STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on June 16, 2011

COMMISSIONERS PRESENT:

Garry A. Brown, Chairman
Patricia L. Acampora
Maureen F. Harris
James L. Larocca

CASE 10-E-0362 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

ORDER ESTABLISHING RATES FOR ELECTRIC SERVICE

(Issued and Effective June 17, 2011)

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BY THE COMMISSION:

I. INTRODUCTION

On July 30, 2010, Orange and Rockland Utilities, Inc. (O&R or the Company) filed rates that would increase the Company's electric delivery revenues by $61.7 million, effective July 1, 2011.[1] The increase would be offset by the expiration of temporary surcharges -- the Energy Cost Adjustment and the interim Revenue Decoupling Mechanism (RDM) adjustment -- leaving a net bill impact of $47.8 million, which represents a 22% increase in electric delivery rates and an overall increase in electric bills of 7.3%.

[1] Notice of the Company's filing was published in the New York State Register on February 2, 2011 (SAPA No. 10-E-0362SA1). The comments that were filed pursuant to this Notice are summarized herein.

The rates proposed by the Company are based on a rate year beginning July 1, 2011, and ending June 30, 2012 (Rate Year). O&R is currently operating under a three-year rate plan, which expires on June 30, 2011 (current Rate Plan).[2]

After considering the parties' positions on exceptions, we determine that the Company's electric delivery base rate revenues should increase by $26.587 million, which represents an increase of approximately 12.1% for electric delivery base rates. The revenue requirement increase, reflected in Appendix A, however, is mitigated, as discussed above, by the elimination of the surcharges, which reduces the overall bill impact of the base delivery rate increase. The elimination of these surcharges produces a net revenue impact of $12.477 million, which represents a bill increase of about 5.7% for electric delivery, and 1.9% for total electric bills.[3]

A. Background

The parties in this case are the Company, Department of Public Service Staff (Staff), and intervenors: the Utility Intervention Unit (UIU) of the New York State Department of State's Division of Consumer Protection, formerly the New York State Consumer Protection Board; the Town of Ramapo (Town or

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[2] Case 07-E-0949, Orange and Rockland Utilities, Inc. – Electric Rates, Order Establishing Electric Rate Plan for Orange and Rockland Utilities, Inc. (issued July 23, 2008)(2008 O&R Rate Order).

[3] Bill impact tables are attached as Appendix B.

Ramapo); and the Municipal Consortium in Support of Reasonable Electric Rates (MC).[4]

Staff and intervenors submitted pre-filed testimony in December 2010 and January 2011. Evidentiary hearings were held on February 4 and 7, 2011, and public statement hearings were held in Ramapo on February 10, 2011 and in Goshen on February 17, 2011. All parties submitted initial post-hearing briefs on February 23 and reply briefs on March 7, 2011.

On April 4, 2011, the Administrative Law Judges assigned to the case issued their Recommended Decision (RD) that addressed the issues presented in this case. The Judges recommended that O&R receive a delivery rate increase of approximately $26.643 million.[5] Briefs on Exception and Briefs Opposing Exceptions to the RD were filed by the parties on April 25, 2011 and May 10, 2011, respectively.

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[4] MC consists of the following municipalities and their elected officials: the Towns of Chester, the Hon. Stefan Neuhaus, Supervisor; Deerpark, the Hon. Karl A. Barbenec, MPA, Supervisor; Goshen, the Hon. Douglas Bloomfield, Supervisor; Haverstraw, the Hon. Howard Phillips, Jr., Supervisor; Highland Falls, the Hon. Edward Magryta, Supervisor; Monroe, the Hon. Sandy Leonard, Supervisor; Tuxedo, the Hon. Peter Dolan, Supervisor; Warwick, the Hon. Michael Sweeton, Supervisor; Wawayanda, the Hon. John Razzano, Supervisor; the Villages of Chester, the Hon. Phil Vilastro, Mayor; Florida, the Hon. James R. Pawliczek, Sr., Mayor; Haverstraw, the Hon. Michael Kohut, Mayor; Highland Falls, the Hon. Joseph E. D’Onofrio, Mayor; Monroe, the Hon. James Purcell, Mayor; Warwick, the Hon. Michael Newhard, Mayor; West Haverstraw, the Hon. John F. Ramundo, Jr., Mayor; and the Cities of Middletown, the Hon. Joseph M. DeStefano, Mayor, and Port Jervis, the Hon. Russell R. Potter, Mayor.

[5] After the release of the recommended decision an error in the priceout of the sales forecast was identified. Correction of the error increased the recommended revenue requirement by approximately $1.435 million to approximately $28 million.

B. Settlement Efforts and Stipulated Matters

On January 6, 2011, O&R gave notice of its intention to enter into settlement discussions with the parties.[6] Those efforts were conducted in January, and although they did not produce a joint proposal, the Company and Staff did reach agreement on a number of issues. The agreement is embodied in a stipulation entered into on February 16, 2011 and is attached as Appendix C. The stipulation addresses the market supply charge, mandatory day ahead hourly pricing (MDAHP), an electronic tariff system, special provisions for service classifications 1 and 2, the uncollectibles percentage to be used for the purchase of accounts receivables (POR) discount, depreciation rates and miscellaneous accounting matters.

C. Public Comments

Throughout this proceeding, the Commission has received customer comments in the mail, over the internet, and by telephone, as well as through the presentations of speakers at the public statement hearings in Ramapo and Goshen. Approximately 30 people spoke at the hearings. As of June 2, 2011, 65 written comments had been received and posted on the Commission's website.

A large majority of the comments were opposed to any rate increase. Commenters' opposition was focused on the poor timing of the request given the state of the economy and the lack of cost of living adjustments for those dependent upon social security or other fixed payments as their primary means of income. Commenters noted that a rate increase could force some to have to choose between electric service and food or medicine. In addition, commenters contended that higher electric rates will force young and older residents to move out

[6] January 6, 2011 letter from Enver Acevedo, Esq. to the Secretary to the Commission pursuant to 16 NYCRR §3.9(a).

of the service territory, and perhaps out of the State. Some commenters suggested the Company could avoid a rate increase if it reduced management and employee pay and benefits, scaled back pension outlays, delayed capital investment, or reduced the Company’s requested rate of return.

Several residential customers pointed out that the charges for delivery service on their O&R bill are now greater than the charges for commodity service. Many commenters also expressed confusion about the apparent need to increase rates to make up for lost sales revenues via the RDM. These commenters were angry that their energy bills were not going down as a result of their efforts to reduce electric consumption in direct response to the Company’s urging that they conserve energy.

Comments in opposition to the rate increase were also received from businesses. The commenters focused on the impact of the economy on business profitability and the narrow profit margins now available to absorb increases in utility costs. They expressed concern that electric bills are becoming a significant factor in the cost of their operations. Some businesses noted that the level of pension and post-employment benefits for their employees are consistent with the economic challenges faced by private businesses. They contended that O&R’s pension and post employment benefits are overly generous and recommended that O&R reduce them.

Elected officials and municipalities expressed general support for the Company but also noted, as did others, that the timing of the requested increase in rates was poor given the state of the economy. Some elected officials stated that they avoided property tax and other tax increases precisely because of the economy and asked that the Company act in the same manner and withdraw its requested rate increase.

D. Summary of Recommended Decision

The April 4, 2011 recommended decision proposed that the Commission allow O&R to increase its revenues for the Rate Year commencing July 1, 2011 by $26.643 million, $35.057 million less than the request included in the Company’s initial filing. The overall revenue impact of the recommended increase in Company delivery revenue, after taking into account the expiration of the temporary surcharges, would be approximately $13 million.

The recommendation was premised on a 9.2% return on equity (ROE) and a capital structure that included a 49% equity ratio. The difference between this recommendation and the Company’s proposed ROE of 11.0% accounted for an $11.9 million reduction in the Company’s requested revenue requirement. Other recommendations contributing to the reduction in the revenue requirement included a slippage adjustment to the Company’s net plant additions to recognize a past pattern of delayed capital projects; a reduction in transmission and distribution operation and maintenance expense; an extension of the period for amortization of costs related to manufactured gas plant site investigation and remediation (MGP SIR); an extension of the amortization period for deferral balances for pensions and other post-employment benefits (OPEBs); and an increase in the forecast of delivery revenues. The RD further recommended adoption of the parties’ stipulation.

II. DISCUSSION

Having carefully reviewed the evidence, the arguments of the active parties, comments by interested public officials, organizations, and the public, and the recommendations of advisory staff, we adopt the recommendations of the RD with certain modifications, which we identify in our analysis of contested issues set forth below.

A. Sales Revenues

O&R, in its initial filing, forecasted electric delivery volumes for the Rate Year of approximately 3,863,115 MWHs. It subsequently revised this number several times, with the latest revision occurring on January 5, 2011, for a Rate Year forecast of 4,001,578 MWHs. The January 5 update resulted in projected non-competitive and competitive Rate Year delivery revenues of $214.065 million, an increase of $0.455 million from the initial filing. The Company's January 5 forecast reflects a number of adjustments recommended by Staff.

Staff forecasted electric delivery volumes for the Rate Year of 3,995,311 MWHs. It priced out its forecast using the Company's pricing model, resulting in projected total non-competitive and competitive delivery revenues of $215.869 million. Staff's forecast of delivery sales revenues is $1.804 million higher than the Company's January 5 forecast.

Staff and the Company employed three models to arrive at their forecasts of delivery volumes for the Rate Year: (1) a residential model; (2) a secondary model (small commercial customers); and (3) a primary model (large commercial and industrial customers).[7]

The RD recommended a sales forecast based upon Staff's residential model, the Company's secondary and primary models, a 10-year weather average and an average of cooling degree days (CDDs) that excluded CDDs occurring outside the cooling season (May to October). The RD's recommendations produced a total non-competitive and competitive service delivery revenue

[7] The sales forecast models also include modeling for Lighting and Public Authority Classes. The RD noted the lack of dispute between the Company and Staff and accepted their agreed-upon numbers. No party has excepted to this recommendation.

forecast for the Rate Year of $215.745 million.[8] In Briefs on Exceptions, the Company indicated, and Staff concurred, that the price-out of the sales forecast for the RD was high by approximately $1.435 million due to double counting of one element in the calculations.

1. Motion to Strike

As attachments to its Brief on Exceptions, UIU submitted some 23 pages of documents consisting of a copy of the New York Independent System Operator (NYISO) Load Forecasting Manual and a presentation concerning the Peak Demand Impacts of Energy Efficiency Programs, apparently made by a NYISO employee on April 4, 2011. The documents were not previously offered in evidence in this case, and were not provided to the other parties to the proceeding prior to the filing of the brief.

In its Reply Brief on Exceptions, O&R objected that the late introduction of these documents unfairly deprived the parties of any opportunity to conduct discovery or cross-examination and argued that the attachments should be given no weight. UIU considered this argument to be in the nature of a motion to strike, and asked the Secretary to authorize, and establish a schedule for responses.[9] On May 13, 2011, the Secretary did so, issuing a “Notice for Replies.” UIU, MC and Staff responded to the notice.

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[8] The Company notes in its Brief on Exceptions that the RD’s sales forecast did not reflect the RD’s recommendation regarding exclusion of off-season CDDs from the weather forecast. The Company’s point is moot because, as discussed below, we now adopt Staff’s position on inclusion of off-season CDDs.

[9] Commission Rule 4.10(a) provides that, after the issuance of a recommended decision, filings other than Briefs on Exceptions and Briefs Opposing Exceptions will be entertained only if they are specifically authorized by the Secretary.

UIU and MC both contend that testimony by a Company witness during the evidentiary hearing asserting that the NYISO forecasts peak load based on extreme weather conditions was inaccurate. They say the attachments to UIU's Brief on Exceptions should be accepted in evidence in order to correct the record.

Staff responds that UIU had ample opportunity to present this information at the evidentiary hearing or within a reasonable time thereafter. By waiting until its Brief on Exceptions, Staff says, UIU unfairly deprived the parties of an opportunity to properly vet the materials submitted.

Discussion

Both procedurally and substantively, UIU's attempt to introduce the NYISO documents at this late stage of the proceeding is defective and we will grant O&R's request that they be given no weight by striking them from the record.

Procedurally, UIU's delay is unacceptable. The NYISO manual has been in existence for over a year. The presentation dates to April 4, 2011. According to MC's response to the Secretary's notice, counsel for UIU had a suspicion at the time of the disputed Company testimony that it was inaccurate. Despite that, UIU did not request that an exhibit be held open for a subsequent submission and did not submit its documents for over three months. That delay unfairly deprived the parties of an adequate opportunity to address the claimed significance of the information proffered.

Substantively, UIU's proffer contributes nothing to the resolution of any material issue in dispute in this case. Contrary to UIU's contention in its Brief on Exceptions, neither the Company nor Staff is obligated to disprove every conjecture raised by another party. Staff and O&R, in a generally adverse position in this proceeding, agree that there is no quantifiable relationship between peak demand growth and total sales growth in the Company's forecasts. We agree with Staff and O&R, as discussed below, therefore, correcting the understanding of how the NYISO forecasts peak load is unnecessary.

2. Residential Model

The Company takes exception to the RD's use of Staff's residential model. According to the Company, the RD justified its recommendation on the grounds that Staff's model was the only one that used a personal income variable to explain sales and that it made intuitive sense that personal income would drive energy usage by households. O&R contends that Staff's personal income variable, when plugged into the Company's residential model, demonstrates that the personal income variable is not statistically significant. Due to the lack of empirical support for the personal income variable, O&R advocates use of its residential model, despite its lack of a personal income variable.

Staff counters that use of the personal income variable is theoretically sound: personal income drives energy usage. It states that the failure of a personal income variable to be statistically significant when plugged into the Company's residential model only proves that the Company's residential model is inadequately constructed. Staff notes that the personal income variable, when used in Staff's residential model, works just fine and is statistically significant.

Discussion

That a model containing the personal income variable is preferable to one that does not is not refuted by the Company. The Company's inability to produce a workable model with the variable is not evidence that the variable is unimportant for use in forecasting residential sales. Even if both the Company and Staff's models produce similar results, we find the theoretical basis of Staff's model to be more reasonable. It makes intuitive sense that household income (also known as personal income) will drive energy usage by households, where increased usage may be attributable to discretionary electricity consuming devices. The sales forecast for the Rate Year, as set forth in Appendix A, relies on Staff's residential model, incorporating the real personal income variable.

3. Small Commercial (Secondary) Model

Before the ALJs, Staff and the Company disagreed on the forecast of the number of customers for the Secondary Model. The RD determined the Company's model to be statistically more reliable than Staff's. It noted that O&R was not obligated to demonstrate that Staff's model was flawed, but rather to show that its model was reasonable. It concluded that O&R had so demonstrated, and therefore, recommended that the Company's model be used for forecasting Rate Year sales revenues.

Staff did not take exception to this recommendation. For the reasons set forth in the RD and stated above, we adopt the recommendation of the RD and will use the Company's Secondary Model in calculating the sales forecast for the Rate Year.

4. Large Commercial and Industrial (Primary) Model

The RD recommended adoption of the Company's Primary Model and its forecast of the number of customers and delivery volumes for the Rate Year. The RD determined the Company's model to be reasonable and supported, and slightly better, from a statistical standpoint, than the Staff model. Moreover, the RD concurred with the Company that employment data is not always a direct indicator of energy usage, as, for example, when companies downsize work force in favor of mechanization of operations.

Staff takes exception to the RD’s recommendation of the Company’s primary model. It contends that the RD fails to recognize that the Company’s model does not employ a proper economic variable that captures the impact of the economy on the per customer electricity consumption of primary customers. Staff notes that the Company’s model does not reflect the fact that an improving economy will cause the per-customer amount of electricity used by primary customers to grow. In response to the downsizing example put forward by the Company, Staff notes that if primary customers were to cut employees in favor of mechanization while the number of primary customers remained constant, the Company’s primary model would not capture this effect on the sales forecast because it only relies on the number-of-customers variable.

Staff asserts that the RD, which notes the growth of primary customer delivery volumes in 2010, cannot be reconciled with adoption of the Company’s primary model, which forecasts a flat primary customer sales forecast, therefore yielding a flat delivery volume forecast. It states that it is logical for a Company that experienced delivery volume growth during the beginning of the economic recovery to experience further growth as the economic recovery continues.

The Company supports the RD’s recommendation to employ its Primary Model. It contends that the number-of-customers variable in its model is a valid economic variable and has a stronger bearing on delivery volumes than Staff’s employment variable. The Company asserts that the volume of energy used by a customer can be driven by the customer’s production process (machine intensive or labor intensive) and it states that an employment variable does not capture this data.

Discussion

The examples provided by Staff and the Company indicate how difficult it can be to accurately forecast delivery volumes for primary customers. While an increase in workers at a workplace is typically associated with increased economic activity and, therefore, increased electricity usage, the number of workers each customer employs could have no bearing on the volume of energy consumed if changes in production processes also had an impact on energy consumption. Therefore, the employment variable is imperfect. While the number-of-customer variable also is less than perfect because it does not forecast changes in use-per-customer, we agree with the RD that the Company's primary model is reasonable and supported by the record, and produces results that are statistically better than the Staff model. We adopt the recommendation of the RD and will use the Company's Primary Model in calculating the sales forecast for the Rate Year.

5. Weather Assumptions

On exceptions, the Company and Staff dispute two issues: (1) the use of a 30-year versus 10-year average of actual CDDs and heating degree days (HDDs); and (2) the inclusion of off-season CDDs (September through April). The RD recommended use of 10-year weather averages and exclusion of off-season CDDs.

a. 30-year vs. 10-year weather averages

The Company objects to the RD's use of 10-year weather averages in forecasting the delivery volumes for the Rate Year. It contends that there is no basis in the record to support a finding that this period captures recent weather trends, and maintains that using a shorter period of time creates a greater likelihood of sampling error. Fewer years of data to smooth out the impact of the extreme weather in any given year, the Company says, could greatly alter the average if there were extremely low or high degree days in a single year.

Staff supports the RD's use of 10-year weather averages. It dismisses the Company's concerns regarding sampling error. Staff maintains that the Commission has moved to this shorter time period in order to better reflect recent weather patterns.[10]

Discussion

We affirm here our preference for use of 10-year weather averages in forecasting delivery volumes. We agree that a 30-year method yields greater stability, but it does so at the expense of giving consideration to capturing trends caused by climate change. Our concern regarding the impacts of climate change is demonstrated by several of our significant energy policies, including our Energy Efficiency Portfolio Standard and our Renewable Portfolio Standard initiatives. The use of a shorter historical period enables us to better capture recent weather trends, which is important as climate change continues to impact our weather patterns.

Furthermore, if the Company's concern regarding sampling error proves justified, O&R's revenues will not be negatively affected. In furtherance of our energy efficiency objectives, O&R operates under an RDM; therefore any deviation between actual sales and the forecast on which rates are set will be automatically corrected.

b. Off-season CDDs

Staff excepts to the RD's recommendation that off-season CDDs be excluded from the weather forecast employed to

[10] Case 10-E-0887, et. al., Central Hudson Gas & Electric Corporation – Electric and Gas Rates, Order Adopting Recommended Decision with Modifications (issued June 22, 2009)(2009 Central Hudson Order).

forecast delivery volumes for the Rate Year. It believes the RD mistakenly accepted the Company's contention that the sole function of CDDs is to reflect air conditioner usage. Staff notes that the RD failed to recognize that, due to the Company's definitions of CDDs and HDDs, which overlap, the Company's measures assume more than simply air conditioner usage.

Staff also notes that, the RD failed to consider that in using historical data to develop its model, the Company included all CDDs and HDDs, regardless of the months in which they occurred. Staff argues that the Company's inclusion of these days for modeling the historical period, but exclusion of such days for forecasting the Rate Year weather produced biased and illogical results.

The Company counters that the Commission concluded in a recent decision that CDDs were intended to capture the use of air conditioning appliances and those appliances normally only run from May through October.[11] It argues that air conditioner usage is unlikely during a brief out-of-season warm spell.

Discussion

We agree with Staff that off-season CDDs should be included in the weather forecast employed to forecast delivery volumes for the Rate Year. We do so primarily because it is improper for the Company to include off-season CDDs for the historical period but not for the Rate Year forecast. Moreover, it is illogical to exclude a CDD that occurs, for example, on April 30 just because it occurs 24 hours before the official start of the cooling season. Therefore, we reject the RD's recommendation and include off-season CDDs for the weather assumptions of the sales forecast reflected in Appendix A.

[11] Case 07-E-0523, Con Edison Electric Rates, Order Establishing Rates for Electric Service (issued March 25, 2008)(2008 Con Edison Order), p. 32.

6. Sales Forecast Price-Out

At the hearing stage of this case, MC objected to the Company's updated sales price-out ($214.065 million), contending that it should have generated a greater increase in sales revenues given the increased number of megawatt hours provided by the updated forecast of delivery volumes. The RD declined to make an adjustment to the price-out of the sales forecast in response to MC's objections. The ALJs accepted the Company's explanation provided in response to MC's objections: a reduction in customer numbers combined with an increase in forecast delivery volumes results in greater energy use per customer, pushing more usage into the lower-priced rate blocks.

On exceptions, MC continues to object to the price-out of the sales forecast. It argues that the increase in sales volume in the Company's update (138,463 MWH), when divided into the amount of the increase in sales price-out ($455,000), produces a rate of $0.0033 per kWh. MC offers several examples, using what it assumes to be current rates, to develop the tail block rates for various customer classes. According to MC, its examples demonstrate that no customer class has a tail block rate as low as the $0.0033 per kWh estimate derived from the Company's updated sales and price-out data. Using the lowest tail block rate it developed for its examples, MC contends that the RD's total revenue requirement is understated by $15 million, or by $7.2 million in non-competitive transmission and distribution revenues.

MC also questions the validity of the sales forecast price-out, noting that during several of the Company's updates to the sales forecast the Company reflected decreases in revenues even while reflecting increases in delivery volumes. In addition, it notes another instance in which projected revenues rose by $2 million on a forecast delivery volume increase of 42,095 MWHs. This MC argues, is in stark contrast to the last update by the Company that showed an increase in revenues of only $455,000 on 138,463 MWHs of additional delivery volume.

Lastly, MC questions the Company's estimate of the effects of demand side management (DSM) on the sales forecast. It finds it odd that, as the Company's update to its sales forecast produced increases in sales, the offsetting DSM adjustment declined in absolute terms. It believes this result further supports its position that the price-out model is untrustworthy and should not be used to set rates.

UIU supports MC's assertions that the price-out model is flawed and should not be used. It contends that a *prima facia* case has been made regarding the fallibility of the model and that the Company has failed to meet its burden of proving its reasonableness. The Company, UIU argues, failed to provide a sufficient explanation for why the January update showing an increase in sales volumes of 138,463 MWHs produced a $455,000 increase in revenues, or why in another instance an update showed a revenue decrease when delivery volumes increased. UIU performed its own calculations which it says show that the Company price-out understates Rate Year revenues for non-competitive delivery service by $7.4 million.

The Company, in its Brief Opposing Exceptions, rejects the contentions of MC and UIU. It states that those parties provided disjointed calculations that the Company was unable to comprehend. It questions whether the calculations should have been provided at an earlier period in the proceeding to allow others to fully investigate them. In particular, O&R contends that MC's calculations fail to take into account that 72% of the increase in delivery volume change between the Company's November and January updates, was attributable to the primary commercial classes where the average usage charge is less than $0.01 per KWh. The Company also notes that the number of customers decreased, thereby reducing, among other things, the customer charge revenue component of non-competitive delivery revenue. These factors, it says, explain why the January update reflects a lower average rate per KWh than earlier updates.

Staff joins the Company in opposing the parties' contentions that the sales price-out is flawed. In its Brief Opposing Exceptions, Staff contends that UIU's calculations erroneously included the Merchant Function Charge balances, which have no relation to non-competitive delivery revenues. Staff also contends that UIU's and MC's analyses of the Company's various updates failed to take into consideration several model corrections that contributed to the decreases in revenue forecasts reflected in the Company's January update.

In addition, Staff responds to MC's contention that the DSM forecast decreased while sales volumes increases. Staff explains that the Company's update to the DSM forecast resulted from an extension of the historical period, which included both realized impact of DSM, and an update on expected DSM impacts. Due to these updates, the incremental DSM accounted for in the January update to the sales forecast was appropriately smaller because the revised sales forecast included the historical experience.

<u>Discussion</u>

All else being equal, it is intuitive that an increase in the forecast of delivery volumes should produce an increase in the forecast in revenue. It is equally intuitive to expect that an increase in delivery volumes and accompanying increase in revenue will serve as the benchmark for all other similar events; each increase in delivery volume should produce a similar increase in revenue. Therefore, the concerns of UIU and

MC regarding the validity of the price-out model are understandable.

That being said, Staff and O&R provide reasonable explanations for the variances among the Company's updates to the forecast of delivery volumes and revenues. For example, corrections that eliminate double counting can drive down revenues at the same time that the forecast for delivery volumes is increased, as was the case for one of the Company's updates. Any apparent anomalies in the model results have been adequately explained. Therefore, we find the Company's price-out model is reasonable and deny the exceptions the MC and UIU exceptions.

In addition, any flaws in the model will be addressed by the RDM. If revenues have been understated, as MC and UIU suggest, application of the adjustments provided for in the design of the RDM will allow ratepayers to receive the benefit of any incremental revenues.

7. <u>Peak Load Forecast</u>

Earlier in this proceeding MC, supported by the Town, contended that the Company's sales forecast should be higher to reflect a number of capital projects, such as substations, that the Company proposes to construct in order to meet expanding customer peak loads and new customer peak loads. The RD rejected these arguments and declined to make an adjustment to the delivery sales forecast based on forecasted growth in peak load.

On exceptions, MC contends that it never advocated, in contrast to the RD's characterization, that a growth in peak load should produce a proportional growth in sales. MC contends, rather, that an increase in load factor means an increase in sales. It argues that the Company's peak load growth implies an increase in sales volumes of 75,604 MWHs in 2011 and 94,244 MHWs in 2012. MC questions why the Company proposes flat, declining or only slightly increasing sales if, according to MC, the Company is designing a system to meet a growth of 25 to 40 MWs of peak demand.

UIU, similarly, contends that increases in peak load should result in an increase in the sales forecast. UIU claims that the Company's witnesses admitted to a relationship between the sales forecast and the peak load forecast. It complains that Staff and the RD did not explain why MC's assertions regarding the relationship between peak load forecast and sales forecast are wrong.

The Company, relying on the testimony of its Forecasting Panel, states that there is no direct link between the peak load forecast and the sales forecast. It explains that the peak load forecast measures the peak experienced in a single hour, usually occurring during the summer, driven by air conditioning usage. The sales forecast, according to the Company, measures usage for the entire Rate Year. The Company admits that, on a theoretical basis, sales may increase when peak loads increase, but it contends that there is no way to quantify this relationship.

Staff opposes the contentions of UIU and MC regarding the linkage between the peak load forecast and the sales forecast with arguments that mirror those of the Company.

<u>Discussion</u>

We agree with Staff and the Company that the RD's rejection of MC's position is proper. No adjustment to the sales forecast is necessary. Although there may be some relationship between the peak load forecast and the sales forecast, there is no basis in the record to determine what impact, if any, could be calculated from the relationship and applied to the sales forecast. Moreover, if the realized growth in peak demand produces an incremental increase in the sales forecast, the effects of this impact will be captured by the RDM, as discussed above.

8. Revenue

The sales forecast and price-out derived as a result of the foregoing discussion produces total non-competitive and competitive service delivery revenue of $215.745 million, which is reflected in the revenue requirement, attached as Appendix A.

B. Other Operating Revenues

Other Operating Revenues include miscellaneous service revenue, rents, regulatory items-reconciliations and regulatory items-recoveries/refunds. The parties agreed on Rate Year forecasts for many elements of Other Operating Revenues, and the RD, therefore, accepted those joint positions. The Company and Staff, however, disputed the Rate Year forecasts for several items within the miscellaneous service revenue category, including billing services, customer reconnect fees, and forfeited customer advances.

For these disputed elements, the Company proposed to forecast the Rate Year level based on a historical three-year average. Staff favored relying on the 12-month period ended March 31, 2010 (historic test year). The RD recommended use of Staff’s forecast for billing services revenues. For customer reconnect fees and forfeited customer advances, the RD recommended averaging the Company’s and Staff’s forecasts. The ALJs reasoned that the arguments proffered by the Company and Staff regarding the forecast of revenue for these two categories were equally compelling, and therefore a forecast based upon an average of the two positions was warranted.

1. O&R Billing Services

On exceptions, the Company objects to the RD’s use of Staff’s forecast of billing services revenue. According to the

Company, this revenue is derived from fees the Company charges energy services companies (ESCO) when it renders a consolidated bill to customers, that is, one that includes charges for both its delivery service and ESCOs' commodity services. The Company contends that the level of revenue received from providing consolidated bills is entirely dependent on customers' decisions to take commodity service from ESCOs. It asserts that the RD did not articulate a reasonable rationale for why revenue for billing services will continue at the historic test year level.

The Company advocates use of a three-year historical average to forecast revenue for billing services. Using this method the Company forecasts billing services revenue of $352,000 for the Rate Year. If the Commission departs from use of a three-year average in forecasting billing services revenue, O&R argues, then it should also do the same for other revenue items, such as collection charges, bad check charges, and agency checks dishonored fees.

Staff supports the RD's recommendation that we adopt the Staff's $474,000 forecast of billing services revenue. Staff points out that revenue from billing services increased 96% from the year ended March 31, 2008 to the year ended March 31, 2009, and increased 53% from the year ended March 31, 2009 to the year ended March 31, 2010. According to Staff, if a three-year average were used to forecast billing services, the Rate Year would reflect a decline of $234,000 from the actual 2010 level of $586,000, a 40% decrease.

Staff defends continued use of a three-year historical average to forecast revenue for other revenue items, because the historic test year and the three-year average produce comparable revenue forecasts: $188,000 and $185,000, respectively. In contrast, Staff contends that the Company's billing services revenue forecast approach ignores current circumstances and produces unreasonable results: the revenue for the historic test year is $474,000 and is $352,000 for the three-year average, while actual 2010 revenue was $586,000.

Discussion

Our review of the record and three years of actual billing services revenues leads us to conclude that it is not reasonable to assume that revenue from billing service will decrease by 40% from recent levels in the Rate Year. There is no indication such a precipitous decrease will take place. We, therefore accept the RD recommendation to adopt Staff's $474,000 forecast for Rate Year revenues. This forecast, as noted in the RD, is a reasonable estimate of Rate Year billing services revenue.

In addition, we reject the Company's request that we forecast other revenue items on a historic test year basis. As Staff indicates, and the facts support, the difference between the results of a forecast based on a three-year average and the historic year is negligible for the other revenue items that are forecast using such an average. The same cannot be said for billing services where the difference in revenue between the three-year average and the historic test year is consequential.

2. Customer Reconnect Fees and Forfeited Customer Advances

Reconnect fees are charged to customers who obtain reinstatement of service after having had service terminated. Customer advances are sometimes required by the Company as a condition of providing service to customers with a poor payment history. The Company retains such advances if a customer's service is disconnected for failure to pay. In its filing in this case, the Company forecasted revenue from these two sources based on a three-year average, while Staff forecasted revenue for both items using the twelve-month period ended March 31, 2010.

The RD noted that the Company’s Rate Year forecasts predicted significant improvement in the economy while Staff’s Rate Year forecasts provided a more bleak picture. Satisfied with neither the Company’s nor Staff’s Rate Year forecasts, the RD used an average of the two, producing a Rate Year revenue forecast of $195,000 for customer reconnect fees and $135,000 for forfeited customer advances. The RD’s forecast represented a reduction in revenue from these two items from 2010 actual levels.

The Company excepts to the RD’s approach. It contends that the ALJs’ concern regarding the impact of the turbulent economy on forecasting these revenues is the very reason why a three-year average should be used; the three-year average smoothes the impact of volatility. In addition, it says, use of an average is flawed, because it includes a double count -- the last year in the Company’s three-year average is the same year incorporated in Staff’s 12-month average. The Company alleges that this results in the forecast giving more weight to a single 12-month period.

Staff supports the RD’s forecast of revenue for customer reconnect fees and forfeited customer advances. It notes, for example, that revenue from reconnect fees has increased by 127% from the year ended March 31, 2008 to the year ended March 31, 2009, and by an additional 41% from the year ended March 31, 2009 through the year ended March 31, 2010. According to Staff, use of the three-year average of revenue to forecast reconnect fees, would decrease the revenue by 33% from the Test Year.

Discussion

As the economy improves it is reasonable to expect that the revenue produced from reconnect fees and forfeited customer advances will decrease because more customers will be in a financial position to maintain electric service. The question for us is how much the economy will improve during the Rate Year, and that is difficult, if not impossible to answer.

The RD's recommendation reflects an appropriate balancing of Staff's and the Company's competing views. While averaging competing forecasts is not our preferred approach to ratemaking, in this instance we find the results reasonable. The fact that the averaging results in a forecast reduction in revenues from 2010 actual levels is consistent with the slight improvement in economic conditions expected to continue into the Rate Year.

C. Operating Expenses

1. Labor

The Company proposed to include several new positions in rates during the Rate Year and in Rate Years Two and Three of its multi-year rate proposal. The RD determined that several positions were well supported by the record and warranted funding in rates. It noted that the vegetation management position and positions related to stray voltage activity will assist the Company in complying with federal or State regulatory requirements, including compliance with our electric safety standards requirements.[12] The RD also noted that the transmission planning/compliance engineer, compliance program specialist, senior specialist - critical infrastructure

[12] Case 04-M-0159, Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems, Order Instituting Safety Standards (issued January 5, 2005); supra, Order Adopting Changes to Electric Safety Standards (issued December 15, 2008).

protection compliance, and an engineer for support services – power systems applications would ensure the Company is complying with reliability requirements and being active in system planning initiatives at the regional and national level. The outage management system administrator, according to the RD, will join one other existing employee, to support the Outage Management System, which is used by 570 Company employees, and the procurement specialist will assist the Company in its purchasing operations.

In its Brief on Exceptions, MC contends that these positions should have been filled, in the first instance, by employees from O&R's parent company, Consolidated Edison, Inc. (CEI). MC complains that the RD's dismissal of its general concerns regarding new positions was unfair because MC has limited resources to rebut the justification proffered by the Company. It implies that O&R's managers have an incentive to request more personnel for their divisions because more personnel mean a higher pay for the manager.

The Company questions MC's claim about its inability to adequately challenge the Company's justification for the new positions, countering that MC did not present specific arguments in testimony or during cross examination against the new positions because it did not have any. It dismisses as baseless MC's assertions with respect to Company managers.

Discussion

Based on the justifications provided by the Company, as generally described above and articulated in the RD, we adopt the recommendation for funding the new positions discussed above. We will address below the RD's recommendation with respect to the project management team positions, the DSM program designer, a regulatory administrator and the community outreach and education administrators.

While we appreciate MC's desire to see the Company's labor costs held down, it is important that the Company have the personnel necessary to comply with State and federal safety and reliability requirements, and to be represented at local and national system planning activities.

a. Project Management Team

The Company proposed funding for additional Project Management (PM) Team positions that included a project manager, a construction manager, a project engineer, and two construction administrators. The construction administrator positions would replace two outside contractors, who are currently performing these duties. Staff, MC, UIU and the Town of Ramapo opposed the Company's request, in part based upon the failure of the Company to demonstrate that the PM Team, which is still in its infancy, is in need of immediate expansion. The RD recommended funding in rates for the five positions, based on the Company's demonstration of need, general support by Staff for the PM structure, and the conclusion that the positions were not self-funding.

On exceptions, Staff disagrees with the recommendation. It contends that the RD erred in over-relying on Staff's support for the PM Team structure and the Company's willingness to realign internal resources in support of the team. Staff notes that the ALJs, although supporting the PM Team positions, also doubt the effectiveness of such positions because the ALJs recommend a slippage adjustment to the Company's capital expenditure targets for the Rate Year. Staff maintains that the ALJs' concerns regarding the workload of the existing PM Team members reflect merely "growing pains" or the inefficiencies in adapting to a new model. It recommends that the Company evaluate the effectiveness of the team in meeting capital project construction schedules and budgets before seeking to expand it.

Staff also complains that the ALJs shift the burden of proof that savings will materialize to offset the costs of the PM Team expansion. It maintains that savings are expected from creation of the new positions because the Team is designed to achieve project efficiencies and savings, and therefore the costs associated with the new positions should be offset by the realized savings from the Team's operation. Staff contends that the Company has the burden to demonstrate otherwise. MC also disagrees with the RD's recommendation to fund the PM Team positions. It contends that the Company has not demonstrated a need for the growth in capital projects, and consequently has not demonstrated the corresponding need to increase its PM Team.

O&R rejects Staff's "growing pains" argument and notes that Staff has not cited any record evidence to support its assertion. It contends that the PM Team currently provides project support to only a fraction of the Company's capital projects. It dismisses MC's assertion that the Company has insufficient growth in capital projects to support the new positions as a re-application of MC's peak load forecast argument, discussed above in the Sales Revenue section of this order.

Discussion

We agree with Staff that it is premature to expand the PM Team by five new positions. The Company, as MC points out, implemented this team in 2010 and the operation of the team and attendant benefits are only becoming known. While we support the Company's efforts, we believe that additional experience with this new structure is warranted prior to its expansion. We anticipate that the Company, in its next rate filing, will be able to provide more recent information as to the efficiency achievements and needs of the PM Team.

We agree, however, with the RD, that the two construction administrator positions should be funded in rates for the Rate Year. The costs associated with these two positions should, according to the Company, be offset by a reduction in outside contracting expense, but it does not appear, from the record, that the Company has appropriately reflected that reduction in revenue requirement. Therefore, while we support funding these two positions in rates, we conclude that such funding should be available without any additional rate allowance.

b. Demand Side Management Program Designer

In its filing, the Company proposed to implement a business model that incorporates a comprehensive approach to Demand Side Management, energy efficiency, demand response, and renewable energy. To administer the model, O&R proposed a new position –- demand side management program designer.

The RD recommended that the position not be funded in rates. It reasoned that some of the new position's responsibilities –- energy efficiency program design -- fall within the realm of activities funded through our Energy Efficiency Portfolio Standard (EEPS), and that, in any event, the Company already appeared to possess sufficient knowledge and skill to develop energy efficiency programs.[13] Although the ALJs were unclear as to the extent to which O&R recovers the costs of program development for energy efficiency programs that do not have EEPS funding, they recommended that the issue be raised in the EEPS proceeding. In addition, the RD found that the record

[13] Case 07-M-0548, Energy Efficiency Portfolio Standard, Order Establishing Energy Efficiency Portfolio Standard and Approving Programs (issued June 23, 2008)(Order Establishing EEPS).

was unclear as to whether a new position was necessary to fulfill the limited role of DSM program designer, especially in light of the Company's practice of reviewing all capital expenditure projects of $5 million or more to determine whether targeted DSM can be employed as an alternative.

The Company disagrees with the RD's recommendation and claims that it is getting the "run around" regarding this issue. It notes that when it brings up the issue of recovery of program development costs in the EEPS proceeding it is directed to raise the matter in its rate case. Now, in its rate case, it is directed back to the EEPS proceeding.[14] The Company argues that the "back office" costs of its energy efficiency programs are not addressed in the EEPS program and customers will lose the opportunity to benefit from an expansion of the Company's efficiency programs.

O&R also argues that it does not currently undertake targeted DSM initiatives because it does not possess staff experienced with such endeavors. The Company complains that its distribution and transmission engineers are completely occupied with their primary responsibilities and have neither the time nor the expertise to develop and administer a targeted DSM program.

Staff supports the RD's recommendation. It counters the Company's claims regarding the inadequacy of EEPS funding of "back office" functions by noting that O&R, like competitive entities, takes certain financial risks in competing to provide energy efficiency programs. Staff contends that ratepayers should not fund the cost associated with the development of unsuccessful energy efficiency program proposals. In support,

[14] Company's Brief on Exceptions, p. 9 (citing Case 07-M-0548, supra, Order Approving Three New EEPS Programs and Enhancing Funding and Making Other Modifications for Other EEPS Programs (issued June 24, 2010), pp. 8, 40).

it quotes our Order Establishing EEPS in which we declined to set fixed budgets for the program in favor of enticing program administrators to develop cost competitive proposals.[15]

Moreover, Staff contends that the Company has not justified the need for this position, even if it can be argued that the Company's distribution and transmission engineers do not possess the time or skill necessary to develop a targeted DSM program. As an example, Staff notes that the Company has not explained why the program cannot be performed by outside contractors.

MC generally disagrees with funding any new position without a demonstration that the Company has not tapped the human resources of CEI. It concurs with Staff's position that the Company has failed to provide record support for the DSM Program Designer position.

Discussion

For the reasons set forth in the RD, and Staff's exceptions, we reject the Company's request for funding of a DSM Program Designer position, at this time. We clarify that O&R should be treated as any other entity vying for EEPS funding for energy efficiency programs, and should not be afforded a competitive advantage by having part of its costs –- "back office" functions –- funded through rates. First, ratepayers provide significant funds, via the EEPS charge on their bills, for energy efficiency programs. Second, if we allowed ratepayer support, apart from the EEPS charge, for these costs, we could inadvertently skew the cost-benefit analysis applied to EEPS funded programs by lowering the total cost of the program through utility specific ratepayer subsidization.

[15] Order Establishing EEPS, p. 54.

With respect to the targeted DSM component of the position, the Company failed to demonstrate that existing personnel are not already reviewing the availability of targeted DSM as means of avoiding infrastructure investments. In addition, for reasons discussed later in this order, the Company needs to provide more detail as to how its proposed targeted DSM program is to operate. More detail regarding the scope of the program is necessary to persuade us that additional internal resources are needed to get the job done.

c. Regulatory Administrator Position

During the current Rate Plan, the Company created and filled a new regulatory administrator position. According to O&R, this position was necessary because the multitude of Commission and NYISO-related proceedings and activities –- including EEPS, net metering, and mandatory hourly pricing -- was overtaxing the abilities of the Company’s Customer Energy Services Department, which is responsible for supporting the various operating divisions within the Company affected by such proceedings and activities.

The RD determined that the Company’s justification for funding the position in rates was substantively lacking. It found unpersuasive the fact that the Company’s shareholders funded the regulatory administrator position during the current Rate Plan. Moreover, the RD reasoned that treating the Company’s decision to fill a position through shareholder resources as definitive with respect to the need for the position, could possibly encourage the creation of new positions prior to the filing of a rate case in order to gain funding approval for future periods.

The Company objects to the RD’s recommendation, claiming that it justified the need for the regulatory administrator position independent of any argument based on prior funding through shareholder resources. It renews its disagreement with Staff's argument that the requested position was already funded in the current Rate Plan. It contends that the position to which Staff refers is responsible for a host of other responsibilities, and thus cannot carry out the responsibilities envisioned for the regulatory administrator position.

Staff asserts that the Company has raised no new argument in its objections to the RD's recommendation. It reiterates its position that the Company has failed to sufficiently explain why the new position is a necessary and cost-effective means of achieving the Company's goals. MC expresses its general objection to the funding of any additional positions during the Rate Year, and expresses a preference that the Company utilize CEI resources first to meet its goals prior to funding the new position.

Discussion

We adopt the recommendation of the RD. We find that the Company did not provide sufficient detail supporting the need for the regulatory administrator position, especially in light of Staff's allegations that the responsibilities of this position were originally assigned to another position for which we approved funding in the current Rate Plan. While it is relevant that the Company filled a new position without a discrete allowance for the associated costs in the current Rate Plan, without additional justification for the position we cannot approve of its funding in rates.

d. Community Outreach and Education Administrator Positions

The Company proposed a new customer outreach and education plan (O&E), which will be discussed in another section of this order. To facilitate this plan, the Company proposed to hire two community outreach and education administrators, one in the Rate Year and another in Rate Year Two, who will work within the Company’s Customer Energy Services unit. As we are setting rates only for the Rate Year, we do not consider the second proposed position at this time.

The RD recommended rejection of the requested position, concluding that the responsibilities assigned to it could be adequately addressed by the Company’s Customer Energy Services Department. That Department has 14 individuals providing services in the areas of customer outreach and education, customer energy services options, and energy efficiency programs, among others. The RD also noted that the Company did not explain why, with its existing methods of outreach via bill inserts and its Corporate Communications Office, it is unable to achieve its outreach and education goals.

The Company excepts to the RD’s recommendation, explaining that only 10 out of the 14 individuals in its Customer Energy Services Department are funded, in part, by O&R’s electric rates, and 6 of the 10 are purely responsible for back office functions for the Company’s Retail Choice program. It claims that the remaining four positions are completely dedicated to other functions, leaving no individual available to be responsible for a community O&E plan, although it does attempt to meet community needs by providing subject-matter experts at community events upon request.

O&R contends that a dedicated O&E administrator position will permit increased outreach in support of the Company’s goals for improving customer outreach and in furtherance of the State’s energy efficiency and conservation objectives. It contends that the Commission’s recent efforts to implement a statewide O&E campaign for the EEPS programs, including grassroots-level community outreach, further support its request for an O&E administrator position. According to O&R, increasing O&E activity is critical at this time given customers' interest in saving money on energy costs in the face of tough economic times. It contends that if the Commission delays funding the O&E position, an opportunity may be missed as customers may be less interested in energy efficiency education when economic conditions improve.

Staff supports the RD's recommendation. It asserts that the Company provided no evidence to support its contention that the state of the economy presents an opportune time to bolster O&E efforts regarding energy efficiency. In support of its view that the Company's current O&E resources are adequate, Staff quotes recent statements from the Company's chief financial officer, who said "[T]he Company is communicating more with and providing additional useful information to our customers."[16] Staff notes that it has not received any complaints regarding the Company's O&E efforts.

Discussion

We concur with the RD that the Company has failed to demonstrate the need for the O&E administrator position. The Company has not explained why using its existing resources and O&E methods are inadequate to achieve its outreach and education goals. Regarding its assertion that more resources are needed for it to conduct O&E regarding energy efficiency, in approving EEPS programs to be administered by O&R and other program administrators, we have provided funding for O&E and marketing of those individual programs. The Company has not demonstrated why it needs to conduct additional EEPS-related marketing

[16] Staff's Brief Opposing Exceptions, p. 13.

activity or how such activity complements our planned statewide energy efficiency marketing effort.

2. Annual Team Incentive Plan

Under the terms of O&R's current Rate Plan, the total compensation package for non-officer management employees includes a variable or incentive component, the Annual Team Incentive Plan (ATIP), which O&R describes as a pay-for-performance program. The Company sought continued ratepayer funding for ATIP in this case.

The RD recommended that funding be approved. It recognized that we had, in several recent rate orders, rejected proposals for incentive compensation programs. Nevertheless, it interpreted our recent discussions on plans as implying that we were primarily concerned with incentive compensation in excess of the level of compensation reasonably necessary to attract and retain capable employees.[17] The RD implicitly concluded that such compensation above "base pay" was not at issue here. It emphasized that ATIP has been a part of the overall compensation package for O&R management employees for many years and was included in the current Rate Plan that we approved. Therefore, the RD concluded, funding for ATIP should be provided as an appropriately incurred labor expense.

On exceptions, Staff maintained that the RD's interpretation of our recent orders as being concerned only with excessive bonus payments is unreasonably strained. It noted that we disallowed funding for incentive compensation in a Central Hudson rate case under factual circumstances very similar to those in this case.[18] Furthermore, Staff points out,

[17] For purposes of this Order, we identify the level of compensation necessary to attract and retain capable employees as "base pay".

[18] 2009 Central Hudson Order, p. 18.

reliance on the inclusion of ATIP in O&R's current Rate Plan as evidence of its reasonableness is unjustified because that plan was the result of a negotiated multi-year joint proposal.[19]

O&R responds that Staff's contention that the inclusion of ATIP in O&R's current Rate Plan is insignificant because the case was resolved through negotiation disregards the fact that Staff did not oppose ATIP in its testimony in that case. The issue, it says, was never in dispute. Therefore, O&R contends, the RD correctly concluded that rejection of ATIP-related costs would deny the Company recovery of labor expenses that have long been included in its rates.

Discussion

In this case, it appears that the Company sought to justify ratepayer funding for the ATIP pursuant to an analysis that tracks our discussion of the incentive compensation issue in our recent rate orders.[20] Our review of the record shows, however, that, O&R did not demonstrate that the criteria for additional compensation under the ATIP program were focused on goals for safety, reliability, environmental protection, or customer service. Moreover, while the ATIP program would provide extra compensation when some safety, reliability or customer service goals were met, the Company's presentation did not quantify or demonstrate the benefits, if any, associated with meeting these goals. The RD, however, distinguished the O&R proposal from proposals made in earlier cases by finding that total compensation, i.e., fixed compensation plus the ATIP or variable compensation, was reasonable, and therefore

[19] UIU took exception to the RD's recommendation concerning ATIP on grounds very similar to those presented by Staff.

[20] Case 10-E-0050, Niagara Mohawk Power Corporation – Electric Rates, Order Establishing Rates for Electric Service (issued January 24, 2011)(2011 Niagara Mohawk Order); 2009 Con Edison Order.

appropriately part of the Company's revenue requirement. It then reasoned that if the Company's overall compensation program were reasonable, the analysis from our earlier cases, which tests the goals and criteria for incentive pay against savings or benefits to ratepayers, or which distinguishes financial goals from safety, reliability, or customer service goals, and quantifies the benefits from each, was unnecessary. The RD also suggested that the reasonableness of the ATIP program was supported by the fact that it has been part of O&R's compensation program for many years and was included in rates under the Company's current Rate Plan.

Assuming that O&R intended to justify its ATIP program under the standards we have set for approval of incentive compensation that is above, or in addition to, reasonable base pay, it has failed to do so. For plans such as, for example, the above base pay incentive plan considered in the Niagara Mohawk Power Corporation (Niagara Mohawk) case, our objective is to ensure that ratepayers are responsible only for costs that are reasonably necessary to provide them safe and adequate service. Where management compensation is concerned, the level of scrutiny required to meet that objective is high because, in effect, utility management has substantial discretion in establishing the amount and make-up of this compensation. Accordingly, we require a very clear, affirmative demonstration that these above base pay incentive compensation programs are designed to return quantifiable or demonstrable benefits to ratepayers in a financial sense or in terms of reliability, environmental impact, or customer service before we will find such compensation to be an ordinary and necessary business expense.

On the record, we find that O&R did not demonstrate that the criteria for additional compensation under the ATIP program were focused solely or in large part on goals for safety, reliability, environmental protection, or customer service. Moreover, while the ATIP program would provide extra compensation when some non-financial goals were met, the Company’s presentation did not demonstrate the extent of the benefits or savings, if any, associated with meeting these goals, or the criteria to measure attainment of these goals. This presentation does not provide a sufficient basis for us to conclude the showing required by our earlier cases has been made.

An alternative showing, which the Company could have attempted to make, would have sought to distinguish the ATIP proposal from the incentive pay proposal we considered in National Grid by emphasizing that, unlike the National Grid incentive pay program, ATIP was a part of the O&R employees’ base pay. Under that approach, a demonstration that overall base pay, including ATIP, was reasonable relative to similarly situated companies, and that the inclusion of ATIP in base pay did not render the Company’s total compensation unreasonable, the record could have justified the inclusion of ATIP as a ratepayer funded expense. The Company in its case and the RD in its analysis did emphasize that past rate orders had permitted the inclusion of ATIP in the Company’s revenue requirement. This reliance on the historical practice does not satisfy the Company’s burden to establish the reasonableness of its proposal or the comparability of its total compensation program, including the ATIP, with that of similarly situated utilities. In general, our regulations make it clear that there is no presumption of reasonableness for rates in effect at the time a new case is filed.[21] More specifically, the extensive discussions of variable and incentive compensation we have

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[21] 16 NYCRR 61.2.

included in numerous cases over the last three years put O&R on notice that reliance on the status quo would be insufficient to support a continuation of ATIP.[22]

We are not suggesting here that a showing cannot be made that O&R's total compensation package is comparable to that of other similarly situated companies and that it is reasonable. If that showing is made, it may well be shown also that the ATIP program is well-aligned with ratepayer interests and not inconsistent with Commission policies. Our conclusion here is that the Company did not come forward to meet its initial burden on these points, and, therefore, it has not provided the record needed to approve the inclusion of the ATIP in rates at this time. Of course, O&R is free to do so in any future rate filing. In that regard, we believe some further guidance as to what we will be looking for is in order.

First and foremost, the Company must demonstrate that its overall management compensation levels, including its incentive compensation, are reasonable relative to similarly situated companies. This is best demonstrated through a compensation study that compares each of the elements of O&R's total management compensation, including base pay, incentive compensation and employee benefits, to the relevant market. An unsupported claim that incentive compensation is necessary to attract and retain competent, qualified management personnel will be insufficient to meet the Company's burden of proof.

In addition, O&R should fully present and describe the design and intent of ATIP. Such a presentation should include not only the goals against which performance is to be measured

[22] 2008 Con Edison Order, pp. 39-41; Case 08-E-0539, Consolidated Edison Company of New York, Inc. – Electric Rates, Order Setting Electric Rates (issued April 24, 2009)(2009 Con Edison Order), pp. 46-54; 2011 Niagara Mohawk Order, pp. 35-41.

in determining whether incentive compensation is paid, but also the corporate objectives underlying them. This aspect of the demonstration should confirm that the incentives will support the provision of safe and adequate service and will have no potential to adversely affect ratepayer interests or to promote results that are inconsistent with Commission policies.

Staff's exception to the RD's recommendation that the cost of ATIP be included in rates is granted. Given this conclusion, the Company's proposal to defer unpaid amounts for ratepayer's benefit is not now ripe for consideration. In any future request to allow the cost of incentive compensation in rates, the pros and cons of such a proposal should be fully explored.

3. Pension/OPEB Expense

The Company's forecast of Rate Year expense for pensions and OPEBs is $40.797 million, comprising pension expense of $28.658 million and OPEB expense of $12.369 million.[23] The forecast amounts are based on actuarial studies and three-year amortization of deferred under-recovered expenses projected as of June 30, 2011. The OPEB cost also reflects amortization of a deferred transitional obligation which will be fully recovered as of December 31, 2012, amortization of lost accrued tax benefits, supplemental pension costs and 401K costs. The RD accepted the Company's forecast of Rate Year expense for pensions and OPEBs, except that it recommended a five-year period for the amortization of accumulated unrecovered expenses deferred from prior periods, and it adjusted the 401K expense to reflect elimination of several new Company positions.

A five-year amortization period would require an allowance of $5.150 million for pensions and $2.4745 million for

[23] The Company's Rate Year forecast includes 1% productivity adjustment.

OPEBs, compared to $8.583 million and $4.574 million using the Company's proposed three-year period. The RD noted that the amortization period is earnings neutral for the Company and stated that the five-year period will mitigate the rate impact of the deferred pension and OPEB balances without an excessively negative impact on the Company's cash flow.

O&R objects to the five-year amortization period contending that the analysis relied upon by the RD conflicts with the rationale used by the ALJs for MGP clean-up costs. The Company asserts that the ALJs' recommendation of a five-year amortization period for deferred costs related to MGP clean-up was based on Company's position of over-recovery of MGP remediation during the current Rate Plan. In contrast, the Company asserts that it is not in such a position for pension or OPEB collections.

In addition, the Company contends that a five-year amortization period would result in an eight-year recovery period for a portion of the deferred balances that existed at the time of the start of the current Rate Plan, because such balances will be rolled into the deferred balance at the start of the Rate Year and be subject to an additional five-year amortization period. Consistent application of recovery of deferred balances, according to the Company, should drive the selection of the appropriate amortization period; credits and debits should be treated in the same manner. Moreover, the Company states that the Commission should be concerned with a build-up of the deferral balance, which may create future pressure on rates.

Staff counters that a five-year amortization period for the pension and OPEB deferral balances is appropriate given the impact of the economy on the growth in these balances. It notes that pension and OPEB costs represent a significant driver in the Company's requested rate increase. While Staff acknowledges that the five-year period will extend the recovery period for the deferred balance from the current Rate Plan, it argues that this extension is necessary to mitigate bill impacts and that the Company will not be harmed by the longer period because it is earnings neutral.

UIU disagrees with the Company's assertion that the RD's treatment of deferred balances for MGP clean-up contradicts the RD's recommendation for deferred pension and OPEB balances. It states that the RD's recommendations for amortization periods for these deferred balances did not depend on a state of over- or under-recovery, but rather on the need to mitigate rate impacts on ratepayers and the minimal impact of the recovery period on Company cash flow. While UIU agrees that the Commission should attempt to avoid a build-up of deferral balances, it contends that the state of the economy warrants a longer amortization period.

MC also supports a five-year amortization period, citing the state of the economy. It maintains that the need of the ratepayers for rate mitigation outweighs the need of the shareholders for revenues for dividends. MC also suggests that the recovery of the stock market may reduce actual pension and OPEB costs during the Rate Year.

Discussion

As stated in the RD, the amortization period, whether a three-year period or a five-year period, is earnings neutral for the Company, as the Company is provided carrying charges on the unrecovered deferred balances. In setting the amortization period we evaluate the need to balance rate mitigation with the impact of that mitigation on Company cash flow. The relevant factors do not involve, as the Company suggests, any over- or under-recovery of costs during the current Rate Plan.

No evidence has been introduced by the Company that a five-year amortization period will have an excessively negative impact on the Company's cash flow. Evidence indicates, however, that economic conditions during the period of current Rate Plan significantly negatively impacted the deferred balances for pension and OPEB expenses. To require ratepayers to make up for recessionary impacts over a short amortization period is unreasonable, particularly while the economy is still slowly recovering. We adopt Staff's five-year amortization period for the deferred pension and OPEB balances, which results in amortization allowances of $5.150 million for pension and $2.745 million for OPEBs.

4. T&D Non-Labor Expense Adjustments

The RD recommended Staff's proposed budget for inspection and repairs and the Company did not take exception. There is, however, a second issue regarding T&D non-labor expenses related to the Company's Transformer Sampling Program. O&R proposed a budget for this program based on an April 7, 2010, an Advanced Notice of Proposed Rulemaking (ANOPR) issued by the US Environmental Protection Agency (EPA), which seeks to reassess the current "use, distribution in commerce, marking, and storage for reuse of liquefied PCBs in electric and non-electric equipment."[24]

The RD found that it is unclear when EPA will issue a final rule and what effect the rule will have on the Company's continued use of electric transformers containing PCBs. The RD, therefore, recommended rejecting this program at this time. The ALJs noted, however, the importance of the Company's knowing the number and location of transformers containing liquid PCBs and ensuring such transformers are appropriately handled.

[24] Federal Register, Volume 75, Number 66, pp. 17645-17667; http://edocket.access.gpo.gov/2010/2010-7751.htm

Therefore, the RD recommended that if O&R renews this request in its next rate filing, it should better define the sampling program and explain how it relates to possible changes in EPA regulations; how it will complement the information already maintained by the Company; and how the replacement program will be incremental to the Company's current practices for transformer replacement.

The Company did not take exception to this recommendation. It did, however, reserve its right to propose a program in its next electric base rate case filing. Therefore, we adopt the RD's recommendation regarding the showing the Company must make in a future filing.

5. Outreach and Education

The Company proposed to: (1) develop a new O&E Plan; (2) create two new O&E positions; (3) increase the electric O&E budget by $100,000; and (4) conduct a new customer survey at an incremental cost of $50,000. The RD recommended denial of the Company's requests regarding the budget increase, the new positions, and the customer survey, and the Company takes exception to each recommendation. We have already discussed the Company's exception regarding the O&E positions and will not repeat that discussion in this section.

a. O&E Plan and Budget

The Company stated that it would develop an organized, focused customer O&E Plan to support the Commission's and the State's energy efficiency and smart grid goals.[25] The Company proposed a Community O&E budget of $100,000 to enable it to implement its O&E plan.

The RD rejected the Company's request to increase its electric O&E budget by $100,000. It found that the Company's

[25] Company's Initial Brief, p. 32.

current O&E budget enables it to provide sufficient consumer information on issues such as energy efficiency, management of energy costs, and Company programs and services, including outage information, billing and payment options, and safety and reliability. Moreover, the RD found that the description of the proposed O&E Plan in the record lacks detail regarding the incremental O&E activity, and does not explain why such activity warrants a $100,000 budget increase.

The Company takes exception to the RD’s rejection of its O&E budget request claiming, for the first time, that it does not have a community O&E budget and that its request to increase the O&E budget by $100,000 is designed to address that lack of funding. It says that the Commission’s energy efficiency goals and smart grid initiative warrant expansion of its O&E activity into these areas, and contends that our orders and studies indicate that New York residents have insufficient information about energy efficiency matters and smart grid technologies. It further claims that the utilities are the key point of contact with energy consumers in the State, and thus could serve a critical function in disseminating information regarding energy efficiency and smart grid technologies. The Company also claims that the downturn in the economy has made customers desirous of energy efficiency information as a means to lower their energy bills, and says that no funding has been provided to facilitate O&E activity on these issues in furtherance of the Commission’s energy efficiency and smart grid goals.

Staff counters that the Company provides no record evidence to supports its claim that it does not have a community O&E budget. It asserts that O&R has an O&E budget of hundreds of thousands of dollars and argues that the Company has not provided evidence to distinguish what portion of existing funding goes to particular activities. Staff notes that the Company admits to participating in some form of community O&E because it has representatives at local home and garden shows and other venues. It says the RD’s recommendation is correct because the Company has provided insufficient information to demonstrate why a $100,000 increase in its O&E budget is necessary and how it would be used.

Discussion

We adopt the RD’s recommendation and exclude from the Rate Year revenue requirement the Company’s request to increase its electric O&E budget by $100,000. We recognize the importance of utility outreach and education activities and we encourage companies to continually reevaluate their O&E plans for the ever-changing characteristics of their audiences and evolving State energy policy. Given the record, however, we cannot grant the Company’s request for increased funding.

First, there is no information in the record to support the Company’s last-minute claim that it has no funding for community O&E. Second, the record shows that the Company’s current O&E budget enables it to provide sufficient consumer information on a variety of issues, including energy efficiency, management of energy costs and Company programs and services, such as outage information, billing and payment options, and service safety and reliability. Third, the proposed O&E Plan, as it is described in the record, provides only general statements regarding O&E activity related to energy efficiency and demand response programs and provides no detail regarding why such activity would cost $100,000. Fourth, before deciding to increase O&E budgets to ramp up energy efficiency outreach activity, the Company would need to demonstrate, at a minimum, (1) how its O&E activity complements our planned statewide marketing activity on energy efficiency programs, and (2) why such marketing activity is not already being conducted as part of the EEPS programs administered by the Company.

b. Customer Survey

The Company currently performs, biannually, a Customer Assessment Survey (CAS) for both residential and industrial and commercial customers with a rate allowance of $75,000. Survey results are used to determine whether the Company has achieved the Company's Customer Service Performance Index (CSPI) targets. The Company requested to discontinue use of the CAS for electric operations and replace it with another survey for purposes of that incentive mechanism.[26] We consider that request below in Section II.H.1.b.

In this case, the Company requested a total budget of $125,000 for customer surveys. The $50,000 increase over the current budget was intended to fund a new Customer Focus Survey (CFS), which would be developed and conducted by outside resources. The new survey, according to the Company, would use a multi-media platform (e.g. the Internet). O&R claimed that the $125,000 budget would cover the cost of reformulating the survey questions as well as the cost of annually conducting and tabulating the survey.

The RD concurred with arguments made by the Town of Ramapo that the Company failed to justify why implementation of the CFS requires a 67% increase in the survey budget. It found that such an increase was not necessary and noted that the Company has adequately met the needs of its customers. In addition, the RD noted that Staff has expressed satisfaction with the Company's current O&E efforts, and it reasoned that any

[26] The CAS survey remains a provision of the Company's gas rate plan (Case 08-G-01398). It thus appears that the CAS must continue, even if it is no longer used for electric operations.

gains in that area from information produced by the new survey would likely be minimal. The ALJs did not object to the Company implementing the CFS; they simply concluded that the incremental cost of the CFS had not been justified by the Company.

The Company takes exception. It maintains that the increase in its survey budget is necessary in order for the survey to be conducted via a multi-media platform. O&R claims that use of the new survey will better enable it to respond to customers' needs, which will improve customer satisfaction.

Staff also takes exception to the RD's recommendation on this issue. It claims that the CAS is no longer relevant and should be terminated for its electric operations regardless of the Commission's decision regarding the CFS. Staff supports the Company's implementation of the CFS because, according to Staff, it would provide the Company with necessary information for the planning of customer education and outreach. Staff, however, states its support for the Company conducting the CFS within its existing survey budget of $75,000. It requests that if the Company cannot perform the new CFS within this budget then the funds should be deferred for the benefit of ratepayers.

Discussion

The Company, as the RD found, has failed to provide evidence supporting its request to increase its survey budget by 67% to $125,000 for its new CFS. It makes only general assertions that a multi-media platform, continual revision of survey questions and evaluation of survey results will cost an additional $50,000. The Company provides no cost proposals from outside vendors or estimates as to the anticipated costs of using a variety of media platforms.

We adopt, therefore, the RD's recommendation and set the survey budget at the current rate allowance of $75,000. If the Company determines that it cannot implement the CFS survey within this budget, then the Company shall defer, for the benefit of ratepayers, the $75,000 rate allowance. The Company will still perform its other customer surveys, as discussed in Section II.H.1.b of this order. If the Company decides to renew its request for an incremental $50,000 to conduct the CFS in its next electric rate case filing, it should, at a minimum, provide a breakdown of costs associated with the new survey.

6. Employee Benefit and Other Insurance Expense

a. Life Insurance

The base premium paid by O&R for employee and retiree life insurance is based on an actuarial forecast of the mortality rate expected within the insured population and the value of benefits provided. When the actual experience in a year varies from the forecast, O&R may be assessed an additional charge or issued a dividend. From 2007 through 2009, it received dividends. O&R requested a rate allowance equal to the base premium; Staff argued that the allowance should be reduced by a net of $19,000 to reflect the likelihood of a dividend.

The RD found that the current arrangement, under which premium dividends are retained by shareholders, creates a perverse incentive. The Company is better off if premiums are set too high, something the insurance carrier is unlikely to find objectionable. Consequently, the RD recommended that the rate allowance be as proposed by Staff, but that it should be reconciled annually with the actual net premium paid after dividend or surcharge. On exceptions, Staff argues that a reconciliation mechanism is neither necessary nor desirable given the small amounts of money involved.

Discussion

On this issue, we agree with Staff. To avoid the perverse incentive described in the RD, the rate allowance for life insurance expense will be based upon the expected net premium as derived from recent experience and there will be no reconciliation of the actual net premium paid. Although recent experience may differ from actual experience in any given year, the very small amount of money at risk does not warrant a formal reconciliation process. Additionally, the derivation of the expected dividend in this case was based on the most recent three years' actual experience. Consistent application of this forecast approach will in effect true-up period-to-period variances over time.

b. Asbestos Claims

The total remaining exposure of O&R's electric business to asbestos-related claims is approximately $955,000, according to an estimate produced by the Company's workers compensation claims administrator as of September 2010. The RD recommended that a rate allowance for such claims for the Rate Year be set equal to one-third of that amount, or $318,333, which is less than O&R requested and more than Staff proposed. No party took exception to the recommendation. We find it reasonable and will adopt it.

7. Incremental Winter 2008/2009 Uncollectible Expense

During the winter of 2008-2009, O&R voluntarily complied with our request that utilities assist customers experiencing payment difficulties during the economic downturn by refraining from shutting off service when the forecast temperature was expected to be below freezing. As a result, the Company says, it refrained from making service terminations on 15 days during the winter of 2008-2009. In this case, it sought a rate allowance to recover the incremental uncollectible expense it incurred because of the delayed shut-offs.

The RD concluded, in agreement with the positions of Staff and UIU, that numerous flaws in the methodology used by the Company to estimate its increased uncollectible costs made it impossible to determine what an appropriate rate allowance should be. The RD also noted, however, that it was undisputed that O&R did postpone terminations during the winter of 2008-2009 in accordance with our request and that such postponements almost certainly caused the Company to incur some level of incremental uncollectible expense. Therefore, the RD recommended that the requested allowance be disallowed without prejudice to the Company's including a revised request in a future rate filing.

No party took exception to the RD's recommendation, and we adopt it.

8. Storm Restoration Expense

O&R requested that reserve accounting be continued for this expense category; that the current rate allowance for the reserve be established based on the average expenditures over the three-year period ended March 31, 2010; and that an accumulated deficit in the account be amortized over three years. Staff supported continued reserve accounting but objected to the historic period chosen by the Company for calculating the current rate allowance, because it included costs associated with abnormally severe storms during the first quarter of 2010. It advocated using the four-year period from 2006 through 2009. Staff also recommended a five-year amortization period for the accumulated deficit.

The RD recommended approval of continued reserve accounting, but accepted neither Staff's nor the Company's position fully. Instead, it concluded that differences of opinion about the choice of a historic period for calculating average storm restoration costs could be resolved by using all of the data in the record, covering the eight years 2003 through 2010, and it directed to Company to update the 2010 figures through the end of the year. The RD also found that the accumulated reserve deficit was mainly attributable to the unusually severe 2010 storms, and reasoned that current customers should not be unduly burdened by the costs of those storms just because they happened to be on the O&R system when the storms occurred. Accordingly, it recommended an eight-year amortization period.

On exceptions, the Company accepted the RD’s recommendation concerning the current reserve allowance, but objected that the proposed amortization period for the accumulated reserve deficit was excessively long.

Discussion

The eight years of storm restoration cost data available in the record includes both high and low cost years. An inflation adjusted average of these expenses, including the 2010 update provided by O&R, reasonably levels the forecast of storm restoration costs for the Rate Year and is not opposed by any party. We will adopt it.

Selection of an appropriate amortization period for accumulated excess expenditures requires a balancing of the impact on ratepayers with the need of the Company to recover costs it has properly incurred. We agree that the RD recommendation is unusually long, but also consider the Company’s three-year proposal to be unnecessarily short given the unusual severity of the 2010 storms. We will adopt the middle ground, the five-year amortization period proposed by Staff.

9. Imputed Savings

a. Management Audit

A management audit of O&R’s affiliate, Consolidated Edison Company of New York, Inc. (Con Edison) produced a report listing 92 specific recommendations. O&R has reviewed the report and determined that 72 of the recommendations are applicable to its electric operations. A number of them have already been implemented.

Staff, supported by UIU and MC, contended that the ongoing implementation effort will likely result in savings during the Rate Year that were not accounted for in the Company's filing. It recommended that revenue requirement be reduced by an imputation of $500,000 in savings, equal to one percent of direct labor expense. It would reduce that amount by $147,000 if O&R elected to go forward with expansion of the PM Team without an allowance in rates for the cost of the new positions.

O&R responded that there was no record basis for Staff's proposal and that any imputation would be entirely speculative. It pointed out that many of the management audit recommendations would not be implemented during the Rate Year and that there would be implementation costs offsetting savings to some extent, particularly in the short run.

The RD agreed with the Company. It found that no specific sources of potential savings were identified in the record, and that there was no evidence to suggest that any efficiency gains achieved through the implementation effort would be incremental to those allowed for in the one percent productivity adjustment. It also concluded that, in the short term encompassed by the Rate Year, there were likely to be offsetting costs to achieve, as with the expansion of the PM Team.

Discussion

We agree with the RD that there is no basis in this record for imputing any specific level of savings from implementation of the management audit recommendations during the Rate Year. Before we can do so, we need some objective basis for the adjustment.

The management audit recommendations call for specific measures that can, when practical, be subjected to an analysis of potential costs and benefits prior to their implementation. Such analyses are important to ensure that we have the information necessary to appropriately account for costs and savings in setting rates. Indeed, simply as a matter of sound business practice, O&R should have performed them prior to implementing any audit recommendations, as we expect implementation to go forward only when the benefits exceed the costs. Therefore, we will require the Company, within 120 days after the issuance of this order, to produce a report detailing its implementation plans for the management audit recommendations, with a forecast of costs to achieve and expected savings. If, prior to that deadline, O&R files a new rate case, a preliminary report is to be included with the filing.

b. Austerity

On May 15, 2009, we issued a notice to all major utilities directing each to "closely examine its capital expenditures, operation and maintenance expenses and any other expense areas over which it has discretion to identify costs that may be reduced without impairing the ability to provide safe and adequate service."[27] Based on that examination, the utilities filed reports detailing the actions they had taken since September 2008, and those they would take in the future, to respond to the need for austerity occasioned by the severe economic downturn being experienced by the country. The reports also discussed the appropriate allocation of savings between the utilities and their customers and the measures to be taken to

[27] Case 09-M-0435 - Proceeding on Motion of the Commission Regarding the Development of Utility Austerity Programs, Notice Requiring the Filing of Utility Austerity Plans (issued May 15, 2009) (Austerity Notice).

ensure that the customer share of savings would be delivered as promptly as possible.

After reviewing those reports, we issued an order indicating our disappointment that the cost-cutting activities described by most utilities did not translate into any immediate savings to customers. Consequently, although we closed the proceeding initiated by the Austerity Notice, we advised utilities that we would expect all rate filings submitted "through 2010" to "identify, for austerity purposes, discretionary spending cuts" and that they should continue their cost-cutting efforts "[u]ntil the current economic downturn reverses."[28]

O&R contended in this case that it has complied with our austerity directives by continuing to identify and implement cost savings measures. As evidence, the Company detailed its efforts to contain pension costs, seek property tax assessment reductions, pursue synergy savings in conjunction with its affiliate, increase employee contributions to the cost of medical benefits, employ competitive bidding for procurement, and so forth.

Staff acknowledged O&R's cost-cutting efforts to be commendable, but said they failed to provide the immediate benefit to ratepayers contemplated by the austerity initiative. It, therefore, recommended that the Company be required to achieve the $825,000 in savings O&R detailed in its report made pursuant to our Austerity Notice, less a credit of $187,000 for savings that were, in fact, reflected in revenue requirement. Based on data for the third quarter of 2010, Staff argued that the economic outlook for the region in which O&R's service

[28] Case 09-M-0435, supra, Order Approving Ratepayer Credits (issued December 22, 2009) (Austerity Order), p. 2.

territory is located remains sufficiently uncertain to warrant the continuation of austerity measures.

UIU and MC called for a much larger adjustment, one that would be of the same relative magnitude as that which we applied in 2009 to Con Edison.[29] MC estimated the adjustment should be about $6 million.

The RD provided two alternative recommendations. First, it noted that we have been clear in our view that austerity adjustments are a necessary, but temporary, response to extraordinary circumstances, and that they should continue only until the economic downturn reversed. Considering whether that reversal was likely to have occurred by the time of the Rate Year in this case, it recognized that the recovery has been slow and that considerable uncertainty remained. It concluded, however, that numerous economic indicators including positive GDP growth and declining unemployment rates would justify our declining to impose an austerity adjustment in this case.

If an adjustment were to be applied, the RD recommended Staff's proposal, reduced by additional savings identified by O&R as having been reflected in revenue requirement but not counted in Staff's calculation. It rounded the $478,000 net amount up to an even $500,000 adjustment. The RD rejected the proposal of UIU and MC as too extreme in light of the substantial cost-cutting already undertaken by O&R.

On exceptions, the Company contends that the RD was correct in suggesting that curtailing utility investment in the local economy at this time might actually do more harm than good. It says applying an adjustment on top of the cost reduction efforts it has already undertaken will force it to reduce necessary expenses jeopardizing reliability and safety. O&R adds that if we determine that an adjustment is required,

[29] UIU's Initial Brief, p. 6.

the number should be the calculated amount stated in the RD, without rounding.

Staff on exceptions focuses on the continued uncertainty in the economy as grounds for continuing an austerity adjustment, and recommends adoption of the RD's $500,000 alternative. MC and UIU continue to advocate for a larger adjustment.

Discussion

In our previous discussions of the subject, we have identified four basic criteria for the application of an austerity adjustment. First, there must be harsh economic circumstances generating widespread hardship for both businesses and consumers. Second, it must be possible to make cuts in spending that are truly discretionary in the sense that they will have no negative impact on safety and reliability. Third, the adjustment must not adversely affect the interests of shareholders; and finally, the savings must inure to the benefit of ratepayers immediately, in order to provide relief during, not after, the recession.

The first question, therefore, is whether the current state of the economy requires an austerity adjustment. Or, to be more precise, whether an adjustment is justified by the likely state of the economy from July 2011 through June 2012, which is when it would be in effect.

Although circumstances have changed very substantially since we issued our Austerity Notice in 2009, the rate of improvement in the economy remains slow, and numerous potential pitfalls could derail the recovery. Levels of job growth and economic activity remain far below pre-recession levels both nationally and within O&R's service territory. Under the circumstances, we find that the type of additional, temporary relief we have required other utilities to provide to their customers should be implemented for O&R ratepayers as well.

Having found that an adjustment is appropriate, we next consider what size it should be. Our conclusion is that the austerity adjustment suggested by the RD and supported by Staff is reasonable and gives due consideration to the cost reduction efforts O&R has undertaken over the last several years. The upward rounding of the adjustment amount to $500,000, however, was not justified by any specific cost data or general uncertainty about the calculated amount. Therefore, we will approve an austerity adjustment of $478,000.

10. Manufactured Gas Plant Site Investigation and Remediation

In its prior rate cases, O&R has been authorized to use deferral accounting for the expenses it incurs to investigate and remediate former MGP sites and other environmental liabilities for which it is legally responsible under applicable environmental laws and regulations (SIR expenditures). The deferral balance is projected to be a surplus of $1.344 million at the end of the current Rate Plan. During the Rate Year, O&R expects to make $12.6 million in additional SIR expenditures, which would leave a reserve deficit of approximately $11.3 million. If this amount were deferred and amortized over three years, as the Company proposed, these expenditures would increase revenue requirement by $3.77 million.

Staff proposed three adjustments in the treatment of SIR expenses projected for the Rate Year. It recommended that recovery of the cost of litigation against the Travelers Indemnity Company for indemnification of MGP SIR costs be delayed pending the outcome of the lawsuit; that the electric operations’ share of the cost of acquisition of land at various

MGP sites be deferred until remediation is completed and the restored property can be valued for use or sale; and that the amortization of the Rate Year MGP SIR expenses be extended over five years rather than three as a rate mitigation measure.[30]

The RD agreed with Staff as to the land acquisition costs and the five-year amortization period, but sided with the Company on the litigation expense issue. No party took exception to these recommendations and we adopt them. When these adjustments are implemented, the revenue requirement associated with O&R's SIR expenditures in the Rate Year is $1,975.[31]

11. Allocation of O&M Expenses to O&R New York

MC takes exception to the RD's conclusion that there was no basis in the record for concluding that O&R's allocation of shared expenses among its operating divisions was inconsistent with its obligations under its Commission-approved Joint Operating Agreement, or otherwise improper. It contends that requiring such evidence would effectively shift the burden of proof to intervenors. It is O&R's obligation, MC argues, to

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[30] While the Staff's proposal to increase the amortization period from three to five years is an "adjustment" to the Company's rate case filing, the historic treatment of O&R's SIR expenditures has been to apply a five year amortization.

[31] In Case 11-M-0034, Proceeding on Motion of the Commission to Commence a Review and Evaluation of the Treatment of the State's Regulated Utilities' Site Investigation and Remediation (SIR) Costs, Order Instituting Proceeding (issued February 18, 2011), we have initiated a new proceeding to review and evaluate the treatment of utility SIR costs and are seeking to complete that review before the end of this year. This is a statewide policy proceeding. Any impact it might have on the recoverability of SIR costs would apply only to utility-specific cases decided in the future. We do not expect the policy proceeding to impact the recoverability of O&R SIR expenditures from past years or of O&R's current expenditures in the Rate Year.

demonstrate that the allocations have been made appropriately. MC also implies that high returns earned by other O&R subsidiaries, the fact that those utilities are not currently involved in rate cases, and a large jump in O&M expenses at O&R during the last half of 2010 are all suggestive of a misallocation of costs among utility subsidiaries.

O&R responds that it met its burden in this case by describing the methodology it used to allocate costs among its utility subsidiaries in its original filing. It notes that MC has failed to provide even a single example of a misallocation, and says that the factors MC calls “circumstantial evidence” are nothing but innuendo and do not raise any inference of a misallocation.

Discussion

O&R specifically addressed the procedures it used to allocate costs to its utility subsidiaries and non-regulated subsidiaries in its initial testimony.[32] This testimony was open to discovery and cross-examination by the parties. It was incorporated in the record upon the affirmation of the witness that it was true and accurate. Unless and until sufficient evidence is presented to raise an inference that it is incorrect, it is adequate to meet the Company’s burden of proof. None of the circumstances cited by MC does that. We agree with the RD that there is no basis for revisiting the allocation issue.

D. Property Taxes

Staff takes exception to the RD’s recommendation that the reconciliation of property tax expense provided for in the Company’s current Rate Plan be continued. It calls the recommendation unprecedented, noting that the RD itself

[32] Tr. 250.

recognizes that only once in recent history have we authorized property tax reconciliation in a one-year litigated rate case.[33] Staff disputes the RD's characterization of these costs as uncontrollable, noting that the Company's own witness detailed the extensive efforts O&R has undertaken to mitigate its tax burden. Furthermore, Staff says, such an extraordinary reconciliation has the effect of shifting risks to ratepayers and away from shareholders. That risk shift should be reflected in the Company's cost of capital.

In reply, O&R points out that the RD found, analogous to the circumstances underlying our 2009 Con Edison Order, that the Company's $27 million property tax bill was a large component of its budget –- 11% of its operating expenses other than purchased power –- and that the probability of further increases remains high given the fiscal pressure on local governments resulting from State and federal budget cutting efforts.

Furthermore, it says, Staff ignores the RD's finding that our consistent policy of allowing utilities to share in refunds realized through tax challenges will continue to provide a strong incentive for tax mitigation efforts even with reconciliation in place. Finally, O&R acknowledges that it vigorously endeavors to reduce its tax burden through legal challenges, but says that the RD correctly concluded that such efforts take years to complete and have little effect on the short-term property tax policies of municipalities.

Discussion

In our 2009 Con Edison Order, we addressed a situation in which property taxes had not only become a major driver of the utility's request for rate relief, but also the continued

[33] 2009 Con Edison Order.

reasonableness of the Rate Year allowance for those taxes was highly uncertain given the depth of the economic downturn the country was then experiencing. O&R, certainly, has a major property tax expense, and the economy is not fully recovered, but the circumstances today are an order of magnitude less uncertain than they were in 2009. We do not consider the extraordinary relief granted Con Edison to be necessary here.

Furthermore, we agree with Staff that adopting a reconciliation mechanism for this major expense category would represent a very significant shift of risk from O&R shareholders to ratepayers. Such a reallocation of risk can be justified only if there are concomitant benefits to ratepayers, which are most likely to be reflected in the Company's cost of capital. Within the context of a multi-year rate agreement, such as the one that included O&R's current reconciliation provision, that balance of interests can be accomplished through any number of negotiated adjustments. While it may be possible to achieve such a balance through a litigated case, there was no specific proposal in this case that could be considered an offset to the increased ratepayer risk that would result from the reconciliation of property taxes.

E. Cost of Capital

O&R sought an after-tax rate of return on its capital of 8.23%, based on a 50.2% equity ratio and an 11.0% return on equity. Staff testified that a 7.12% after-tax rate of return should be used, based on a 48.0% equity ratio and a 9.0% return on equity, while UIU supported an 8.7% ROE. Although the parties used similar methodologies in developing their recommendations, they differed on several of the data inputs used by their models. The RD called for a 7.26% after-tax rate of return, based on a 49.0% equity ratio and a 9.2% return on equity.

1. Cost of Equity

In recent rate cases, we have repeatedly affirmed certain key elements of the methodology we use in determining the appropriate cost of equity to be included in rates. These include (1) the application of Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM) analyses to a representative proxy group of utility companies; (2) utilization of a two-stage DCF computation with inputs derived from *Value Line*; (3) basing the CAPM result on an average of the outcome from standard and zero-beta models with a risk-free rate based on Treasury bonds, market risk premium provided by Merrill Lynch's *Quantitative Profiles*, and betas taken from *Value Line*; and (4) a 2/3 – 1/3 weighting of the DCF and CAPM results, respectively. We agree with the RD that no convincing demonstration has been made in this case that something about this particular utility or these particular economic times is sufficiently unique to require us to modify any of these basic aspects of our model. There are, however, a number of issues concerning the application of the methodology, which we address below.[34]

a. Proxy Group and Credit Quality Adjustment

Staff proposed an adjustment to its calculated ROE to reflect the difference between the average "Baa" credit rating of its proxy group and O&R's higher "A" rating. It derived the adjustment by applying the percentage difference in the five-year average spreads between "A" and "Baa" rated utility bonds with balances over $100 million and maturities around 30 years to the median proxy group ROE. The result was a 2.7% discount

[34] We note that the RD included several additional concerns the judges had about the methodology we use for calculating the ROE allowed in rates. We agree with Staff that this discussion was purely *dictum* and need not be addressed in resolving the litigated issues in this case.

that reduced the DCF component of the ROE calculation by 23 basis points.

O&R objected, noting that Staff acknowledged that it was unaware of any research supporting its assumption of a negative correlation between credit rating and required ROE and provided no explanation of the reasonableness of its methodology. Furthermore, to test the empirical basis for the adjustment, O&R performed a regression analysis of the relationship between credit quality and ROE for Staff's proxy group. That analysis indicated, albeit at a statistically insignificant level, that ROE and credit ratings were actually positively correlated.

Given the questions raised by the Company, the RD proposed an alternative approach. It reasoned that since the credit quality adjustment is intended to address a difference between the credit rating of the target company and the average credit rating of the proxy group, no adjustment would be necessary if there were no difference. Therefore, using Staff's numeric credit scoring system, the ALJs selected from among the 32 members of Staff's proxy group, a subgroup of 13 companies having an average credit rating nearly identical to that of O&R. They then calculated ROE for the smaller proxy group using Staff's data and Staff's methodology. The result was an 18 basis point increase over Staff's pre-credit adjustment ROE estimate, corroborating the Company's regression analysis. The RD, therefore, recommended that we adopt an ROE based on the ALJs' modified proxy group rather than Staff's proxy group with a separate credit quality adjustment.

On exceptions, Staff acknowledges that "given the current particular circumstances present in this case and in the market in general," the RD's recommendation is "not wholly unreasonable."[35] It also acknowledges that "currently, the credit ratings and calculated ROEs of the individual companies in our proxy group are directly correlated, rather than inversely correlated."[36] It argues, nonetheless, that this situation will not continue indefinitely, and that the credit quality adjustment it used represents the "best, consistent option."[37]

Staff also raises various concerns about the make-up of the proxy group selected by the RD and suggests that the ramifications of using a smaller, credit-specific proxy group have not been sufficiently developed to warrant adopting the approach. It says that its method, by contrast, is relatively consistent and objective.

Discussion

Initially, we agree with Staff that more analysis is necessary before we can comfortably conclude that a smaller, credit-tailored proxy group can be used consistently and objectively to calculate ROE. The pool of proxy candidates has already been considerably reduced by the consolidation of utility companies over time, and that trend has not abated. In fact, two companies used by both Staff and the RD are now involved in mergers, a circumstance that all parties agree disqualifies them for use in a proxy group analysis. In the future, finding a suitable small proxy group while avoiding data-skewing outliers could become difficult.

Fortunately, in this case we see no need to consider such a change. We will adopt Staff's proxy group, which was selected in a manner consistent with our past practice. The

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35 Staff's Brief on Exceptions, p. 15.

36 Id.

37 Id.

only issue, then, is whether the ROE calculations based on that group should be further adjusted.

As we have stated previously, allowed returns should be commensurate with the risk inherent in the rates we establish, and we have accepted credit ratings as a proxy for how that risk will be perceived by equity investors.[38] In our 2011 Niagara Mohawk Order, however, we noted that the use of credit ratings to assess equity investors' measurement of risk might be imprecise, and we stated that we remained open to considering another approach.[39] The additional information on the record in this case shows that the correlation expected by Staff between credit ratings and equity investors' return requirements is absent.

While we continue to agree with the theoretical premise that there should be a direct correlation between risk and return, there appears, at least recently, to be a difference between bondholders' perception of risk and that of equity investors. Therefore, we will not use credit ratings as the basis for a credit quality adjustment in this case, nor will we use credit ratings to narrow the proxy group beyond our normal requirement that all group members be at least investment grade. In effect, we deny Staff's exceptions to the RD's recommendation that no credit quality adjustment be applied in this case, but grant its exceptions to the use of a smaller, credit-specific proxy group. In the future, however, parties are free to propose a credit quality adjustment to ROE if they believe one to be required, and can provide an empirically supportable approach for developing it.

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[38] 2009 Con Edison Order, pp. 136-137; 2011 Niagara Mohawk Order, pp. 80-81.

[39] 2011 Niagara Mohawk Order, p. 81.

b. Discounted Cash Flow

The Company calculated the cost of equity, in part, using a constant growth DCF model and three-stage (multi-stage) DCF model. The constant growth DCF estimates the cost of equity as the sum of (1) the expected dividend yield and (2) the expected long-term growth rate. Assumptions of the constant growth model include: (1) constant earnings, dividend and book value growth rates; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate.

The Company contended that dividends per share and book value per share growth rates are directly dependent on earnings growth. Therefore, it maintained that estimates of earnings growth are more indicative of long-term investor expectations than dividend growth estimates. As a consequence, the Company employed growth in earnings per share as its measure of long-term growth rates for its constant growth DCF model.

The Company also employed a multi-stage DCF model, which it contended was a better predictor of investor expectations because it tracks near-term, middle-term and long-term investment periods. The Company's three-stage model set the proxy group companies' stock prices equal to the present value of cash flows over three stages; cash flows for stages one and two equal projected dividend yields and stage three cash flows equal both dividends and the expected price at which the stock will be sold at the end of the period (terminal price).

Staff employed a two-stage DCF model to calculate the cost of equity. It utilized *Value Line* data to estimate the dividends that can be expected from each of its proxy group companies. The data included earnings per share, dividends per share, book value per share and a forecasted amount of outstanding common stock. Staff then determined the discount rate (required return) necessary to convert the series of expected dividend payments into the current stock price to arrive at the cost of equity.

The RD recommended use of Staff's DCF methodology. It reasoned that the use of earnings growth rates in the DCF model results in unrealistic expectations as to the ultimate ROE that the proxy group companies would need to achieve given the growth rates that fall out of the Company's three-stage DCF method. In addition, the RD found that the growth rates produced by Staff's model, as compared to those produced by the Company's model, are closer to the forecasted growth of the nominal gross domestic product (GDP), as published in the October 2010 issue of *Blue Chip Economic Indicators*.

On exceptions, the Company states that the RD mischaracterized the Company's application of dividend payments in its constant growth DCF. According to the Company, dividend increases are generally distributed over calendar quarters, and to account for that the Company applied "one half of the expected annual dividend growth for purposes of calculating the expected dividend yield component of the DCF model."[40]

The Company also excepts to the RD's rejection of its DCF growth rates. It complains that the RD fails to acknowledge that Staff made an assumption similar to the Company's regarding the relationship between dividend and book value growth and earnings growth. It also faults the RD for not considering the Company's statistical analysis, which, it argues, demonstrates that earnings growth rates have a "meaningful statistical relationship to valuation multiples," one supported by academic research.[41] It maintains that DCF growth rates must have a

[40] Company's Brief on Exceptions, p. 24.

[41] Company's Brief on Exceptions, p. 25.

measureable relationship to prices and that only earnings growth rates have such a relationship. It also maintains that that the basic premise of the DCF model –- higher expected future dividends equals higher stock prices –- is not realized when Staff's projection and the projected price/earnings ratios are examined.

In addition, the Company faults the RD for accepting the contention that Staff's growth rates are reasonable. It argues that Staff's median DCF result is 165 basis points below the median *Value Line* projected ROE, whereas the Company's DCF result is within three basis points of this projection. Being closer to the *Value Line* projected ROE, according to the Company, supports its contention that its DCF growth rates are more reasonable than Staff's growth rates. Moreover, the Company complains that Staff's use of a single source to calculate its DCF growth rate produces an inferior result, as compared to the Company's growth rate, which is premised on data from three separate resources.

The Company accuses the RD of misinterpreting the Company's multi-stage DCF model and the associated calculation of growth rates used in the model. It argues that its model produced growth rates as reasonable as Staff's model because the growth rate for the first stage of its model produced a 3.95% rate, which, according to the Company, is 75 to 80 basis points below the long-term GDP growth rate assumed by Staff.

Staff opposes the Company's exception to the RD's use of Staff's growth rates. It makes three substantive points in defense of its growth rates: (1) the *Value Line* median projected ROE (10.59%) is inflated, and thus not comparable to Staff's DCF result; (2) the earnings growth rate is irrelevant in that the price of stock is equal to the present value of all future dividends; and (3) the Company’s model discounts cash flows at unrealistic rates.

First, Staff agrees with the Company that its median DCF is 165 basis points lower than the median *Value Line* projected return. It contends, however, that the *Value Line* projection is for a future period of three-to-five years from the present, while Staff’s DCF calculation is focused on investors’ required return during the Rate Year. In addition, Staff asserts that the *Value Line* projection is derived from utility holding companies, which are inherently a riskier investment than a purely regulated entity such as O&R, and therefore, higher returns would be required by investors.

Second, Staff dismisses the use of earnings growth rates in the DCF methodology because, according to Staff, the DCF model is based on the presumption that the price of stock is equal to the present value of all future dividends. Staff maintains that focus on the future dividends is appropriate because a stockholder will only receive cash flow from such dividends until such time as the stockholder sells the stock. It does recognizes that earnings growth rates may be a valid growth rate for the DCF, but only in instances where the payout ratios of the subject companies are expected to remain constant. Staff does not believe this scenario will ever arise given the nature of the electric and gas utility industries.

Lastly, Staff contends that the Company’s growth rates for its multi-stage DCF model are unreasonable because the model assumed cash flows –- based on earnings per share growth -- growing at 5.73%, 5.75% and 5.76%. According to Staff, these growth rates produce dividend growth rates of 7.5% and 5.76% in the second and third stages of the model. Staff notes that both the earnings and dividend growth rates exceed the expected growth rate in the GDP, which is 4.7% to 4.8% for the 2017-2021 time period.

Discussion

We adopt the RD's recommendation to utilize Staff's DCF methodology in establishing the ROE for the Company and reject the Company's request that we depart from our standard practice. Therefore, we decline to apply the Company's method for calculating the dividend yield or to substitute earnings growth rates for dividend growth rates.

Regardless of the RD's accuracy in depicting the Company's approach in developing the dividend yield component of the Company's DCF model, we have previously stated our preference for use of the approach advocated by Staff. Staff's methodology uses a forward-looking estimate of the first year's dividend stream. Investors can earn a higher return by reinvesting the dividends in Company shares. Thus, inflating the dividend yield is not necessary to account for any additional return.

Regarding Staff's recommended ROE not being in line with the *Value Line* projection, Staff noted that, the *Value Line* projection is focused on a different period of time than that contemplated by a one-year rate case. In addition, the companies used in the projection are generally riskier companies –- in that they are holding companies with unregulated investments -- that need higher ROEs to attract capital.

As stated in the RD, the use of earnings growth rates to project future dividends reflects a departure from the Commission's previously approved DCF methodology. The use of earnings growth rates in the DCF model, as indicated above, is unreasonable because such rates exceed the growth rate predicted for the GDP. Because utilities serve the enterprises that make up our economy, we do not expect that utility growth rates will exceed the growth rate of the economy for any sustained period of time. Staff's growth rates, on the other hand, are closer to the forecasted nominal GDP, as published in the October 2010 issue by *Blue Chip Economic Indicators*.

c. Capital Asset Pricing Model

The CAPM model determines ROE "as the sum of the current market return on a risk-free investment plus the stock's beta coefficient multiplied by the market risk premium" (MRP).[42] The Company's CAPM model used: (1) the three-month average yield on 30-year Treasury Bonds for its risk-free rate; (2) two forward-looking estimates for the MRP; and (3) beta estimates from *Value Line* and Bloomberg (12 months of market data).

The Company calculated one of its MRPs as the expected return on the S&P 500 Index less the current 30-year Treasury bond yield, and for its other MRP it used a Sharpe Ratio. The Sharpe Ratio is "the ratio of the risk premium relative to the risk, or standard deviation of a given security or index of securities."[43]

Staff's CAPM model, in pertinent part, used a risk-free rate derived from the average of 10-year and 30-year Treasury bond yields and calculated the MRP using Merrill Lynch market return estimates. According to Staff, Merrill Lynch employs a multi-stage dividend discount model and a CAPM model to calculate the monthly expected return for the S&P 500. The MRP is then calculated by subtracting the risk-free rate from the market return estimate.

The RD recommended adoption of Staff's CAPM methodologies, as modified by the use of the RD's proxy group. The RD reasoned that use of 10-year and 30-year Treasury yields is consistent with Commission practice and supported by the

[42] Company's Initial Brief, p. 70.

[43] Company's Initial Brief, p. 71.

varying nature of investor holding periods. The RD found that a blend of the two time periods gives an average period of 20 years that appropriately reflects a reasonable investor holding period.

The RD also found that the market return estimates provided by Merrill Lynch that are used in Staff's calculation of the MRP are reasonable and have been consistently used by the Commission in setting the cost of equity. The ALJs agreed with Staff that any alteration in this method of calculating the MRP should be done in a way that avoids increasing the volatility of the CAPM, something that is not accomplished by the Company's proposed method of deriving the MRP.

i. Risk-Free Rate

The Company excepts to the RD's recommendation to use an average of the 10-year and 30-year Treasury yields as the risk-free rate. It argues that the risk-free rate should represent not an expected term of an investor's ownership of the stock, but rather the term of the life of the underlying investment. The Company asserts that the life of a utility asset closely aligns with the 30-year Treasury yield. It notes that Staff's MRP is derived from a Merrill Lynch report indicating an equity duration of 25 years for utilities. The Company also notes that there is a statistical relationship between the proxy group average dividend yield and the 30-year Treasury yield.

Staff objects to the Company's exception and defends its risk-free rate. It argues that the Company incorrectly applied a plain language definition to the term "equity duration," whereas the term, when used in this context, demands a term of art definition. Specifically, Staff quotes the Merrill Lynch definition of the term: "'equity duration' is 'an adaptation of our Dividend Discount Model which measures the interest rate sensitivity of a stock. Longer durations (higher numbers) suggest more interest rate sensitivity.'"[44]

Staff reiterates its belief that a 20-year time frame in its risk-free rate -- the average of the 30-year and 10-year Treasury yields –- reasonably represents an investor's notion of a long-term period. Staff concludes that even if 25 years is the expected duration of utility stocks, as argued by the Company, its average of 20 years is no further from that mark than the Company's average of 30 years.

Discussion

We adopt the RD's recommendation that the CAPM model employ a risk-free rate utilizing 10-year and 30-year Treasury yields. Using a combination of Treasury yields is consistent with our practice and supported by the varying nature of investor holding periods. A blend of the two time periods gives an average period of 20 years that appropriately reflects a reasonable holding period. Even assuming the Company was correct that the average investor holding period for utility stocks is 25 years, both 20- and 30-year periods would provide equally reasonable estimates. Therefore, there is no reason for us to depart from our traditional practice of using the average of the 10-year and 30-year Treasury yields.

ii. Market Risk Premium

The Company objects to the RD's use of Staff's MRP for the CAPM model. It contends that the ALJs erred by failing to hold Staff accountable to what it believes was a Commission directive in a previous case, to utilize multiple data sources for the MRP.[45] Specifically, it claims that Staff failed to demonstrate the reasonableness of utilizing only the Merrill

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[44] Staff's Brief Opposing Exceptions, p. 23.

[45] Company's Brief on Exception, pp. 28-29 (citing 2009 Con Edison Order, p. 133).

Lynch report. The Company argues that its MRP is more reasonable than Staff's because it is based on two forward-looking measures that were derived from currently-traded market securities and reflected current market relationships.

In defense of its use of the Sharpe Ratio, the Company points out that the ratio only produces "volatile" results when the market is experiencing high volatility. The Sharpe Ratio, according to the Company, bears a similar relationship to current market trends as does the MRP. It contends that the RD would have the Commission reject use of the Company's MRPs due to perceived volatility in favor of a single MRP.

Staff disputes the Company's characterization that the Sharpe Ratio is a "forward-looking" analysis. It maintains that the Company's method is not "forward-looking" because a component of the Sharpe Ratio is based on a historical MRP figure of 6.7% derived from Morningstar covering a period from 1926 to 2008.

In addition, Staff disputes O&R's assertion that we are seeking a change to the MRP inputs. It contends that we only reviewed the need for multiple MRP inputs during a time of turbulent market conditions. Such market conditions are no longer present, Staff argues, and our recent decision in the Niagara Mohawk case demonstrates that our concerns in this area have been assuaged.[46]

With respect to the Sharpe Ratio, Staff contends that its use adds increased volatility to the CAPM calculation. According to Staff, the results of the Sharpe Ratio-based MRP during the course of this proceeding demonstrated significant volatility. Staff argues that the market over that same period was relatively stable, indicating that the volatility of the Sharpe Ratio was not due to the influence of market conditions.

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[46] Staff's Brief Opposing Exceptions, p. 24 (citation omitted).

Discussion

The market return estimates provided by Merrill Lynch that are used in Staff's calculation of the MRP are reasonable, and we have consistently used this data for the MRP. We agree with Staff that any alteration in this method should be done in a manner that avoids increasing the volatility of the CAPM. Based on the record evidence, it appears that the Company's proposed method of deriving the MRP introduces unwarranted volatility; therefore, we decline to use the Company's recommended MRP. Consequently, we deny the exceptions and adopt the RD's position on this issue.

d. Conclusion

Based on the foregoing discussion, with model inputs updated as of April 2011, we find O&R's cost of equity for the Rate Year to be 9.2%.

2. Capital Structure

The Company requested that rates be set on a stand-alone average capital structure for the Rate Year. It forecasted a long-term debt ratio of 48.71%, a common equity ratio of 50.20%, and a customer deposit ratio of 1.09%. Staff recommended a capital structure for the Rate Year of 49.7% long-term debt, 1.3% customer deposits, 1.0% preferred stock, and 48.0% common equity. The Company and Staff were in agreement regarding the Company's long-term debt cost rate of 5.50%, and no party objected to this component.

The RD recommended a capital structure for the Rate Year of 48.7% debt, 1.0% preferred stock, 1.3% customer deposits, and 49.0% equity. This recommendation was based upon CEI's consolidated capital structure which, as of September 30, 2010, had an equity ratio of 48.8%, which the ALJs rounded up to 49%.

The Company did not take exception to this recommendation, but Staff did. Staff advocates a 48% equity ratio on the basis that (1) O&R should receive, at a minimum, no higher an equity ratio than CEI, reflecting the regulated nature of its operations, and (2) the ratio should reflect the level of risks presented by the rate plan and the operating environment of the Company.

Staff argues that a stand-alone capital structure should not be used for O&R because: (1) there could be double leveraging by the holding company; (2) the holding company could use the financial strength of the utility to bolster its unregulated investments; and, (3) the overall equity ratio may not reflect the riskiness of the utility rate plan. Staff also argues that it is unreasonable to establish an equity ratio for O&R that is higher than CEI's. Establishing such a ratio, it says, would mean that either (a) CEI's unregulated companies are being financed with less equity (thus lowering CEI's consolidated equity ratio) than Con Edison and O&R or (b) Con Edison and O&R are being designated as having radically different equity ratios.

Staff asserts that it appropriately first evaluated the entire CEI capital structure to determine if utility and unregulated investments are properly capitalized. Then it employed the utility capital structure instead of individual utility divisions' ratios, thereby combating any equity shifting among utility operations. Staff contends that the utility investments of CEI produce a 48.3% equity ratio. It states that CEI's unregulated investments have an approximately 61% equity ratio, and their inclusion in the consolidated equity ratio increases the total ratio to 48.8%, which is the figure relied upon by the ALJs. Staff points out that if we include the unregulated investment in the capital structure, ratepayers would be unfairly forced to pay a higher amount due to the existence of the unregulated operations.

Staff states that after determining the appropriate consolidated capital structure, it evaluated the reasonableness of the equity ratio in light of the risks faced by the Company under its rate plan and in its operating environment. Staff explains that O&R has several risk mitigation factors in its current Rate Plan, nearly all of which are included in the RD, including an RDM and reconciliations (e.g. pension and OPEB costs, commodity costs).

Staff acknowledges that the capital structure should be set at a level that maintains the financial integrity of the Company. It points out that several recent major rate case decisions have established a 48% equity ratio for other New York utilities, and contends that the those utilities have each maintained their credit ratings and have had full access to credit markets on reasonable terms.

In addition, Staff presents a “sanity check” of its 48% equity ratio by comparing it to the equity ratios of various regulated electric utilities. It notes that according to a 2010 report by Regulatory Research Associates (RRA), such utilities had an equity ratio of approximately 48.3%. Staff explains that the regulated electric utilities studied in the RRA report are, on average, riskier than O&R, and consequently, their average should be slightly higher than the equity ratio required for O&R to maintain its financial integrity.

O&R opposes Staff’s exception to the RD’s recommendation of a 49% equity ratio. The Company rejects Staff’s concerns regarding application of a stand-alone capital structure because none of those concerns is present in this case. It points out that Staff has admitted that CEI has neither double leveraged Con Edison or O&R, nor has it used the financial strength of the utilities to capitalize unregulated investments.

The Company claims that the median equity ratio for the members of Staff’s proxy group having business risk profiles comparable to that of O&R is 49.5%, and complains that the RD and Staff have understated the risks faced by the Company. It dismisses the RRA reported equity ratio mentioned by Staff on the basis that the utilities used to calculate the average equity ratios are not comparable to O&R. It questions Staff’s consistency in being willing to examine the equity ratios of other utilities for assessing the reasonableness of capital structure when it has declared such comparisons to be inappropriate for setting ROE.

Finally, O&R argues that Staff’s position ignores the fact that equity funds raised by CEI have been invested in the regulated infrastructure of O&R in the same manner as the debt raised by O&R, It asserts that a strong capital structure is necessary given the capital intensive needs of CEI’s regulated utilities, including O&R.

Discussion

We grant Staff’s exception. The RD inappropriately based its recommendation on CEI’s consolidated capital structure, inclusive of unregulated investments. In addition, the RD should have considered the reasonableness of setting a 49% ROE in light of the risks faced by the Company, as outlined in the RD, and the ability of the Company to maintain its financial integrity at the 48% equity ratio recommended by Staff.

While double leveraging and inappropriate unregulated Company capitalization are currently not an issue for O&R, the fact remains that even a utility-only equity ratio must be reviewed for reasonableness. As Staff indicates, a 48% equity ratio is reasonable given the myriad reconciliations provided to the Company, including an RDM. Moreover, other New York regulated utilities have operated with a 48% equity ratio and have been able to access, on favorable terms, the credit markets and have preserved their credit ratings. O&R should encounter no difficulty with accessing the credits markets with the same equity ratio.

In addition, a 48% equity ratio is in the general range of equity ratios of companies facing greater business risks than the Company. Despite O&R's lower risks (and their lower equity cushion need), we are allowing a similar equity ratio. We expect O&R's financial integrity will be maintained at this level.

3. Overall Rate of Return

Based on a 9.2% ROE, a 48% equity ratio, and other uncontested parameters of the cost of capital which we are adopting, O&R's overall allowed after-tax rate of return for the Rate Year is 7.22%, calculated as follows:

ORANGE AND ROCKLAND UTILITIES, INC.
RATE OF RETURN REQUIRED FOR THE RATE YEAR
TWELVE MONTHS ENDING JUNE 30, 2012

PER COMMISSION

	Average Capitalization	Cost Rate	Weighted Cost Rate
Long-Term Debt	49.70%	5.50%	2.73%
Preferred Stock	1.00%	5.34%	0.05%
Customer Deposits	1.30%	1.46%	0.02%
Common Equity	48.00%	9.20%	4.42%
Total	100.00%		7.22%

F. Rate Base

1. Capital Expenditures

For the Rate Year, O&R proposed a budget for electric capital expenditures of $80.919 million, and forecast electric capital plant additions to rate base of $98.345 million. During its current Rate Plan, the Company experienced a shortfall in its average net electric plant which, due to a reconciliation mechanism, has resulted in a credit for ratepayers of approximately $28 million, representing the carrying charges on the revenue requirement effect of the shortfall. The RD proposed that this credit be amortized over a three-year period, commencing with the Rate Year.

The RD also recommended adoption of a “slippage adjustment” that would decrease Staff’s forecast of the Company’s average net electric plant additions for the linking period and the Rate Year by 20%.[47] The RD based the recommendation on the level of shortfall in historic average net electric plant. The 20% adjustment reflects the rounded average level of the shortfall for 2009 and 2010.

The RD, however, found adequate support for the capital projects proposed by the Company. It, therefore, recommended an upward net plant true-up to allow the Company to defer carrying charges on amounts spent above the RD’s recommended electric capital net plant of $717.962 million if it succeeds in completing its forecasted capital projects for the Rate Year. The true-up would be capped at the level of Staff’s $748.720 million forecast of electric capital net plant. In addition, the RD recommended continuation of the electric capital net plant investment reconciliation mechanism, which defers the revenue requirement effect of any shortfall in O&R’s average net electric plant balance for ratepayer benefit.

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[47] The linking period is April 1, 2010, through June 30, 2011.

The Company, on exceptions, seeks clarification as to the workings of the downward-only net plant investment reconciliation mechanism and the upward net plant true-up.[48] It interprets the relationship between the mechanisms as follows:

> 1. If the actual Rate Year net plant investment is less than $717.962 million, the Company will defer carrying charges on the amount of the shortfall for future credit to customers.
>
> 2. If the actual Rate Year net plant investment is more than $717.962 million, the Company will defer for future collection from customers carrying charges on the amount of the excess up to a total of $30.758 million (i.e., $748.720 million less $717.962 million).
>
> 3. To the extent actual Rate Year net plant investment is more than $748.720 million there will be no deferral of carrying charges on the amount in excess of $748.720 million.[49]

Other than the request for clarification, the Company did not take exception to the slippage adjustment.

Staff does not oppose the slippage adjustment. It merely seeks to clarify, as we have done above, that the $28 million currently deferred represents carrying charges associated with a shortfall in O&R's average net electric plant balance, and that the downward-only reconciliation mechanism for net plant investment also involves the deferral of the revenue requirement effect of any shortfall.

Given the slippage adjustment, Staff dropped its proposal for a Project Performance Matrix, which would have subjected the Company to negative revenue adjustments for

[48] The Company, although not taking specific exception to the RD's recommendation for continuation of a downward-only adjustment, generally opposes such an adjustment and reserves its rights to oppose such an adjustment in future cases.

[49] Company's Brief on Exception, p. 31.

failure to complete certain capital projects within a specified timeframe or within ten percent of the budget.[50] It cautions, though, that with the slippage adjustment, should the Company manage to meet Staff's forecast of average net electric plant balance of $748.720 million, a deferral amount of approximately $3.8 million would need to be recovered from ratepayers.

UIU supports the RD's slippage adjustment, but notes that the average of the 2009 and 2010 shortfall in O&R's average net electric plant balance was 21.5%, not 20%. It recommends that the slippage adjustment be 21.5%. MC makes the same point.

Discussion

We adopt the RD's recommendation of a 20% slippage adjustment. As noted in the RD, an adjustment is proper to bring the forecast of net plant investment in line with past experience. Allowing ratepayers to benefit from a reduction in revenue requirement now is preferable to having them benefit from a future amortization of a deferral balance. Also, the slippage adjustment should not present any reliability issues for the Company as some of its projects have already slipped beyond their in-service dates on several occasions during the current Rate Plan, and during the linking period, without any apparent effect on current service quality. We decline to grant UIU's and MC's request that we employ a 21.5% slippage adjustment. The RD's recommendation of 20% is reasonable in light of the associated reconciliation and true-up mechanisms.

We agree with the Company's representation as to the relationship between the downward-only net plant investment reconciliation mechanism and the upward net plant true-up. For the Rate Year, O&R will have a symmetrical true-up, capped on

[50] As a result of Staff's withdrawal of its Project Performance Matrix proposal the RD's recommendation regarding that proposal is moot and we need not address it.

the upside at Staff’s average electric net plant forecast of $748.720 million. We also clarify, as requested by Staff, that the $28 million deferral balance discussed in the RD represents carrying charges associated with the shortfall in O&R’s average net electric plant balance that occurred during the current Rate Plan, and that a deferral required by the downward net plant investment reconciliation mechanism during the Rate Year will be a deferral for ratepayer benefit of carrying charges associated with any shortfall in O&R’s average net electric plant balance.[51]

a. Customer Contributions

The Company proposed several capital projects that are primarily the result of load growth and relate to the needs of specific industrial or commercial customers. MC criticized the Company’s capital budget for failing to include adequate contributions from customers benefiting directly from projects such as substations. The RD rejected MC’s concerns and found that the Company complied with its tariff with respect to customer contributions for capital projects.

On exceptions, MC disagrees with the RD’s finding and renews its complaint regarding the Company’s efforts to obtain customer contributions for capital projects. MC states that of the 35 capital projects proposed by the Company, O&R obtained minimal customer contributions on three –- Snake Hill Road Substation, Corporate Drive Substation and Dean Substation. MC argues that our rules (16 NYCRR Parts 98, 99, 100) and the Company’s tariff require that O&R obtain a greater customer contribution for its capital projects. It dismisses the value attributed by the Company to the easements provided by the three customers associated with the Snake Hill Road Substation, Corporate Drive Substation and Dean Substation. According to

[51] The carrying charges will be calculated at the pretax rate of return plus the composite depreciation rate.

MC, such easements are required by the Company's tariff as a condition of service, and therefore, provide no value beyond the minimum required.

The Company rejects MC's allegations, contending that the evidence in the record does not support MC's assertion that the Company should have obtained additional customer contributions for its projects. The Company argues that of the 35 projects proposed only 3 had targeted and known customer expansion and development as their primary driver.

O&R counters MC's specific allegations with respect to the Snake Hill Road Substation, Corporate Drive Substation and Dean Substation by noting that the projects will serve the needs not only of the customers hosting the substations, but also of customers in the surrounding areas. The Company also notes that customers are only required by tariff to provide easements when the equipment to be installed will solely serve them. That is not the case with the new substations, which will also serve customers in the surrounding area.

Discussion

We find that the Company has complied with its tariff with respect to customer contributions for capital projects. While we appreciate MC's desire to minimize the Company's revenue requirement associated with capital projects by increasing customer contributions, the tariffs MC relies on in making its argument address capital projects that are constructed for the sole purpose of serving individual customers. The three new substations will serve customers in the surrounding area and help improve reliability and system operations. Consequently, the Company acted appropriately in obtaining partial customer contributions in the form of easements for these substations.

2. Smart Grid Projects

Staff and the Company disagreed on the inclusion of smart grid projects in the Company's proposed Rate Year electric capital plant additions. These projects include a smart grid expansion blanket (expanding application of an on-going smart grid pilot program) and the smart grid stimulus projects that were approved in Case 09-E-0310.[52] The RD agreed with Staff that these smart grid projects should not be included in the Rate Year forecast of electric capital plant additions.

The smart grid expansion blanket involves expanding the Company's ongoing pilot program to other areas of its electric system. The RD found that such expansion is not reasonable until the Company has evaluated its experience with the pilot. The RD recommended that the Company file with the Commission, within 90 days of completion of the program, a report detailing the results of the pilot.

With respect to the smart grid stimulus projects, the RD found that Staff did not have the opportunity to review the costs associated with the projects. It also found that the record was unclear as to the timing of when the projects would be placed into service.

The Company does not take exception to the RD's recommendation to remove these smart grid projects from rate base. It does disagree with the assertion that Staff did not have an opportunity to review the smart grid stimulus project costs. The Company states that it intends to pursue recovery of costs related to both smart grid projects in a subsequent filing.

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[52] Case 09-E-0310, American Recovery and Reinvestment Act of 2009, Order Authorizing Recovery of Costs Associated with Stimulus Projects (issued July 27, 2009)(Stimulus Order); Staff's Initial Brief, p. 116.

Discussion

The RD's recommendation regarding the smart grid projects is reasonable, and uncontested by the Company. With respect to the smart grid expansion blanket, we adopt the RD's recommendation that the Company file with the Commission, within 90 days of completion of the smart grid pilot program, a report detailing the results of the pilot.

G. Revenue Allocation/Rate Design

1. Revenue Allocation

In approving O&R's current Rate Plan, we noted that the revenue allocation provided for in the joint proposal left a number of service classes contributing revenues that are either more than 10% above or more than 10% below the cost to serve them. Consequently, we directed the Company to produce a new embedded cost of service (ECOS) study and to make a revenue allocation proposal that would "shorten materially the number of years in which these revenue/cost imbalances would persist, while still taking into account customer billing impacts."[53]

In this case, O&R concluded that a full reallocation of revenue surpluses and deficiencies among service classes would result in excessively large bill impacts for certain classes. Consequently, it proposed to reallocate only one-third of the imbalances prior to allocating its proposed rate increase.

Staff argued that the Company's mitigation measures were inadequate. It proposed to revise the allocation such that no customer class would receive a rate decrease, and none would experience an increase greater than twice the system average.

The RD concluded that the Company's approach better balanced the objectives of minimizing revenue/cost imbalances

[53] 2008 O&R Rate Order, p. 53.

while mitigating bill impacts. Staff took exception to this recommendation.

Discussion

Fairness dictates that customers should generally pay for service neither more nor less than what it costs to serve them. Our preference, therefore, is to reduce revenue allocation imbalances whenever it is reasonable to do so. Fairness also requires, however, that such steps be taken with due regard for the bill impacts that will be experienced by all affected rate classes. We must strike a balance between these competing concerns.

In this case, given the substantial rate increase initially proposed by O&R, we can appreciate Staff's emphasis on bill impact mitigation. Now, however, that increase will be much smaller, giving us greater leeway to reduce revenue allocation imbalances without excessive adverse bill impacts. Accordingly, we consider this an appropriate time to adopt the slightly greater reduction in cross-subsidies offered by the Company's proposal, and we accept the RD's recommendation.

2. Customer Charges

a. Service Classification No. 1, Residential

For the residential service class, O&R proposed to raise the monthly customer charge by $4.48 from the current level of $11.12 to $15.60. It pointed out that the charge now in effect is not only barely over half the customer cost of $21.38 as determined by the ECOS study, but also nearly $2.00 less than the lowest residential customer charge in effect on any other New York electric utility.

Staff proposed to limit the increase to $2.00. It contended that the Company's proposal produces excessive bill impacts for low usage customers. The RD agreed with the Company, and Staff takes exception.

Discussion

Although the cross-subsidies generated by the difference between the customer charge and customer costs are internal to the residential class rather than among service classes, this issue is analogous to that of revenue allocation generally as discussed above. Our desire is to accelerate movement toward parity, but with due regard for bill impacts.

Here, O&R's customer charge is not only low with respect to cost, it is low in absolute terms. Even with the full increase requested by the Company, it will remain modest in comparison with other utilities, and will still be well below the embedded cost determined by the ECOS study. As with our discussion of revenue allocation, we conclude that this case presents a good opportunity for more significant movement towards a cost-based customer charge, and we adopt the RD's recommendation in favor of the Company's proposal.

b. Other Service Classes

The RD recommended that the customer charges proposed by the Company for service classes 2, 3, 9, 20 and 22 be approved. Staff takes exception to the recommendation only with respect to the SC2 primary and SC2 unmetered service sub-classes for which it says the percentage increases in the charge would be too high. O&R points out in response that the average bill for an SC2 primary customer is $3,900 per month, making a $13.12 increase in the customer charge nearly imperceptible.

Discussion

Staff's focus on percentage increase in the customer charge is unwarranted given that for an SC2 unmetered customer, the charge will increase by only $2.73 from its current $8.06 level, and will still be well below the embedded customer cost of $16.40. For the SC2 primary subclass, the customer charge is a very small component of the average customer's bill, and even after the Company's proposed increase, it will still reflect only about 46% of the $52.26 customer cost.

The RD's recommendation is consistent with our desire to accelerate the movement of customer charges toward a cost basis without undue bill impacts, and we will adopt it.

3. <u>Block Rate Structures</u>

a. <u>Service Classification Nos. 2 & 3 Declining Block</u>

Consistent with the objective of eliminating rate structures that create a disincentive to control total electric consumption, Staff proposed that the declining rate blocks for Service Classes 2 and 3 be replaced with a flat volumetric charge that would be phased in over three years. O&R defended the fairness of its current rates, but acknowledged that they can be confusing and said it was open to considering a change. It added, however, that making the transition fair to all customers would require an analysis the Company had not done for this case.

The RD asked the parties to suggest a process for revising the rates for these classes.

<u>Discussion</u>

Both Staff and the Company indicated that there is insufficient time to develop a proposal for our consideration in this case but that one could be prepared in conjunction with O&R's next rate filing. Accordingly, we will direct the Company to develop a proposal to be included with its initial filing in its next rate case, if possible, and in any event, to be presented to the parties to that case no later than 60 days following such initial filing.

4. <u>Lighting Service Classifications</u>

The Town of Ramapo raised several concerns about the lighting service classifications, particularly SC4 Street Lighting. First, it noted that a handful of towns in O&R's

service territory account for the majority of street lighting fixtures, and suggested that lower rates should be established for these higher volume customers. Next, it complained that the current 2% of inventory limitation on the number of fixture replacements a customer can obtain annually without charge prevents it from upgrading more quickly to lower cost, higher efficiency lighting. Ramapo asked that an energy-only lighting class be established to allow customers to own and maintain their own luminaires. It called for a collaborative to develop the details of these proposals.

The RD found, consistent with Staff's position, that Ramapo's proposals would have significant implications for the rates paid by other municipalities, and that these issues were not adequately developed in the record. It also concluded that substantial analysis not yet performed would be necessary before the initiation of a collaborative process should be considered. The RD did, however, agreed that an energy-only lighting class should be investigated further, and recommended that we require a proposal for such be included in the Company's next rate filing. It noted that such service had been initiated recently at both New York State Electric & Gas and Central Hudson.[54]

On exceptions, O&R points out that this proposal was not advanced in any meaningful sense until the evidentiary hearing in this case, and indicates that it did not address the subject in its initial filing because there has historically been little interest expressed by municipalities in owning and maintaining their own street lights. It says that development of the service class involves numerous legal, operational and financial issues that would have to be addressed and resolved,

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[54] Central Hudson – Service Class No. 8, amendments effective July 1, 2010; NYSEG, Service Class No. 4, effective September 15, 2010.

and suggests that if we require such an effort, it should lead to a tariff filing laying out the terms and conditions of service in detail.

UIU expresses concern over the possibility of delay. It asks that the Company be required to analyze both the proposals for an energy-only service class and for the expansion of the 2% limit on fixture replacements within four months of an order in this case, and then initiate a collaborative with interested parties to attempt to develop final tariff proposals.

Discussion

Both raising the 2% limitation on fixture replacements and creating an energy-only service classification may enhance the ability of municipalities to reduce costs and energy usage by accelerating the adoption of newer, more efficient luminaires. These proposals should be explored further on a reasonably expedited basis, consistent with a thorough analysis of the issues discussed by the Company, and with a full opportunity for participation by interested parties as suggested by UIU.

The viability of an increase in the 2% replacement limitation is purely a question of cost and should be addressed within a rate case. Therefore, we direct the Company to include in its next rate filing, a projection and explanation of the increased cost per luminaire that would be required for each 1% increase in the replacement rate.

We also direct O&R to develop a proposal for an energy-only street lighting service to be filed with the Secretary and served on the parties to this proceeding no later than October 31, 2011. We will decide at that time what further process, including the possibility of a collaborative, will be used to permit interested parties to provide meaningful input on the proposal.

H. Other Issues

1. Performance Matrices

a. Reliability Performance Matrix

Under its current Rate Plan, O&R's system reliability performance is subject to two inter-related measurements. The System Average Interruption Frequency Index, or SAIFI, is calculated by dividing the total number of service interruptions experienced by its customers by the total number of customers served. The Customer Average Interruption Duration Index, or CAIDI, is determined by dividing the sum of all customer interruption durations by the total number of customer interruptions. The Reliability Performance Matrix assigns a target to each measure, and a 20 basis point negative revenue adjustment if the Company fails to meet the target.

The RD recommended that this basic structure for the performance mechanism be retained, with the target for SAIFI lowered from its current level of 1.36 to 1.20, as urged by Staff. It concluded, however, that the target for CAIDI should be raised to 1.90 as requested by O&R, finding that the 1.85 proposed by Staff did not allow enough leeway given a recent actual CAIDI result of 1.83.

Staff takes exception to the CAIDI recommendation. It notes that the 1.83 figure was reached in 2008, and contends that the RD failed to consider the many efforts the Company has recently begun to undertake to improve its CAIDI results.

Discussion

We agree with Staff. As the RD noted in supporting a lower SAIFI target, the infrastructure improvements that have contributed to a reduced frequency of interruptions have been funded by ratepayers, and ratepayers are entitled to realize the benefit of their investment. The same is true with CAIDI, as the increased resources being deployed by O&R to reduce the duration of interruptions are also funded by ratepayers. Furthermore, in light of that increased effort and the fact that the Company's high point on the CAIDI measure was 1.83, we do not believe that a target of 1.85 is now an unreasonable stretch. The Reliability Performance Matrix applicable to the Company for the Rate Year is provided in Appendix C.

b. Customer Service Performance Incentive Mechanism

Staff and the Company support continuation of the Customer Service Performance Incentive mechanism (CSPI) that is in effect under the Company's current Rate Plan. Each, however, proposed a number of modifications. We direct that the CSPI be continued, as provided in Appendix D, with the changes discussed below.

i. Customer Satisfaction Survey

The CSPI includes a measurement of customer satisfaction obtained by means of a Customer Assessment Survey (CAS). Two versions of the survey are administered separately to samples of residential customers and commercial and industrial customers. The Company is at risk for a maximum negative revenue adjustment of $300,000 for each of the two surveys -- $600,000 total -- if the survey results fall below defined target satisfaction levels.

O&R also measures customer satisfaction by means of a Customer Contact Satisfaction Survey (CCSS). The CCSS is conducted monthly by an outside contractor through a telephone survey of O&R customers who have recently had contact with a customer service representative. The CCSS is not currently a component of the CSPI.

In this case, O&R proposed to discontinue the CAS for its electric operations and to use the existing CCSS for the customer satisfaction component of the CSPI. It called for a target CCSS satisfaction level of 86% with negative revenue adjustments of up to $300,000 if the survey results fall short of that level, and also proposed a positive revenue adjustment if the satisfaction level exceeds the Company's historic average of 90.6%. O&R contended that Staff's proposed target is higher than those in place for other utilities in the State and is unreasonable.

O&R also proposed to institute a new Customer Focus Survey (CFS). The CFS would be a multi-modal (e-mail, internet, etc.) means of gathering information from customers about their areas of interest and concern, allowing the Company to modify its O&E program prospectively to more specifically target customers' needs. The CFS would not be used to measure customer satisfaction for purposes of the CSPI. We discuss the CFS and the funding proposed to implement it above in section II.D.5.b.

Staff supported the elimination of the CAS and the use of the CCSS for the CSPI. It recommended, however, that the target satisfaction level be set at 89%, and it opposed the inclusion of a positive revenue adjustment. Staff pointed out that its recommended target was well below the Company's historic average score, and said O&R's complaint that the target would be higher than those set for other utilities in the State was irrelevant. Targets, Staff said, are survey and service territory-specific, making comparisons meaningless. The only appropriate benchmark is past performance.

Discussion

No party disagrees with the proposals to eliminate the CAS for the Company's electric operations and to use the CCSS as the basis for measuring customer satisfaction for purposes of the CSPI. Perhaps due to acronym overload, however, the ALJs appear to have been under the mistaken impression that the CAS was to be replaced by the new, as yet untested, CFS, and the RD recommended against the change. Since it is the CCSS that will be used, a survey with which the Company has substantial experience, the RD's concern about using a new, unproven survey is unwarranted, and we approve the changes as proposed.

The same confusion impelled the judges to recommend that the lower target satisfaction levels proposed by the Company be used, rather than those supported by Staff, until the Company has gained experience with the "new" survey format. As the survey is not new, the question remains, which proposed targets best reflect the Company's past, and expected future, performance?

On this, we agree with Staff. Staff's proposed 89% target is reasonable in light of the Company's past performance and supports the CSPI's objective of ensuring that the quality of service received by ratepayers continues to be commensurate with the level of funding provided in rates. We have been consistent in promoting that objective across utilities. The fact that targets vary among service territories is not a reflection of differential treatment of utilities, but rather of differences in the territories themselves, and in the surveys used to measure satisfaction.

Finally, we adopt the RD's recommendation against approval of the Company's proposed positive revenue adjustment for customer satisfaction levels exceeding the historic average. The purpose of the CSPI is to help ensure that ratepayers receive the level of service they pay for in rates, not to require them to pay for a level of performance beyond that which constitutes the provision of safe and adequate service.

ii. PSC Complaint Rate

The RD recommended adoption of a target PSC complaint level of 1.8 per 100,000 customers, as proposed by Staff. This level happens to be the same as that currently applicable to the Company's gas business. The RD reasoned that because there is only a single complaint rate calculated for the utility -- one that aggregates all complaints whether they involve gas service or electric service -- it makes no sense to have different targets for the two businesses. Furthermore, the RD found that the recommended target should not be a stretch for O&R given that its performance over the past 5 years has averaged about 0.6 complaints per 100,000 customers.

On exceptions, O&R responds that the 1.8 target applicable to the gas business was adopted as part of a negotiated joint proposal. It claims that imposing the target on its electric business will cast a shadow over future settlement negotiations, inhibiting its willingness to agree to measures in one case that may subsequently be held up as the standard in a future litigated proceeding.

Discussion

On the merits of whether the recommended 1.8 target is reasonable, the argument over the desirability of consistency between the gas and electric businesses is not pertinent. The facts in this case demonstrate that 1.8 is not a stretch goal, and could quite reasonably have been set considerably lower. O&R very well may be the beneficiary, rather than the victim, of Staff's desire to achieve consistency for administrative convenience. We adopt the RD’s recommendation.

iii. Call Answer Rate

Staff proposed the addition of a new performance measure for the percentage of customer service calls that are timely answered. O&R responded that no such measure is necessary because its performance in this area has consistently been satisfactory, its increased use of technology allows customers to avail themselves of self-help when they call, and its average answering time is under 30 seconds. The RD agreed with the Company, but recommended continued monitoring of O&R’s performance. Staff takes exception to the recommendation.

Discussion

We will adopt the RD’s recommendation. Given Staff’s acknowledgement that O&R’s performance has consistently been satisfactory, we see no reason to adopt an additional measure at this time. We agree fully with Staff, however, that getting prompt responses to service calls is important to customers. We will continue to monitor the Company’s performance, and may revisit this measure in future rate cases if there is any material degradation of service in this area.

iv. Adjusted Bill Measure

Staff proposed a second addition to the portfolio of measures included in the CSPI that would establish a target level for the percentage of customer bills that have to be adjusted and reissued. Failure to meet the target would result in negative revenue adjustments of up to $150,000. Staff contended that O&R's performance in this area has been deficient as reflected by bill adjustment rates that are consistently higher than those at other New York utilities.

The RD agreed that ensuring accurate bills for customers is an important objective and that if O&R's performance were demonstrably poorer than that of its peers, a targeted performance metric would be appropriate to spur improvement. It concluded, however, that there was inadequate information in the record to permit a finding that such a measure was warranted. Staff took exception to the recommendation.

Discussion

In this case, we are concerned with the absolute level of adjusted bills and the evidence presented suggests that the numbers are not good and are not improving. A performance metric with associated negative revenue adjustments is appropriate in order to place greater emphasis on the need for improvement in this area. Any issue as to the comparability of measurements among utilities is avoided by basing the target for this measure on the Company's own historical statistics.

Accordingly, we grant Staff’s exception. At a bill adjustment rate of 2.42%, the highest level experienced by the Company over the last five years, a $50,000 negative revenue adjustment will be assessed. Additional $50,000 adjustments will be assessed at 0.12% intervals up to a maximum total of $150,000 at 2.66%.

v. Customer Payment for Missed Appointments

Staff proposed the institution of a $20 payment to customers for missed appointments. The RD recommended rejection of the proposal because O&R already has a voluntary program under which it pledges to keep all mutually agreed appointments within one hour of the scheduled time, and to provide a $25 bill credit if it fails to do so. The RD noted that the program is apparently working well, given Staff’s acknowledgement that the Company’s appointments kept record has been excellent.[55]

On exceptions, Staff agrees that O&R’s program is a good one, and simply proposes that we make it mandatory. The Company responds that Staff has provided no rationale for the change.

Discussion

We consider the timely keeping of appointments to be an important element of the level of service that customers pay for in their rates. For that reason, we have instituted

[55] O&R says that payments under the voluntary program have averaged less than $1,000 annually over the last three years. Company’s Brief Opposing Exceptions, p. 25.

mandatory missed appointment payments for many of the State's utilities.

Our goal, however, is good service, not new mandates. To the extent utilities keep their appointments without our prodding, shareholders, ratepayers and regulators are all better off. O&R has had in place since 2004 a voluntary program that not only pays customers more than Staff's proposal for a missed appointment, but also appears to be working very well to keep utility employees focused on meeting their commitments. Therefore, we will adopt the RD's recommendation. Converting this well-functioning program into a regulatory mandate would be a classic example of "no good deed goes unpunished."

That said, however, we consider O&R's willingness to continue its program to be an important factor in our decision. If the Company proposes to eliminate the program in the future, we direct that it provide at least 90 days' notice to the Director of the Office of Consumer Policy, with an explanation of the basis for the decision.

vi. Negative Revenue Adjustments

Under O&R's current rate plan, the maximum negative revenue adjustment that O&R could incur as a result of failure to meet CSPI targets is $1.1 million -- $600,000 for the customer satisfaction surveys and $500,000 for the PSC complaint rate. Staff proposed to have the same amount at risk for the Rate Year. In order to accommodate the maximum $150,000 negative revenue adjustment associated with each of its new Call Answer Rate and Adjusted Bill measures, it shifted $300,000 from customer satisfaction. On exceptions, Staff argues that if the new measures are not adopted, the unused adjustment amounts should be reallocated to other CSPI measures.

Discussion

We agree with Staff that the total amount of revenue at risk for failure to provide adequate customer service should not be reduced. Because we decline to adopt the proposed Call Answer Rate measure, there is $150,000 that is not allocated. We do not consider it appropriate to assign these funds to the new Adjusted Bill Measure or to the PSC Complaint Rate measure which already accounts for 45% of the total at risk. Therefore, we will reallocate the $150,000 to the Customer Satisfaction Survey. Consistent with Staff's formula for this measure, the negative revenue adjustment increments would then be $150,000 if customer satisfaction fell below 89% and $150,000 for each percentage point below 89%, up to a maximum adjustment of $450,000 for a customer satisfaction level below 87%.

2. Revenue Decoupling Mechanism

The Company proposed to continue its RDM, with certain changes. Specifically, it proposed: (1) to consolidate certain service classes for RDM purposes; (2) to specify treatment of revenues derived from customers no longer taking service under economic development riders (economic development customers); (3) to replace the $3 million dollar threshold for interim RDM adjustment with a 1.5% of delivery revenues threshold; (4) to modify the recovery period for the interim RDM adjustment; and, (5) to permit it to exercise discretion in implementing interim RDM adjustments.

The RD recommended that the Company be authorized to consolidate certain service classes, revise treatment of revenues of previous economic development customers, establish a 1.5% threshold for interim RDM adjustments, and grant the Company discretion in implementing the interim RDM adjustments once the threshold has been met. In addition, the RD agreed with Staff that the recovery period for the interim adjustment should remain the same, thereby rejecting the Company’s request to shorten the time period.

Staff takes exception to the RD’s recommendation regarding the threshold for the interim RDM adjustment. Staff favors a 3% threshold on the basis that it is better for ratepayers to experience less frequent adjustments, even if the adjustment is larger than would occur under a 1.5% threshold.

The Company supports the RD’s recommendation for implementation of a 1.5% threshold. It contends that a 3% adjustment would result in greater bill impacts for ratepayers. In addition, it contends that the Commission should be more concerned with the magnitude of the bill impacts rather than the frequency of the adjustments.

Discussion

We adopt the recommendations in the RD for the RDM, with the exception of the discretion afforded to the Company in implementing the RDM adjustment. We expand that discretion to allow the Company to determine when the interim adjustment should be triggered and the appropriate time period for recovery that should be employed. Because we authorize a lower threshold for the interim RDM adjustment, as discussed below, the Company should be allowed to shorten the time period for recovery of the interim adjustment, when appropriate, after consultation with Staff. Any exercise of discretion by the Company, however, must be done in accordance with our primary objective for the interim RDM adjustment, which is to minimize ratepayer bill impacts.

With respect to the threshold, we agree with the Company; minimizing bill impacts is more important than the frequency of the adjustment. Some commenters in this proceeding expressed frustration with an interim RDM adjustment on their bill, which they see as a penalty for participating in energy efficiency efforts. It is important as we continue to pursue the State's goals of energy efficiency that we implement the RDM in a manner that minimizes bill impacts, and thus ratepayer frustrations. Implementing the Company's proposed 1.5% threshold appears the best alternative to mitigate large rate swings.

3. Low Income Program

a. Discount Level

The RD recommended we adopt Staff's proposal that the Low Income Program discount be increased from $5 for non-heating customers to $7 and from $10 for heating customers to $15. The discount is applied on a monthly basis for non-heating and heating electric customers, respectively, who receive a grant under the Home Energy Assistance Program (HEAP).[56] The RD reasoned that Staff's proposal provides a reasonable increase in assistance to low income customers while minimizing the impact to other customers of providing such assistance. The RD also concurred with the UIU that the Commission should consider developing metrics for setting low income discounts for all utilities via a generic proceeding.

The Company does not take exception to the RD's recommendation for the program discount level, but the UIU does. It recommends a program discount of $10 for non-heating customers and $20 for heating customers, which, according to the Company, would raise the requested funding level for the Low Income Program from the approximately $1 million recommended in the RD, to $1,434,000.[57] UIU states that a majority of the parties to the proceeding agree that energy costs pose a significant burden on low-income customers, but disagree on the appropriate levels of discount. It asserts that selection of

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[56] Tr. 1272-1274.

[57] UIU's Brief on Exceptions, pp. 18-20.

Staff’s discount levels was arbitrary because Staff did not provide evidence in support of its proposal, but rather relied on the existing discount level, inflated to account for Staff’s recommended increase in the customer charge. UIU contends that it is the only party that did provide information in support of its proposed discount level by means of a comparison of the cost of the program, both in total and as a percentage of Company revenues, with that of programs at other utilities.

UIU claims that the RD simply follows past practice of adopting whatever discount levels are proposed by Staff and notes that the existing discount levels, which serve as the initial basis for Staff’s proposal, have no foundation in evidence as they were the result of a settlement. In addition, UIU notes that its proposal is equivalent to approximately 0.28% of O&R’s electric revenue, which is not much different from the 0.20% represented by Staff’s proposal. It questions why, given the similarities in the level of electric revenue percentages, Staff’s proposal should be deemed more reasonable than UIU’s proposal.

Staff claims that it took into consideration a host of factors when arriving at its proposal for discount levels.[58] It maintains that in recommending the levels, it took into consideration the size of the low income population, the economic conditions of the service territory and the impacts on non-participants. Staff disagrees with UIU’s use of the revenue metric, as that metric provides too narrow a view on appropriate utility program funding for the low income program.

Specifically, it notes that the revenue metric does not account for the differences between the utilities’ service territories (e.g., number of low income customers and economic factors of the service territory), which the Commission has

[58] Staff’s Brief on Exceptions, p. 42.

deemed to be pertinent factors in employing a revenue metric in setting low income program funding.[59]

Staff also takes exception to the RD's recommendation that the Commission consider adoption of a generic set of metrics for setting low income discounts for all utilities. It maintains that it employed general metrics in this proceeding, including size of the low income population, the economic conditions of the service territory and the impacts on non-participants. Staff also contends that a standard approach to setting discount levels would be difficult to define given the different needs of the populations in each utility's service territory.

UIU rejects the notion that differences in needs among customer populations preclude the application of generic standards. It claims that these differences are exactly why appropriate metrics are necessary. It notes the successful application of the Generic Finance Proceeding in setting ROE as an example for how generic metrics can successfully help establish a statewide approach.

UIU advocates for a consistent set of measures to establish low income program funding. It contends that a generic proceeding could examine "the appropriateness of using common metrics while crafting a low-income program such as service territory-specific census data showing the average income, the number of people earning below the federal poverty line, the number and percentage of a utility's low-income heat and non-heat customers, the typical bill of low-income customers, the number of disconnections and reconnections, the

[59] Staff's Brief Opposing Exceptions, p. 27 (citing Case 09-G-0795, Con Edison – Gas Rates, Order Establishing Three-Year Steam and Gas Rate Plans and Determining East River Repowering Project Cost Allocation Methodology (issued September 22, 2010), pp. 67-68).

number and percentage of customers in arrears and average arrearages, and percentage of revenues allocated to the low-income program."[60]

Discussion

As stated in the RD, setting the appropriate funding level and program parameters for utility low income assistance programs historically has not been a precise science, and this proceeding has proven no different. In determining the scope and structure of utility low income assistance programs, we strive to reflect best practices among utilities as well as a myriad company-specific current facts and circumstances including those identified by Staff and UIU. In addressing these issues, we are mindful that we are asking other ratepayers to shoulder the burden of paying for the program.

An increase in the discount level is appropriate in this case, and the best balance of competing interests –- providing bill relief to low income customers and minimizing costs to non-participants –- is provided by Staff's proposal. Increasing the Low Income Program discounts for non-heating customers to $7 and heating customers to $15 will provide low income customers bill assistance without overburdening the remainder of ratepayers. Overall, funding for the program would increase from $330,000 in current rates, to $1 million, reflecting both an increase in the per-participant discounts and in the number of program participants. In addition, as is currently the case, we will require that any over or under spending on this program be reconciled and deferred, with appropriate carrying charges.

We reject the RD's recommendation that we consider commencing a generic proceeding to establish statewide metrics for use in setting the appropriate funding level and program

[60] UIU's Brief Opposing Exceptions, p. 14.

parameters for utility low income programs. The list of factors identified by UIU, as well as others that may be developed, are best considered along with utility-specific facts and circumstances in utility-specific proceedings. Such an approach avoids the potential regulatory burden on intervenors, utilities and Staff that often accompanies generic proceedings.

b. Reconnection Fee Waiver

The RD recommended adoption of Staff’s and UIU’s proposals to implement a reconnection fee waiver for the Company’s Low Income Program. The recommendation was based on the Company’s provision of such a waiver for its gas service and a finding that its application to electric service is equally important to help minimize this impediment to reconnection. The RD also recommended (1) allowing the Company to modify the program as necessary in light of under- or overspending, and (2) directing the Company to ascertain whether social service payments cover the reconnection of service fee prior to granting the reconnection fee waiver.

The Company takes exception to a reconnection fee waiver and faults the RD for not understanding that the Company agreed to such a waiver for its gas business because the gas business experiences far fewer reconnections than does the electric business. It notes that in 2010, the Company had 20 times the low income reconnections for electric service as it did for gas service; 15 times as many in 2009; 28 times as many in 2008. O&R contends that the issue is not one of “can’t pay” versus “won’t pay” but rather who should pay –- low income customers or other customers –- when low income customers “fail to make timely arrangements to avoid service disconnections.”[61]

Staff counters that there is no record evidence supporting the Company’s contention that disconnection of

[61] Company’s Brief on Exception, pp. 35-36.

service for low income customers results from their failure to make timely payment arrangements rather than an inability to pay. It contends that the higher number of electric reconnections than gas reconnections actually supports the need for a reconnection fee waiver for electric customers. The waiver is appropriate assistance for low income customers, Staff says, because it increases the amount of money the customer has available to maintain service.

UIU opposes the Company's exception and notes that the O&R position implicitly assumes that low income customers have the resources to pay their utility bills but instead choose not to. It claims that O&R has failed to demonstrate why its electric customers are being treated differently than its gas customers, who have the benefit of a reconnection fee waiver. UIU explains the difference in the number of low income reconnections for gas versus electric as a function of (1) the desire to preserve heating service during the winter season, and (2) the complicated and labor-intensive nature of shutting off gas service as compared to electric service.

Discussion

The Company's exception is denied. As the RD noted, a reconnection fee waiver for the Low Income Program is consistent with the waiver provided by the Company's Low Income Program for its gas service, and its application to electric service is equally important to help reduce the impediments to reconnection of service. We also adopt the RD's recommendation with respect to the Company's ability to modify the program as necessary in light of under- or overspending. To the extent that reconnection of service results from a payment from social service agencies, the Company must ascertain whether the payment covers the reconnection of service fee prior to granting the reconnection fee waiver.

c. Reporting Requirements

The RD recommended Staff's proposal, supported by UIU, that the Company be directed to file, at the end of each calendar quarter, the following information regarding the Low Income Program, broken down by heating and non-heating customers: (1) the number of program participants; (2) the aggregate amounts of low income discounts provided to date for the Rate Year; (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; and (5) a brief narrative explaining any significant changes or developments since the last report.[62]

The Company takes exception to this recommendation. It complains that the reporting proposal would impose an unnecessary burden on it at a time when it is trying to achieve productivity savings and allocate resources cost effectively, particularly in light of the RD's recommendation that the Company's regulatory administrator position not be funded in rates. O&R contends that Staff has not justified, and the RD has not articulated, the need for the information on a quarterly basis, and points out that no complaints have been lodged by customers regarding the operation of the program. Moreover, the Company notes that the program runs automatically without the need for it to make any judgment as to who can participate –- HEAP customers are automatically enrolled. It also notes that Staff is provided the number of HEAP recipients on a biannual basis.

Staff opposes the Company's exception and argues that the critical nature of the program and the potential for large deferral balances from program costs supports active Staff monitoring of the implementation of the program. UIU mirrors

[62] Staff's Initial Brief, p. 155; Tr. 1488-1489.

this sentiment, and notes that parties interested in tracking trends associated with low income customers would benefit from these quarterly reports. It claims that such information, taken together with the reports of other State utilities, could foster a better understanding of New York's socioeconomic characteristics.

Discussion

We reject the Company's exception to the RD. The Company has the capability to provide such data to Staff, and requiring that it provide the information on a quarterly basis will only better ensure that Staff has the information necessary to properly monitor the program. Moreover, the Company's biannual provision of HEAP numbers does not provide Staff with the numbers of customers actually receiving the discount because the number of HEAP customers is not static. The increase in reporting frequency is also reasonable in view of recent substantial changes in enrollment in the low income assistance program, as well as the significant changes in funding we are authorizing in this order, and is consistent with our recent determinations in rate cases for other utilities. In addition, the reconnection fee waiver, being a new program feature, is not covered by reports regarding low income customer participation currently being provided by the Company to Staff.

4. Three-Year Rate Plan

The Company proposed a three-year rate plan as an alternative to a single year rate case. The ALJs, given the extent of the disputes among the parties as to the revenue requirement for the Rate Year, determined that there was little basis in the record for determining the appropriate cost escalators to apply to derive second and third year revenue requirements. The RD recommended, and the Company does not take exception to, the Commission establishing rates for only the Rate Year.

In coordination with its three-year rate plan proposal, the Company advocated implementation of a Distribution Infrastructure Surcharge (DIS). The DIS would allow the Company to recover, via a surcharge, the carrying costs from ratepayers on capital investments that took place after the end of its proposed three-year rate plan. The RD rejected the Company's proposal. The RD noted that there was little discussion as to the mechanics of the DIS, such as how and when Staff would be able to review the basis for the surcharge prior to its implementation. The ALJs stated, however, that the mechanism might have appeal in that it could lengthen the period of time between utility rate filings, if the mechanism were properly defined. It is this latter point to which Staff takes exception. It argues that the DIS has no appeal and does not merit examination in any future proceedings.

Discussion

We decline to dismiss outright any future consideration of ratemaking mechanisms that may lengthen the period of time between utility rate filings without undue harm to ratepayers or utilities. With the continuing need to seek out and obtain economic efficiencies, proposals such as the DIS may be a creative means to accomplish efficient rate regulation. However, we find that Staff has raised a number of shortcomings with the Company's proposed DIS and therefore we reject its implementation here.

a. Amortization of Ratepayer Credits

The RD recommended retaining the three-year amortization period for ratepayer credits. It reasoned that the accumulation of these credits took place over the three years of the current Rate Plan, and, therefore, it is reasonable to utilize them over the same period of time.

MC disagrees with the RD and requests that ratepayer credits be entirely passed back during the Rate Year. It contends that a customer who overpays a bill normally gets the amount of overpayment back in the next bill. MC notes that the ratepayer credit associated with the Company's underspending of its capital expenditure budget is sizeable($28 million).

UIU shares MC's view that all ratepayer credits should be passed back to customers during the Rate Year. In addition, UIU advocates amortization of regulatory assets (shareholder credits) -- deferred balances for pensions and OPEB -- over a longer period of time, longer than the five-year period we adopt in this order.

Staff, while not taking exception to the RD's recommendation, notes that the Commission could reduce the revenue requirement by reducing the amortization for ratepayer credits over a shorter period of time.

<u>Discussion</u>

We decline to implement a shorter amortization period for ratepayer credits (regulatory liabilities) and a longer period for amortization of balances due the Company (regulatory assets). As the RD indicated, the amortization period for regulatory liabilities reflects the fact that the accumulation of these credits took place over a three-year period. Moreover, we have adopted a longer amortization period (5 years) for regulatory assets to help mitigate the rate increase in this case. We are aware from the Company's filing that it will be applying to increase rates in succeeding years. If we were to use all available credits in the Rate Year, as UIU and MC suggest, we would create a situation in which the bill impact of future delivery rate increases would be exacerbated due to the expiration of the amortization of credits. For this reason UIU’s and MC’s exceptions are denied.

5. Deferral Accounting/Reconciliations

The issues of deferral accounting for property tax expense and reconciliation related to electric net plant have been addressed in previous sections of this order and will not be discussed again here.

The Company and Staff are in agreement regarding the continuation of deferral accounting for pension and OPEBs, environmental remediation, and the Low Income Program. They are also in agreement regarding the use of reserve accounting for major storm costs, asbestos claim payments, and deferral of shortfall for contractor tree trimming expenditures.

The Company and Staff further agreed on the continuation of the true-up for the Company’s variable rate tax-exempt debt and swap costs associated with the debt, as well as the amortization period for debt issuance costs, which is the shorter of the remaining life of the refunded issues or the life of the new issues. In addition, the Company proposed, and Staff agreed, that the actual cost of replacement tax-exempt or taxable debt issues, and the new interest rate, should be trued up. Staff noted that the true-ups are reasonable given the uncertainty of these costs at this time and recommended that such reconciliations be supported with details of the costs incurred, the reasonableness of those costs, and designation of which costs had been allowed in rates.

The Company sought, with Staff’s support, authorization to reconcile the benefits generated by a tax law change increasing bonus depreciation. It testified that the impact of the tax law change, which became effective on December 20, 2010, was still being assessed by the Company, and therefore the Company was unable at this time to fully utilize the additional tax deductions afforded by the change in law. Staff requested that the interest accrue at the authorized pre-tax rate of return.

The Company also proposed to use deferral accounting for costs associated with compliance with an expected directive from the North American Electric Reliability Corporation leading to a change in the definition of the bulk electric system by the Federal Energy Regulatory Commission. It does not appear from our review of the record that Staff or any other party addressed this request.

Noting no objections from the parties, the RD recommended that the deferral accounting and reconciliations listed above be authorized. No party takes exception to this recommendation.

Discussion

The Company is authorized to defer costs of, apply reserve accounting to, and reconcile actual amounts for the various items discussed above. We also direct that any variation between the actual effect of the tax law change associated with bonus depreciation and the amount assumed in rates accrue interest at the authorized pre-tax rate of return.

6. Seasonal Disconnect/Reconnect Fee

The Company proposed to implement a $27 fee for disconnection and reconnection of service to seasonal customers, if a customer had a reconnection or disconnection of service in the preceding twelve months. The RD recommended the imposition of such a fee, finding the fee to be reasonable and reflective of costs borne by the Company when seasonal customers disconnect or reconnect service.

The ALJs, in reviewing the Niagara Mohawk tariff cited by the Company in support of its request, found that Niagara Mohawk imposes a lesser fee where the same seasonal customer has more than one seasonal meter or account at the same location.[63] Consequently, the RD recommended that the Company's seasonal disconnection/reconnection tariff include provisions comparable to those contained in the Niagara Mohawk tariff.

Staff takes exception to the RD's recommendation. It opposes the imposition of a disconnection fee for any customer. Staff worries that the Company will misclassify customers as seasonal customers and impose a disconnection fee on customers who request disconnection of service for reasons unrelated to seasonal usage. It requests that, should the Commission allow this fee, the Company provide a modified definition of seasonal customers to ensure that the fee is only applied to seasonal customers.

Discussion

We adopt the recommendation of the RD and authorize the Company to impose, via tariff, seasonal disconnection and reconnection fees. The Company has provided reasonable justification for the imposition of both fees, as well as the modification to the tariff language for the service fee.

We also concur with Staff, however, that it is important that the Company properly define "seasonal customer" in order to ensure that the disconnection fee is not being misapplied. Therefore, the Company's tariff must include, in addition to the language it proposes: (1) language providing a reduced fee where multiple disconnections are requested at the same location; and (2) a definition of seasonal customer that enables the Company to clearly identify such customers. To this end, we require the Company to incorporate a statement in its tariff to the effect that, "A disconnection fee shall not apply

[63] Niagara Mohawk, PSC No. 220, Leaf 78, 9.2.2.1. (effective April 27, 2009).

to disconnections taking place due to a termination of service pursuant to PSL §32."

7. Double-Wood Poles

Before the ALJs, the Town contended that double-wood poles are a serious problem, as we recognized in instituting a proceeding to address the issue.[64] It asserted that O&R does not have records of double/abandoned utility poles, but that, in an audit, the Company found 39 double-wood poles on a single route in Ramapo.

The Company testified that it is actively participating in the Commission's Facility and Equipment Transfer Proceeding, and it takes seriously the issue of double-wood poles. Of the 39 double-wood poles it identified in the Town of Ramapo, the Company said it will address eight during the spring of 2011. The remaining poles require the relocation of facilities by communications companies before the Company can remove the pole.

The Company committed to following defined procedures to ensure cooperation of the communication companies, including issuance of a 30-day facility transfer deadline. It also committed to conduct a survey of the Town during the spring of 2011 to identify all existing double-wood poles and to develop a plan of action. It insisted that pole removal would be conducted in consultation with the Town.

The RD first acknowledged that Staff issued a report on March 17, 2011, entitled "Improving the Equipment Transfer Process for Utility Poles in New York State" in the Facility and Equipment Transfer Proceeding. The report describes a

[64] Case 08-M-0593, Proceeding on Motion of the Commission to Evaluate a Standardized Facility and Equipment Transfer Program, Order Initiating Proceeding (issued June 5, 2008)(Facility and Equipment Transfer Proceeding).

Standardized Facility and Equipment Transfer Program (SEFET Program) that includes, among other things, pole transfer and removal guidelines, treatment of double-wood poles that existed prior to the SAFET Program, and dispute resolution and penalty action provisions. The report, in relevant part, states:

> No timeframe for actual work on pre-existing conditions is suggested, but Staff urges that the companies expeditiously address those issues in due course. The pole owners are expected to utilize the Program's notification system to manage the pre-existing facilities as well as current conditions. The pole owners should submit to Staff, within 180 days of the SAFET Program's effective date, a plan that addresses their pre-existing double pole conditions, with the goal of eliminating pre-existing conditions. Staff will continue to monitor pre-existing conditions.[65]

Next the RD determined that the Commission is addressing the issue of double-wood poles in the Facility and Equipment Transfer Proceeding and recommended that the Town, MC and UIU raise any specific concerns with respect to the Company's handling of double-wood poles in that proceeding.

The RD, however, recommended that the Company be required to follow through with its commitments to the Town of Ramapo, and it suggested that the Commission require that the Company file progress reports with Staff. The RD also recommended that the Company be required to take steps to ascertain whether similar commitments to other municipalities in the service territory are reasonable in light of the Facility and Equipment Transfer Proceeding.

The Company takes exception to the recommendation that it file a separate report with Staff regarding its commitments

[65] Staff Report, p. 13.

to the Town. It argues that in light of the requirements of the Facility and Equipment Transfer Proceeding, such reporting would be duplicative. In addition, the Company contends that the recommendation that the Company explore similar commitments to other municipalities is unnecessary because such commitments are already addressed in the Facility and Equipment Transfer Proceeding.

UIU supports the RD's recommendations, but requests that any progress report submitted by the Company be done on a quarterly basis and be served on all parties to the proceeding.

Discussion

In May of 2011 we voted to implement the SAFET Program. We found that double-wood poles result in unnecessary costs to utilities and ratepayers and may present an unsafe condition that jeopardizes public safety. Although the removal of existing double-wood poles is not part of the SAFET Program, for that program is a prospective one, we are concerned about this issue and have required each pole owner to submit a report to Staff indicating how it proposes to reduce the number of double-poles currently in existence. In addition, pole owners are required to describe impediments to reducing the number of existing double-wood poles. The report must be filed with Staff by January 1, 2012.

Given our implementation of the SAFET Program and the report on current double-wood poles the Company is required to file by the first of the year, we decline to subject the Company to additional reporting requirements in this proceeding. Moreover, while we encourage the Company to follow through on its commitments to the Town of Ramapo, we will not direct the Company to make similar commitments to other municipalities. The Company is required to address double-wood poles in accordance with the SAFET Program and its treatment of pre-existing double-wood poles will be addressed by the report the Company is required to file by January 1, 2012.

8. Targeted DSM Incentive

The Company contended that it does not have a targeted DSM program, and only achieves DSM through electric energy efficiency programs approved by the Commission in the EEPS Proceeding. It said that EEPS-funded DSM programs are not focused on providing load relief for specific distribution system components, and proposed to develop a targeted DSM program that would enable it to forestall capital infrastructure investment.

The Company also requested that it be able to earn a positive incentive for its targeted DSM program, through sharing equally with ratepayers in the benefits generated by the program. Those benefits would be calculated as the approved rate of return applicable to avoided infrastructure costs. The Company contended that a DSM incentive is consistent with Commission policy, which encourages utility engagement in DSM. It argued that the Commission's reasons underlying its decision to provide incentives for energy efficiency apply equally to targeted DSM.

The RD supported the Company's use of targeted DSM, noting that the Company generally reviews DSM options in lieu of capital infrastructure investments that exceed $5 million, but said that this was an obligation imposed by its statutory responsibility to provide safe and reliable service at just and reasonable rates. Consequently, the RD recommended rejection of the Company's request to recover the cost of its targeted DSM Program through the Energy Cost Adjustment Clause. The RD determined that the Company would need to provide greater detail regarding the its targeted DSM Program if it were to obtain recovery of program costs or if an incentive mechanism were to be considered. It stated that that detail should include: (1) how the Company will identify infrastructure projects that could be delayed; (2) how DSM measures to avoid those projects will be implemented, including criteria for choosing between the use of internal resources and procurement from external sources; (3) the process the Company will utilize to ensure megawatt reductions; and (4) the means for tracking and reporting the performance of DSM measures, with a continuing assessment of their success in delaying the avoided infrastructure investment.

The RD also recommended rejection of the Company's request for an incentive, primarily because of the lack of program detail as discussed above. While the ALJs agreed that the logic behind energy efficiency incentives seemed applicable to DSM incentives, they noted that the Commission generally declined to take that approach. In addition, the RD noted that the issue of incentives for targeted DSM is a matter better addressed generically.

In its Brief on Exceptions, the Company complains that no clear process has been provided for the approval of cost recovery and incentives for targeted DSM programs. It requests clarification as to the proper venue to address targeted DSM programs: the EEPS proceeding or an independent utility filing. It asks if the costs associated with targeted DSM programs should be recovered through base rates, an adjustment clause mechanism, a surcharge, or the System Benefits Charge. The Company also complains about the uncertainty regarding whether the utility should (1) earn a return on assets of targeted DSM programs and (2) be able to earn an incentive based on megawatt savings or cost savings.

O&R argues that targeted DSM programs offer less costly alternatives for meeting infrastructure needs. It requests that the Commission establish a process for approval of its targeted DSM programs, and that the process include treatment of costs through a recovery mechanism. To that end, it requests that the Commission allow it to recover targeted DSM Program costs via its Energy Adjustment Clause. It also requests that it be allowed to earn incentives based on a sharing of benefits with customers, although it does not define the term “benefits.”

Staff supports the RD’s rejection of the Company’s targeted DSM Program proposal. It contends that the Company provided little or no detail for the program and notes that the RD articulated the type of program information that needs to be provided in order to properly evaluate a proposal. With this type of information, Staff maintains that the Commission will be able to address the process questions the Company raises, such as the suitable cost recovery mechanism.

Discussion

We support DSM as a reasonable tool to manage energy system needs. We agree with Staff and the RD, however, that the Company’s proposed targeted DSM Program is not sufficiently defined. The RD identifies the minimum amount of information that would be necessary for review of the program. We refer the Company to the process followed by Con Edison, which resulted in our June 1, 2011 order in Case 09-E-0115 addressing Con Edison’s new targeted DSM program and suggest that a similar process be followed if the Company desires to pursue a targeted DSM program for its system.[66]

With regard to the Company’s request for incentives for implementing a targeted DSM program, we concur with the RD

[66] Case 09-E-0115, Proceeding on Motion of the Commission to Consider Demand Response Initiatives, Order Adopting With Modifications a New Targeted Demand Side Management Program for Consolidated Edison Company of New York, Inc.(issued June 1, 2011)

that this issue is best addressed generically. At this time, however, we see no reason to allow the Company to earn incentives for pursuing demand side alternatives to delay infrastructure investment or to obtain less-costly alternatives to projected system needs. On a daily basis, utilities plan their systems and manage their capital programs to meet the needs of their customers. The evaluation of demand side alternatives to traditional capital investment should be included in this processes. We concur with the RD that the Company has a statutory obligation to review DSM measures as part of its responsibility to provide safe and reliable service at just and reasonable rates and, without further development on a generic basis of the issues surrounding incentives for targeted DSM, including the need for and cost thereof, we do not here provide an incentive for the Company to meet to this obligation.

I. Stipulation

On February 16, 2011, the Company and Staff executed a Stipulation, attached as Appendix E, addressing several non-controversial issues including the market supply charge (MSC), service classification provisions, electronic tariff, uncollectibles percentage for purchase of accounts receivable, mandatory day ahead hourly pricing, depreciation rates, and miscellaneous accounting matters. The RD determined that the Stipulation provides reasonable resolutions of these issues.

The Stipulation proposes that the MSC be calculated based upon the Company’s forecast of price and hedging gains or losses for the month in which the MSC is billed, as a means of mitigating MSC volatility. In addition, the MSC for voluntary time-of-use classes would be provided as monthly peak and off-peak rates, reflecting the nature of time-of-use rates.

SC1 and SC2 Special Provisions would be closed to new customers. These classifications provide a lower rate for higher usage for electric water heating, space heating, and heat pump space conditioning. The parties agreed that closing these classifications would be consistent with the Commission’s stated policy goal of promoting the efficient use of electricity.

Staff proposed, and the Company agreed, to convert the Company’s electric tariff schedule to the Electronic Tariff System (ETS). This conversion would take place within six months of the effective date for new rates. According to the Stipulation, the ETS should enable better consumer and party access to the Company’s tariffs.

The Stipulation further provides for a reduction in the threshold for MDAHP from 500 kW to 300 kW. The Company would engage in customer outreach and education to assist new customers that would be subject to MDAHP. In addition, the Company commits to specific dates for meter installations (May 2012) and commencement of MDAHP billing (May 2013).

The Company and Staff agree on proposed changes to depreciation rates and recommended extension of the average service life for a single account. The changes are proposed to reflect the useful life of electric plant. The changes to depreciation rates do not increase expense, but rather reflect the level of expense being incurred.

The miscellaneous accounting adjustments proposed by both the Company and Staff are addressed in Schedules 1 and 2 of Appendix E. The adjustments are non-controversial, and in some instances reflect simple corrections of errors, or track the effect of agreements on other issues (e.g. depreciation) on the revenue requirement.

Discussion

We find the resolutions of the issues addressed by the Stipulation are reasonable, and we accept the RD's recommendation that we adopt it.

III. CONCLUSION

With the modifications described in the foregoing discussion, we adopt the recommendations of the April 4, 2011, Recommended Decision as to the rates, charges and terms of service of Orange and Rockland Utilities, Inc. for electric service for the Rate Year commencing July 1, 2011.

The Commission orders:

1. Orange and Rockland Utilities, Inc. is directed to file cancellation supplements, effective on not less than one day's notice, on or before June 26, 2011, cancelling the tariff amendments and supplements listed in Appendix F to this order.

2. Orange and Rockland Utilities, Inc. is directed to file, effective on not less than one day's notice on July 1, 2011, such further tariff revisions as are necessary to effectuate the provisions adopted by this order. The Company shall serve copies of its filing on all parties to this case. Any comments on the compliance filing must be received at the Commission's offices 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.

3. 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 2 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.

4. Orange and Rockland Utilities, Inc. is directed, within 120 days after the issuance of this order, to produce a report detailing its implementation plans for management audit recommendations, with a forecast of costs to achieve and expected savings. If, prior to that deadline, O&R files a new rate case, a preliminary report is to be included with the filing.

5. Orange and Rockland Utilities, Inc. is directed to file a report detailing the results of its Smart Grid pilot program within 90 days after completion of the pilot.

6. Orange and Rockland Utilities, Inc. is directed to develop a proposal to replace the declining rate blocks for Service Classes 2 and 3 with a rate structure that includes a volumetric charge. The proposal is to be included with the initial filing in the next rate case initiated by Orange and Rockland Utilities, Inc., if possible, and in any event, to be provided to the parties to that case no later than 60 days following such initial filing.

7. Orange and Rockland Utilities, Inc. is directed to determine the rate impact of a one percent increase in the luminaire replacement rate under Special Condition A of its Service Classification No. 4, and to include the information with its initial filing in its next rate case, if possible, and in any event, to be provided to the parties to that case no later than 60 days following such initial filing.

8. Orange and Rockland Utilities, Inc. is directed to develop a proposal for an energy-only street lighting service to be filed with the Secretary and served on the parties to this proceeding no later than October 31, 2011.

9. Orange and Rockland Utilities, Inc. is directed to implement the measures agreed to in the Stipulation attached hereto as Appendix E, in the manner, and within the timeframes specified in the Stipulation.

10. Except as herein granted, all exceptions to the April 4, 2011, Recommended Decision are denied.

11. Except as specified herein, the April 4, 2011, Recommended Decision is adopted as part of this order.

12. The Secretary is authorized, upon a showing of good cause, to extend the filing deadlines set forth in the body of this order.

By the Commission,

Jaclyn A. Brilling

Digitally Signed by Secretary
New York Public Service Commission

JACLYN A. BRILLING
Secretary

Case 10-E-0362

Appendix A
Schedule 1

Orange and Rockland Utilities Inc.
Electric Operating Income, Rate Base & Rate of Return
For Rate Year Ending June 30,2012
($000's)

	Per Recommended Decision	Adj. No.	Commission Adjustments	As Adjusted by Commission	Revenue Requirement Adjustment	As Adjusted for Revenue Requirement
Operating Revenues						
Sales & Delivery to Public	$ 460,888	1	$ (1,435)	$ 459,453	$ 26,587	$ 486,040
Sales for Resale	27,292			27,292	-	27,292
Sales Revenues	488,180		(1,435)	486,745	26,587	513,332
Other Operating Revenues	20,085	2	(7)	20,078	139	20,217
Total Operating Revenues	508,266		(1,442)	506,824	26,726	533,550
Operating Expense						
Purchased Power	245,567			245,567		245,567
Deferred Purchased Power	(71)			(71)		(71)
Operation & Maintenance Expense	157,975	3	(814)	157,161	136	157,297
Depreciation Expense	27,281			27,281		27,281
Amortization of LTD Term Plant	3,667			3,667		3,667
Taxes Other Than Income Taxes	35,931	4	(9)	35,922	271	36,193
Total Operating Revenue Deduction	470,350		(823)	469,527	407	469,934
Operating Income Before Income Taxes	37,915		(619)	37,296	26,319	63,615
New York State Income Tax	1,557	5	(66)	1,491	1,869	3,360
Federal Income Tax	6,524	6	(305)	6,219	8,558	14,777
Total Income Tax	8,081		(371)	7,710	10,427	18,137
Utility Operating Income	$ 29,834		$ (248)	$ 29,586	$ 15,893	$ 45,478
Rate Base	$ 643,996	7	$ (421)	$ 643,576		$ 643,576
EBCAP Adjustments to Rate Base	(13,694)			(13,694)		(13,694)
Total Rate Base	$ 630,303		$ (421)	$ 629,882		$ 629,882
Rate of Return	4.73%			4.70%		7.22%

Orange and Rockland Utilities Inc.
Other Operating Revenues
For Rate Year Ending June 30, 2012
($000's)

	Per Recommended Decision	Adj. No.	Commission Adjustments	As adjusted by Commission	Revenue Requirement Adjustment	As Adjusted for Revenue Requirement
Miscellaneous Service & Other Revenues						
Late Payment Charges	$ 2,443	2	$ (7)	$ 2,436	$ 139	$ 2,575
Late Payment Charges - Sundry	5			5		5
O&R Billing Services	474			474		474
Customer Reconnect Fees	155			155		155
Collection Charges	96			96		96
Bad Check Charge	40			40		40
Forfeited Customer Advances	135			135		135
Carrying Charge	58			58		58
Agency Checks Dishonored	(2)			(2)		(2)
Other	9			9		9
Total Other Operating Revenues	3,413		(7)	3,406	139	3,545
Rents						
Rent from Electric Property - Pole Attachments	1,683			1,683		1,683
- Other Electric Property	858			858		858
- Transformers	1			1		1
Intercompany Billing - Joint Use Rents	2,922			2,922		2,922
Total Rent	5,464		-	5,464	-	5,464
Regulatory Items - Reconciliations						
POR Discount - Credit And Collections	839			839		839
POR Discount - Uncollectibles	402			402		402
Total Reg. Rec. Items	1,241		-	1,241	-	1,241
Regulatory Items - Recoveries / Refunds						
Interest on Pollution Control Debt	-			-		-
Property Tax Refunds - Haverstraw (86%)	(49)			(49)		(49)
Smart Grid Stimulus Project	-			-		-
CATV Order Deferred Billing (A/C 456451)	115			115		115
Net Plant Reconciliation (A/C 456064)	9,245			9,245		9,245
Performance Penalties - CAIDI	468			468		468
Oil Supplier Refunds (70%)	55			55		55
Deferred SIT - NYS Rate Change 7.5% - 7.1%	-			-		-
Current SIT - NYS Rate Change 7.5% - 7.1%	101			101		101
Refund of interest on repair allowance depreciation	32			32		32
Total Revenue Subject To Refund	9,967		-	9,967	-	9,967
Total Other Operating Revenues	$ 20,085		$ (7)	$ 20,078	$ 139	$ 20,217

Orange and Rockland Utilities Inc.
Operation & Maintenance Expenses
For Rate Year Ending June 30, 2012
($000's)

	Per Recommended Decision	Adj. No. 3	Commission Adjustments	As Adjusted by Commission	Revenue Requirement Adjustment	As Adjusted For revenue Requirement
Operating Expenses						
Purchased Power Costs	$ 245,496			$ 245,496		$ 245,496
Direct Labor (Excl. Shared Services)	43,899	a	(1,263)	42,636		42,636
Shared Services	9,610			9,610		9,610
Employee and Other Insurance Costs	8,676	b	(22)	8,654		8,654
R&D, MHP, Low Income Program	2,678			2,678		2,678
Pensions and OPEBS	35,535			35,535		35,535
Uncollectible Accounts	2,621	c	(7)	2,614		2,614
MGP Sites & West Nyack Environmental Costs	1,975			1,975		1,975
Tree Trimming / T&D O&M	24,845	d	960	25,805		25,805
Regulatory Commission Expenses	1,333			1,333		1,333
Customer Programs	13,511			13,511		13,511
Other O&M Costs						
- Advertising	33			33		33
- Building Services	304			304		304
- Information Technology Solutions	3,787			3,787		3,787
- Legal & Other Professional Services	853			853		853
- Rents	1,124			1,124		1,124
- Reproduction						
- Materials and Supplies	1,368			1,368		1,368
- Corporate & Fiscal	1,154			1,154		1,154
- Telephone	52			52		52
- Transportation	506	e	(4)	502		502
- Other O&M	4,110			4,110		4,110
Additional Imputed Management Audit Savings						
Imputed Austerity Savings		f	(478)	(478)		(478)
Total O & M Expenses	$ 403,471		$ (814)	$ 402,657		$ 402,657

Orange and Rockland Utilities Inc.
Taxes Other Than Income Taxes
For Rate Year Ending June 30, 2012
($000's)

	Per Recommended Decision	Adj. No.	Commission Adjustments	As Adjusted By Commission	Requirement Adjustment	As Adjusted For Revenue Requirement
Property Taxes :						
State, County & Town	$ 6,976			$ 6,976		$ 6,976
Village	1,394			1,394		1,394
School	16,726			16,726		16,726
3 Year Amort of Deferred Balance	2,386			2,386		2,386
Total Property Taxes	27,482			27,482	-	27,482
Payroll Taxes	3,319	5	(9)	3,310		3,310
Mobility Tax	285			285		285
Mobility Tax (3 Yr Amort of Deferred Balance)	206			206		206
Revenue Taxes - Sales Revenue	4,640			4,640	271	4,911
Total Taxes Other Than Income Tax	$ 35,931		$ (9)	$ 35,922	$ 271	$ 36,193

Orange and Rockland Utilities Inc.
New York State Income Tax
For Rate Year Ending June 30, 2012
($000's)

	Per Recommended Decision	Adj. No.	Commission Adjustments	As Adjusted By Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Operating Income Before Income Taxes	$ 37,915		$ (619)	$ 37,296	$ 26,319	$ 63,615
Permanent Differences:						
Add: Additional Income and Unallowable Deductions						
Unallowable Business Expense						-
Non Taxable Income, Unallowable Deductions	-			-		-
Total Flow Through Additions	-		-	-	-	-
Deduct: Non Taxable Income & Add'l Allowed Deductions						
Interest Expense	17,750		317	18,067		18,067
Medicare Reimbursement	-			-		-
Total Flow Through Deductions	17,750		317	18,067	-	18,067
Pretax Income	$ 20,165		$ (936)	$ 19,229	$ 26,319	$ 45,548
Normalized Items:						
Add: Additional Income & Unallowable Deductions:						
Book Depreciation - Charge to Expense	$ 29,843		$ -	$ 29,843		$ 29,843
- Charge to clearing Account	4,085			4,085		4,085
Book Depreciation - Expense (Proposed Rates)	1,105			1,105		1,105
- Clearing (Proposed Rates)	-			-		-
Total Normalized Additions	35,033		-	35,033	-	35,033
Deduct: Nontaxable Income and Additional Allowable Deductions:						
NYS Tax Depreciation (Existing Rates)	42,551		-	42,551		42,551
(Proposed Rates)	-			-		-
Cost of Removal	2,331			2,331		2,331
Lien Date Property Tax Deduction	740			740		740
AFUDC	-			-		-
Loss On Disposition of Property	831			831		831
Total Normalized Deduction	46,453		-	46,453	-	46,453
Section II - Normalized Items						
Add: Additional Taxable Income and Unallowable Deductions:						
Post Employment Benefits Capit. / Exp. (FASB 106)	10,540			10,540		10,540
Contributions In Aid of Construction	620			620		620
Contributions In Aid of Const. - Refundable	(166)			(166)		(166)
Increase In Deferred Fuel Cost	(71)			(71)		(71)
R&D Expense Credited To Reserve	472			472		472
Environmental Reserve	-			-		-
Interest On Net Plant	(9,245)			(9,245)		(9,245)
Supplemental Pension - Nonqualified	1,647			1,647		1,647
Revenue Subject To Refund	-			-		-
Unallowable Book Pension Expense	21,452			21,452		21,452
Property Tax Refunds	(101)			(101)		(101)
Total	25,148		-	25,148	-	25,148
Deduct: Nontaxable Income and Additional Allowable Deductions:						
Rate Case Costs	(50)			(50)		(50)
OPEB Funding	4,808			4,808		4,808
Environmental Cost - QER Expend. Section 198	1,641			1,641		1,641
Storm Damage Deferred on Books	(1,251)		-	(1,251)		(1,251)
Pension Funding	15,186			15,186		15,186
Amortization - CIAC Pyramid Mall	120			120		120
Change of Accounting- Sec 263A Adj.	14,646			14,646		14,646
Software Cost - Developed CIMs- Plus - Walker	2,602			2,602		2,602
Total	37,702		-	37,702	-	37,702
Taxable Income or (Loss)	$ (3,809)		$ (936)	$ (4,746)	$ 26,319	$ 21,573
Summary of State Income Taxes						
Current State Income Taxes @ 7.1%	$ (270)	6	$ (66)	$ (337)	$ 1,869	$ 1,532
Deferred State Income Taxes @ 7.1%	1,701		-	1,701	-	1,701
Total SIT (Excl MTA)	1,432		(66)	1,365	1,869	3,234
MTA Tax @1.53%	-			-		-
Deferred State MTA Taxes @ 1.53%	-			-		-
NYS Income Tax	$ 1,432		$ (66)	$ 1,365	$ 1,869	$ 3,234
Deferred NYS Income Tax- Rate Change	126			126		126
Prior Period Over / Under Accrual	-			-		-
NYS Income Tax Per Books	$ 1,558		$ (66)	$ 1,491	$ 1,869	$ 3,360

Orange and Rockland Utilities Inc.
Federal Income Tax
For Rate Year Ending June 30, 2012
($000's)

	Per Recommended Decision	Adj. No.	Commission Adjustments	As Adjusted By Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Operating Income Before Income Taxes	$ 37,915		$ (619)	$ 37,296	$ 26,319	$ 63,615
NYS Income Tax	1,557		(66)	1,491	1,869	3,234
Book Income Before FIT	36,358		(553)	35,805	24,450	60,381
Section I - Flow Thru Items:						
Add: Additional Taxable Income and Unallowable Deductions						
Book Depreciation - Charge to Expense	29,843		-	29,843		29,843
- Charge to clearing Account	4,085			4,085		4,085
Book Depreciation - Expense (Proposed Rates)	1,105			1,105		1,105
Total Flow Through Additions	35,033		-	35,033	-	35,033
Deduct: Non Taxable Income & Add'l Allowed Deductions						
Interest Expense	17,750		317	18,067		18,067
Lien Date Property Tax Deduction	740			740		740
Tax Depreciation./Amort (Flow Thru)	27,057		-	27,057		27,057
Tax Depreciation./Amort (Flow Thru) (Proposed Rates)	720			720		720
Cost of Removal	2,331			2,331		2,331
Loss On Disposition of Property	831			831		831
Total Flow Through Deductions	49,430		317	49,747	-	49,747
Pretax Income	$ 21,961		$ (870)	$ 21,091	$ 24,450	$ 45,667
Section II - Normalized Items						
Add: Additional Taxable Income and Unallowable Deductions:						
Amortization of Bond Redemption Cost	$ 155			$ 155		$ 155
Post Employment Benefits Capital. / Exp. (FASB 106)	10,540			10,540		10,540
Deferred State Income Tax Non Deductible	1,700			1,700		1,700
Contributions In Aid of Construction	620			620		620
Contributions In Aid of Const. - Refundable	(166)			(166)		(166)
Increase In Deferred Fuel Cost	(71)			(71)		(71)
R&D Expense Credited To Reserve	472			472		472
Interest On Net Plant	(9,245)			(9,245)		(9,245)
Book Amortization Computer Software	2,602			2,602		2,602
Supplemental Pension - Nonqualified	1,647			1,647		1,647
Excess Book over Tax Depreciation - B. H.	(21)			(21)		(21)
Unallowable Book Pension Expense	21,452			21,452		21,452
Property Tax Refunds	(101)			(101)		(101)
Total Normalized Additions	29,584		-	29,584	-	29,584
Deduct: Nontaxable Income and Additional Allowable Deductions:						
R&D Expense Debited to Reserve	-			-		-
Rate Case Costs	(50)			(50)		(50)
OPEB Funding	4,808			4,808		4,808
Excess Tax Depreciation Over Vehicle Leas Exp.	(378)			(378)		(378)
Environmental Cost - QER Expend. Section 198	1,641			1,641		1,641
Storm Damage Deferred on Books	(2,001)			(2,001)		(2,001)
Pension Funding	15,186			15,186		15,186
Amortization - CIAC Pyramid Mall	120			120		120
Tax Depreciation (Norm) - ADR/ACRS/MACRS	6,797		-	6,797		6,797
Tax Depreciation (Norm) - ADR/ACRS/MACRS	(720)			(720)		(720)
Tax Depreciation - CIAC	897			897		897
Change of Accounting- Sec 263A Adj.	13,499			13,499		13,499
Software Cost - Developed CIMs- Plus - Walker	2,602			2,602		2,602
Total Normalized Deductions	42,400		-	42,400	-	42,400
Taxable Income or (Loss)	$ 9,145		$ (870)	$ 8,275	$ 24,450	$ 32,851
Summary of Federal Income Taxes						
Current Federal Income Taxes @ 7.1%	$ 3,201	7	$ (305)	$ 2,896	$ 8,558	$ 11,498
Deferred Federal Income Taxes @ 7.1%	4,486		-	4,486	-	4,486
Amortization of Deferred FIT - Section 263A	(1,206)			-	-	(1,206)
Total Current Period FIT	6,481		(305)	7,382	8,558	14,778
Prior Years (Over)/Under Accrual	-			-		-
Federal Income Tax Expense	$ 6,481		$ (305)	$ 7,382	$ 8,558	$ 14,778

Orange and Rockland Utilities Inc.
Rate Base
For Rate Year Ending June 30, 2012
($000's)

	Per Recommended Decision	Adj. No.	Commission Adjustments	As Adjusted By Commission	Revenue Requirement Adjustment	As Adjusted For Revenue Requirement
Utility Plant:						
Electric Plant In Service	$ 928,440		$ -	$ 928,440	$ -	$ 928,440
Electric Plant Held for Future Use	10,018			10,018		10,018
Common Utility Plant (Electric Alloc.)	119,446			119,446		119,446
CWIP Not Taking Interest	13,817			13,817		13,817
Total Utility Plant	$ 1,071,721		$ -	$ 1,071,721	$ -	$ 1,071,721
Utility Plant Reserves:						
Acc. Prov. For Depreciation of						
Electric Plant In Service (Includes Future Use Plant)	$ (300,409)		$ -	$ (300,409)	$ -	$ (300,409)
Acc. Prov. For Depreciation &	-			-		-
Amortization of Common Plant	(53,350)			(53,350)		(53,350)
Total Utility Plant Reserves	$ (353,759)		$ -	$ (353,759)	$ -	$ (353,759)
Net Plant	$ 717,962		$ -	$ 717,962	$ -	$ 717,962
Working Capital Requirements:						
O&M Expenditures	21,505	7a	(195)	21,311		21,311
Materials & Supplies	6,178			6,178		6,178
Prepayments	8,852			8,852		8,852
Regulatory Assets & Other Rate Base Additions:						
Deferred Unbilled Revenue	20,215			20,215		20,215
Deferred Purchased Power Various	2,404			2,404		2,404
Deferred M.T.A. Surtax - (Net of FIT) Various	1,514			1,514		1,514
Deferred M.T.A. Mobility Tax - ((Net of FIT)	311			311		311
Deferred MFC Credit and Collection (Net of FIT)	613			613		613
Deferred Storm Reserve Expenditures (Net of FIT)	5,665	7 b	(226)	5,439		5,439
Deferred Environmental Expenditures (Net of FIT) MGP	2,354			2,354		2,354
Deferred Environmental Expendi.(Net of FIT) West Nyack	251			251		251
Deferred Environmental Expend.(Net of FIT)Cottman / Newark Bay / Borne	308			308		308
Deferred R & D Expenditures (Net of FIT)	712			712		712
Deferred Workers Comp Expense (Net of Tax)	119			119		119
Deferred Low Income Program (Net of FIT)	234			234		234
Deferred Property Tax Undercollection	3,602			3,602		3,602
Deferred Property Tax Refund (Net of FIT)	152			152		152
Deferred Rate Case Cost (Net of FIT)	76			76		76
Deferred Smart Grid Stimulus Project (Net of FIT)	29			29		29
Regulatory (Liabilities) & Other Rate Base Deductions:						
Deferred Carrying Charges Net Plant Recon. (Net of FIT)	(13,957)			(13,957)		(13,957)
Deferred Performance Reliability Revenue Adj. (Net of FIT)	(707)			(707)		(707)
Deferred Accum Prov. For Rate Refund-SIT Rate Change (Net of FIT)	0			0		0
Deferred Current NYS Tax Rate Change (Net of FIT)	(152)			(152)		(152)
Conservation Cost - Net of Tax	(223)			(223)		(223)
Deferred Oil Supplier Refunds (70% - Net of FIT)	(83)			(83)		(83)
Customer Advances For Construction (Net of FIT)	(19)			(19)		(19)
Deferred CATV Billing (Net of FIT)	(174)			(174)		(174)
Accum. Deferred Income Taxes						
Accum. Deferred FIT - ACRS/ ADR /MCRS Various	(79,541)			(79,541)		(79,541)
Accum. Deferred FIT - 263(A) Capitalized Overheads	(32,856)			(32,856)		(32,856)
Accum. Deferred FIT - 263(A) Capitalized Overheads-Update	1,215			1,215		1,215
Accum. Deferred SIT Various	(8,624)			(8,624)		(8,624)
Accumulated Deferred Investment Tax Credits	(933)			(933)		(933)
Change in Accounting / Repair Allowance	(1,773)			(1,773)		(1,773)
Bonus Depreciation	(11,232)			(11,232)		(11,232)
Average Electric Rate Base	$ 643,997		$ (421)	$ 643,577	$ -	$ 643,577
Rate Base (Over) / Under Capitalization	(13,694)			(13,694)		(13,694)
Total Average Electric Rate Base	$ 630,303		$ (421)	$ 629,882	$ -	$ 629,882

Orange and Rockland Utilities Inc.
Working Capital Allowance
For Rate Year Ending June 30, 2012
($000's)

	Per Recommended Decision	Adj. No. 7 a	Commission Adjustments	As Adjusted By Commission
Materials & Supplies				
Materials & Store General Expense	$ 5,322			$ 5,322
Materials & Store Common- Electric Portion	856			856
Total M&S	6,178			6,178
Prepayments				
Local Property Taxes	8,766			8,766
Interest - Unfunded Debt	3			3
Insurance	87			87
NYPSC Assessment	604			604
NYS 1% Utility Tax	(283)			(283)
NYS Gross Receipts Tax	(325)			(325)
Total Prepayment	8,852			8,852
Cash Working Capital				
Operation & Maintenance Exp.	403,471		(814)	402,657
Less:				
Purchased Power	243,444			243,444
Uncollectibles	2,611		(7)	2,604
Regulatory Items (Deferred Charges):				
- Deferred purchased power	(71)			(71)
- Research & Development (deferrals) / Amortization	472			472
- System Benefits Charge	10,573			10,573
- Renewable Portfolio Standard	2,938			2,938
- 18A Assessment				
- Workers Compensation	170			170
- Storm Reserve (Deferral) / Amortization	1,251		750	2,001
- Environmental Remediation (Net of Deferrals)				
-- MGP Amortization	1,823			1,823
-- West NYACK Amortization	38			38
-- Cottman Avenue, Newark bay, Borne	114			114
Working Capital Requirements	140,108		(1,557)	138,551
Cash Working Capital @ 1/8	17,513		(195)	17,319
Add: Working Capital Related to Purchased Power ($244,978 x 1.64%)	3,993			3,993
Total Cash Working Capital	21,505		(195)	21,311
Total Working Capital Requirements	$ 36,536		$ (195)	$ 36,341

Orange and Rockland Utilities Inc.
Capital Structure
Per Commission
For Rate Year Ending June 30, 2012

	Ratio	Cost Rate	Weighted Average Ratio	Pre Tax Ratio @ 60.385%
Long Term Debt	49.70%	5.50%	2.73%	2.73%
Customer Deposits	1.30%	1.46%	0.02%	0.02%
Total Cost of Debt	51.00%		2.75%	2.75%
Preferred Stock	1.00%	5.34%	0.05%	0.08%
Common Equity	48.00%	9.20%	4.42%	7.32%
Total Capitalization	100.00%		7.22%	10.15%

Orange and Rockland Utilities Inc.
Explanation of Commission's Adjustments
For Rate Year Ending June 30, 2012
($000's)

Adj. No.	Explanation		Amount
1	**Sales Revenue - Schedule 1**		
	To reflect Commission's sales forecast.		$ (1,435)
2	**Other Operation Revenues - Schedule 2**		
	To reflect Commission's adjustment to Late Payment Charges tracking sales adjustment.		$ (7)
3	**Operation and Maintenance Expenses - Schedule 3**		
	a. Direct Labor		
	1) To reflect Commission's adjustment to remove Company's request for the Project Management Group positions	$ (117)	
	2) To reflect Commission adjustment removing ATIP funding	(1,146)	
	Total Adjustment to Direct Labor		$ (1,263)
	b. Employee and Other Insurance Costs		
	To reflect Health Insurance costs associated with Commission's Direct Labor allowances.		(22)
	c. Uncollectibles		
	To adjust uncollectibles associated with Commission's sales forecast.		(7)
	d. Major Storm Costs		
	1) To reflect a five year amortization of deferred storm costs	$ 750	
	2) To reflect Commission 8 year average funding level for storm costs.	210	
	Total Adjustments to Storm costs		960
	e. Other O&M Costs		
	To remove transportation expense associated with the removed Project Management Group positions.		(4)
	f. Austerity Savings		
	To reflect Austerity Savings		(478)
	Total Adjustment to Operation & Maintenance Expense		$ (814)
4	**Taxes Other Than Income Taxes - Schedule 4**		
	To reflect payroll tax adjustment associated with the additional Project Management Group positions.		$ (9)
5	**State Income Taxes - Schedule 5**		
	To reflect Commission's SIT adjustments per Schedule 5.		$ (66)
6	**Federal Income Taxes - Schedule 6**		
	To reflect Commission's FIT adjustments per Schedule 6.		$ (305)
7	**Rate Base - Schedule 7**		
	a. Working Capital - Schedule 8		
	To reflect effect of Commission's Adjustments on working capital.	$ (195)	
	b. Deferred Major Storm Reserve		
	To reflect impact of Commission's treatment of deferred Storm Costs.	(226)	
	Total Adjustments to Rate Base		$ (421)

Orange and Rockland Utilities, Inc.
Case 10-E-0362
Company and Customer Impacts

Base Rate Revenue Increase (000):	$	26,587
Percent Increase of Delivery Revenues :		12.1%

Base Rate Revenue Increase:	$	26,587
Elimation of Temporary Surcharge and Current RDM Surchage:	$	14,110
Net Impact on Customer:	$	12,477

Percent Increases on Customers (net of elimination of Temp Surcharge and RDM surcharge ($12,477 M)):

Delivery Bills:	5.7%
Total Bills:	1.9%

Net Impact on Cutomer Groups:

	Residential	Small C&I	Medium C&I	Large C&I	Lighting
Net Delivery Revenue Increase:	6.7%	3.4%	3.5%	2.1%	21.6%
Net Total Bill Increase:	2.7%	1.2%	0.8%	0.3%	12.3%

APPENDIX C

Service Reliability Performance Mechanism

Average Duration of Interruptions (CAIDI)

The Company-wide average duration of interruption level target is 1.85 Hours/Interruption (“Interruption Duration Target”) for each calendar year. If, for any calendar year ending after July 1, 2011, Orange and Rockland fails to achieve the Interruption Duration Target, a penalty equal to 20 basis points on New York electric equity will be assessed.

Average Frequency of Interruptions (SAIFI)

The Company-wide average frequency of interruption level target is 1.20 Hours/Customer (“Interruption Frequency Target”) for each calendar year. If, for any calendar year ending after July 1, 2011, Orange and Rockland fails to achieve the Interruption Frequency Target, a penalty equal to 20 basis points on New York electric equity will be assessed.

APPENDIX D

Orange and Rockland Customer Service Peformance Incentive

	Threshold Level	Negative Revenue Adjustment
PSC Complaint Rate Per 12 Months	1.8	$150,000
	1.9	$300,000
	>=2.0	$500,000
Customer Satisfaction Survey	>89.0%	$0
	<=89.0%	$150,000
	<=88.0%	$300,000
	<=87.0%	$450,000
Adjusted Bills	<=2.42%	$0
	>2.42%	$50,000
	>2.54%	$100,000
	>2.66%	$150,000
Maximum Total		**$1,100,000**

Orange and Rockland Utilities, Inc.
Case 10-E-0362
Stipulation

NEW YORK STATE
PUBLIC SERVICE COMMISION

CASE 10-E-0362 **Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service**

Stipulation and Agreement of Certain Matters Relating to Rate Design, Depreciation and Miscellaneous Accounting Matters

Orange and Rockland Utilities, Inc. ("the Company"), the Staff of the Department of Public Service, and the other signatories (collectively referred to herein as "the Signatories") to this stipulation and agreement ("Stipulation") hereby agree to resolve the specific issues indicated below that are presented in the testimony of Company witnesses Charles Hutcheson, Richard Kane and the Company Rates Panel and Staff witnesses Richard George, Christopher Graves, Rosanne Maiello, Liliya Randt and the Staff Accounting Panel in this proceeding in the manner set forth below. Issues not expressly addressed in this Stipulation are not resolved hereby.

A. Rate Design

The Market Supply Charge ("MSC") price and hedging gains or losses will be based on the Company's forecast price for the month in which the MSC is billed. The Company will change MSCs for the voluntary time-of-use classes from a single monthly rate to monthly peak and off-peak rates for each service class.

The threshold for mandatory day ahead hourly pricing ("MDAHP") will be lowered from 500 kW to 300 kW. MDAHP meters will be installed by May 2012 and billing would commence with bills having a "from" date of May 2013 to be consistent with the current schedule for MDAHP billing for the above 500 kW population. The Company is not pursuing any changes to the reactive power threshold in this proceeding. The Company will engage in customer seminars and other education and outreach efforts to prepare affected customers for MDAHP billing.

The Company will convert its electric tariff to the Commission's Electronic Tariff System within six months of an order setting rates in this proceeding.

Under Service Class Nos. 1 and 2, the Company will close to new customers the special provisions for heating discounts (e.g., water heating, space heating, heat pump space conditioning and off-peak energy storage options).

The uncollectibles percentage used to develop the purchase of receivables discount will be revised to reflect the Company's actual uncollectibles experience for the 12-month period ended June 30, 2010. Thereafter, annual filings will be made with an effective date of November 1st to reflect the Company's actual uncollectibles experience for the twelve month period ended the previous June 30.

B. Depreciation

The Company accepts the deprecation rate changes proposed by Staff witness Richard George (but not Staff's level of depreciation expense, which reflects certain plant-in-service adjustments proposed by the Staff Infrastructure Panel).

C. Accounting Issues

The Signatories agree to the miscellaneous accounting matters set forth in Attachment A.

D. Stipulation Intent

This Stipulation is intended to resolve certain matters for the purposes of this Proceeding and is designed to reduce the issues in controversy to be resolved through a litigated evidentiary hearing. This Stipulation states the position of the Signatories that resolves each of the issues presented. Adequate and sufficient evidence supporting each resolution of an issue will be found in, or within the scope of, the testimonies and exhibits that will be submitted at the evidentiary hearing conducted in this Proceeding. The Signatories request that the Administrative Law Judges adopt the resolutions reached herein in any Recommended Decision or report and that the Commission adopt them in its final decision in this Proceeding.

E. Signatories' Support

The Signatories believe that the resolutions reached in this Stipulation are just and reasonable and otherwise in accordance with the New York Public Service Law, the Commission's regulations and applicable Commission orders. Each of the Signatories agrees to support the terms of this Stipulation as just and reasonable, agrees not to take a position in the Proceedings in these matters contrary to the agreements set forth herein, and agrees not to assist another participant in taking such a contrary position in the Proceedings.

F. Integrated Agreement

The terms of this Stipulation are submitted as an integrated whole. If the Commission does not accept this Stipulation as the basis of the resolution of these issues without change or condition, each Signatory shall have the right to withdraw from this Stipulation upon written notice to the Commission within ten (10) days of the Commission Order. If the Company gives such notice, this Stipulation shall be deemed withdrawn, it shall not constitute part of the record of the Proceedings or any future proceeding addressing any of the issues within the scope of this Stipulation and it shall not be used in evidence or cited against any Signatory or used for any other purpose.

G. Settlement Discussions Privileged

The discussions between and among the Signatories that have resulted in this Stipulation have been conducted with the explicit understanding, pursuant to the Commission's regulations, that all written and oral offers, prior proposals of settlement and discussions relating thereto, as well as supporting materials, will remain confidential communications, are without prejudice to the position of any of the Signatories and other entities participating in any such discussions, are not admissible into evidence in the Proceedings or any other proceedings, and will not be used in any manner in connection with the Proceedings, other proceedings, or for any other purpose other than enforcement of the provisions hereof. As such, each Signatory agrees to maintain the confidentiality of all discussions, all offers of settlement and discussions related thereto, as well as all supporting materials.

H. No Admission

The making of this Stipulation shall not be construed, interpreted or otherwise deemed in any respect to constitute an admission by any Signatory regarding any allegation, contention, or issue raised in the Proceedings or addressed in this Stipulation.

I. Stipulation Parameters

This Stipulation is intended to relate only to the specific matters referred to herein and shall have no bearing on the outcome of any other issues in the Proceedings. Nothing in the Stipulation shall determine or constitute a ratemaking principle binding on the Signatories in the future, and no Signatory shall be deemed to have approved, accepted, agreed, or consented for purposes other than these proceedings to any specific ratemaking methodology or principle, accounting treatment, or level of expense or revenue. Nothing in this Stipulation restricts the Company from initiating new rate proceedings, to the extent permitted in the New York Public Service Law and the Commission's regulations. The agreements set forth in this Stipulation are solely for the purpose of the above-captioned proceeding and nothing in this Stipulation restricts any signatories to this Stipulation from taking any position or lawful action or making any filing in any future proceedings. Except as expressly set forth herein, nothing in this Stipulation shall impair, diminish, or restrain the rights of any of the Signatories. Nothing in this Stipulation shall be construed to limit the Commission's authority under the New York Public Service Law.

J. Counterparts

This Stipulation may be executed in one or more counterparts, all of which taken together shall constitute one and the same instrument.

K. Entire Agreement

This Stipulation, including all attachments, exhibits and appendices, if any, represents the entire agreement of the Signatories with respect to the matters resolved herein.

SIGNATURES APPEAR ON NEXT PAGE

Case 10-E-0362

Stipulation

IN WITNESS WHEREOF, the Signatories have each caused this Stipulation to be signed in their names and on behalf of their duly authorized representatives.

Enver Acevedo

On behalf of: Orange and Rockland Utilities, Inc.

Date: February 14, 2011

Brandon F. Goodrich

On behalf of: Department of Public Service Staff

Date: Feb 16, 2011

Case 10-E-0362

ORANGE AND ROCKLAND UTILITIES, INC.

INDEX OF SCHEDULES

Accepted Adjustments
and Corrections

SCHEDULE	TITLE OF SCHEDULE	WITNESS
1	Company Adoption of Adjustments Proposed by Staff see Exhibit__ (E-19), Schedule 1	R. A. Kane
2	Staff Adoption of Updates included in the Company's January 5th Update Filing	Staff Accounting Panel

Case 10-E-0362

January 5, 2011 Update
Exhibit_ (E-19)
Schedule 1

Orange and Rockland Utilities Inc.
Accepted Staff Adjustments
For Rate Year Ending June 30, 2012
($000's)

Adj. No.	Explanation		Incr / (Decr) In Revenue Requirement
3	**Operation and Maintenance Expense - Schedule 3**		
	c. Shared Service Cost:		
	1) To reflect Staff's proposal of removing the allocated restricted stock payment from Con Edison (AP)	(60)	
	2) To reflect Staff's proposal of using labor escalation rate of 3.82% vs Company's 5.27% (AP)	(73)	
	3) To reflect Staff's proposal of reflecting Mgm't Audit benefit in Shared Service Labor escalt'n of 2.28% (AP)	(78)	
	4) To reflect Shared Service fringe benefit adj. tracking Staff's proposal on S.S Cost Labor Component (AP)	(17)	
	5) To reflect Shared Service fringe benefit adj.Tracking Staff's proposal on mgm't audit in S.S.Labor (AP)	(18)	
			(247)
	d. Employee and Other Insurance Costs:		
	3) To reflect Staff's correction of the Co's Health & Life Insurance Capitalization calculation (AP)		(328)
	f. Pension and OPEB		
	2) To reflect Staff's adjustment to Company's 401(k) forecast (AP) (Note: reflects Company wage factor)		(615)
	i. Prevailing Wages		
	To reflect Staff's proposal of removing and reconciling prevailing wages (AP)		(1,756)
	l. Other O&M Costs		
	1) To reflect Staff's adjustment to the Company's Legal and Other Professional Services forecast (AP)		(127)
	Total Adjustments to Operating and Maintenance Expenses		**(3,074)**
4	**Depreciation**		
	Partial acceptance of depreciation expense related to Staff's Cap Ex adjustments (George)		(176)
	Total Adjustment to Expenses		**$ (3,250)**
8	**Rate Base - Schedule 7**		
	a. Average Book Cost of Plant		
	To reflect removal of Woodbury land purchase from RY1 & add to RY2		(604)
	b. Average Accumulated Depreciation		
	1) To reflect removal of Woodbury land purchase from RY1 & add to RY2	4	
	1) To reflect Staff's capital expenditure of electric plant adjustment	832	
	2) To reflect Staff's Capital Expenditure of Common Plant adjustment. (EIP)	77	
			913
	d. Regulatory Asset/Liability Reconciliation- Net of Tax		
	2) **MGP/Superfund**		
	a) To correct deferred MGP rate year balance		(3,925)
	Total Adjustment to Rate Base		**$ (3,616)**
	@ Pretax ROR		**11.00%**
	Rate Base Adjustments @ Pretax ROR		**$ (398)**
	Total Adjustment to Expenses		**(3,250)**
			(3,647)
	Gross Up factor for revenue taxes, uncollectibles, and late payment charges		**98.99%**
	Revenue Requirement Adjustment		**$ (3,685)**

Case 10-E-0362 | Schedule 2

Orange and Rockland Utilities Inc.
Staff Adoption of Company's January 5th Updates
For Rate Year Ending June 30, 2012
($000's)

Adj. No.	Explanation	Incr / (Decr) In Revenue Requirement	
1	**Sales Revenue - Schedule 1**		
	To eliminate duplicate Billing and Payments Processing charges, included in both sales revenues and in other operating revenues in the Company's filling	$ 600	
2	**Other Operation Revenues - Schedule 2**		
	To reflect Company's amortization of deferred Pole Attachment rent	66	
	Refund of Interest on Repair Allowance	(32)	
	Total Adjustment to Sales and Other Operating Revenues		**$ 634**
3	**Rate Base - Schedule 7**		
	Deferred Income Taxes - Bonus Depreciation/Repair Allowance	(7,875)	
	Total Adjustment to Rate Base		**(7,875)**

SUBJECT: Filing by ORANGE AND ROCKLAND UTILITIES, INC.

Amendments to Schedule P.S.C. No. 2 – Electricity

Original Leaves Nos. 22-O-2, 22-O-3, 22-O-4, 22S-1, 22S-2, 22S-3, 22S-4, 22S-5, 22S-6, 22S-7, 22T-1, 26A, 27A-1
First Revised Leaves Nos. 5E, 8C, 10D-1, 10D-3, 10E-1, 10E-2, 10E-3, 10H-1, 10H-2, 10H-3, 10K-3, 10K-4, 23Z-5-1, 23Z-5-2, 23Z-5-3
Second Revised Leaves Nos. 23Z-3-1, 23Z-3-2, 23Z-3-3, 77A-1
Third Revised Leaves Nos. 22-O, 22-O-1, 22P, 22Q, 22R, 22S, 23Z-5
Fourth Revised Leaves Nos. 16F-1, 22M, 22N, 22T, 22U, 22U-1, 22U-2, 23Z-14, 128A
Fifth Revised Leaves Nos. 5D, 10I, 10K, 89A
Sixth Revised Leaves Nos. 5B, 10B, 30, 34, 74, 127
Seventh Revised Leaves Nos. 10E, 22L-4, 27C, 32B, 33A, 77A, 78, 99, 99A, 126
Eighth Revised Leaves Nos. 10H, 16F-4, 38, 79
Ninth Revised Leaves Nos. 22L-3, 93, 95A, 128
Tenth Revised Leaves Nos. 16F, 92A
Eleventh Revised Leaves Nos. 16, 23Z, 98
Twelfth Revised Leaf No. 100
Thirteenth Revised Leaves Nos. 10G, 16B, 16C, 23Y, 95
Fourteenth Revised Leaf No. 2C
Fifteenth Revised Leaf No. 25B
Sixteenth Revised Leaf No. 33
Seventeenth Revised Leaf No. 71
Eighteenth Revised Leaves Nos. 72, 92
Nineteenth Revised Leaves Nos. 32A, 77, 94
Twentieth Revised Leaf No. 49
Twenty-First Revised Leaf No. 29A
Twenty-Second Revised Leaves Nos. 10F, 75
Twenty-Third Revised Leaves Nos. 76, 91
Twenty-Fifth Revised Leaves Nos. 6, 48A
Twenty-Seventh Revised Leaf No. 27B
Twenty-Eighth Revised Leaf No. 2B
Twenty-Ninth Revised Leaves Nos. 25C, 48
Thirty-Third Revised Leaf No. 88
Thirty-Fourth Revised Leaf No. 29
Thirty-Fifth Revised Leaf No. 32
Thirty-Seventh Revised Leaves Nos. 25A, 47

Thirty-Ninth Revised Leaf No. 37
Forty-Sixth Revised Leaves Nos. 27A, 28
Fifty-First Revised Leaf No. 27
Sixty-Seventh Revised Leaf No. 26
Seventy-Fifth Revised Leaf No. 24

Supplement Nos. 195, 197