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November 24, 2008

Via E-Mail and Overnight Delivery
Honorable Jaclyn A. Brilling
Secretary
New York State Department
of Public Service
Three Empire State Plaza
Albany, NY 12223

Case No. 08-E-1003

Dear Secretary Brilling:

Enclosed for filing are an original and five copies of the Reply Comments of Orange and Rockland Utilities, Inc. in the above referenced proceeding.

An electronic copy will be provided to Staff Counsel assigned to this matter and copies will be provided through the ListServer in Case 07-M-0548.

Thank you for your assistance in this matter.

Sincerely,

cc: Anthony Belsito, Esq, Staff (*via e-mail*)

STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

Petition of Orange and Rockland Utilities, Inc. for Approval of an Energy Efficiency Portfolio Standard "Fast Track" Utility-Administered Electric Energy Efficiency Program	**PSC Case No. 08-E-1003**

Reply of Orange and Rockland Utilities, Inc.
to Comments on its
"Fast Track" Electric Energy Efficiency Programs

Introduction

In it's Order Establishing Energy Efficiency Portfolio Standard and Approving Programs, issued and effective June 23, 2008 in Case 07-M-0548 ("EEPS Order"), the New York State Department of Public Service ("Commission") explained that one of the highest priorities of New York State and the Commission is to develop and encourage long-term, cost-effective energy efficiency measures while also immediately implementing and augmenting near-term efficiency measures (EEPS Order at p. 1). Orange and Rockland Utilities, Inc. ("O&R" or "Company") fully supports the Commission's goals and has been an active participant in this proceeding since its inception on May 16, 2007.[1]

In the EEPS Order, the Commission established specific, interim targets for MWh reductions, approved specific energy efficiency programs for immediate implementation, and, most importantly, called for New York's utilities to file energy efficiency programs

[1] Case 07-M-0548, Petition on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard, issued and effective May 16, 2007.

for approval. The call for a substantial utility presence was based in part on the utilities knowledge and ability to reach its customer base, the ability to offer a diversity of approaches that would create competitive energy efficiency programs and the need to meet the substantial energy efficiency goals established by the Commission. The Company full supports the Commission's ideas and believes that a substantial utility presence is the only way to achieve the State's goals.

Unfortunately, the review by Department of Public Service Staff ("Staff") of the Company's proposed programs, is a significant departure from the Commission's framework for obtaining immediate and long-term, cost effective energy efficiency measures. In its review, Staff, in many instances, changes the rules mid stream. For example, Staff recommends a generic, Statewide Residential HVAC Program which is contrary to the Commission's express goal of seeking innovative, utility specific programs. Staff also unnecessarily changed the underlying assumptions for its cost-benefit analysis so that the Company's program proposals are not being reviewed on the cost benefit information initially agreed to by Staff.

And finally, Staff proposes a series or operating procedures and reporting requirements that will deny the Company the ability to run its approved programs in the manner its sees fit. These operating procedures are inconsistent with the overall framework of having these energy efficiency programs subject to incentive and penalties on performance. That is, the Company is willing to be subject to penalties for its performance, but not under Staff's proposals that propose to take away basic decision making authority under the programs.

In essence, Staff's additional proposals and requirements will only delay the implementation of the immediate energy efficiency programs that the Commission called for under the EEPS Order. New York cannot afford such delay. Therefore, the Commission should review and approve the Company's program proposals, as filed.

Background

On June 23, 2008, Commission issued its EEPS Order, which authorized New York's electric utilities and certain gas utilities to submit program plans, for Commission approval, for two "fast track" expedited electric utility programs (EEPS Order, Ordering Clause 9, pp 71-72) and one "fast track" expedited residential gas heating, ventilation and air conditioning ("HVAC") energy efficiency program (EEPS Order, Ordering Clause 11, pp. 72-73).

The EEPS Order was issued following more than a year of intensive collaborative processes, filings and comments (EEPS Order, at pp. 3-8). These extensive interactions resulted in the Commission developing and providing explicit criteria under which the utility electric energy efficiency programs would be evaluated including the applicability of the Total Resource Cost ("TRC") Test; a demonstration that collaborative discussion had taken place between utilities, NYSERDA and other interested parties; and the development of detailed protocols for measurement and verification, and compliance with the requirements of Appendix 3 of the EEPS Order (EEPS Order at 58).

In its ruling the Commission also recognized the need for a longer-term framework that included a "more substantial role for utilities" and established that framework (EEPS Order at p. 35). As the EEPS Order further stated "[t]here are numerous reasons, however, for establishing investor-owned utilities as program administrators. Utilities have direct access to customers and customer usage information. They offer a diversity of approaches that may lead to a wider offering of programs than would occur under a centralized administrator" (EEPS Order at p. 49). The Commission, accordingly, determined that utility–administered programs would account for slightly more than half of the fast track funding, significantly higher than the 20% figure initially proposed by Staff (EEPS Order at p. 36).

Following this direction, O&R designed and submitted to the Commission its Small Commercial and Industrial ("C&I") Direct Installation and Residential HVAC Programs on August 22, 2008 ("60-Day Filing"). The 60-Day Filing complied with all of the criteria articulated by the Commission in the EEPS Order, but was unable, based on the allowed funding, to meet the Commission's energy-efficiency MWh goals.

The Commission subsequently established Case 08-E-1003 – Petition of Orange and Rockland Utilities, Inc. for Approval of an Energy Efficiency Portfolio Standard "Fast Track" Utility – Administered Electric Energy Efficiency Program – as the venue for reviewing O&R's 60-Day Filing.

On November 17, 2008, Staff filed initial comments on O&R's 60-Day Filing in Case 08-E-1003 ("Staff's Initial Comments"). Staff has stated that it may serve supplemental comments and if Staff does so, O&R will also need to respond to those comments. O&R also received comments from the New York State Energy Research and Development Authority ("NYSERDA") on O&R's 60-Day Filing.

The O&R Programs

Program Budgets and Goals

Staff does not recommend approval of O&R's Residential HVAC Program, pending further analysis for cost effectiveness, and recommends rejecting the Company's Small Business Program as too costly (Staff's Initial Comments at 31). Staff further recommends that the Small Business Program should be allowed to proceed only if O&R accepts the budget and energy savings goal specified in the EEPS Order (Staff's Initial Comments at 31). Staff's recommendations should be rejected.

Both programs, when combined with the Company's expansion of these programs and the additional programs detailed in the Company's 90-Day Filing, meet the portion of the "jurisdictional gap" required in the Company's service territory, while meeting the overall budget and program funding levels dictated by the EEPS Order. As described in detail below, the funding allocated to the Company for its fast track programs, combined with the restrictions imposed by the EEPS Order on the types of fast track programs that could be implemented by the utilities, precludes O&R from meeting the MWh goals of the EEPS Order for those programs. Nonetheless, the Company effectively designed its combined suite of programs within the budget constraints of the available jurisdictional gap spending to achieve 100,411 MWh over three years, exceeding the O&R minimum target of 67,365, found on Table 11 of the Order, by 2011. Moreover, the Company's fast track Residential HVAC Program and Small C&I Direct Install Program, when expanded as proposed in both the Company's 60-Day Filing and its 90-Day Filing, can achieve the Company's assigned EEPS fast track goals.

The Market Potential Study

In July, 2008, O&R's consultant, Optimal Energy, completed a Market Potential Study of the Company's service territory. No such Study had been conducted over the ten years in which NYSERDA administered energy efficiency programs in the Company's service territory. Both the consultant selected to conduct the Market Potential Study and the scope of the study were fully vetted with and agreed to by Staff and NYSERDA in Case No. 07-E-0548. Optimal Energy then utilized the completed Market Potential Study to assist O&R in the design of its proposed Residential HVAC and Small Commercial and Industrial (C&I) Direct Install Program for the Company's 60-Day Filing.

Based on the findings of the Market Potential Study, O&R developed and submitted its fast track programs to the Commission. The Company acknowledged in its 60-Day Filing that although both of its proposed programs are cost effective as designed, neither program could achieve the goals dictated by the Commission in its EEPS Order under the budgetary constraints provided therein. As such, the Company was faced with the dilemma of meeting the budgetary goals of the EEPS Order, but not the energy savings goals, or finding an alternative means of assisting the Commission in meeting the requirements of the jurisdictional gap and the State's declared 5x15 goals. O&R chose the latter.

Residential HVAC Program

The EEPS Order seeks energy savings of 1,461 MWh on a budget of $1,318,412 for Residential HVAC (Staff's Initial Comments at 4). Based on the analysis performed by Optimal Energy,[2] those MWh energy savings cannot be met.

O&R's Residential HVAC Program would provide for Energy Star central air conditioners and air source heat pump equipment incentives with quality installations encouraged, but not required; efficient fans as part of a new oil or gas furnace; and duct sealing of new HVAC distribution systems. The Program is designed to target air conditioners that are in need of replacement. Based on the measure life of central air conditioning units, it is estimated that only 7% of the air conditioners in the Company's service territory will be in need of replacement annually. O&R's Market Potential Study revealed central air conditioner saturation below 40%. Nonetheless, due to the constraints outlined in the Commission's EEPS Order, O&R was not free to address this factor by offering, along with its HVAC Program, a room air conditioner rebate or turn-in program that could provide energy efficiency opportunities to the remaining 60% of the Company's residential customers. Rather, if the Company wished to provide a fast track program, it was required to design it consistent with the requirements outlined by the Commission, and O&R followed those requirements.

Despite the low central air conditioner saturation in O&R's service territory, the Company was able to design a cost effective Residential HVAC Program, which, even with the design and budget limitations mandated by the EEPS Order, has a benefit cost

[2] The models, programs, inputs and calculations were provided to Staff in response to Staff interrogatories numbers 1 and 2.

ratio of 1.5. The Company could not, however, meet its prescribed MWh goal (60-Day Filing at p. 4). As such, the Company requested an increase in funding of $535,000 which would, at minimum, allow the Company to achieve 65 percent (949 MWh) of its prescribed goal. This program is even more cost effective, with a benefit cost ratio of 2.3. According to Optimal Energy, this increased funding will allow O&R to maximize the achievable potential for the Residential HVAC Program. Therefore, as described below, O&R is seeking to increase its contribution to the MWh energy saving through its other programs.

Small C&I Direct Install Program

The EEPS Order seeks energy savings of 33,877 MWh on a budget of $9,087,821 for small businesses (Staff's Initial Comments at 4). Based on the analysis performed by Optimal Energy,[3] those MWh energy savings cannot be met because the actual cost per MWh for measures under a small C&I direct install program exceed the funding levels provided to O&R in the EEPS Order.

O&R's Small C&I Direct Install Program will target C&I customers with annual peak demands of less than 100 KW. According to the Company's Market Potential Study, approximately 90% of the electric economic potential identified in the commercial market segment is attributable to lighting, cooling, ventilation and refrigeration upgrades. O&R's program targets each of these uses and focuses on the most cost effective measures, but these measures are still expensive.

Despite costs that were higher than the $305 per MWh estimated in the EEPS Order (at p. 12) the Company was able to design a cost effective Small C&I Direct Install

[3] The models, programs, inputs and calculations were provided to Staff in response to Staff interrogatories numbers 1 and 2.

Program, with a benefit cost ratio of 2.5 while meeting the design and budget limitations mandated by the EEPS Order. The Company could not, however, meet its prescribed MWh goal (60-Day Filing at p. 5).

As designed and supported by the Company's Market Potential Study, O&R's Small C&I Direct Install Programs achieves 62% of O&R's assigned MWh goal of 33,878 MWh for the program at the funding level provided by the Commission. According to the Company's analysis, its Small C&I Direct Install Program has a benefit cost ratio of 2.5 at the Commission's prescribed funding level of $7.6 million. However, the Program can achieve O&R's assigned MWh goal of 33,878 MWh with a program budget of $16.7 million, an increase of $9.1 million over the prescribed budget. The benefit cost ratio for the expanded program is also 2.5.

Additional Funding

In its 60-Day Filing O&R requested additional funding for both the Residential HVAC Program and the Small C&I Direct Install Program as noted above.

Essentially, O&R proposes to take funding authorized by the Commission to meet the jurisdictional gap and utilize those funds to increase the performance of the Company's proposed fast track programs. The Company has proposed, over the next three years, to provide energy efficiency savings of 100,411 MWh within the allowed program budgets for its service territory of $33,848,031.

Avoided Costs and Free Ridership

Staff is proposing to use its updated October estimates of avoided costs for its analysis of O&R's cost benefit analysis (Staff's Initial Comments at p. 14). While this proposal results in a conclusion that the Company's Small C&I Direct Install Program is cost effective, the same conclusion was not reached with respect to the Company's Residential HVAC Program. The Company believes that Staff's cost benefit analysis is inaccurate.

O&R has conducted an avoided cost study as part of its Market Potential Study performed by Optimal Energy. The avoided costs were used to screen measures in the development of the economic potential. The Company believes that service territory specific avoided costs are more accurate and reliable than Staff's upstate/downstate delineation and, as such, the Company's proposed avoided costs should be used for program cost-effectiveness screening.

The methodology used to develop the long-term avoided costs and the results are provided here as Attachment A. This document, which was also provided to Staff in response to interrogatory number 8 in Case 08-G-1004, provides the Company's basis for the estimated $76.49 in avoid costs for distribution capacity per kW, contrary to Staff seeing "no such savings at this time" (Staff's Initial Comments at p. 14).

O&R believes that it is important to put its cost effective programs on a fast track in order to begin effectuating the energy efficiency benefits that have been denied to its customers under NYSERDA's programs. Staff's desire to change the basis of the avoided cost estimates, with no support for utilizing estimates that are not specific to the Company's service territory, will only serve to delay the implementation of the fast track programs. The avoided cost data provided by O&R should be used to evaluate the programs

Staff has also unilaterally doubled the net free rider rate from 5% to 10% and restored rebates paid to free riders to the resource costs. The Company has fully explained that its decision to use 5% as a free rider rate was a preliminary assumption for planning purposes and a proxy measure of uncertainty concerning consumers' response to the programs. The actual levels of free-ridership in the proposed programs are ultimately an empirical question to be answered after the programs are implemented and evaluated. Moreover, during adverse economic conditions such as those now being encountered, free ridership rates are typically lower due to the increased unlikelihood of energy savings measures being installed without incentives. As such, Staff's adjustment is unwarranted.

<u>Continued Review</u>

On several occasions, Staff claims not to have enough information concerning certain aspects of the proposed O&R programs and this alleged lack of information is Staff's potential rationale for not having completed its analysis of the cost effectiveness of the Company's Residential HVAC Program. Staff also seems to indicate that certain information is outstanding or insufficient. For example, Staff claims that the Company did not provide adequate documentation concerning its energy savings estimates by program and measure (Staff's Initial Comments at 9). That statement is incorrect. In response to the first two interrogatories issued by Staff, the Company provided the detailed models, calculations and source data that were used to calculate the energy savings estimates by program and measure. Staff did not advise the Company that those responses were insufficient.

In addition, in order to facilitate Staff's understanding of these responses, the Company held two conference calls with Staff and the Company's consultants – each several hours long – in order to provide Staff further information on its Programs.

Some of this information had already been provided through discovery responses previously provided to Staff.

Approval of the Company's Programs

Residential HVAC Program: The Company requests that Staff complete its review of the information that the Company has already provided regarding the cost effectiveness of its Residential HVAC Program and, to the extent Staff needs more details from the Company to complete its analysis, the Company requests that Staff clarify in a timely manner the precise information that it requires. Additionally, that review should be undertaken with the territory specific avoided cost information underlying the Company's Market Potential Study and the design of its programs. Staff has not supported the use of generic upstate/downstate avoided costs for use by the Company.

Small C&I Direct Install Program: As noted in Staff's Initial Comments, O&R can implement a cost effective Small C&I Direct Install Program on the $7.6 million allocated to it in the EEPS Order. What it cannot do is meet the Commission-dictated energy savings' goals utilizing that budget. Missing those goals will not adequately advance the mission of achieving energy savings of 15% by 2015 and will risk penalties for the Company under the Commission's Order Concerning Utility Financial Incentives issued and effective August 22, 2008 (:Incentive Order"). Both results are untenable. Either the Company's Fast Track goal needs to be reduced, or the Company should be allocated the additional funding required to meet the goal. Since this additional funding is dedicated exclusively to the installation of new energy efficiency measures, the Company proposes the latter. It is important to provide the

Company with adequate funding for its fast track programs so that it can begin effectuating the necessary energy efficiency benefits for its customers.

Other Policy Issues

Statewide Residential HVAC Program

In addition to the Company-specific comments, Staff also provides the general recommendation that the same program attributes be offered by each utility statewide for the Residential HVAC Program. While O&R notes that its Program was designed utilizing service territory-specific information that was ascertained from its recently completed Market Potential Study, the Company is nevertheless agreeable to exploring with the other utilities the extent to which its program design can be revised to result in a more uniform approach to be implemented statewide.

However, O&R does not want any such review to delay approval of any of the fast track programs submitted by various program administrators. Such delay would only postpone the acquisition of the necessary inventory of energy efficient equipment by trade allies. The need for immediate energy efficiency programs was recognized by the Commission in the EEPS Order. As such, to the extent uniform approaches can eventually be identified they should be implemented and used to modify any programs approved as part of the overall EEPS proceeding.

Information for Implementation Plans

Staff claims that O&R has not "developed a contractor training and program orientation plan" and should provide those details in its implementation plan (Staff's Initial Comments at 11). Staff also requests that O&R should provide the following in its implementation plan details about its Quality Assurance plan (Staff's Initial Comments at 11);

- details of coordination of program activities with other parties (Staff's Initial Comments at 11) and;
- details of how it will coordinate program delivery with other entities to make customers aware of all programs for which they are eligible, avoid double counting of program savings achieved, and avoid duplicative rebates to customers for installing the same measures (Staff's Initial Comments at 12).

O&R is committed to filing an implementation plan. The implementation plan, however, awaits approval of programs to be implemented. The same is true for quality assurance programs, contractor training programs and other post program approval activities. It is not cost effective or reasonable to expect any prospective program-administrator to develop such supporting documentation without knowing the programs, budgets and targets to which such documentation would apply. In addition, since the implementation plans will be developed in conjunction with outside vendors, the Company needs the actual program information in order to develop the appropriate requests for proposals.

Operational and Reporting Concerns

Staff has proposed additional reporting requirements that are unnecessary. Staff has also proposed numerous restrictions that will limit the flexibility of program administrators to respond to changing market conditions and run their programs as they see fit. These rigid requirements are not consistent with the Commission's goal of supporting competitive and diverse energy efficiency programs.

Such detailed oversight is unnecessary given that the Company has proposed ambitious targets and faces incentives and penalties for meeting or failing to meet those targets. This structure is an integral component of the Commission's Incentives Order. In this Order the Commission clearly states that utilities must face a balanced risk and structured the incentives available for energy efficiency so that poor performance will subject the utilities to "negative incentives" (Incentives Order page 41). By adding layers of approval and mandates and restricting the Company's ability to modify its programs in response to evaluations and the market, Staff changes the risk equation and imposes more risk on the Company. It is simply unreasonable to put the utility program administrators at risk for penalties while denying them the ability to make basic business decisions to administer their programs.

Budget Allocations and Expense Tracking

Staff proposes that any utility proposal for changes to approved program budgets, eligible energy efficiency measures, or customer rebates be submitted to Staff for review and comment 90 days prior to implementation (Staff's Initial Comments at 28). Staff review is unnecessary and unduly burdensome. The utilities are responsible for running the programs and meeting established goals. The utilities are subject to penalties for failure to make those goals. The proposed process will hinder the Company's flexibility and ability to make changes quickly when needed to improve the performance of the Company's programs and achieve the proposed goals. Most companies would be unlikely to embark on new businesses under such restrictive circumstances.

Staff also proposes that budget reallocations of more than 10% from the total approved annual budget be subject to Commission approval (*Id.*). Again, the need to address changing market circumstances (particularly in the current market climate in which conditions have declined dramatically since budgets were proposed in August and September) and provide innovative programs is inconsistent with this type of oversight. The potential delay that this structure will impose is unreasonable and will slow the delivery and of energy efficiency programs and thus savings to be achieved by such programs. For example, O&R may want to make program funding changes to address an unforeseen seasonal circumstance and yet the season will pass before review and approval can be completed. This delay could also result in efforts coming to a halt – such as when allocated funds for one program become fully expended. Programs need continuity in order to be successful, and this continuity may be achieved by shifting funds from one program to another. The potential for delay combined with the "no borrowing or banking" criteria stated by the Commission in its Incentives Order, substantially changes the risks utilities faced under the EEPS Order.

Staff also noted it is concerned that determining whether "internal costs charged to a utility's energy efficiency program are truly incremental to the base rate expense allowances, and thus recoverable through a separate SBC surcharge, is very difficult, if not impossible, to prove" (Staff's Initial Comments at 3). The Company believes that all costs related to efficiency programs can be adequately tracked through the use of accounts designed to track the various activities that will comprise programs. As it did during its Power Partners Program, the Company will develop accounts adequate for that purpose.

Monthly Scorecard

In addition to reports on a quarterly and annual basis as required by the order (EEPS Order at 73), Staff is recommending an additional monthly "scorecard report" from all program administrators (Staff's Initial Comments at 30). O&R supports uniform reporting of results and uniform, full public reporting by all entities receiving ratepayer funding. Staff has recommended, and O&R agrees, that quarterly reports be submitted within 45 days of the end of the quarter and its annual report within 60 days of the end of the year.

O&R does not, however, support the additional requirement of monthly reporting. Monthly reporting will not materially add to public understanding of the program spending or achievements but will create additional burdens, increase the complexity of the reporting function and thus add costs to the programs. The Company does not expect large changes in program information on a month over month basis, particularly during start up. Producing reports that do not provide meaningful information is unduly burdensome.

Audit Fee

Staff has recommended that each utility establish a customer energy audit fee of $50 for the small business program (Staff's Initial Comments at 24). The Company disagrees.

As was noted in the EEPS Order (Appendix 1, page 2), the small business direct install effort in New York is currently very small. The small business segment is a difficult segment to reach. As the Company noted in its filing, the market barriers to addressing this segment include time constraints on business owners (60-Day Filing at p. 14). In addition, declining economic conditions may serve as another barrier to reaching this hard to reach market. Requiring an audit fee will only act as another barrier to entry for small businesses that are looking, possibly for the first time, at energy efficiency.

While the audit may not result in a small business customer undertaking a costly efficiency project in every instance, the free audit will produce good will. The Company believes that quick, broad penetration of the small business market is critical for success, particularly in this economic climate and an audit fee will hamper that penetration.

Joint Administration

Con Edison and Orange and Rockland Utilities, Inc. will coordinate the Request For Proposal(s) (RFP) process for implementation, technical and administrative contractor services in the delivery of the energy efficiency programs outlined in each Company's Energy Efficiency Portfolio Standard (EEPS) filings. The determination of whether to issue a joint RFP remains under review.

At this juncture, the RFP will specify a full range of tasks across multiple program specific areas. The RFP will address marketing requirements, education, trade ally outreach and support services, incentive review and processing services including payments. Program-specific promotional activities will also capture trade ally and local work force recruitment and training, responses to customer inquiries, call center responsibility, energy assessments/advice, rebate applications, payment processing and referrals to corresponding programs or parallel service suppliers such as NYSERDA, NYSEG, Central Hudson, and National Grid NY.

Since the RFP remains a work in progress, additional program tasks and items will be added or eliminated as the Companies evaluate and determine the final set of contractor requirements.

Technical Appendix

As part of Staff's Initial Comments, Staff informed O&R (and other utilities) that Staff had "requested that the independent consultant providing EEPS related evaluation advisory service to Staff (TecMarket Works), develop a technical manual illustrating standardized approaches, calculations and assumptions for program administrators to estimate Fast track program energy savings at the measure level" (Staff's Initial Comments at 24).

O&R believes that the proposed assumptions in Appendix A should be considered preliminary and should not be used pending more rigorous analysis by experts. O&R generally supports the development and adoption of a standard set of methods and assumptions for calculation of savings from various measures by New York utilities. However, the final adoption of such standards by the Commission should be subject to a public review process before they are adopted.

Conclusion

The Commission has established aggressive, but obtainable, goals for energy-efficiency programs to be implemented in New York. These goals are worthy and O&R is committed to assisting the State meet these goals.

O&R can run a cost effective Small C&I Direct Install Program and a Residential HVAC Program with the funding allocated to it in the June 23, 2008, Order. What it cannot do is meet the dictated goals utilizing that budget. However, the combination of

O&R's programs in the 60-Day Filing and the 90-Day Filing allow the Company to meet the energy savings goals within the total budget allocated to the Company.

Therefore, O&R respectfully requests that the Commission approve its program filing, including the request for increased funding, so that the Company can start bringing cost-effective energy efficiency benefits to its customers.

New York, New York
November 24, 2008

Respectfully submitted,

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ATTACHMENT A – AVOIDED COST METHODOLOGY

AVOIDED ENERGY COSTS

Flat Wholesale Block Prices

Our projection of avoided energy costs started with the April 11, 2008 NYMEX forwards for wholesale blocks of on-peak and off-peak power in Zone G, the NYISO zone that includes O&R. Zone G forwards in April 2008, NYMEX was reporting forward prices for the rest of 2008, 2009, 2010 (off-peak only) and 2011. We estimated the 2010 Zone G on-peak forward as

the Zone A on-peak 2010 forward price

times

the ratio of Zone G to Zone A on-peak forward prices for 2009 (1.322).[1]

After 2011, we assumed that avoided energy costs would be constant in real terms. While some factors suggest that energy prices may decline (Henry Hub gas futures decline slightly after 2011; renewables, transmission from PJM, and a few combined-cycle plants will add lower-cost energy to the mix), other factors suggest that prices may rise (some older coal—and perhaps oil—plants are likely to be retired or derated due to environmental constraints; carbon allowances will drive up dispatch costs and market prices; Ontario's retirement of its coal plants will reduce its exports and increase its imports), and still others are ambiguous (costs of delivering gas to New York may rise or fall).

For each forecast year, we computed the average annual price for flat, around-the-clock wholesale energy blocks (46.5% on-peak energy, 53.5% off-peak).

AVOIDED RETAIL COSTS BY PERIOD

The average annual flat price would be the appropriate avoided energy cost for a measure that reduced load by the same amount in every hour of the year. Most measures have effects much different from a flat block reduction, both because they have different load reductions in various seasons and times of day and because usage varies within each time period, as a function of weather and other factors. We therefore computed a load-weighted price in each of O&R's six pricing periods:

Summer peak: June–August weekdays 12 pm to 6 pm

[1] The corresponding ratio for 2011 was essentially the same, at 1.321.

Summer off-peak:	June–August weekdays midnight 8 AM June–August weekend, all hours May, September and October, all hours
Summer shoulder:	June–August weekdays 8 AM to noon, 6 PM to midnight
Winter peak:	December–February weekdays, noon to 8 PM
Winter off-peak:	December–February weekdays, midnight to 8 AM December–February, all weekend hours March, April, and November, all hours
Winter shoulder:	December–February weekdays 8 AM to noon, 8 PM to midnight

To convert the average annual flat price to the load-weighted price in each of O&R's pricing periods, we computed the ratio of the load-weighted average price in each of the corresponding periods in the latest available one-year period, March 2007 through February 2008 to the flat average in the same one-year period.[2] The load-weighted price for each pricing period is:

$$\frac{\sum\limits_{\text{hrs in period}} MW_{hr} \times DA\ LMP_{hr}}{\sum\limits_{hrs} MW_{hr}}$$

where the MW load and day-ahead LMP are both for Zone G.

The prices and the ratios to the flat, forward-based wholesale prices are:

	Average Price	Ratio to Annual Flat
Summer Peak	$108.47	1.461
Summer Off-Peak	$65.95	0.888
Summer Shoulder	$78.88	1.062
Winter Peak	$99.24	1.336
Winter Off-Peak	$75.64	1.018
Winter Shoulder	$101.22	1.363
Annual Flat	$74.27	

AVOIDED GENERATION CAPACITY COSTS

The NY-ISO capacity prices are set by a series of auctions:

[2] We considered extending the analysis further back, but the previous year had very unusual winter weather, which would likely produce anomalous results.

- A six-month strip acquired in April for the summer (May-October) and in October for the winter (November–April).
- Auctions for each month, from the month prior to the start of the season to the month prior to the delivery month.[3]
- A spot auction for each month, conducted in the preceding month.

The price in the spot auction is set by the demand curve, which reduces the capacity price as the reserve margin rises. Load-serving entities must provide capacity throughout the year, based on their contribution to the previous summer's peak (adjusted for migration) plus the reserve margin implied by the spot auction.

O&R's service territory is entirely in the rest-of-state (ROS) capacity zone, which is the entire state other than New York City and Long Island.

In principle, knowing the current demand-curve parameters, the proposed parameters for the next three-year period (2008–2011) and forecasted loads and additions, we should be able to forecast the ROS capacity price. As the statewide reserve margin declines, the capacity price should rise until it is high enough to support new entry, and then bounce around that price as generation is added, plants are retired, load grows, etc.

This simple picture is complicated by a number of factors:

- The demand curve for ROS capacity uses total New York Control Area (NYCA) load and capacity, so addition of capacity downstate can affect prices upstate. Con Edison, NYPA and LIPA have all built and contracted for generation capacity and transmission connections that the market did not provide, and NYPA and LIPA continue to pursue capacity additions.
  - The market power of the three owners of former Con Edison generation in NYC (KeySpan, Reliant and NRG) have caused them to withhold enough capacity from the market to maintain their maximum allowed prices for in-City capacity.
  - A new capacity-price mitigation scheme has been accepted by FERC, which would require the pivotal in-City generators to bid at lower prices, likely resulting in more capacity clearing in New York City.
  - It is not clear how much capacity LIPA will bring into NYCA, and whether that capacity will continue to depress ROS capacity prices.

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[3] So there is only one monthly auction for May and November capacity, while there are six for October and April.

- Generators outside New York (in PJM, New England, Ontario, and Quebec) can export capacity to the ROS market, while New York generators can export capacity to PJM and New England. NYISO does not appear to report the amount of imports that clear in the capacity auctions, or the amount of capacity withdrawn from the NYISO market for export.

Recent ROS capacity prices have been somewhat less than would be implied by the demand curve with only the capacity in NYCA and net firm contract imports, suggesting that NYISO has been a net purchaser of capacity. This situation appears to be changing, as capacity prices rise in the new forward markets in both PJM and ISO-NE.[4] For 2007–2008, ROS capacity prices were about $30/kW-yr, while the capacity price in neighboring portions of PJM was under $15/kW-yr and in ISO-NE the capacity price was $36.60.

The reserve margin required by NYISO depends on the quantity of capacity included in the determination of the capacity price under the demand curve. The difference between winter and summer capacity also increases the average reserve margin over the year. In 2007 the required reserve margins (the UCAP requirement divided by the summer peak load) were 11.3% in summer and 10.1% in winter. In addition, the NYCA spot auctions produced an average excess of 2,551 MW (7.6% of load) in summer 2007 and 3,257 MW (9.7% of load) in winter 2007/08, for total reserves of 18.9% in the summer and 19.8% in the winter. Including reserves, the total ROS UCAP capacity price to load in 2007/08 was $35.58/kW-year. Under the current demand curves, the ISO's target (or "reference") annual UCAP price would be $86.52/kW-yr (six summer months at $9.09/kW-month and six winter months at $5.33/kW-month) would be reached with an average reserve margin of about 10.8%. That reference price is based on an estimate of the cost of new entry in 2015, by which time New York is expected to need of new capacity.[5] The capacity price that would be charged to load is the reference price increased by the reserve margin, i.e., $86.52×1.108, or $100.80/kW-yr.

Our forecast of capacity prices charged to load, i.e. increased for reserves, expressed in $2007, is a linear interpolation of capacity prices in ROS, staring from the actual price in 2007 ($35.58 per kW-yr) and ending with the ROS reference price in 2015 ($102.15 per kW-yr). After 2015 we hold the price constant.

The following table compares our projection of ROS prices to actual capacity prices determined by rule or forward auction for PJM and ISO-NE and to the projection developed by the DPS for the Energy-Efficiency Portfolio Standard docket, Case 07-M-0548.[6] The actual capacity prices are UCAP capacity prices for PJM and ISO-NE,

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[4] In the February 2008 ISO-NE forward capacity auction, 641 MW of New York capacity was accepted.

[5] The 2008–2011 demand curves increase the ROS reference price by about 25%.

[6] DPS projection from *E&G LRACs new MAPS energy Master.xls*, provided by Steven Keller in Case 7-M-0548, 4/4/08, increased 2.1% for inflation from 2007 to 2008, about 5% for UCAP and by annual reserve.

deflated to 2008 dollars at 2.5% and with our projected ROS reserve margins. Our projection appears reasonable relative to the prices in the neighboring markets, and is very close to the DPS's projection.

Comparison of Forward Capacity Prices and Projections (2008$, including NYISO reserve margin)

Year beginning	PJM	ISO-NE	Our ROS Projection	DPS ROS Projection
2007			$35.58	$38.10
2008	$45.76	$52.40	$43.73	$44.32
2009	$77.09	$55.86	$51.88	$51.47
2010	$70.88	$56.25	$60.03	$59.79
2011			$68.19	$69.50
2012			$76.34	$80.67
2013			$84.49	$93.68
2014			$92.64	$108.84
2015			$100.80	$108.84

Avoided T&D Costs

Transmission

O&R was not able to provide us with any information on marginal or avoided transmission costs. An application of traditional historical marginal-costing methods (based on the NARUC Cost Allocation Manual) found negative incremental transmission investment the last decade, suggesting that O&R's investment was not even sufficient to replace retired plant in that period. O&R did inform us that it was generally in a period of catch-up in T&D investment, which would be consistent with our results.

Distribution

We estimated avoided distribution costs using the historical method described in the NARUC Cost Allocation Manual, starting with FERC Form 1 data on annual additions and retirements for 1997 through 2006. We included as load-related 100% of additions of substation equipment and 75% of other distribution plant (FERC accounts 360, 361, 364–368), excluding services, meters, installations on customer premises, and streetlighting. We assumed that each dollar of retired plant was replaced with three dollars of additions.

The net additions, converted to 2006 dollars and divided by 331 MW of load growth from 1997 to 2006, averaged $312/kW-yr.[7] At an 11.21% real-levelized economic carrying

[7] Orange and Rockland Utilities System Peak Loads (1980 - present). Brian Daly. O&R Energy Management, 01/14/08

charge, that would be $41/kW-yr. In addition, O&R had average T&D O&M of about $22/kW-year, for a total of $63/kW-year in 2006 dollars or about $66/kW-year in 2008 dollars.

In addition, O&R informed us that its distribution investments through 2006 did not include all the plant required by load growth in that period. O&R identified a total of $87.7 million in distribution substation investment expected to enter service in 2008–2012 that was needed to meet load distribution load-related criteria before 2006 (including $20.1 million required for feeder relief), and another $21.9 million of distribution substations required by transmission reliability constraints.[8] We do not have data on additions in 2007, but some deferred projects may have entered service in that year. The $87.7 million in deferred substation investment adds about $265/kW (or about $29/kW-year) to the cost of meeting the 1997–2006 load growth, bringing the total to $92/kW-year. Deferrals to 2007 and transmission-related substation projects might add to this total, as would any associated delayed feeders.[9]

The DPS avoided costs cited above included $55/kW-year (in 2007 dollars, or $56/kW-year in 2008 dollars) of avoided T&D costs upstate.

We used avoided distribution costs of $65/kW-year in our analysis.

LOSSES

There is a loss of electricity between the generating unit and the ISO's delivery points, where power is delivered from the ISO-administered pool transmission facilities (PTF) to O&R's local transmission and distribution systems. There are also losses on the O&R system. Therefore, a 1 kilowatt load reduction by a customer at the point of end use reduces the quantity of electricity that a generator has to produce by 1 kilowatt plus the additional quantity it would have had to generate to compensate for losses.

We calculated full losses from generator to end use at peak. We add those losses to the capacity price, which is stated in dollars per kilowatt-year at the generator, to obtain an avoided capacity cost at point of end-use. We also calculate losses from the transmission system to end use by energy pricing period. We add those losses to the energy prices, which are stated in $/MWh at the ISO delivery point, to obtain avoided energy prices at point of end-use. (The energy prices traded on the wholesale market reflect the losses between the generating unit and the ISO delivery points into the O&R system.)

For calculating the avoided cost of capacity we use average losses from the generator to the end use. For calculating the avoided cost of energy we use marginal losses from

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[8] 2008-2012 Budget—Substations and associated spreadsheets provided February 27 and 28, 2007.

[9] Load reductions in 2008–2012 may be even more valuable, in that they will reduce loads on already overloaded substations and improve reliability.

the ISO delivery point to the end use. The rationale for using average losses for capacity is that reducing peak load will generally result in reduced T&D investment, which may well keep average peak losses constant as a percentage of peak load. For energy, on the other hand, changes in power flows do not usually result in changes to the T&D system. For a fixed system, with a fixed resistance, variable line losses vary roughly as the square of load, since the power dissipated in the lines varies with the square of current. In other words,

$W = I^2 \times R$, where

W is the energy released,

I is the current (which varies with load), and

R is the resistance

Thus, average percentage losses (loss ÷ load, or $I^2R \div I = IR$) varies roughly linearly with load, but the marginal change in losses with a change in load is the derivative of I^2R, or $2 \cdot IR$. Thus, marginal losses are about twice average losses at any given load level.

We started with the 7.987% average energy loss factor to secondary reported by O&R in its "Retail Access Implementation Plan and Operating Procedure," February 18, 2004. While some customers are metered at higher voltages, essentially all energy use and all energy conservation occurs at the secondary level. We did not include losses from the meter to the end use.

We assumed that 2% of these losses are due to fixed transformer losses, leaving 1.07987 ÷ 1.02 = 5.87% variable losses at average load. We then estimated the variable losses in each energy pricing period by multiplying the 5.87% average variable losses by the ratio of average load in the energy pricing period by the average annual load, using Zone G data for March 2007 through February 2008. We estimated the marginal energy losses as twice the variable losses for the same period.

	Average load as % annual average	Variable	Marginal
Annual Average		5.9%	
Summer Peak	1.392	8.2%	16.3%
Summer Off-Peak	0.951	5.6%	11.2%
Summer Shoulder	1.247	7.3%	14.6%
Winter Peak	1.084	6.4%	12.7%
Winter Off-Peak	0.926	5.4%	10.9%
Winter Shoulder	1.095	6.4%	12.9%
Peak Hour	1.838	10.8%	

For peak hour average losses, we added back fixed losses. Since we assumed that the fixed losses were 2% of average load, they would be about 1.1% of peak load, resulting to total average peak losses of 11.9%.

While the wholesale energy costs are expressed for energy delivered to O&R's take points from the NYISO-administered transmission system, generation capacity costs are stated at the generator. We add in the 2.6% losses on NYISO transmission in the O&R zone.[10]

[10] "2007 Weather Normalization," Forecasting Task Force, December 18, 2007, Arthur Maniaci, System & Resource Planning, NY ISO.