kV UG Exits	-	-	-	-	-	-	$ 3,656
	2025	14	138kV UG Exits	-	-	2,073	2,149	-	-	$ 4,222
	2021	15	138kV UG Transmission	-	-	-	-	-	-	$ 43,797
	2025	16	138kV UG Transmission	-	-	-	50,569	-	-	$ 50,569
	2021	17	Line 53 structure	-	-	-	-	-	-	$ 488
	2025	18	Line 53 structure	-	-	276	287	-	-	$ 563
	2021	*	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	**$ 68,660**
	2025	*	TOTAL	$ -	$ -	$ 14,096	$ 65,181	$ -	$ -	**$ 79,278**

GAS CONVERSION REPORTING REQUIREMENTS

Definitions:
A. Conversions - "Conversions" include those customers who used no gas before the conversion and those non-heating gas customers that install gas heating equipment.

B. Inquiries - "Inquiry to convert" represents a written request for a service determination made by potential customers who are interested in converting to natural gas service. If warranted, the Company may need to determine if an additional amount is owed by the customer to extend mains/services and/or needs to determine if the existing gas distribution system needs reinforcement before responding to an inquiry. The time period for a pending inquiry represents the number of days between the date the customer inquired about converting to natural gas and the date the utility informs the customer that it can provide the customer with natural gas and the amount due from the customer, if any.

C. Requests - A "request to convert" assumes that the customer has affirmatively agreed to the conversion (with or without an initial inquiry) and has agreed to pay any amounts due in accordance with tariff provisions if any. The time period for a pending request represents the number of days between the date the customer agreed to convert to natural gas (and pay any additional amounts due) and the date the utility actually begins providing natural gas to the customer.

The Company will report on an annual basis, in quarterly format, the following information relating to prospective customer inquiries and requests for conversion to gas service:

1. Customer name and address;
2. Service Classification;
3. Distance from existing main;
4. Current heating system type and fuel type (to the extent potential customer agrees to provide this information);
5. Date of applicant submission of documentation formally requesting a service determination related to natural gas service;
6. Date of Company reply to applicant (service determination);
7. A list of applicants rejected because they are outside of the Company's franchise area;
8. Contribution in aid of construction ("CIAC"), if required, including the date the quote was given, dollar value, footage required and amounts received;
9. Date applicant requested that Company move forward with conversion;
10. Date the Company confirmed applicant's desire to move forward; and
11. Service initiation date (actual date service line and metering installed).
12. Total conversions by month and year
13. Annual number of conversion customers paying a CIAC
14. Annual total CIAC dollars collected

Annual reports are to be filed with the Secretary by February 28 following the end of the Rate Year (e.g., the 2016 report will be filed by February 28, 2017).

SUBJECT: Filings by ORANGE AND ROCKLAND UTILITIES, INC.

Amendments to Schedule P.S.C. No. 3 – Electricity

Original Leaf No. 108.2
First Revised Leaves Nos. 9, 68, 158, 159, 160, 161, 162, 166, 167, 168, 169, 173, 210, 258, 271, 287, 346, 351, 357, 388, 389, 390, 391, 392
Second Revised Leaves Nos. 3, 106, 139, 147, 151, 164, 214, 218, 250, 252, 255, 257, 261, 262, 277, 286, 296, 303, 343, 348
Third Revised Leaves Nos. 4, 155, 259
Fourth Revised Leaves Nos. 260, 264, 266, 267, 268, 269, 270, 272, 274, 276, 278, 283, 284, 285, 290, 309, 310, 312, 321, 322, 331, 332, 333, 335, 336, 341, 345, 347, 350, 352, 356, 358, 359, 372, 373, 374, 375
Fifth Revised Leaf No. 295
Seventh Revised Leaf No. 89

Suspension Supplement Nos. 5 and 8

Amendments to Schedule P.S.C. No. 4 – Gas

Original Leaves Nos. 20.1, 47.1, 193.1
First Revised Leaf No. 20
Second Revised Leaves Nos. 4.1, 94.25, 113.4, 122.1.1, 122.3, 136, 141.1.1, 185.1, 190, 191.1, 191.2, 192, 197.1
Third Revised Leaves Nos. 77.1, 135, 148, 149, 151.1, 151.2, 183.1, 191, 193, 197
Fourth Revised Leaves Nos. 2, 79.2, 93, 113.1, 130.1, 151
Fifth Revised Leaves Nos. 113.2, 126, 152.3, 184
Sixth Revised Leaves Nos. 5, 47, 79.1, 80.4, 94.18, 122.1, 122.2, 134, 141.4, 154.1
Seventh Revised Leaves Nos. 80.3.2, 122, 141.2
Eighth Revised Leaves Nos. 74, 76, 120, 121, 127, 150
Ninth Revised Leaves Nos. 75, 81.1, 94.9, 94.10, 119, 183
Tenth Revised Leaves Nos. 118, 137, 137.2, 141.3
Eleventh Revised Leaves Nos. 112, 131, 132
Twelfth Revised Leaves Nos. 77, 94.16, 137.1, 153
Thirteenth Revised Leaves Nos. 80, 117

Fourteenth Revised Leaves Nos. 33.3
Fifteenth Revised Leaves Nos. 72, 80.1, 82, 115, 138.1
Sixteenth Revised Leaves Nos. 138, 155
Eighteenth Revised Leaf No. 73
Twenty-Second Revised Leaves Nos. 114, 130
Twenty-Fourth Revised Leaf No. 133
Twenty-Fifth Revised Leaf No. 116

Suspension Supplement Nos. 58 and 61