New York Power Authority

January 2003 Report on

Hydroelectric Production Rates

Rate Modification Plan

Appendix B

April 2003

NEW YORK POWER AUTHORITY

Report on Hydroelectric Production Rates

Rate Modification Plan

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Executive Summary

At the December 18, 2001 meeting, the Trustees directed the Staff to propose new preference power rates. The directive came as a result of the conclusion of the *Bergen* litigation.[1] The litigants in *Bergen* contested the Authority's functionalization and allocation of Indirect/Overhead costs using the labor-capacity method. The courts ruled in favor of the plaintiffs' preferred labor-labor method (labor ratios). Complying with the ruling, the Trustees directed the Controller to "…employ an indirect allocation methodology for the hydroelectric preference power customers based on labor ratios…"

The Trustees acknowledged that preference power rates were set last in 1992 and recognized that "there have been significant changes in the Authority's business and hydroelectric cost structure since 1992…". Specifically, they mentioned $220 million invested in plant modernization at Niagara and St. Lawrence and $33 million in St. Lawrence relicensing. These capital investments and relicensing expenditures will continue well into the next decade when the St. Lawrence upgrade and Niagara upgrade and relicensing will be completed.

The Trustees directed Staff to incorporate the change in allocation methodologies and investments in the plants since 1992 and to do the following:

1) make the current energy rate of $4.92/MW-hour an interim rate, subject to refund or surcharge, based upon the results of item 2;

2) calculate a new cost-based rate retroactive to December 18, 2001 based on a test-year period from October 1, 2001 to September 30, 2002 using a labor ratio methodology;

3) make a recommendation for future preference rates; and

4) seek public comment on the rate proposal from interested parties.

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[1] *Village of Bergen, et al. v. Power Authority of the State of New York,* 284 A.D.2d 976, 726 N.Y.S.2d 902 (4th Dep't), *reargument denied,* 731 N.Y.S.2d 136 (4th Dep't), *lv. to app. denied,* 97 N.Y.2d 606, 738 N.Y.S.2d 289 (2001) (*Bergen*).

Staff retained The Brattle Group (Brattle) to provide analysis in developing a test year and future rate proposal. Brattle is a recognized expert on capital cost recovery and has prepared a report on the recovery of debt and equity investments. The Brattle Group's proposal incorporates capital charges that maintain the Authority's financial integrity.

The Staff also asked Brattle to develop a rate that excludes the cost of producing generation-based ancillary services from the preference power rate. Under New York's 1999 electric market restructuring, the New York Independent System Operator (NYISO) is now the sole provider of these ancillary services to Load Serving Entities (LSEs), and the Authority cannot now provide them to customers. The costs for these services were previously bundled in customers' prices. The Brattle Group's goal was to determine the costs of producing these services so that such costs can be removed from the cost of service study.

Based on these major components -- use of labor ratios for functionalization and allocation, the recovery of increased capital investment and the exclusion of certain ancillary services costs -- the Staff has proposed a refund of $4.4 million for the retroactive rate period from December 18, 2001 through April 30, 2003 (Interim Rate Period). For the four years subsequent to the Interim Rate Period beginning on May 1, 2003 and ending with the rate year beginning May 1, 2006, Staff proposes also to implement the accrual of employee postretirement benefits and to redesign the preference rates to collect all of the rate increase in the demand charge. Staff chose to exclude from the Test Year the costs attributable to the accrual of employee postretirement benefits and the modified rate design.

For the Interim Rate Period, the new billed demand and energy rates will be $1.00/kW-month and $4.59/MW-hour, respectively. For the four subsequent years, Staff proposes base rates as summarized in the table below. Each rate year runs from May 1 to April 30 of the following year.

Rate Year [2]	Demand Rate $/kW-month	Energy Rate $/MW-hour	Effective Rate[3] $/MW-hour	% Change
2003	$1.45	$4.92	$7.76	13%
2004	1.71	4.92	8.27	7
2005	2.10	4.92	9.02	9
2006	2.39	4.92	9.59	6

[2] Runs from May 1 of the calendar year indicated to April 30 of the following year.

[3] Effective rate at 70% load factor.

Report on Hydroelectric Production Rates

Rate Modification Plan

Description of Facilities and Customers

The Authority owns and operates two large hydroelectric plants, the Niagara Project, a 2,400 MW combined pump-storage and run-of-river facility on the Niagara River near the City of Niagara Falls, New York and the St. Lawrence-FDR Project, an 800 MW run-of-river facility located near the Town of Massena, New York (collectively referred to as the Hydro Facilities). The Hydro Facilities serve three investor-owned utilities (IOUs), 47 municipal electric systems, four rural electric cooperatives (the municipals and cooperatives are jointly known as M&C customers), seven Neighboring State customers, three direct service industrial customers and two regional transportation authorities. The investor-owned utilities purchase power and energy from the Hydro Facilities for their residential customer class, industrial customers specified by the Authority and for general system use. The M&C customers can be grouped into full requirements M&C customers who purchase all their system requirements from the Authority, and partial requirements M&C customers who purchase just their hydro allocations from the Authority and obtain the remainder of their system requirements from other sources. The rates at issue (Rural and Domestic or R&D Rates) apply to the residential customers of the IOUs, the Neighboring State customers and the M&C customers (collectively referred to as R&D Customers).

Rate History

Historically, the R&D Rates were based on the production costs of the Hydro Facilities. In developing the initial rate in the late 1950's, the Authority chose not to allocate production costs into demand or energy classifications, nor did it allocate these costs to the various customer classes. The demand charge was set at $1.00/kW-month and costs in excess of the demand charge were recovered through an energy rate.

Initial Rate (1958-1981): The initial R&D Rates went into effect in 1958 with the start of commercial service at the St. Lawrence Project. The R&D Rates were set at $1.00/kW-month and $2.67/MW-hour. These rates were extended to the Niagara Project when it began service in 1961. The Authority retired the St. Lawrence and Niagara Project bonds by year-end 1981. Following the retirements, the Staff conducted a review of the R&D Rates.

1983 Rate Report: In April 1983, Staff issued a report recommending that the energy part of the R&D Rate be reduced from $2.67/MW-hour to $2.05/MW-hour, retroactive to January 1, 1982. The test period covered the 1982-1983 calendar years. The report stated that capital costs still exist for the Hydro Facilities even though debt has been retired and provided an estimate of the net plant value predicated on a study by the Authority's outside consultants. The report advocated using the Trended Original Cost (TOC) method for capital cost recovery. As implemented by the Authority, the TOC method involved a return of capital through the depreciation expense indexed by inflation. However, it did not include a real return, that is, a return *on* capital.

The Trustees adopted the Staff recommended R&D Rates in July 1983. Thereafter, various parties initiated a total of three separate legal actions seeking additional rate reductions. In March 1986, the Authority and these parties negotiated the *Auer* Settlement[4] under which the Authority agreed (a) that the R&D Rate cost of service would not include expenses associated with the debt service for certain non-hydroelectric projects, and (b) to refund to the parties that portion of the rates that had included debt service for the cancelled Greene County and Arthur Kill plants. In return, the parties seeking additional rate reductions would drop their legal actions against the Authority.

The *Auer* Settlement states that, "Broad discretion is given to the Authority to determine the components of its costs, and it is not required to guarantee any specific rate." It may include a reasonable charge for depreciation, which exercise of business accounting principles would allow. Under the *Auer* Settlement, Authority may collect

[4] Stipulation Discontinuing Action With Prejudice, *Martin S. Auer, et al. v. Power Authority of the State of New York,* No. 11999-84 (Sup. Ct. N.Y. Co. Mar. 5, 1986).

depreciation and an inflation component on its investment, but not a real return above inflation.

The *Auer* Settlement also states that once the preference rate is set, any excess revenues can flow to the Authority's general fund. Specifically, the settlement provides: "If there are still excess revenues, there is no statutory prohibition which would prevent the transfer of such revenues to the general fund." Pursuant to the settlement, the Trustees adopted a further energy rate reduction of $0.34/MW-hour to $1.71/MW-hour retroactive to January 1, 1982.

1987-1991 Period: In December 1986, the Staff proposed a multi-year rate increase for the 1987-1991 period. After receiving customer input, the Trustees adopted a modified rate proposal on April 28, 1987. The Staff subsequently issued a Final Staff Report in May 1987. The R&D Rates adopted by the Trustees included a number of methodologies that continue to be employed, including: (a) the use of long-term average river flows to estimate generation levels when setting the energy portion of the R&D Rates; (b) creation of the Revenue Stabilization Reserve (RSR) which tracks and accumulates annual differences in actual costs and revenues; and (c) definition of the Rate Year as being from May 1 to April 30. The energy rates approved for the 1987-1991 period went from $1.99/MW-hour in the first rate year to $3.34/MW-hour in the last rate year of the five-year plan.

Current Rate Methodology

The current rates were established in 1992 through a rulemaking process. In February 1992, Staff issued its Preliminary Staff Report which proposed setting the 1992-1995 R&D Rates. After receiving customer input, in May 1992 the Trustees approved lower R&D rates than had been proposed by Staff. A Final Staff Report was subsequently issued in June 1992. The adopted R&D Rates:

a) continued the then-current rate treatment of Indirect/Overhead expenses by functionalizing these costs between production and transmission using labor ratios and then allocating costs among the production facilities using capacity ratios;

b) adopted rates which remained below cost in the first three years and would only phase-in to a cost-based rate in the final rate year;

c) continued the use of long-term flows and generation when setting the energy portion of the R&D Rates; and

d) included a 15-year amortization of roadwork expenses incurred at the Niagara Project to minimize rate impact.

The Final Staff Report stated that in the event the RSR balance became positive (*i.e.* indicating over-recovery), the next rate phase-in would be suspended. (For year-end 1991, the balance was negative $6 million which showed under-recovery.) In April 1995, the RSR balance was calculated and showed a cumulative positive $2.8 million balance ending December 31, 1994. At their May 23, 1995 meeting, the Trustees suspended the rate change scheduled for May 1, 1995. The energy rate in effect as of April 30, 1994 of $4.92/MW-hour remains in effect today.

Test Year and Forecast Years

For the purposes of this study, the Test Year is the twelve months beginning October 1, 2001 and ending September 30, 2002. As noted above, the rates for the Interim Rate Period (December 18, 2001-April 30, 2003) will be subject to refund or surcharge. The Test Year is used to determine whether a refund or surcharge is needed for the Interim Rate Period; it is not used for development of the rates for the 2003 to 2006 rate years.

For the future rate periods, the calendar years (CY) 2003, 2004, 2005 and 2006 are used as projected test years, or “Forecast Years.” For example, the rate proposed for the Rate Year ending April 30, 2004 uses the 2003 calendar year as the Forecast Year. While the Test Year data reflects actual energy generation from the Hydro Facilities long-term average water flows were assumed for determining the energy generation levels for the Forecast Years. The Test Year also included capital improvement costs associated with the generator upgrades at both Hydro Facilities. These costs were also included in each of the Forecast Years as well to reflect the amount of upgrade costs that will be incurred each year through the 2006 Forecast Year.

Rate Issues Addressed in Cost-of-Service Study

Capital Program and Capital Cost Recovery

New Capital Costs at the Hydro Facilities: The Authority is engaged in a multi-year modernization program at both the Niagara and St. Lawrence-FDR Projects involving overhaul and replacement of major plant equipment. In addition, the Authority is in the midst of a Federal Energy Regulatory Commission (FERC) relicensing process for the St. Lawrence-FDR Project and is beginning the relicensing process for the Niagara Project.

At the Robert Moses Niagara plant (the run-of-river part of the Niagara Project), the Authority initiated a modernization program that resulted in the installation of an upgraded prototype turbine and generator modifications in 1993. The modernization program consists of replacement of the existing turbine and step-up transformer for each of the thirteen generators, modifications to the existing generator equipment and associated equipment replacement or modification. The modernization is being done one unit per year to minimize loss of output and is scheduled to be completed by 2006. As of October 31, 2002, $209.4 million was spent on modernizing these units at Niagara. To date, the Authority has modified nine of thirteen units. An additional $85.5 million is expected to be spent at Niagara through 2006. Additional capital projects included in the estimate for these years are generator stator rewinding and control system automation.

The FERC license for the Niagara Project will expire August 2007. Relicensing costs are a capital expense of the project and the Authority has spent $20.5 million on administrative activities related to relicensing through October 31, 2002. The Authority has budgeted an additional $55.8 million for relicensing-related activities through 2006. Administrative costs include consultant fees for the Initial Stage Consultation Document, which will provide essential information about the Niagara Project, as well as legal fees.

For the St. Lawrence-FDR Project, the Authority began a Life Extension and Modernization (LEM) program in 1998 that will continue until 2013. The LEM program involves replacement of turbines and transformers for sixteen generator units, replacement of breakers and control equipment among other items. Through October 31, 2002, a total of $54.2 million has been spent on the LEM. The Authority has budgeted an additional $78.8 million for LEM work through 2006. Other expected capital improvements at St. Lawrence include an upgrade of security (*i.e.* installation of access control equipment, fencing, security cameras, and a new visitor center) and for control system automation, communication systems and switchyard upgrades.

As with the Niagara Project relicensing activities, the Authority is capitalizing the costs associated with St. Lawrence-FDR Project relicensing. The Authority has spent $39.5 million on relicensing activities through the end of October 2002. Through 2006, additional St. Lawrence relicensing costs are budgeted at $76.8 million. These costs include both administrative (or "process") costs and compliance costs. Process costs consist of engineering and environmental studies by Staff in support of the relicensing activities. Compliance costs involve payments to affected communities, fish enhancement and mitigation payments and payments to a Habitat Improvement Fund among other payments. Compliance costs are a capital cost because the Authority has made certain commitments as part of its St. Lawrence relicensing application which was filed at FERC in 2001.

The capital costs for St. Lawrence relicensing do not include the anticipated expenditures associated with the proposed St. Lawrence Aquarium and Ecological Center, due to the uncertain timing of such expenditures. Such costs will be included in the cost of service in the future. Also excluded are potential settlement costs related to the Mohawk Nation's land claims.[5]

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[5] For the Niagara Project, Staff did not include relicensing compliance costs because the Authority has not yet filed its FERC relicensing application and such costs are unknown at this time.

Capital Cost Recovery: When the Authority initially built the Hydro Facilities, the initial rates were set to recover debt service, reserves, and operation and maintenance expenses. Normally, utility rates are set using Original Cost or OC methodology. Under OC, an asset or group of assets is depreciated over their useful lives on a straight-line basis (return of capital) and a return on capital is applied to the remaining value of the asset(s). This results in a cash flow pattern that is highest at the beginning of the asset life and decreases to zero at the end of the asset life. This cash flow pattern is a close match to the cash flow required for debt financing. The return on capital is comprised of an inflation compensation component and a real return component. The inflation compensation component compensates investors for the expected loss of purchasing power over time. The real return component is the return above inflation that investors require predicated on their perception of the risk level of the investment and alternative investments available.

With the repayment of the original hydro bonds in 1982, the Authority (as discussed earlier) adopted a version of the Trended Original Cost or TOC method. Under the TOC method adopted by the Authority, straight-line depreciation is charged, but the depreciation charge is increased for inflation and the capital account is increased by an inflation factor. However, the Authority does not collect a return *on* its capital investment, *i.e.* it does not receive a real rate of return on its capital. The Authority made this method part of the *Auer* Settlement.

Compared to the OC methodology, the *Auer* TOC methodology defers capital cost recovery to the later years of the asset life. The *Auer* TOC method is applied only to that portion of the Hydro Facilities' capitalization financed with equity. With the addition of new debt as well as internally-generated funds (equity) to finance new investments in the Hydro Facilities, the Authority needs to adopt a hybrid capital cost recovery structure. The new structure will have to provide for recovery of debt service costs associated with the debt-financed portion while continuing to recover costs associated with the portion financed with internally-generated funds through the *Auer* TOC method. The Authority proposes this capital cost recovery approach in order to provide adequate cash flow to meet the Authority's ongoing obligations for the debt-financed part of these

capital investments, while at the same time applying the *Auer* TOC method to the equity-financed portion of its capital investment.

The Authority retained The Brattle Group to design an appropriate capital cost recovery method using both Original Cost and TOC methods. A proposed capital cost recovery mechanism along with a detailed description of the TOC methodology and a comparison of TOC with OC rate treatment are contained in the attached report of Dr. A. Lawrence Kolbe of The Brattle Group.

Removal of Ancillary Services-Related Costs

The proposed hydroelectric rates exclude certain capital and O&M costs associated with the production of ancillary services at the Hydro Facilities. These ancillary services, described more fully below, are sold to the NYISO. Segregation of these costs is necessary because customers can obtain these services only from the NYISO. The proposed hydroelectric rates appropriately remove the costs for services that cannot be supplied by the Authority to the R&D Customers.

Transition to NYISO Operation: The New York Control Area (NYCA) has been operated as a “tight” power pool since 1966. In a “tight” power pool, a central agent dispatches the most economical generation in the NYCA to meet load regardless of where the generators or loads are located within the NYCA. The central agent was the New York Power Pool (NYPP), which dispatched generation and directed operation of the transmission system within the NYCA on behalf of the seven IOUs and the Authority. The NYISO assumed this function in November 1999. In addition to the functions performed by the former NYPP, the NYISO also provided open, non-discriminatory transmission access to all parties and a central market for generators, marketers and Load Serving Entities to buy and sell capacity, energy and ancillary services among others.

As a generator, the Authority provides certain ancillary services to the ISO from its generation resources including the Hydro Facilities. At present, all ancillary services are provided by or sold to the ISO. It is not possible at this time for an LSE to self-supply

ancillary services from its own resources or to buy them from a third-party generator on a bilateral basis. Since the R&D Customers must purchase ancillary services from the NYISO and cannot purchase these services directly from the Authority, the Authority proposes to reduce the cost of service by the portion of plant and O&M used to provide ancillary services.

Exclusion of Voltage Support, Black Start Service, Regulation Service and Operating Reserves: The Brattle Group calculated a cost basis for those ancillary services that are embedded in the current Hydro Facilities production rates. Brattle's analysis determined the amount by which the embedded costs of the Hydro Facilities should be reduced by the costs attributable to the following ancillary services: Voltage Support Service; Black Start Service; Regulation Service; and, Operating Reserves. This analysis reduces the production rates by excluding a portion of both the capital costs and the associated O&M expenses used to provide these ancillary services.

NYPA-1, page 2, lines 2-9, shows the cost of these ancillary services that have been embedded in the Hydro Facilities production rates. A more detailed description of the embedded costs of providing ancillary services at the Hydro Facilities can be found in the attached report of Frank C. Graves of The Brattle Group.

Voltage Support is a generator's capability to produce additional current required to maintain system voltage to enable real power delivery. Black Start Service is the capability to start a generator without the availability of an outside electric supply (*i.e.* as a result of a blackout) through the use of key on-site power sources.

For Voltage Support, Brattle used the ISO's methodology (based on FERC accounts and the generator's reactive power capability) to determine what percentage (capital share) of the Hydro Facilities' plant is dedicated to Voltage Support. That portion of plant would be removed from the capital portion of the hydroelectric cost of service study. Brattle also determined the specific dollar amounts of O&M associated with Voltage Support and removed that amount from the O&M expenses. Similarly for Black Start Service, Brattle determined what capital share of the Hydro Facilities' plant is dedicated to Black Start and the specific dollar amounts of O&M associated with Black

Start. For the Forecast years 2003 to 2006, the capital share for Voltage Support ranged from 1.27% to 1.47% and Voltage Support O&M expenses ranged from $149,800 to $161,400. The capital share for Black Start ranged from 0.057% to 0.053% and Black Start O&M expenses ranged from $45,700 to $49,200.

For Regulation and Operating Reserves, Brattle determined the share of capital and O&M expenses to be removed from the hydroelectric cost of service study. Regulation is the generating capacity that the ISO can direct to quickly shift its output up or down to match moment-to-moment changes in load. Operating Reserve is capacity maintained "on call" by the ISO, able to be dispatched within 10-30 minutes to compensate for the unanticipated loss of a major generating or transmission facility. The assets and costs associated with Regulation and Operating Reserves cannot be distinguished from those used to provide power. Thus, a fraction of the total cost of service (capital and O&M expenses, after removal of costs allocated to Voltage Support and Black Start) is allocated to Regulation and Operating Reserves. This fraction is the same for capital and O&M costs, and is based on the Regulation and Operating Reserves needs of the contract load served by the Hydro Facilities.

For the Forecast years 2003 to 2006, the capital share and O&M expenses for Operating Reserve ranged from 5.37% to 5.16%. The capital share and O&M expenses for Regulation ranged from 0.76% to 0.73%. Removal of ancillary service related costs reduces the hydroelectric cost of service by $8.9 million for Interim Rate Period, and by an average of $11.6 million per year for 2003-2006 Rate Years.

Staff recommends that this proposal to remove Hydro Facilities plant and O&M expenses associated with ancillary services be reviewed at such time when the NYISO or its successor organization permits physical self-supply of Voltage Support, Black Start Service, Regulation Service or Operating Reserves.

Operation & Maintenance Expenses

For the purposes of calculating the R&D Rates for the Forecast Years, the O&M component includes only site O&M expenses and directly-assigned Shared Services.

Site O&M expenses for the Hydro Facilities include day-to-day operation of the projects and ongoing expenses associated with major maintenance programs and non-capital modifications.

Shared Services cover the costs at the Authority's White Plains and Albany offices that serve all Authority operations, which include support from the Executive Offices, Business Services, Human Resources, Energy Services and Marketing, Economic Development and Supply Planning. They are included in the O&M to the extent they can be directly assigned to the Hydro Facilities. Shared Services that cannot be directly assigned are discussed below in the section on Allocation of Indirect/Overhead Expenses.

NYPA-1, page 1, lines 1-3 show the O&M expenses used in the cost-of-service study.

Accrual Accounting for Post-Retirement Benefits Other than Pensions

The hydroelectric cost of service includes costs reflecting the switch to accrual accounting for post-retirement benefits other than pensions or "PBOPs." PBOPs consist of health care benefits and insurance for retirees, their dependents and beneficiaries. The Authority has calculated that this obligation is approximately $271.1 million, which it proposes to amortize over a twenty-year period. The Authority has estimated that the total average annual cost for PBOPs is approximately $24.6 million, $10.6 million of which is allocable to the hydroelectric cost of service based on the same labor ratio methodology used to allocate Shared Services costs.

Prior Accounting Treatment of PBOPs: Prior to 2002, the Authority used the cash or "pay-as-you-go" method for PBOP costs. In other words, the Authority would recognize the PBOPs costs as occurring during the period that the costs were actually paid to current retirees, and recover these from ratepayers. However, this method ignored the fact that the Authority had been incurring a large obligation represented by the PBOPs owed in the *future* to both its present employees and current retirees. The accrual

method recognizes the general ratemaking principle that current ratepayers should pay for the costs associated with present employment. This is known as the "matching" principle. As shown below, accrual accounting for PBOPs is an accepted method for utilities to recover these costs.

Prior to the 1990s, PBOPs costs received little attention because of their relatively small effect in determining public utilities' revenues. Due to various factors, such as spiraling medical costs, early retirements, an aging population and the resulting accumulation of benefit obligations, the potential future liability for PBOP costs rose dramatically.

The Financial Accounting Standards Board (FASB), which sets the accounting standards in the private sector, became concerned with the accuracy of financial statements if employers' growing PBOP costs continued to be reported on a cash basis. In 1990, FASB issued Financial Accounting Standard No. 106 (FAS 106), which requires employers to implement accrual accounting for PBOPs effective 1992.[6]

The effect of accrual accounting for PBOPs is that employers will recognize a large liability now for benefits owed in the future to present employees and current retirees. This large liability is known as the "transition obligation"; *i.e.* the accumulated but previously unrecognized obligation to PBOP recipients in future years. In the typical scenario, the employer amortizes the transition obligation over a number of years in order to minimize the impact of the transition obligation.

Subsequent to the issuance of FAS 106, FERC endorsed, and the federal courts have upheld, the inclusion in rates of the costs of accrual accounting for PBOPs. *New England Power Company,* 61 FERC ¶ 61,331 (1992), *reh'g denied,* 65 FERC ¶ 61,036 (1993) (*NEPCo*), *aff'd sub nom. Town of Norwood v. FERC,* 53 F.3d 377 (D.C. Cir.

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[6] Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions (December 1990) (FAS 106) (requiring all companies subject to FASB accounting standards with over 500 plan participants to adopt accrual accounting for PBOP expenses no later than fiscal years beginning after December 15, 1992, whether regulated or unregulated).

1995).[7] These decisions pointed out that the switch to accrual accounting does not cause the utility to over-recover its PBOP costs. The utility recovers the same total PBOP costs as it would on a cash basis. The main change under accrual accounting is the timing and manner of its PBOP cost recovery. *See NEPCo,* 61 FERC at 62,213. On a cash basis, current ratepayers pay for PBOP costs associated with services performed in the past, which violates the matching principle. The accrual method recognizes that PBOPs are earned by employees during their working careers. *Id.* As indicated, the *switch* to the accrual method imposes a transition obligation, which is simply a "make-up" provision for prior deferred expenses. *Town of Norwood,* 53 F.3d at 381.

FERC recognized that the transition obligation entails some violation of the matching principle, since current ratepayers are being charged for the costs associated with services provided in prior years. 61 FERC at 62,215; 53 F.3d at 381. However, these cases emphasize that the switch to the accrual method is more faithful to the matching principle overall. FERC determined that a "make-up" provision such as the transition obligation is a permissible way to make a utility whole for properly deferred, prior period costs. 61 FERC at 62,215; 53 F.3d at 381. Moreover, delaying the switch to accrual accounting will simply enlarge the amount of deferred costs that need to be recovered from current ratepayers. Beginning the amortization of the transition obligation now will ensure adherence to the matching principle sooner rather than later.

The inclusion of PBOPs costs in rates on an accrual basis has also been the policy of the New York State Public Service Commission (PSC) since 1993. In its *Statement of Policy*, the PSC determined that jurisdictional utilities must switch to the accrual method for PBOPs for both accounting and ratemaking purposes, unless particular circumstances demonstrated that it is unwarranted.[8]

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[7] *See also Post-Employment Benefits Other Than Pensions*, Statement of Policy, 61 FERC ¶ 61,330 (1992).

[8] *See generally Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions And Postretirement Benefits Other Than Pensions,* Case 91-M-0890, 33 NY PSC 1107,

Although the Authority is not currently required to adopt the accrual method for PBOPs, the Governmental Accounting Standards Board (GASB) has permitted this method since 1994[9], and actively recommends that its member governmental employers do so. GASB has issued tentative decisions during 2002 expressing its intention to require accrual accounting by 2006 and that early implementation would be encouraged.

Implementation of the Accrual Method for R&D Rates: On November 19, 2002 the Staff recommended to the Authority's Audit Committee that it adopt accrual accounting for PBOPs. The recommendation was adopted. The Staff had retained Buck Consultants to perform an actuarial valuation report of the Authority's future PBOP costs.[10]

Buck Consultants performed estimates of the Authority's total future liability as of January 1, 2002 for PBOPs using various amortization periods and methodologies. The Authority chose a plan based on a 20-year amortization period, and the methodology used in GASB 27.[11] Other underlying assumptions include a 6% discount rate and an initial medical inflation rate of 12%. Under this scenario, the estimated financial obligation for future retiree health benefits is $271.1 million, which represents the transition obligation. On an annual basis, the PBOPs costs will average $33.8 million through 2006.

In order to ensure that no double counting occurs with respect to this switch to accrual accounting, the Authority reduces this annual amount by the PBOPs costs paid per year

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1993 N.Y. PUC LEXIS 33 (September 7, 1993) (applying to electric, gas, telephone and water utilities) (*PSC Statement of Policy*).

[9] *See* Statement No. 27 of the Governmental Accounting Standards Board, Accounting for Pensions by State and Local Governmental Employers (November 1994) (GASB 27).

[10] The Staff's recommendation to the Audit Committee and the Buck Consultants' report are attached herein.

[11] A 20-year amortization period has been accepted as reasonable by FERC and the PSC. *NEPCo,* 61 FERC at 62,213 n.41; *PSC Statement of Policy,* mimeo at 4, 10.

to existing retirees.[12] Thus, the Authority estimates that it will accrue an average of $24.6 million per year in PBOPs through 2006.

Over the term of the rate plan, the Authority estimates that an average of $10.6 million or 43% of the $24.6 million total annual PBOPs costs is attributable to the hydroelectric project based on labor ratios.

Allocation of Indirect/Overhead Expenses

Indirect/Overhead expenses include Shared Services, Research and Development, Projects' Studies debt service and White Plains Office debt service. As stated in the Current Rate Methodology section above, until December 18, 2001, the Authority had been assigning Indirect/Overhead expenses by first functionalizing them between production and transmission facilities using labor ratios and then allocating those costs functionalized to production to the generating facilities using capacity ratios (labor-capacity ratios). At their December 18, 2001 meeting the Trustees of the Authority directed that Indirect/Overhead expenses be allocated to the projects by using labor ratios, consistent with the decision in the *Bergen* litigation.

NYPA-1, page 1, lines 5-9, sets forth the Indirect/Overhead expenses for calendar year 2001, the Test Year and the Forecast Years. For calendar year 2001, in which the Authority employed the labor-capacity method, Indirect/Overhead expenses at the Hydro Facilities were $52 million. Of this amount, $41 million was comprised of Shared Services. For the Test Year in which the Authority used labor ratios, the Shared Services expense allocable to the Hydro Projects was $32 million, or a decrease of $9 million.

In addition to the Indirect/Overhead expenses discussed above, the Authority has also used labor ratios to allocate Shared Services plant. During the 2003-2006 period, the Authority plans to invest nearly $39 million in Shared Services plant, of which $17

[12] The PBOPs costs paid per year to existing retirees over this 20-year amortization period are accounted for as a separate component to the O&M cost.

million is allocated to the Hydro Facilities. The annualized costs are included in NYPA-1, lines 19-20.[13]

Normalized Water Flows

Previous Staff reports have used normalized, long-term average generation to calculate cost-based rates. In the 1992 Staff Report, several parties recommended using short-term, higher generation, which produces a lower energy rate, compared to the long-term average. While Staff proposes to continue the use of long-term average for the projected period, in recent years actual generation has been well below the long-term average. If this trend continues, the actual cost-based rates that are calculated each April will be higher than the proposed rates, causing a revenue shortfall that will be reflected in increasingly negative RSR balances. Nonetheless, Staff continues to believe that using normalized water flows is the most accurate and reliable predictor of generation levels for cost-based rates. For the historical test year, Staff used actual generation to calculate the rate that applies during the Interim Rate Period. See NYPA-2, which shows the historic and long-term average generation levels of the Hydro Facilities.

Interim Rate Period

Based on the changes in costs discussed above applicable to the Test Year, Staff concludes that the rates should be reduced by a total of $4.4 million for the Interim Rate Period, *i.e.* December 18, 2001 through April 30, 2003. Staff left the demand charge of $1/kW-month constant and calculated that the reduced costs yield an energy charge of $4.59/MW-hour. Staff proposes as part of this rate plan that the R&D Customers receive $4.4 million in refunds.

[13] These investments are equity-financed in accordance with past practice, and have been included in Dr. Kolbe's TOC calculations.

Rate Design and Forecast Year Rates

The Staff proposes a revised preference rate design for the 2003-2006 rate years such that the total proposed rate increases would be recovered through increases to the demand charge rather than through increases in the energy charge.

From their inception in 1958, the Authority's R&D Rates were designed with a $1.00/kW-month demand charge. All subsequent rate increases were recovered through increases in the energy charge, which grew from $2.67/MW-hour in 1958 to the current $4.92/MW-hour, the energy charge in effect since 1994. By leaving the demand charge constant over this period, the Authority's current rate design collected all increased costs through the energy charge.

The magnitude of the increased capital costs for Hydro Facilities discussed above requires the Authority to reevaluate the R&D rate design. The NARUC manual provides the following useful classification of costs which are demand-related and those affecting energy:

> Production plant costs are either fixed or variable. Fixed production costs are those revenue requirements associated with generating plant owned by the utility, including cost of capital, depreciation, taxes and fixed O&M. Variable costs are fuel costs, purchased power costs and some O&M expenses. Fixed production costs vary with capacity additions, not with energy produced from given plant capacity, and are classified as demand related. Variable production costs change with the amount of energy produced.[14]

For the Hydro Facilities, water is the "fuel," which has no cost. Costs associated with hydroelectric plants, in general, and the Hydro Facilities in particular, are largely fixed in nature, and do not vary with output. Thus, there should be a bias towards recovering

[14] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* 35 (January 1992).

such demand-related costs through the fixed charge component of the rate. The Authority staff does not propose that all project costs that are fixed be collected in the demand charge since that charge would create a significant impact and is not warranted to achieve the Authority's cost recovery objective. Instead, Staff proposes that the Authority keep the current energy rate of $4.92/MW-hour and allocate increased costs described in this report to the demand charge. This achieves a reasonable compromise between the stringent classification of all fixed costs to the demand component, rate stability, and customer impacts.

The proposed R&D Rates as recommended by Staff are:

		2003	2004	2005	2006
Demand ($/kW-month)	(Jan – Apr)	1.00	1.45	1.71	2.10
	(May - Dec)	1.45	1.71	2.10	2.39
Energy ($/MW-hour)		4.92	4.92	4.92	4.92

Revenue Stabilization Reserve (RSR)

The RSR was established in the 1987 in response to public comment that short-term rather than long-term hydro generation forecasts should be used to set current hydro rates. The RSR has a range of +$25 million to -$25 million and is designed to capture over or under recovery of costs relative to the costs collected in the fixed demand and energy charges, due to differences in net generation and actual cost incurrence. At its initiation, the RSR had a positive balance of $20 million. By design, if the RSR balance exceeds either +$25 million or -$25 million a credit or surcharge will be assessed against the R&D hydro rate. See NYPA-3 which shows the historical RSR balances. At year-end 2001, it was negative $725,000. The RSR mechanism will not be used to reconcile actual costs over the period from December 18, 2001 to December 31, 2002 and therefore, the RSR balance will not show any adjustments for over or under-recoveries for that period. Over or under recoveries of costs will be tracked and accumulated in the RSR starting January 1, 2003. The annual calculation performed in the first quarter of 2004 will cover the May-December 2003 period and start with the beginning balance of negative $725,000.

Staff recommends that the range within which no credit or surcharge would be applied should be reduced from +/- $25 million to +/-$15 million for the 2003-06 Forecast Years.

Staff's recommendation to collect more of the hydro R&D costs through the demand charge (discussed above) will reduce the volatility in cost recovery and hence the RSR balances. For 2001, the RSR was drawn down by $12 million, bringing the RSR balance to -$725,000. The changes in the RSR balance are due to variances in either costs or generation as compared to the cost and flow (i.e. generation) assumptions used to develop the base R&D rates from the cost based rates. Unlike generation levels, there is little change in the billed demand levels. Thus, overall revenue recovery will be more stable and predictable with Staff's proposed rate design. By recovering more costs in the demand charge under the proposed rate structure, the variability in future over/under recoveries are minimized. Consequently, Staff believes it is reasonable to reduce the size of the RSR "deadband" to +/-$15 million.

Other Matters

Purchased Power: For the past several years, below-normal generation levels have caused the Authority to curtail firm loads. Each month, the Authority forecasts the expected level of curtailment and advises its customers. The Authority has given its customers a choice on securing support energy. They can either secure it themselves, as chosen by most partial requirements customers, or they can elect to have the Authority purchase it on their behalf. For those customers electing to supply their own substitute energy, the Authority provides a curtailment credit to the demand portion of the bill.

These services to customers for whom the Authority purchases substitute energy are temporary measures to assist customers until normal water flows resume. The Authority is not guaranteeing that this policy will continue indefinitely until normal flows return. The hydroelectric cost of service does not account for the revenues and expenses associated with these conditions. The test year and projected 2003-2006 rate years capture the cost of providing generation at the hydroelectric projects, as opposed

to a cost of service to support the customer loads. Therefore, all costs associated with support energy transactions are excluded as well as the accumulated unrecovered costs due to the Authority's voluntary actions to mitigate the impacts of low flow.

Rate Comparison and Customer Impacts

Over the 2003-06 Forecast Years, the R&D customers will experience modest rate increases as compared to the status quo. For the M&C customer class as a whole, the annual rate increase ranges from 7.2% to 8.7%. On a system-wide basis, the annual increases are less than 2%. The annual rate impacts on the M&C customers' residential customers range from 1.1% to 1.4%. If the full rate plan is implemented, an average full requirements M&C customer will experience a $0.67 increase in its monthly bill for each year of the proposed future rates; an average partial requirements M&C customer will experience a $0.55 increase in its monthly bill for each of these same years. See NYPA-4 for more detailed data on the effects of the Authority's proposal on M&C customers.

The annual rate impact on the IOUs' residential customers is 0.2%. Since the average utility residential rates are higher than those of the M&C customers, the impact of the production rate increase is correspondingly smaller. See NYPA-4 for more details on the IOU residential customer impacts.

Recommendations

Staff recommends that a notice of the proposed rate plan for the R&D customers described herein be published in the State Register; that the comments of interested parties be solicited in writing and at a public forum; and that a proposed final rate plan be presented to the Trustees following the comment period prescribed by the State Administrative Procedures Act.

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
PRODUCTION COST OF SERVICE

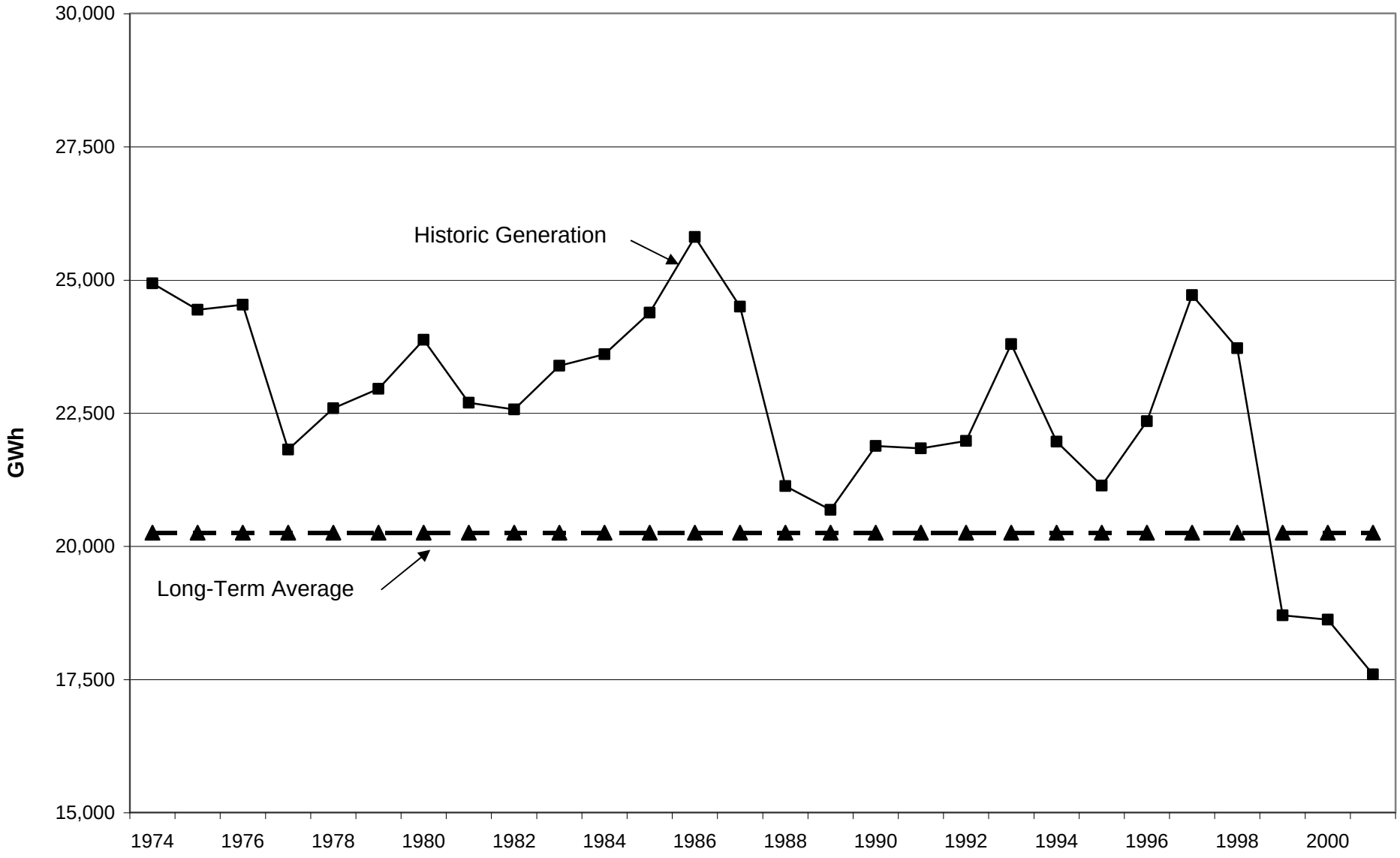
($000)

Line	Description	Actual 2001	TY (10/01-9/02)	2003	2004	2005	2006
1	Operations & Maintenance/A&G	44,657		61,256	59,942	62,280	64,457
2	Amortized Roadwork	4,080	4,157	4,288	4,395	4,505	4,617
3	Subtotal O&M/A&G (line 1 + line 2)	48,737	53,728	65,544	64,337	66,785	69,074
5	Shared Services	41,139	32,212	33,137	33,871	35,037	36,229
6	Research & Development	4,500	2,700	3,363	4,245	4,330	4,417
7	Projects' Studies Debt Service	3,737	2,703	2,413	2,273	2,327	2,012
8	White Plains Office Debt Service	2,336	1,433	970	1,308	4,212	4,305
9	Subtotal Indirect Overheads (sum lines 5-8)	51,712	39,047	39,883	41,698	45,906	46,963
10	St. Law. Relicensing, expensed			2,000	2,000	2,000	2,000
11	Retirement Health Costs (Accrued)		-	9,978	10,370	10,786	11,234
12	Capital Costs						
13	Existing Plant						
14	Depreciation	24,647	23,874	23,114	22,505	21,897	21,289
15	Inflation	18,583	15,532	16,235	16,766	17,268	17,740
16	New Plant						
17	Depreciation, debt funded		350	838	5,618	7,430	8,718
18	Interest on debt		730	1,854	8,400	14,176	19,871
19	Depreciation, cash funded		755	2,646	482	667	1,425
20	Inflation		19	90	102	119	156
21	Subtotal Capital Costs (sum lines 14-20)	43,230	41,260	44,777	53,873	61,557	69,199
22	Total Cost of Service (sum lines 3,9,10,11,21)	143,679	134,036	162,181	172,278	187,033	198,470
23	O&M Cost of Service (line 22 - line 21)		92,776	117,404	118,405	125,476	129,271

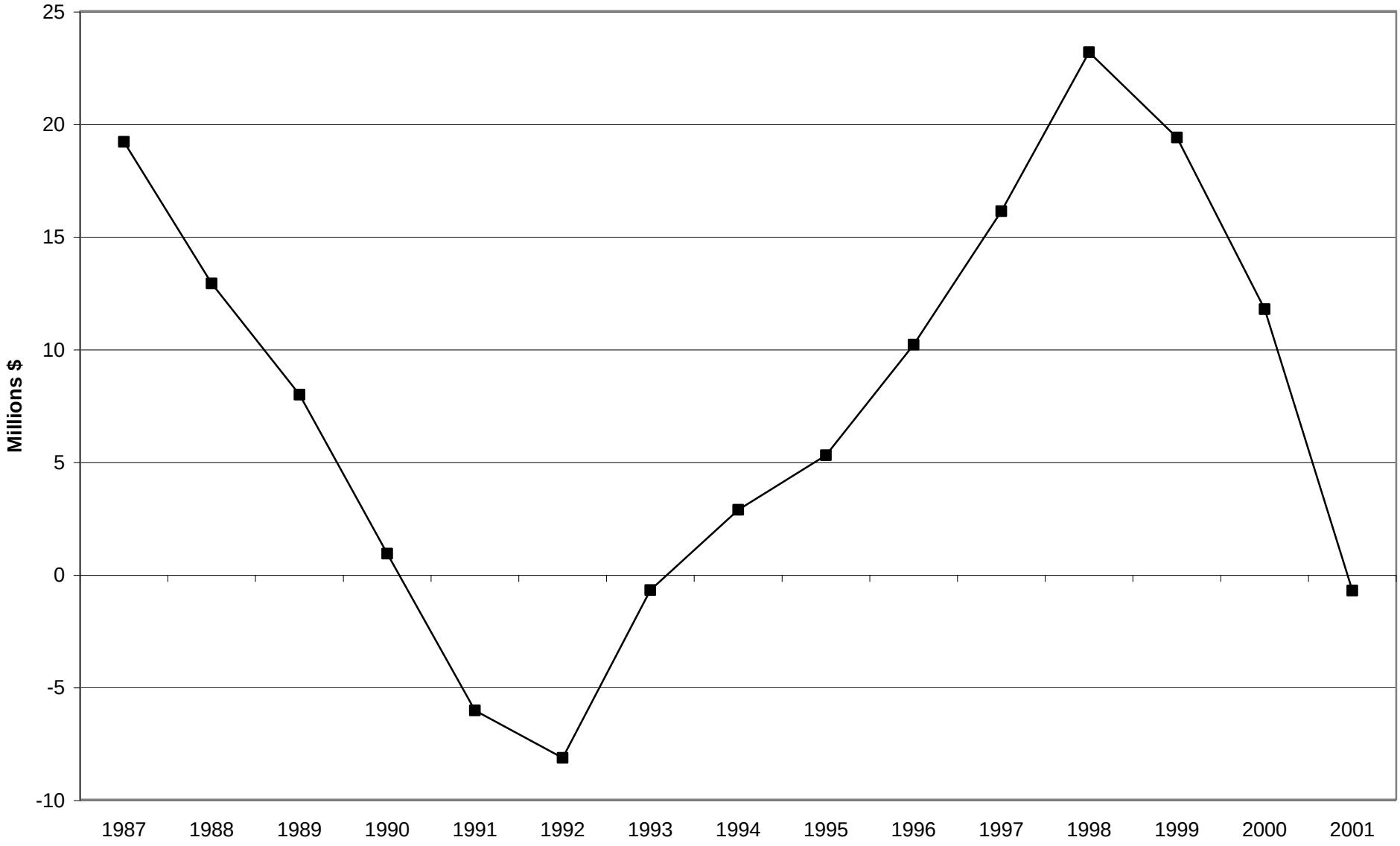
NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECTS
PRODUCTION COST OF SERVICE

Line	Description		Actual 2001	TY (10/01-9/02)	2003	2004	2005	2006
1	Total Cost of Service	($000)	143,679	134,036	162,181	172,278	187,033	198,470
2	Credits for ancillary services	($000)						
3	Black Start, O&M			44	46	47	48	49
4	Voltage Control, O&M			145	150	154	157	161
5	Remaining O&M (page 1, line 23 - (line 3+line 4)			92,586	117,209	118,204	125,271	129,061
6	Operating Reserves, O&M			5.52%	5.37%	5.28%	5.22%	5.16%
7	Regulation, O&M			0.78%	0.76%	0.75%	0.74%	0.73%
8	Subtotal OR, Reg. O&M			6.30%	6.13%	6.03%	5.96%	5.89%
9	Op. Res.+ Reg. O&M credit (line 8 * line 5)	($000)		5,833	7,185	7,128	7,466	7,602
10	Capital Reductions							
11	All ancillary services			7.43%	7.44%	7.34%	7.33%	7.33%
12	Subtotal capital reductions (page 1, line 21 * line 11)	($000)		3,066	3,330	3,954	4,512	5,072
13	Total Ancillary Credits (line 9 + line 12)	($000)		8,899	10,515	11,082	11,978	12,674
14	Adjusted Cost of Service (line 1 - line 13)	($000)	143,679	125,137	151,666	161,196	175,055	185,796
15	Billing Demand	mW	35,172	35,345	35,854	35,927	36,000	36,073
16	Billing Demand Revenues	($000)	35,172	35,345	52,046	61,576	75,435	86,176
17	Billed demand Rate (line 16 / line 15)	$/kW/m	1.00	1.00	1.45	1.71	2.10	2.39
18	Total Costs less demand (line 14 - line 16)	($000)	108,507	89,792	99,620	99,620	99,620	99,620
19	LTA Generation	GWh	20,258	20,251	20,248	20,248	20,248	20,248
20	Annual Generation	GWh	17,237	19,566	17,830	19,390	19,560	20,223
21	Cost Based Rate @ LTA (line 18 / line 19)	$/MWh	5.36	4.43	4.92	4.92	4.92	4.92
22	Cost Based Rate @ annual (line 18 / line 20)	$/MWh	6.30	4.59	5.59	5.14	5.09	4.93
23	Billed actual/Proposed Rates							
24	Energy Rate							
25	January - April	$/MWh	4.92	4.92	4.92	4.92	4.92	4.92
26	May - December	$/MWh	4.92	4.92	4.92	4.92	4.92	4.92
27	Demand Charges							
28	January - April	$/kW/mo	1.00	1.00	1.00	1.45	1.71	2.10
29	May - December	$/kW/mo	1.00	1.00	1.45	1.71	2.10	2.39

NYPA Report on Hydroelectric Rates
Historic and LTA Hydroelectric Generation



NYPA Report on Hydroelectric Rates
Year Ending RSR Balances



NEW YORK POWER AUTHORITY
ESTIMATED AVERAGE ANNUAL CUSTOMER IMPACTS
Prices (cents/kWh) include demand and energy components

	Test Year (Oct 01-Sept. 02)	2003	2004	2005	2006
Full Requirements Customers					
PRODUCTION RATES (cents/kWh)	0.692	0.752	0.817	0.885	0.950
Change		0.06	0.06	0.07	0.06
Percent		8.7%	8.6%	8.4%	7.3%
SYSTEM RATES (cents/kWh)	3.60	3.66	3.72	3.79	3.85
Change		0.06	0.06	0.07	0.06
Percent		1.6%	1.7%	1.8%	1.6%
RESIDENTIAL RATES (cents/kWh)	4.62	4.68	4.74	4.81	4.87
Change		0.06	0.06	0.07	0.06
Percent		1.3%	1.3%	1.4%	1.3%
cents/month		62.83	67.90	71.32	67.37
Partial Requirements Customers					
PRODUCTION RATES (cents/kWh)	0.687	0.745	0.808	0.875	0.938
Change		0.06	0.06	0.07	0.06
Percent		8.5%	8.5%	8.2%	7.2%
SYSTEM RATES (cents/kWh)	4.35	4.41	4.46	4.53	4.58
Change		0.05	0.06	0.06	0.06
Percent		1.2%	1.3%	1.4%	1.3%
RESIDENTIAL RATES (cents/kWh)	4.72	4.77	4.83	4.89	4.95
Change		0.05	0.06	0.06	0.06
Percent		1.1%	1.2%	1.3%	1.2%
cents/month		51.66	55.83	58.64	55.39
Residential Utility Customers					
PRODUCTION RATES (cents/kWh)	0.781	0.868	0.962	1.061	1.155
Change		0.09	0.09	0.10	0.09
Percent		11%	11%	10%	9%
RESIDENTIAL RATES (cents/kWh)	12.46	12.48	12.50	12.53	12.55
Change		0.02	0.02	0.02	0.02
Percent		0.2%	0.2%	0.2%	0.2%
cents/month		11.54	12.47	13.10	12.37

The Brattle Group Report
On
Capital Cost Recovery

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECT PRODUCTION RATES

REPORT OF A. LAWRENCE KOLBE
THE BRATTLE GROUP

PREPARED FOR THE NEW YORK POWER AUTHORITY

ON

ANNUAL COST-BASED CAPITAL CHARGES
FOR HYDROELECTRIC INVESTMENTS,
2001-2006

January 22, 2003

ANNUAL COST-BASED CAPITAL CHARGES FOR THE HYDROELECTRIC INVESTMENTS OF THE NEW YORK POWER AUTHORITY, 2001-2006

A. Lawrence Kolbe
The Brattle Group
44 Brattle Street
Cambridge, Massachusetts 02138

January 22, 2003

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ANNUAL COST-BASED CAPITAL CHARGES FOR THE HYDROELECTRIC INVESTMENTS OF THE NEW YORK POWER AUTHORITY, 2001-2006

I. INTRODUCTION AND SUMMARY

My name is A. Lawrence Kolbe. My business address is The Brattle Group, 44 Brattle Street, Cambridge, Massachusetts, 02138. I am a Principal of The Brattle Group, Inc. ("Brattle") an economic, environmental and management consulting firm with offices in Cambridge, Washington, London, and the San Francisco Bay area. My work concentrates on financial and regulatory economics. I hold a B.S. from the U.S. Air Force Academy and a Ph.D. from the Massachusetts Institute of Technology, both in economics.

I have been asked by the New York Power Authority ("NYPA") to calculate the cost-based capital charges through 2006 for its Niagara and St. Lawrence hydroelectric facilities, for the purpose of helping to determine the electric rates to be charged to NYPA's "preference rate customers." In the context of NYPA's hydroelectric cost of service, the term "preference rate customers" means customers entitled to receive Niagara and/or St. Lawrence hydroelectricity at cost.

A. QUALIFICATIONS

My qualifications for this work may be summarized as follows. Brattle's specialties include financial economics, regulatory economics, and the gas and electric industries. Among other duties, I lead the financial economics practice at Brattle. I and other Brattle members have authored or co-authored a number of standard references and many articles on these topics. In the areas of cost-of-

capital estimation, investment risk assessment and related matters such as capital charge calculations, these include the leading graduate textbook in corporate finance, Richard A. Brealey and Stewart C. Myers, *Principles of Corporate Finance*, New York: McGraw-Hill Book Company [now McGraw-Hill/Irwin] (1981, 2nd ed. 1984, 3rd ed. 1988, 4th ed. 1991, 5th ed. 1996, 6th ed. 2000, 7th ed. 2003); A. Lawrence Kolbe and James A. Read, Jr., with George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, Cambridge, MA: The MIT Press, 1984; A. Lawrence Kolbe, William B. Tye and Stewart C. Myers, *Regulatory Risk: Economic Principles and Applications to Natural Gas Pipelines and Other Industries*, Boston: Kluwer Academic Publishers (1993); *The Utility Capital Budgeting Notebook*, EPRI TR-104369, Palo Alto, CA: Electric Power Research Institute, 1994 (Principal Investigators A. Lawrence Kolbe and James A. Read, Jr.), and Richard A. Brealey and Stewart C. Myers, with The Brattle Group, *Financing and Risk Management* (Brattle author James A. Read, Jr.) and *Capital Investment and Valuation* (Brattle author A. Lawrence Kolbe), both volumes New York: McGraw-Hill/Irwin, 2003. Additionally, Professor Myers, Dr. William B. Tye and I have co-authored the basic papers on the theory of Trended Original Cost. Prof. Myers successfully sponsored this method before the U.S. Federal Energy Regulatory Commissions as a way to regulate the oil pipeline industry. (NYPA currently uses a variant of Trended Original Cost to set capital charges on the facilities in question.) All of the above authors except George R. Hall are or have been Brattle Principals. (Professor Brealey cut back on his other activities following a stint as a special advisor to the Bank of England and is now a Brattle Senior Advisor.)

I have testified on the cost of capital, investment risk and related matters such as capital charge calculations for more than a dozen industries, regulated and unregulated alike, in many

forums. These include international arbitrations in The Hague, London and Melbourne, Australia; lawsuits in U.S. District Courts; U.S. arbitrations; and regulatory proceedings before Canadian and U.S. federal, provincial and state regulatory bodies. Additional information on my qualifications is in the Appendix.

B. SUMMARY OF FINDINGS

NYPA is required to provide service from its hydroelectric facilities at cost to a group of "preference rate customers," which include municipalities and investor-owned electric utilities. It has been doing so under the methodology established by the "Auer II Settlement" ("Auer").[1] NYPA now needs to make material new capital investments in its hydroelectric facilities. I have been asked to apply the principles underlying Auer to determine cost-based capital charges through 2006 considering both the existing and new investments.

For these purposes, the chief feature of Auer is the way it sets capital charges. Auer capital charges are based on a partial implementation of "Trended Original Cost," or "TOC." TOC is a cost-based method of rate regulation that tracks the cost of investment outlays for property, plant and equipment and gives the companies making those investments a fair opportunity both to (1) recover the capital they have invested, through subsequent depreciation and amortization charges, and (2) earn a fair rate of return on the capital while it remains unrecovered. In this, it is like the Original Cost ("OC") method widely used to set rates for investor-owned utilities in North America. It differs

[1] The "Auer II Settlement" refers to the March 5, 1986 settlement of an action that was pending in the Supreme Court of New York for the County of New York, "STIPULATION DISCONTINUING ACTION WITH PREJUDICE," MARTIN S. AUER, JOHN G.A. O'NEIL, LAWRENCE SLOANE and MUNICIPAL ELECTRIC UTILITIES ASSOCIATION OF NEW YORK STATE v. THE POWER AUTHORITY OF THE STATE OF NEW YORK, Index No. 11999-84.

from OC in that inflation compensation under TOC comes through an increase in the value of the assets employed, not through an inflation premium in the allowed rate of return on those assets. The result is that over the life of the investment, capital charges under TOC start lower and finish higher than capital charges under OC. However, the starting present values of the capital charges are the same and equal the initial amount invested.[2] Thus, both methods exactly recover the cost of the investment from customers over time, albeit in different patterns. Figure 1 illustrates the difference between OC and TOC for a $1,000, 20-year investment with an 8 percent overall cost of capital and a 3 percent inflation rate. Since the present values of the cash flows at the time of the initial investment are the same, the initial present value of the excess of OC over TOC capital charges in the early years exactly equals the initial present value of the excess of TOC over OC capital charges in the later years.

[2] "Capital charges" in this context equal the sum of depreciation and amortization plus the return on capital. Sometimes "capital charges" for privately owned rate-regulated companies are defined to include income taxes. However, since NYPA does not pay income taxes, this component of capital charges can be omitted from consideration in this report's calculations.

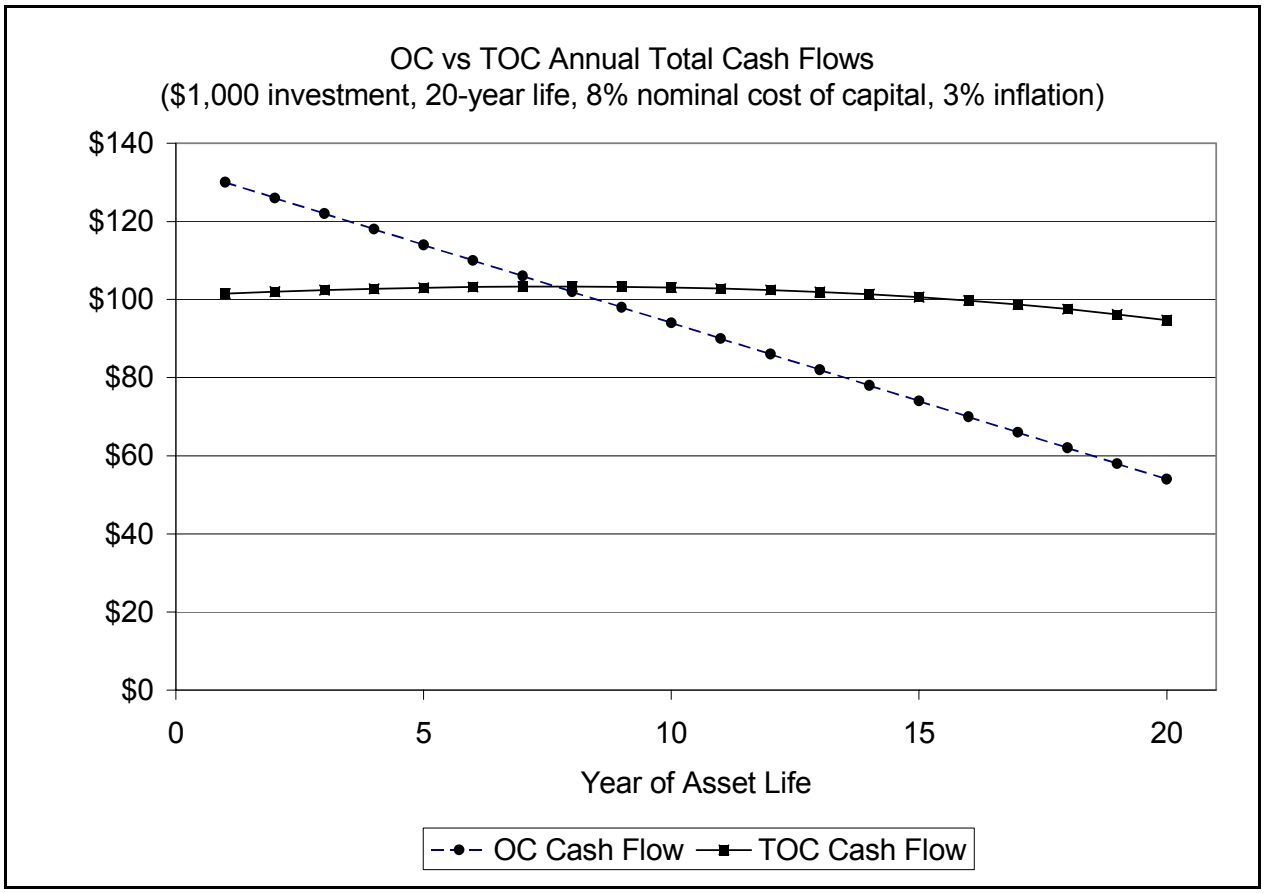

Figure 1

The Auer method deviates from a normal application of TOC, however, because it does not include the rate of return on capital. Figure 2 compares OC and ordinary TOC with the Auer version of TOC. The Auer version leaves NYPA with less than full cost recovery, since it omits the return on capital. This makes the present value of the capital charges under this version of TOC fall well short of the cost of the initial investment. That is, the OC and TOC lines have the same present value, equal to the $1,000 initial investment, but the Auer line has a present value of only $631. Note also that since NYPA's assets have much longer lives than the example's assets, the actual shortfall from full cost recovery for NYPA will be a higher proportion of the initial investment than

this. For example, with a 50-year asset and the assumptions otherwise unchanged, NYPA gets back only $373 in present value under Auer-style TOC, well below half of the actual cost of the investment.

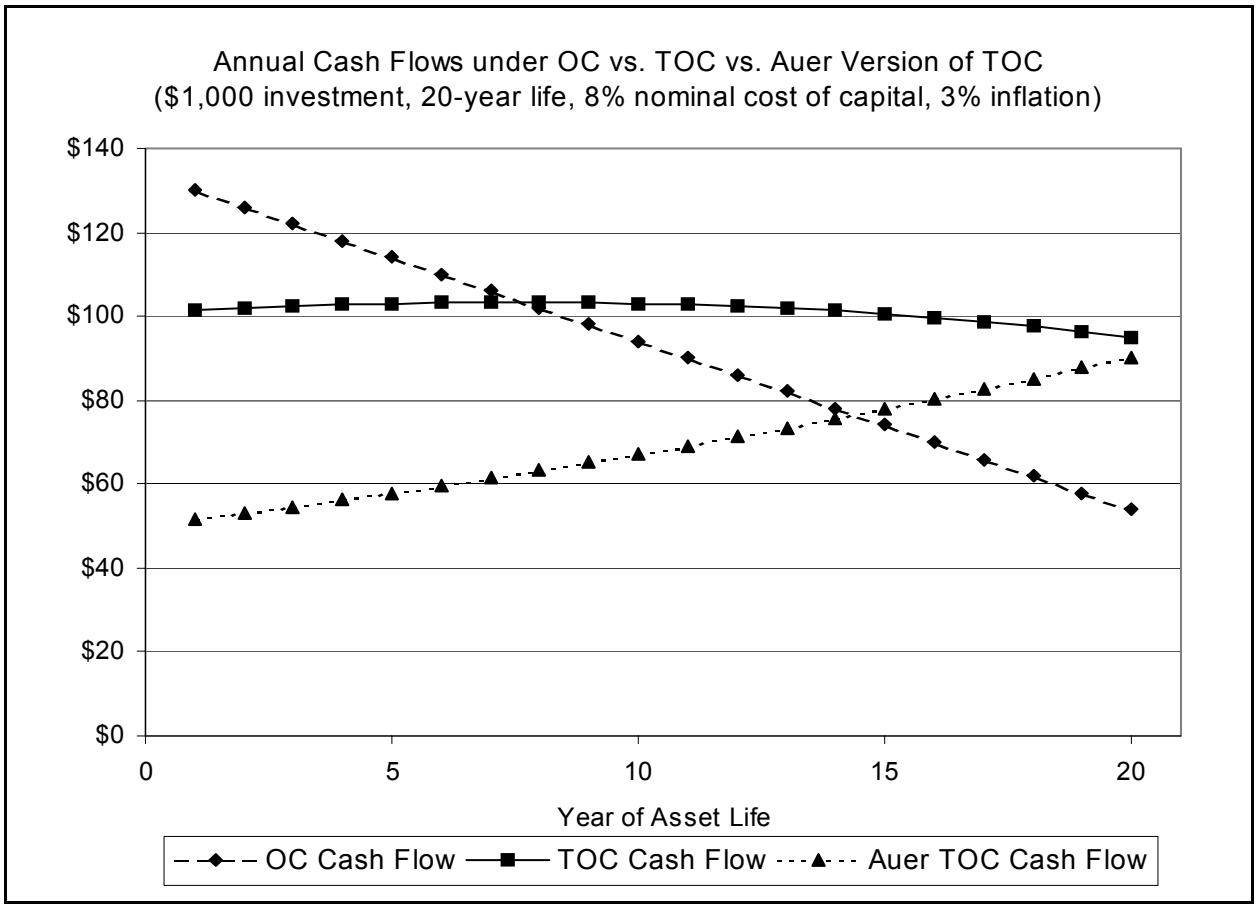

Figure 2

Despite this material under-recovery of the cost of its investments, NYPA has advised me it is still bound by the principles under the Auer settlement, which does at least permit the collection of the interest expense on the debt NYPA issues for the new investments. Since the total cost of capital of those investments, debt and equity combined, will exceed the interest expense on the debt-

financed part of the investments, this means NYPA will charge less than the full cost for the capital employed on behalf of preference rate customers on the new investments as well as the old ones.

NYPA has supplied me with the details of its existing capital charges, its new investments by type, the capital structure it plans to use, and the interest rates it expects to pay. I understand NYPA will set rates to recover its interest expense, whether tax-preferenced or not, on the debt-backed part of the new investments. Since the interest rate includes an inflation premium, NYPA does not simultaneously get an inflation-based write-up of the debt-backed part of its investment. It does get an inflation-based write-up on the equity-backed part of the investment, but foregoes the equity return on its investment as it did with the old investments under Auer.

I use the NYPA-supplied information and the relevant economic principles to determine a set of planned capital charges going forward. Table 1 reports these capital charges in the format requested by NYPA, as an input to the rate calculations.[3]

The remainder of this report contains two sections. Section II discusses the principles behind OC and TOC, which are both cost-based methods of recovering capital investments. Section III describes my calculations to apply these principles for NYPA in order to produce Table 1.[4]

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[3] My Brattle colleague, Frank C. Graves, has applied Auer and the procedures that have evolved out of it to enable NYPA to develop cost-based charges for ancillary services, which are the subject of another part of NYPA's presentation.

[4] Additional details of my calculations are in my workpapers, which have been supplied to NYPA.

II. COST-BASED CAPITAL RECOVERY MECHANISMS

Since rates to NYPA's preference rate customers must be cost-based, a cost-based mechanism must be found to set the annual amount to charge for the capital used. The natural starting points for this task, and the ones that underlie Auer, are the methods that have evolved to charge annually for rate-regulated companies' capital assets.

In particular, rate regulation in the U.S. and Canada often limits allowed rates to those that will just recover the cost of providing service.[5] The cost of providing service includes the cost of the capital employed, which has two components:

- A return *on* capital, consisting of a rate of return on invested asset value sufficient to compensate for the pure time value of money, inflation, and the risks borne by those supplying the capital, which is akin to interest on a bond,[6] and
- A return *of* capital, consisting of a depreciation and amortization charge, which is akin to principal repayment on a bond, but typically levied as an annual charge rather than a lump-sum payment at the end.

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[5] Other forms of regulation, such as "price cap regulation," have been adopted as well, but they are more tenuously linked to cost and so of less relevance in the present context.

[6] In rate regulation, the company must recover the pre-tax cost of capital from its customers in order to be left with an adequate rate of return after paying taxes. Since NYPA does not pay income taxes, this report can ignore them in the calculations, although they are mentioned in the discussion of principles from time to time for completeness.

The return on capital is applied to an approved valuation of the amount of capital invested, normally called the "rate base." The return of capital consists of the annual amount of depreciation and amortization allowance for the assets in the rate base.[7]

A. ORIGINAL COST ("OC") REGULATION

OC is the most widely used system used to set the return on and of capital in the U.S. and Canada, but not necessarily elsewhere. Under OC regulation, investments are added to the rate base at their historical cost and valued at depreciated historical cost until cumulative depreciation charges recover all of the invested capital.

However, inflation erodes the purchasing power of the dollars recovered through the OC depreciation charge. This erosion can be material for long-lived assets, such as those used to generate, transmit, and distribute electric power. As compensation for this erosion in the purchasing power of the return *of* capital, investors under OC regulation receive an "inflation premium" in the allowed rate of return *on* capital. This allowed rate of return is normally the "cost of capital," defined as the expected rate of return in capital markets on alternative investments of equivalent risk.[8] Thus under OC, the annual capital charge consists of (1) a depreciation charge that is based on the original, historical cost of the assets employed, plus (2) a *nominal* cost of capital (i.e., one that

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[7] The rate base typically includes not just the value of the assets actually purchased or constructed, but also a capitalized allowance for the cost of the outlays made during construction, i.e., during the years before the asset is placed in service and begins earning a return on capital in current rates. Amortization of this "AFUDC" – allowance for funds used during construction – is part of the annual recovery of capital once the asset is placed in service.

[8] This concept of the cost of capital is developed in Brealey and Myers, *op. cit.*, 7th ed., pp. 16-18 and 529-30, or more generally, Chapters 7 and 8.

includes an inflation premium) times the remaining undepreciated original cost of the assets employed, plus (3) income tax expense if applicable.

OC regulation therefore is akin to the return of and on an ordinary bond issue that happens to have a fixed annual proportion redeemed each year. The annual redemption amount (akin to the return *of* the rate base) is based on the historical face value of the bonds, and does not change even if inflation erodes the purchasing power of the bonds' principal materially. The interest rate (akin to the return *on* the rate base) is higher as a result, since the bondholders demand an inflation premium in the rate of return to make up for the lack of inflation protection in the purchasing power of the bonds' principal. Most interest rates quoted in the financial pages are nominal interest rates, which reflect the pure time value of money, inflation, and the risks borne by the person to whom the interest is owed.

For example, suppose a rate-regulated company invests $1,000 in a 20-year asset under OC regulation. Straight-line depreciation of this asset is $1,000/20 = $50 per year. Suppose also that the overall, after-tax cost of capital on this investment is 8 percent, which includes a premium for annual inflation of 3 percent. Then the first year, the company is entitled to earn, after taxes, $1,000 x 0.08 = $80 on the investment. Its total cash flow is $50 + $80 = $130. The next year, the company will have recovered $50 in depreciation charges, so the remaining, "rate base" value of the investment is $1,000 - $50 = $950. It is entitled to another $50 in depreciation charges, but its earnings now should be only $950 x 0.08 = $76. Its second year cash flow will be $50 + $76 = $126. This process continues until the asset is fully depreciated 20 years later.

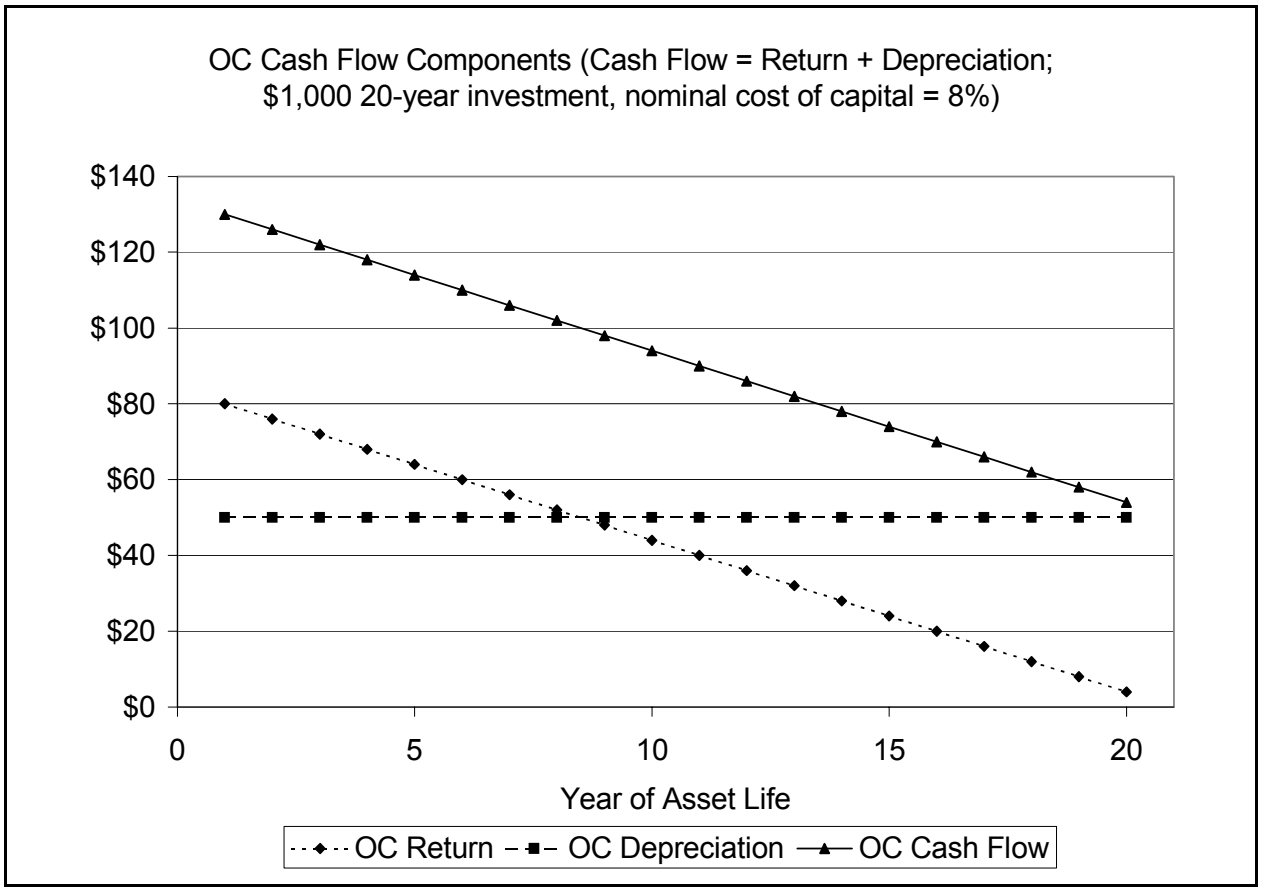

Figure 3

Figure 3 graphs this series of cash flows through the life of the asset. Annual depreciation expense is a constant $50, but the return on capital declines linearly as the asset is depreciated. That makes the final year's return very small, 8 percent of the final $50 of undepreciated rate base, or $4.

B. TRENDED ORIGINAL COST ("TOC") REGULATION

TOC is another purely cost-based system that is sometimes used. TOC is similar to OC in some ways, but inflation compensation comes through growth in the value of the assets rather than

in a premium in the rate of return on those assets. This turns out to change the pattern of annual capital charges on each asset over its life.[9]

The depreciation charge and the value of the rate base under TOC are based on historical cost adjusted for cumulative inflation, either using (1) a general inflation index (to maintain the purchasing power of the dollars involved), or (2) an industry construction cost index (to track the net replacement cost of the assets).[10] The rate of return is reduced from the nominal cost of capital by the expected annual rate of increase in the inflation index used, to avoid compensating for inflation twice. Taxes, if applicable, are calculated to leave the right after-tax capital charge in the company's hands.[11]

The chief advantage of TOC over OC is that it better replicates the capital charges implicit in competitive prices. The price of power from two identical plants regulated on OC but constructed in different years will differ, solely due to inflation. But the price of tomatoes does not depend on the age of the tractor. The average price of power under TOC need not depend on the age of the power plant, either, if the depreciation schedule were chosen to achieve this end.[12] And even without a precisely calculated depreciation schedule, TOC will come closer than OC to the capital charges

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[9] See Stewart C. Myers, A. Lawrence Kolbe and William B. Tye, "Inflation and Rate of Return Regulation," *Research in Transportation Economics* 2 (1985), 83-119, and William B. Tye and A. Lawrence Kolbe, "Optimal Time Structures for Rates in Regulated Industries," *Transportation Practitioners Journal* 59 (1992), 176-196.

[10] If an industry construction cost index is used and its expected inflation rate differs from the expected rate of general inflation, an offsetting adjustment should be made to the TOC allowed rate of return. This issue is moot under the Auer version of TOC, since it provides no TOC allowed rate of return.

[11] Of course, tax and regulatory depreciation charges differ even under OC. Under TOC, the calculation also has to take account of the fact that the IRS treats the inflation adjustment to the depreciation charge as income, not depreciation.

[12] See Tye and Kolbe, *op. cit.*, in particular, for discussion of this issue. I am indebted to Stewart C. Myers for the "tomatoes theorem" stated in the text.

implicit in competitive prices, since asset values under competition do grow in value because of inflation. Landlords, for example, expect part of their return through appreciation of property values, in addition to whatever cash return rent provides.

TOC regulation therefore is akin to an issue of inflation-indexed bonds, such as some issued by the U.S. or U.K. governments, that happens to have a fixed proportion redeemed each year. The annual redemption amount (i.e., the return *of* capital) of this type of bond will grow with inflation. However, the interest rate for the current cash return on capital is lower than on ordinary bonds, since investors do not require an inflation premium to make up for the (non-existent) loss in the purchasing power of their principal. The inflation part of the return on capital comes from appreciation of the bond's redemption value, not in cash as with a conventional bond.

Consider the previous example of a $1,000 investment under OC. Under TOC, the depreciation charge is held constant in purchasing power, not in historical dollars. If inflation runs at 3 percent, it takes $50 x 1.03 = $51.50 in end-of-year dollars to buy as much as $50 would have purchased at the start of the year. The first year's depreciation charge under TOC is therefore $51.50. Since inflation compensation occurs through asset appreciation, it must be removed from the rate of return the regulated company earns. Instead of 8 percent, the company requires only 8% - 3% = 5% on its rate base.[13] Thus the first year's TOC return is $1,000 x 0.05 = $50, and the total first year cash flow is $51.50 + $50 = $101.50.

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[13] As a technical note, with discrete compounding, the "real" cost of capital in this example will equal (1.08/1.03 - 1) = 4.85 percent, not 5 percent. Nonetheless, 5 percent is the right allowed rate of return, since the discrete return is received in end-of-year dollars. That means the end-of-year rate of return needs to be (4.85% x 1.03) = 5%. In the actual calculations, I assume investment outlays and capital charge receipts occur mid-year and use annual compounding with this convention.

In the second year, two things happen to the rate base: it decreases in value due to depreciation, but it increases in value due to inflation. The decrease due to depreciation is the $51.50 already calculated. The increase in the rate base is $1,000 x 0.03 = $30. Thus the rate base at the start of the second year is $1,000 - $51.50 + $30 = $978.50. Depreciation on that rate base has to be the original $50 in end-of-year-two dollars, or $50 x 1.03 x 1.03 = $53.045. The return on the rate base is $978.50 x .05 = $48.925. The total cash flow in the second year is therefore $53.045 + $48.925 = $101.97. This continues until the asset is fully depreciated. In year 20, the depreciation charge is $50 x $(1.03)^{20}$ = $50 x 1.806 = $90.31. This may seem like a lot, but it buys exactly the same amount as $50 did when the investment was made. By the last year the rate base is down to $87.68 (which is the final $50 in historical cost x $(1.03)^{19}$, cumulative inflation through the start of the last year), and the return on capital is $87.68 x 0.05 = $4.38. The total capital charge is $90.31 + $4.38 = $94.69. The TOC capital charges for all years appear in Figure 4.

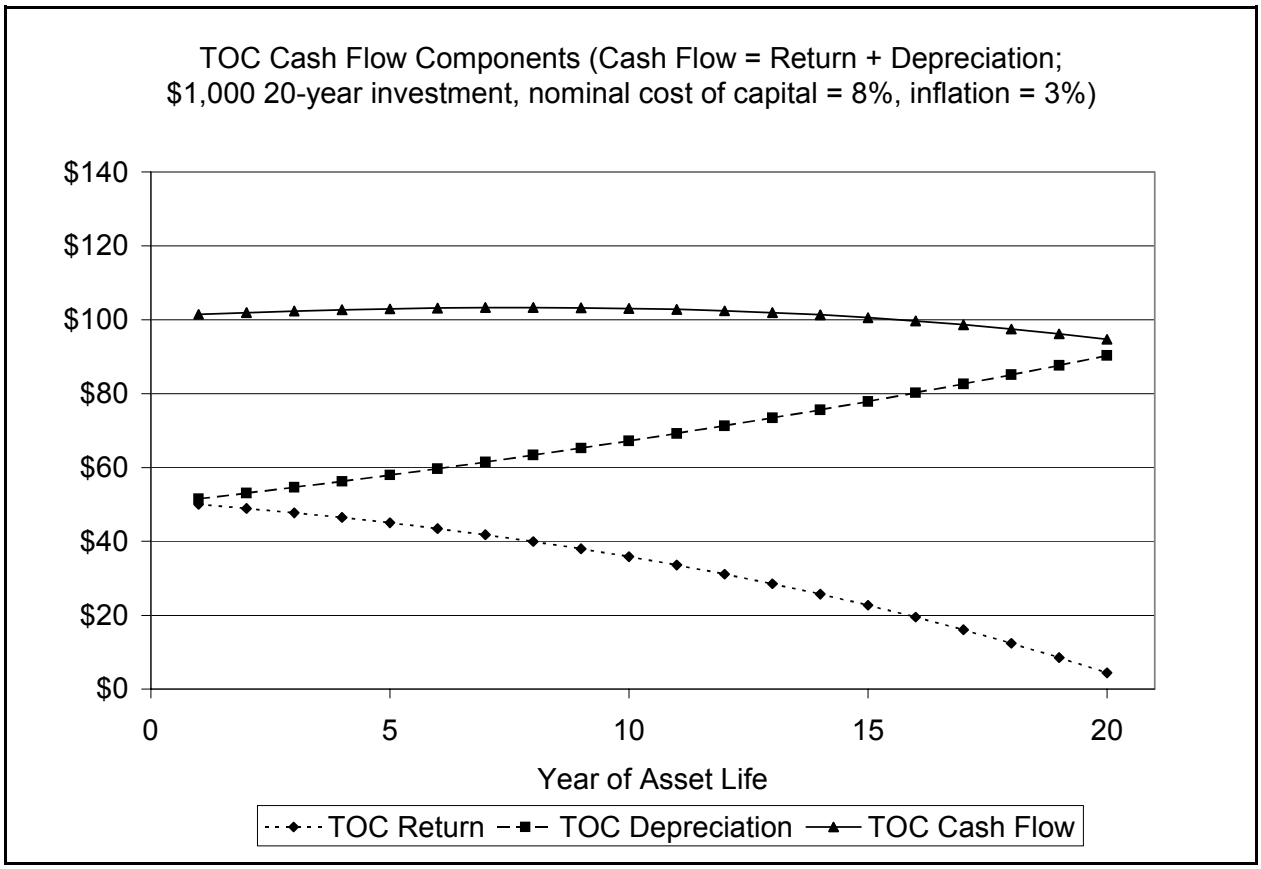

Figure 4

C. COMPARISON OF OC AND TOC

Figure 1, at the outset of this report, compared the total capital annual charges for OC and TOC under these assumptions. Figure 5 compares the components head to head. The OC return starts higher than the TOC return, because the former includes an inflation premium and the latter does not. OC depreciation stays flat in nominal dollars, while TOC depreciation grows with inflation. Under Auer, NYPA may collect only this TOC depreciation charge for assets financed by equity.

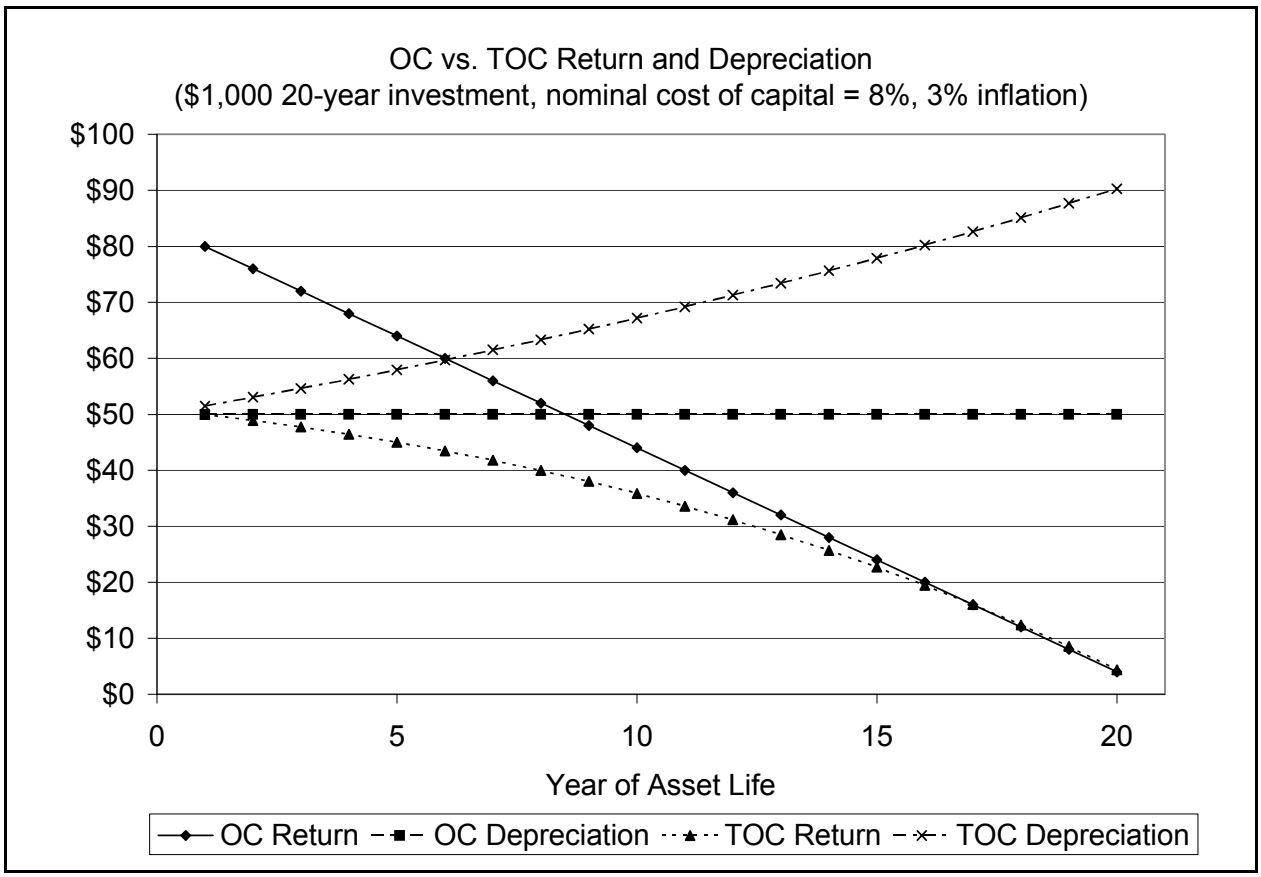

Figure 5

The essential difference between OC and TOC is the treatment of inflation. It therefore is useful to recall that the dollars in the graphs to this point are not strictly comparable year to year, since they buy ever-shrinking amounts as time passes. Figure 6 makes this clear by restating the total annual capital charges of Figure 2 in dollars of constant purchasing power, or "real" dollars in the economic jargon. Figure 6's TOC capital charges have the same linear shape as Figure 2's OC capital charges, but are less steeply sloped. Figure 6's OC capital charges decline exponentially, as inflation erodes the value of the dollar.

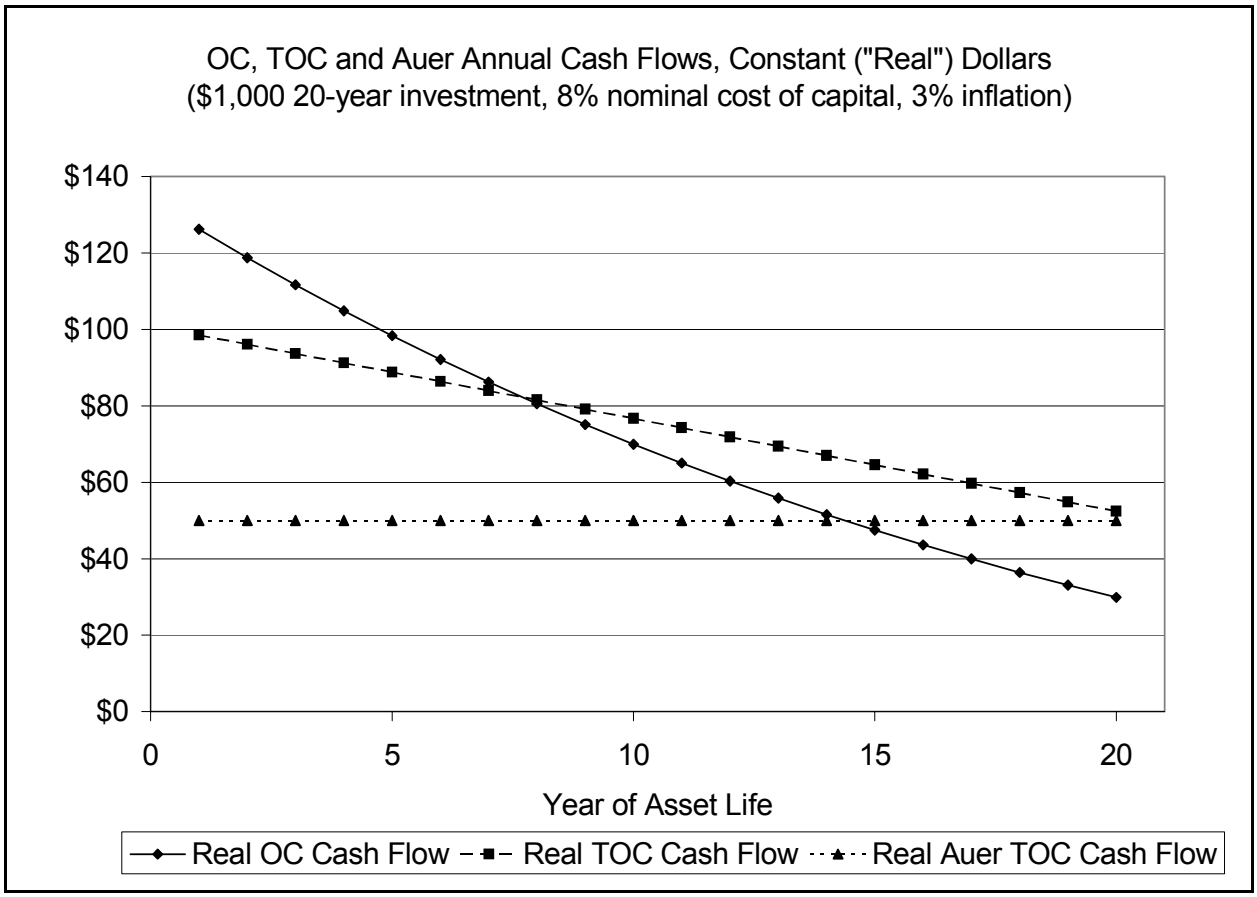

Figure 6

Figure 6 also plots the real TOC capital charges under Auer. This makes clear that Auer only provides depreciation in dollars of constant purchasing power. Under Auer, NYPA agreed to forego of the return on its TOC investment, which is the area between the "Real TOC Cash Flow" and "Real Auer TOC Cash Flow" lines. The OC and TOC in Figure lines have the same present value (if discounted at the real rather than nominal cost of capital), equal to the $1,000 initial investment, but the Auer line again has a present value of only $631. Moreover, as noted above, since NYPA's assets have much longer lives than the example's assets, the actual shortfall from full cost recovery for NYPA will be a higher proportion of the initial investment than this. With a 50-year asset and

these assumptions otherwise, the initial present value of the Auer depreciation charges is only $373. Thus, NYPA has agreed under Auer to forego well over half of its equity investment.

III. IMPLEMENTATION OF THESE PRINCIPLES FOR NYPA

NYPA charged for its interest expense and depreciation while it had outstanding debt on the original hydroelectric facilities. This is like OC. After the debt was retired in 1981, it continued to charge for its remaining unrecovered depreciation plus a rate of return equal to inflation only, but in 1983 started setting the depreciation amount in accord with TOC using a construction cost index, an approach codified by Auer, and foregoing a current return on capital entirely. Thus, under Auer NYPA does *not* include a charge for the rate of return on capital to which it would be entitled under TOC regulation. As discussed in the previous section of this report, a regulated company under TOC would charge both for trended depreciation *and* for a "real" rate of return (i.e., a rate of return without an inflation premium) on the current trended rate base.

As also noted above, NYPA has informed me that the principles of the Auer settlement continue to apply in determining cost-based rates for its new hydroelectric investments. This implies the debt-backed part of the new investments will be charged for interest expense as well as depreciation. The equity-backed parts of the new investments, like the old investments, will be charged only for depreciation, not depreciation plus a real rate of return as under TOC. However, equity-backed investments will accrue an inflation-based write-up, and this write-up will be amortized in future years, as under TOC. The remainder of this section describes my implementation of this approach.

A. GENERAL METHODOLOGY

My model calculates the capital charges for NYPA's hydroelectric assets for the years 2001 through 2006, including the test year (October 1, 2001 to September 30, 2002). The model distinguishes two general categories of investments, existing assets and new investments. The existing assets include all investments made by NYPA before 2000 and some of the equity-financed investments made in 2000. All investments made after 2000 and some of the 2000 investments are part of the "new investments."

Existing assets get one kind of capital charge, depreciation and amortization of past inflation-based write-ups under the Auer version of TOC. The capital structure for new investments changes from year to year in ways specified by NYPA. Annual capital charges on new investments in any year are the sum of depreciation and amortization of past inflation-based write-ups on those investments, plus interest expense on the parts of the new investments financed with debt. Total capital charges for the test year and for calendar years 2003 to 2006 are shown in Table 1, discussed at the outset of this report.

B. SPECIFIC PROCEDURES

Test Year: A complication arises from the timing of the test year. Usually, NYPA distinguishes calendar (January to December) and rate (May to April) years. For example, the rates charged from May 1, 2005 to April 30, 2006 are based on the forecasted costs for the calendar year 2005. However, the test year was scheduled from October 1, 2001 to September 30, 2002. The rates based on the test year will be charged retroactively from December 18, 2001 through April 30, 2003.

The rates effective starting May 1, 2003 will be based, as usual at NYPA, on forecasted costs for the calendar year 2003.

NYPA instructed me to calculate the capital charges for the test year by adding one quarter of the capital charges of calendar year 2001 and three quarters of the capital charges of calendar year 2002. (Table 2 reports the Table 1 data but with the test year broken into its 2001 and 2002 components, to show the basis of the test-year calculation.) This causes additional underrecovery of NYPA's capital costs for the calendar year 2002. That is, since NYPA is investing new capital on an ongoing basis, the capital charges calculated for the last quarter of 2002 would be higher than the capital charges for the last quarter of 2001. Under the regular schedule, the rates charged in 2002 would be based on the capital charges for 2002. The timing of the test year causes NYPA to under-recover capital charges in 2002.

Costs of Ancillary Services: The ancillary services costs will be subtracted from NYPA's total cost, including capital charges, as calculated in the Ancillary Services Model developed by Mr. Graves. Therefore, my Capital Charge Model does not consider ancillary services-related issues.

Inflation Rates: NYPA requested that I recommend an inflation rate for future capital costs, and I have used an inflation rate of 2.5 percent in these calculations. This is the five-year average forecast of the annual change in the Consumer Price Index ("CPI") for all urban consumers for the period 2004 to 2008, as published by *Blue Chip Economic Indicators* on October 10, 2002. According to my calculations, from 1970 to 2001 the average changes in the Engineering News-Record ("ENR") Construction Cost Index were very similar to changes in the CPI. On average, from 1970 to 2001 the Construction Cost Index exceeded the CPI by 0.13 percentage points. The average change in the Handy Whitman Index of Public Construction Costs ("HWI") was also similar to the

change in the CPI. According to my calculations, from 1981 to 2000, the average change in the HWI was 0.57 percentage points below the average change in the CPI. The difference is not statistically significant at conventional levels. Therefore, in my opinion, the forecasted inflation of the CPI is an appropriate measure of the expected changes in NYPA's capital cost levels that are caused by inflation.

Cost of Debt: NYPA provided me with a schedule of their expected new debt issues between 2000 and 2006. The schedule is separated into debt issued for Niagara and St. Lawrence and, in the case of Niagara, distinguishes tax-exempt and taxable debt. For each issue, NYPA gave me the issue amount and the expected interest rate.

NYPA will issue debt at irregular intervals. Therefore, the actual amounts of debt issued and the amounts of debt implied by NYPA's investment plan will be different at most points in time. For example, one large debt issue will normally be cheaper than several smaller ones. NYPA's investment plan includes a financing structure. However, if NYPA chooses to diverge from its investment plan's financing structure because of other considerations, such as underwriting cost minimization, an issue arises as to how to treat the interest expense on the difference between funds raised and funds invested. Under standard cost-based ratemaking principles, NYPA earns a return on and of the money it invests to provide service, not the money it raises. The focus of the rate base is the asset side of the balance sheet, not the liability side. Under this principle, for example, NYPA should not be able to recover additional capital costs in rates from a security issue that is larger than immediately necessary until the proceeds actually are invested to provide hydroelectric service. I adopt this principle in my calculations.[14]

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[14] NYPA normally would be entitled to an allowance for funds used during construction. However, NYPA has informed me that it does not wish to include this charge, which further reduces its rates below the

With the exception of a $66.3 million tax-exempt issue in 2000, NYPA expects all debt during the period in question to be issued as commercial paper, with maturities of not more than 270 days (the debt is rolled over at maturity). Since all of the taxable debt and later tax-free commercial paper is short-term, I use the current year's rates on that debt to calculate interest charges. NYPA currently plans to convert outstanding commercial paper into 40-year fixed rate debt in 2008 (debt issued for Niagara plant) and 2011 (debt issued for St. Lawrence plant). The 2000 debt issue was not in the form of commercial paper, but instead had already a 40-year maturity. Repayment of this issue will not start until 2020.

Since the year 2000 tax-exempt issue remains outstanding, its interest rate does not change annually. No new tax-exempt debt is issued until 2005, when the projected interest rate differs. For 2005 and 2006, I calculate the weighted-average cost of tax-exempt debt using the year 2000 issue and the total tax-exempt commercial paper issues in those years.

For the headquarters' hydroelectric portion of investments, NYPA uses equity only, a policy reflected in my calculations.

Year 2000 Financing: One complication arises for the year 2000. Total new investments at Niagara were $18.1 million. However, $5.1 million of this was already accounted for in the (equity) capital charge for prior investments. Since the capital charge for the equity-financed $5.1 million is already in the capital charges on old assets, I exclude this amount from the calculation of new investment capital charges.

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cost-based level.

C. CALCULATION OF CAPITAL CHARGES

As described above, three asset classes need to be treated separately in my model: existing assets, debt-financed new investments, and equity-financed new investments. Starting with the year 2000, the capital expenditures as provided by NYPA are broken down into investments at the hydroelectric plants, Niagara and St. Lawrence, and allocated headquarters investments. NYPA further classifies the hydroelectric plant investments as Upgrade, Addition, Other/LEM (Life Extending Maintenance), or Relicensing. A total of nine investment categories (four for each hydroelectric facility plus headquarters) results. NYPA provided depreciation rates for each category and instructions to use these historically-based rates to depreciate future investments. NYPA supplied the fractions of the new investments that are financed with tax-exempt debt, taxable debt, and equity, as described above. While the depreciation rates differ among the four investment categories of each plant, the capital structure of new investments is the same for each investment category within the same plant. The capital structure only varies by plant (Niagara, St. Lawrence, or headquarters) and year.

Table 1, discussed at the outset of the report, provides the overall capital charge amounts for the test year and for 2003-2006. Table 2 shows the Table 1 test year components separately. The remainder of this part of the report discusses the derivation of the data in Tables 1 and 2.

Capital Charges for Existing Assets: NYPA has calculated capital charges of existing assets based on TOC depreciation with a return on equity of zero. In 2001, the total TOC depreciation charge was $39.4 million composed of a straight-line (OC) base depreciation of $24.3 million and an amortization of accumulated inflation component of $15.1 million (see Table 3). Following the TOC methodology, the sum of (1) the historical cost depreciation charge, which is

equivalent to OC deprecation on these assets, plus (2) the amortization of the inflation-based write-up, will increase annually at the inflation rate. However, some of the existing assets will be retired, or fully depreciated, in the future. NYPA assumes that an amount equal to 2.5 percent of the existing capital at the end of 2000 will be retired each year. Therefore, the existing capital OC base depreciation is expected to decline by about $0.61 million (= $24.3 million x 2.5 percent) per year. According to this schedule, the existing capital will be completely depreciated by 2041 and will not incur additional depreciation charges after that time. Existing capital does not incur any interest charges or return on equity, per Auer.

Capital Charges for New Debt-Financed Investments: The treatment of new investments varies with capital structure. Table 4 reports NYPA's planned capital structures for the new investments. The depreciation charges caused by debt-financed new investments are based on a straight-line, OC depreciation schedule starting in the year following the investment. For example, an investment made during 2004 will receive its first depreciation charge in 2005. The depreciation charges are shown in Table 5.

New investments financed with debt incur and recover interest expense. The interest charge for a particular year is calculated by multiplying the prior year's debt-backed rate base times the prior interest rate, i.e., the interest rate in effect at the time the capital was committed to use. (All investment outlays and capital charge receipts are assumed to occur mid-year.) For example, for an investment made during 2004, the first interest charge occurs in 2005 and is calculated by multiplying the original investment amount times the appropriate 2004 interest rate. For each investment, I keep track of which fractions were financed with tax-exempt and taxable debt. I use this information to calculate interest charges separately for tax-exempt and taxable debt. The total

interest charges and new investment-related debt amounts are shown in Table 6. The depreciated values of debt-financed new investments are presented in Table 7. These value change year to year not only because of depreciation, but also because of the changing capital structures shown in Table 4.

Capital Charges for New Equity-Financed Investments: TOC-type depreciation represents the only capital charge for equity-financed new investments, since equity-financed new investments do not receive a return on capital. As with the OC depreciation charges, the first TOC depreciation charge for a new investment occurs in the year after the investment was made. For example, for an investment made during 2004, the first TOC depreciation charge occurs in 2005. It is calculated by multiplying the original investment times the OC depreciation rate, and increasing the result by the inflation rate. Then the TOC depreciation increases by the inflation rate each year. Once the asset reaches the end of its assumed life and is fully depreciated, depreciation drops out of the capital charge. TOC depreciation charges for equity-financed new investments were reported in Table 2, and the underlying OC depreciation and amortization of inflation-based write-up components are presented in Tables 8 and 9, respectively.

Collectively, these results produce the numbers in Table 1, which are the values used by NYPA in its rate calculations.

Tables

Table 1
Capital Charges for Existing Assets and New Investments - Test Year ($ in 000s)

	Existing Assets		New Investments				
			Debt-Financed		Equity-Financed		
	Original Cost Depreciation [1]	Amortization of Write-Up ("Inflation") [2]	Original Cost Depreciation [3]	Interest [4]	Original Cost Depreciation [5]	Amortization of Write-Up ("Inflation") [6]	Total [7]
Test Year [8]	23,874	15,532	350	730	755	19	41,259
2003	23,114	16,235	838	1,854	2,646	90	44,777
2004	22,505	16,766	5,618	8,400	482	102	53,873
2005	21,897	17,268	7,430	14,176	667	119	61,557
2006	21,289	17,740	8,718	19,871	1,425	156	69,200

Notes:
[1]: Table 2 [1]
[2]: Table 2 [2]
[3]: Table 2 [3]
[4]: Table 2 [4]
[5]: Table 2 [5]
[6]: Table 2 [6]
[7]: [1] + [2] + [3] + [4] + [5] + [6]
[8]: The test year charges consist of one quarter of 2001 charges and three quarters of 2002 charges.

Table 2
Capital Charges for Existing Assets and New Investments - Calendar Year ($ in 000s)

	Existing Assets		New Investments				
			Debt-Financed		Equity-Financed		
	Original Cost Depreciation [1]	Amortization of Write-Up ("Inflation") [2]	Original Cost Depreciation [3]	Interest [4]	Original Cost Depreciation [5]	Amortization of Write-Up ("Inflation") [6]	Total [7]
2001	24,330	15,094	174	378	144	4	40,125
2002	23,722	15,678	409	847	958	23	41,636
2003	23,114	16,235	838	1,854	2,646	90	44,777
2004	22,505	16,766	5,618	8,400	482	102	53,873
2005	21,897	17,268	7,430	14,176	667	119	61,557
2006	21,289	17,740	8,718	19,871	1,425	156	69,200

Notes:
[1]: Table 3 [1]
[2]: Table 3 [4]
[3]: Table 5 [10]
[4]: Table 6 [6]
[5]: Table 8 [10]
[6]: Table 9 [10]
[7]: [1] + [2] + [3] + [4] + [5] + [6]

Table 3
Capital Charges for Existing Assets - Calendar Year ($ in 000s)

	Original Cost Depreciation [1]	Inflation Rate [2]	Cumulative Inflation Factor [3]	Amortization of Write-Up ("Inflation") [4]	Total [5]
2001	24,330	1.99%	1.62	15,094	39,424
2002	23,722	2.50%	1.66	15,678	39,399
2003	23,114	2.50%	1.70	16,235	39,349
2004	22,505	2.50%	1.74	16,766	39,271
2005	21,897	2.50%	1.79	17,268	39,165
2006	21,289	2.50%	1.83	17,740	39,029

Notes:
[1]: 2001: Provided by NYPA
2002-2006: Value of previous year less the annual retirement amount (2001 Original Cost Depreciation x 2.5%, provided by NYPA)
[2]: 2001: Actual change in Handi-Whitman Index; 2002-2006: Based on Blue Chip CPI forecast
[3]: 2001: [4] / [1] + 1; 2002-2006: prior year value of [3] x (1 + [2])
[4]: 2001: Provided by NYPA; 2002-2006: [1] x ([3] - 1)
[5]: [1] + [4]

Table 4
Capital Structure of New Investments

	Niagara			St. Lawrence			Headquarters		
	Percent of Financing			Percent of Financing			Percent of Financing		
Year	Tax-Exempt Debt [1]	Taxable Debt [2]	Equity [3]	Tax-Exempt Debt [4]	Taxable Debt [5]	Equity [6]	Tax-Exempt Debt [7]	Taxable Debt [8]	Equity [9]
2001	39%	0%	61%	0%	0%	100%	0%	0%	100%
2002	39%	0%	61%	0%	0%	100%	0%	0%	100%
2003	39%	61%	0%	0%	100%	0%	0%	0%	100%
2004	39%	61%	0%	0%	100%	0%	0%	0%	100%
2005	39%	55%	5%	0%	91%	9%	0%	0%	100%
2006	39%	45%	15%	0%	75%	25%	0%	0%	100%

Notes:
[1] - [9]: Supplied by NYPA. Percentages may not add to 100% due to rounding.

Table 5
Depreciation Excluding Amortization of Write-up for Debt-Financed New Investments ($ in 000s)

	Year						
	2000	2001	2002	2003	2004	2005	2006
Niagara							
[1] Upgrade	0	174	323	563	2,052	2,523	2,846
[2] Additions	0	0	86	101	281	323	346
[3] Other	0	0	0	63	240	330	413
[4] Relicensing	0	0	0	111	463	764	1,017
St. Lawrence							
[5] Upgrade	0	0	0	0	1,093	1,508	1,927
[6] Additions	0	0	0	0	275	323	339
[7] Other	0	0	0	0	112	275	349
[8] Relicensing	0	0	0	0	1,100	1,385	1,481
[9] Headquarters	0	0	0	0	0	0	0
[10] Total	**0**	**174**	**409**	**838**	**5,618**	**7,430**	**8,718**

Notes:
[1]: Workpaper 1a [8]
[2]: Workpaper 2a [8]
[3]: Workpaper 3a [8]
[4]: Workpaper 4a [8]
[5]: Workpaper 5a [8]
[6]: Workpaper 6a [8]
[7]: Workpaper 7a [8]
[8]: Workpaper 8a [8]
[9]: Workpaper 9a [8]
[10]: Sum of column

Table 6
Interest Expense of New Investments ($ in 000s)

Year	Prior Year's Taxable Debt [1]	Prior Year's Tax-Exempt Debt [2]	Prior Year's Total Debt [3]	Prior Year's Taxable Interest Rate [4]	Prior Year's Tax-Exempt Interest Rate [5]	This Year's Total Interest Expense, as Payment for Prior Year's Debt [6]
2001	0	7,141	7,141		5.30%	378
2002	0	15,976	15,976	4.11%	5.30%	847
2003	0	34,986	34,986	2.03%	5.30%	1,854
2004	191,031	50,362	241,392	3.00%	5.30%	8,400
2005	252,345	65,112	317,457	4.25%	5.30%	14,176
2006	288,148	80,348	368,495	5.50%	5.01%	19,871

Notes:
[1]: Table 7 [2], amount from prior year
[2]: Table 7 [1], amount from prior year
[3]: [1] + [2]
[4]: NYPA forecast, prior year's rate
[5]: NYPA forecast, prior year's rate
[6]: ([1] x [4]) + ([2] x [5])

Table 7
Rate Base for Debt-Financed New Investments ($ in 000s)

		Year						
		2000	2001	2002	2003	2004	2005	2006
[1]	Tax-Exempt	7,141	15,976	34,986	50,362	65,112	80,348	96,595
[2]	Taxable	0	0	0	191,031	252,345	288,148	272,603
[3]	**Total**	**7,141**	**15,976**	**34,986**	**241,392**	**317,457**	**368,495**	**369,198**

Notes:
[1]: Sum of tax-exempt debt in Workpaper 1a [4] to Workpaper 9a [4]
[2]: Sum of taxable debt in Workpaper 1a [5] to Workpaper 9a [5]
[3]: [1] + [2]

Table 8
Depreciation Excluding Amortization of Write-up for Equity-Financed New Investments ($ in 000s)

	Year						
	2000	2001	2002	2003	2004	2005	2006
Niagara							
[1] Upgrade	0	144	496	864	0	0	163
[2] Additions	0	0	132	155	0	0	20
[3] Other	0	0	0	97	0	0	24
[4] Relicensing	0	0	0	170	0	0	58
St. Lawrence							
[5] Upgrade	0	0	50	560	0	0	190
[6] Additions	0	0	191	235	0	0	33
[7] Other	0	0	0	19	0	0	34
[8] Relicensing	0	0	0	312	0	0	146
[9] Headquarters	0	0	89	233	482	667	757
[10] **Total**	**0**	**144**	**958**	**2,646**	**482**	**667**	**1,425**

Notes:
[1]: Workpaper 1b [6]
[2]: Workpaper 2b [6]
[3]: Workpaper 3b [6]
[4]: Workpaper 4b [6]
[5]: Workpaper 5b [6]
[6]: Workpaper 6b [6]
[7]: Workpaper 7b [6]
[8]: Workpaper 8b [6]
[9]: Workpaper 9b [6]
[10]: Sum of column

Table 9
Amortization of Write-Up ("Inflation") for New Investments ($ in 000s)

	Year						
	2000	2001	2002	2003	2004	2005	2006
Niagara							
[1] Upgrade	0	4	14	36	36	36	40
[2] Additions	0	0	3	7	7	7	7
[3] Other	0	0	0	2	2	2	3
[4] Relicensing	0	0	0	4	4	4	6
St. Lawrence							
[5] Upgrade	0	0	1	15	15	15	20
[6] Additions	0	0	4	10	10	10	11
[7] Other	0	0	0	0	0	0	1
[8] Relicensing	0	0	0	8	8	8	11
[9] Headquarters	0	0	2	8	20	37	57
[10] **Total**	**0**	**4**	**23**	**90**	**102**	**119**	**156**

Notes:
[1]: Workpaper 1d [3]
[2]: Workpaper 2d [3]
[3]: Workpaper 3d [3]
[4]: Workpaper 4d [3]
[5]: Workpaper 5d [3]
[6]: Workpaper 6d [3]
[7]: Workpaper 7d [3]
[8]: Workpaper 8d [3]
[9]: Workpaper 9d [3]
[10]: Sum of column

Appendix

Appendix: QUALIFICATIONS OF A. LAWRENCE KOLBE

Lawrence Kolbe is a Principal of The Brattle Group ("Brattle"), an economic, environmental and management consulting firm with offices in Cambridge (Massachusetts), Washington, London, and the San Francisco Bay area. Before co-founding The Brattle Group, he was a Director of Putnam, Hayes & Bartlett, and before that, he was a Vice President of Charles River Associates ("CRA"). Earlier, he was an Air Force officer assigned to the Office of the Secretary of Defense with the job title "Health Economist," and before that, he was assigned to Headquarters, USAF with the job title "Systems Analyst."

His work has included extensive research in financial economics, especially as it applies to rate regulation, project or asset valuation, and the decisions of regulated firms. Clients for this work include the California Public Utilities Commission, the Consumer Advocate in a Newfoundland proceeding, the Edison Electric Institute, the Electric Power Research Institute, the Interstate Natural Gas Association of America, the Newfoundland Federation of Municipalities, the Nova Scotia Board of Commissioners of Public Utilities, the Town of Labrador City, the U.S. Department of Energy, the U.S. Department of State, and a number of private firms.

He is the coauthor of three books and he has published a number of articles. He is coauthor of a report filed with the British Office of Fair Trading, in London, and he has been an expert witness in: proceedings before the U.S.-U.K. Arbitration Concerning Heathrow Airport Landing Charges (under the auspices of the International Bureau of the Permanent Court of Arbitration) in The Hague, the Iran-United States Claims Tribunal in The Hague, U.S. District Courts in Arizona, Colorado, New Jersey, Oklahoma, Pennsylvania, Texas and Virginia, the Supreme Court of the State of New Mexico, a commercial arbitration tribunal in Australia, a commercial arbitration tribunal held in London concerning a dispute in Australia, the Minerals Management Service of the U.S. Department of the Interior, the Master Settlement Agreement Tobacco Arbitration Panels for the State of Louisiana and the Commonwealth of Massachusetts (which determined fee awards to private counsel assisting the state), and a commercial arbitration in Arizona; federal regulatory proceedings before the Canadian Radio-television and Telecommunications Commission, the [Canadian] National Energy Board, the [U.S.] Postal Rate Commission, the [U.S.] Surface Transportation Board, the U.S. Federal Communications Commission, the U.S. Federal Energy Regulatory Commission and the U.S. Federal Maritime Commission; and state or provincial regulatory proceedings in Alaska, Alberta, Arkansas, California, Connecticut, Illinois, Maine, Massachusetts, Michigan, Montana, Newfoundland, New Mexico, New York, Nova Scotia, Ohio and Virginia.

He holds a B.S. in International Affairs (Economics) from the U.S. Air Force Academy and a Ph.D. in Economics from the Massachusetts Institute of Technology. Additional information on his qualifications follows.

HONORS AND AWARDS

Sears Foundation National Merit Scholarship, 1963 (declined).

Fairchild Award, U.S. Air Force Academy, 1968 (for standing first in his class, academically).
National Science Foundation Graduate Fellowship in economics, MIT, 1968-1971.
Joint Service Commendation Medal, 1975.

PROFESSIONAL AFFILIATIONS

American Economic Association
American Finance Association
The Econometric Society
Served as Referee for *The Rand Journal of Economics*, *Land Economics*, *The Journal of Industrial Economics*

AVAILABLE PAPERS AND PUBLICATIONS

Capital Investment and Valuation, (with Richard A. Brealey and Stewart C. Myers, with "The Brattle Group" listed as third author), New York: McGraw-Hill/Irwin (2003).

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The Brattle Group Report
On
Ancillary Services

NEW YORK POWER AUTHORITY
HYDROELECTRIC PROJECT PRODUCTION RATES

REPORT OF FRANK C. GRAVES
THE BRATTLE GROUP

PREPARED FOR THE NEW YORK POWER AUTHORITY

ON

THE EMBEDDED COSTS OF PRODUCTION OF ANCILLARY SERVICES
AT THE NIAGARA AND ST. LAWRENCE HYDROELECTRIC PROJECTS,
2001-2006

January 22, 2003

ANNUAL COST-BASED CAPITAL CHARGES FOR THE HYDROELECTRIC INVESTMENTS OF THE NEW YORK POWER AUTHORITY, 2001-2006

Frank C. Graves
The Brattle Group
44 Brattle Street
Cambridge, Massachusetts 02138

January 22, 2003

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FOR THE HYDROELECTRIC INVESTMENTS OF THE
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ANNUAL COST-BASED CAPITAL CHARGES FOR THE HYDROELECTRIC INVESTMENTS OF THE NEW YORK POWER AUTHORITY, 2001-2006

I. INTRODUCTION AND SUMMARY

My name is Frank C. Graves. I am a Principal of The Brattle Group, Inc. ("Brattle") an economic, environmental and management consulting firm with offices in Cambridge, Washington, London, and the San Francisco Bay area. My work concentrates on financial and regulatory economics with a particular focus in the electric industry.

I have been asked by the New York Power Authority ("NYPA") to calculate the embedded cost of ancillary services through 2006 for its Niagara and St. Lawrence hydroelectric facilities, for the purpose of helping to determine the generation rates to be charged to NYPA's "preference rate customers." In the context of the hydro cost of service, the term "preference rate customers" means customers entitled to receive Niagara and/or St. Lawrence hydroelectricity at cost. The ancillary service costs I identify should be deducted from the total hydro cost of service before determining cost-based rates for generation.

A. QUALIFICATIONS

The Brattle Group's specialties include financial economics, regulatory economics, and the electric and gas industries. I personally have over 20 year of experience consulting in the electric and gas industries and have been deeply involved in the restructuring of electric power and natural gas markets, including investigations into the effect of restructuring on hydro generators. Regarding

hydro, for various clients I have helped to unbundle ancillary service embedded costs, investigated market opportunities for hydro (including both ancillary service and energy markets), and evaluated and optimized operating strategies for hydro assets (again, for both ancillary services and energy). More broadly, my work has involved utility ratemaking, service design and rate design; unbundling of generation, transmission, distribution, and ancillary services; investment and contract valuation; strategies for coping with regulatory restructuring; transmission system analysis for developing access terms, conditions, and prices; and risk management. I have published in professional and trade journals, am an occasional lecturer at MIT, and am a member of several professional societies. I hold a Bachelor's Degree from Indiana University (Bloomington, Indiana) in mathematics and psychology and a Master's Degree in management with a concentration in finance from the Sloan School of Management at the Massachusetts Institute of Technology. Additional information on my qualifications is contained in Appendix.

B. SUMMARY OF FINDINGS

The move to competitive generation markets and the start of operations by the New York Independent System Operator ("NYISO", or "ISO") have fundamentally changed the nature of the electric industry in the New York Control Area ("NYCA"). One change is that electric service has now been unbundled into separate component products. Prior to the new market structure, the incumbent utility provided customers with all aspects of electric power, bundling generation (capacity and energy) together with all of the network support services that are necessary to deliver it reliably. Now, the ISO's new market structure distinguishes and charges separately for these network support services. The ISO acquires these support services from competitive suppliers, and

passes the cost of each unbundled service or product through to customers, separate from the cost of generation.

These changes in the industry unbundle the components of electric service, and thus it is appropriate that NYPA unbundle its costs, separating out from its hydro cost of service the embedded cost that are associated with these ancillary services. I have been asked by NYPA to perform this unbundling of ancillary service costs in support of developing hydro generation rates. The ancillary services I consider are 1) Voltage Support, 2) Black Start, 3) Regulation, and 4) Operating Reserve. A brief description of each of these services is given in Section III of this report.

The embedded costs that I identify for these four ancillary services are not new costs, nor are the services themselves new. Rather, in the past all services and costs have been bundled together, but now the new market separates them. Starting with the total cost of service of the NYPA hydro facilities (which in total supports the provision of all electric services), I identify the relevant ancillary services that are distinct from generation, and allocate the appropriate portion of total costs to these ancillary services. After deducting the cost of these ancillary services, the remainder of the total cost of service is associated with generation, and will be used going forward to develop the cost-based generation rates for NYPA's preference rate customers. The unbundling does not change NYPA's total costs; it merely allocates these costs among energy and the ancillary services identified.

Table 1 shows the results of my analysis for the test year (October 2001-September 2002) and for calendar years 2003-2006. For each year, the O&M component of the hydro cost of service should be reduced by line [9]: Ancillary Service O&M Costs ($), and the remainder should be further reduced by line [10]: Ancillary Service O&M Share (%). In addition, the capital component of the

hydro cost of service should be reduced by line [11]: Ancillary Service Capital Share (%). Generation rates (capacity and energy charges) should be based on the costs that remain after these deductions for ancillary service costs.

II. BACKGROUND AND OVERVIEW

The start of operations of the New York ISO in November, 1999 significantly changed the operation of the electrical system in the state of New York. Prior to this, the NYISO's predecessor, the New York Power Pool ("NYPP"), operated the New York electric system, pooling the resources of the state's eight largest utilities (seven IOUs and NYPA) to reduce costs and improve reliability. With restructuring of the electric industry and the move from a regulated to a competitive power market, the NYPP members dissolved the NYPP and replaced it with an expanded entity, the NYISO. In order to make the new competitive market function properly and offer the greatest advantage for customers, and as required by the Federal Energy Regulatory Commission ("FERC"), the NYISO separates electric service into its constituent components, and it operates integrated competitive markets for energy and several ancillary services. The new market structure is intended to offer benefits in terms of improved market integration (facilitating advantageous transactions that may not have occurred previously) and market competitiveness, which should enhance efficiency in both operation and investment. But it also entails a new structure for electric services - in particular, breaking down electric power into its component services and pricing them separately.

Historically, NYPA's Niagara and St. Lawrence hydro generation rates recovered the cost of service entirely through energy and capacity charges, without breaking out charges for non-power,

or "ancillary", services. Most of these other ancillary services were nonetheless provided in the past; their costs were simply rolled into the energy and capacity charges. Because the relative need for these services varies over time and across customers, and because not all suppliers are equally adept at providing these services, the new market structure in New York unbundles electric service into its constituent components and sets out separate charges for them. The NYISO does not allow direct provision of ancillary services by a supplier for its customers. Thus, it is appropriate that the embedded costs associated with ancillary services be separated out and removed from the hydro cost of service before NYPA develops its cost-based generation rates.

In order to accomplish this, I separate out from the total hydro cost of service the costs associated with four ancillary services (Voltage Support, Black Start, Regulation, and Operating Reserve). Only the costs remaining after these deductions will be used to determine hydro generation rates (capacity and energy charges) for preference rate customers. How NYPA charges its customers for ancillary services purchased on their behalf from the NYISO is outside the scope of this report.

Note that beyond the four ancillary services considered here, a number of other ISO services and charges appear under the new market structure. Examples include Schedule 1 Services (Scheduling, System Control and Dispatch), Local Reliability Uplift; Demand Response Uplift; NYISO-wide Uplift; and Residual Adjustments. There are no NYPA hydro embedded generation costs that can be associated with these services; these are costs that arise from the nature of the restructured marketplace, unrelated to NYPA hydro assets. Since they do not affect the costs allocated to the four ancillary services considered or to generation, they are not addressed here. Similarly, I do not separate out NYPA embedded costs that correspond to ISO charges for Losses,

LSE Balancing, and Congestion. These are energy-related services provided by the ISO that have no direct connection to NYPA's proposed hydro embedded generation costs. How NYPA charges its customers for these other ISO services purchased on their behalf form the NYISO is also outside the scope of this report.

III. DESCRIPTIONS OF ANCILLARY SERVICES

The ancillary services that I identify and unbundle are Voltage Support Service, Black Start Service, Regulation Service, and Operating Reserve Service. Below is a brief description of each service.[1]

Voltage Support Service: Reactive power results from the fact that in an alternating current (AC) transmission system, the current and voltage waveforms may be slightly out of phase. The system operator uses generators to inject or absorb reactive power to maintain the proper reactive power balance on the system, which is necessary to maintain transmission voltages. The capability of a generator to produce or absorb reactive power on the instructions of the ISO constitutes Voltage Support Service.

Black Start Service: Most generators require the input of some amount of electric power to start up, which they normally take from the grid. In the event of a partial or system-wide blackout, power from the grid is unavailable. To restore the system to operation, some generators must be able to start without the availability of an outside electric supply (typically, they utilize an onsite auxiliary

[1] The descriptions given here are intended only to qualitatively communicate the nature of these services. For precise definitions, see NYISO Ancillary Services Manual, available at http://www.nyiso.com/services/documents/manuals/pdf/oper_manuals/ancserv.pdf.

power source, such as a diesel-fired generator or direct-current batteries). These units can then energize the grid, allowing other units to start and loads to reconnect. This capability is Black Start Service.

Regulation Service: Because electricity cannot be stored economically, in order to provide reliable electric service, the amount of power consumed must be exactly balanced by the amount of power produced, on a moment-to-moment basis (an imbalance will cause system frequency to deviate from 60 Hz). A generator providing Regulation Service assists in this moment-to-moment matching – the generator automatically increases or decreases its power output in real time in response to signals from the ISO (predominately through the use of Automatic Generation Control, or AGC, technology), so as to balance moment-to-moment fluctuations in supply and demand.

Operating Reserve Service: Operating Reserve Service provides backup generation in the event that a major generating resource fails. There are several classes of Operating Reserve Service, depending on whether the generation is initially spinning (synchronized with the grid) and on its response time: 10-minute spinning reserve, 10-minute non-synchronized reserve, and 30-minute reserve. Within the overall quantity of Operating Reserve required, the NYISO sets subsidiary requirements for the quantities of the faster Operating Reserve classes in order to ensure that the backup generation can be dispatched with sufficient speed.

IV. COST ALLOCATION FOR ANCILLARY SERVICES

To unbundle costs in a manner consistent with the new market structure, the total hydro cost of service must be allocated among generation and the four ancillary services identified above. After

subtracting off the appropriate costs related to these ancillary services, the balance of cost is allocated to generation, to be recovered via capacity and energy charges.

As noted above, NYPA assets do not directly provide ancillary services for NYPA customers – the NYISO requires that all customers acquire ancillary services from the ISO, and all suppliers offering ancillary services offer them to the ISO (i.e., self-supply of ancillary services is not allowed). However, this does not interfere with allocating costs between ancillary services and generation. To perform the cost allocation appropriately, I allocate NYPA hydro embedded costs associated with the identifiable assets that are capable of producing the ancillary services. This approach is appropriate even though NYISO control of ancillary service provision means that the actual real-time production of ancillary services by NYPA assets does not necessarily match the real-time requirements of NYPA customers, as explained further below.

The electric industry has some experience in unbundling ancillary service costs, since FERC requires utilities to unbundle their ancillary service costs in their Open Access Transmission Tariff ("OATT"). The OATT ancillary service charges are typically based on embedded cost, because FERC generally requires cost-based rates (an exception is in regions where an ISO operates competitive markets for some ancillary services, such as the NYISO markets for Regulation and Operating Reserve). Although utilities provide the (cost-based) rates for ancillary services in their OATTs, they seldom explain in detail the methods they used to arrive at these rates, so it is usually difficult for an outsider to document the approach that a utility uses to unbundle its ancillary service costs. The basic steps in cost unbundling consist of 1) identifying the assets and activities associated with the provision of ancillary services, and 2) applying accepted utility ratemaking principles to these assets and activities to develop the embedded cost associated with each ancillary

service. In my experience, though utilities generally use quite similar approaches, there can sometimes be slight differences in their methods. In fact, some judgment is inevitably required, though it generally will not have a significant effect on the resulting unbundled costs. Differences may involve the precise assets (or portion of assets) that are associated with the ancillary services (e.g., the fraction of a generator that is allocated to Voltage Support), or they may involve the ratemaking approach (e.g., whether an asset-specific or system-average depreciation rate is used; how overhead costs are allocated among functions).

In the case of the four ancillary services considered here, it is relatively straightforward to identify the major components of cost that can be assigned to each. For Voltage Support and Black Start, it is possible to identify a distinct, specialized subset of plant equipment that is required to provide these services. I assign capital costs based on the share of gross capital accounted for by this equipment, and also assign the associated O&M costs. In contrast, it is impossible to distinguish the equipment used to provide Regulation and Operating Reserve, because it is primarily the same generating capacity that is needed to produce power.[2] To address this, year-by-year I determine the share of Niagara and St. Lawrence capacity that is dedicated to Regulation and Operating Reserve (based on the hydro capacity allocation of NYPA customers, and NYISO requirements for Regulation and Operating Reserve). I then allocate this same share of total costs to these services. The details of all of my calculations are shown in my workpapers, which have been provided to NYPA.

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[2] It is true that in addition to generic plant capacity, some specialized equipment is used to provide Regulation and Operating Reserve (e.g., automatic generation control equipment for Regulation, and communications and control equipment for Operating Reserve). However, it is not possible in this case to distinguish these costs separately from other hydro costs.

A. ALLOCATION OF COSTS FOR VOLTAGE SUPPORT SERVICE

The methodology I utilize to identify costs associated with Voltage Support is the same as that used by the NYISO, which allocates costs to Voltage Support as a function of the FERC account breakdown of a generator's costs, and its power factor ("PF") rating.[3] Using this approach makes the calculation of NYPA's embedded Voltage Support costs consistent with how the NYISO calculates Voltage Support payments and costs for suppliers and consumers in the NYCA.

The NYISO method is applied to both existing (1999 and earlier) and new (2000 and forward) capital to identify capital associated with Voltage Support over the time horizon of the analysis. The NYISO method allocates 30%*(1-PF) of the FERC capital account for waterwheels, turbines, and generators, 10% of the FERC account for accessory electric equipment, and 0.2% of the remaining FERC capital accounts to Voltage Support. Because NYPA has not classified its future capital expenditures in terms of FERC capital accounts, I have assumed that the breakdown for capital additions after October 2002 is the same as that for capital investments made during the historical period January 2001 - September 2002. After determining the total gross capital invested in Niagara and St. Lawrence for each year of the time horizon, I apply the NYISO voltage allocation method to determine the amount of voltage capital in each year. The ratio of these (Voltage Capital/Total Capital) gives the share of total annual hydro Capital Costs that should be allocated to Voltage Support.

The NYISO method also allocates to Voltage Support 30%*(1-PF) of certain FERC O&M accounts for supervision and engineering. I begin with actual 2001 and Test Year values for these

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[3] Power factor is a measure of the extent to which the unit is designed or operated to produce reactive power (Voltage Support) in lieu of "real power" used to drive end-use loads.

FERC O&M accounts. For years 2002 and forward, I adjusted the Test Year values for inflation.

As shown in Table 2, for the Test Year, 1.15% of total hydro capital charges should be allocated to Voltage Support. In addition, $145,271 of O&M expenses should be allocated to Voltage Support. By 2006, these values grow to 1.47% and $161,354, respectively, due to new investments and inflation.

B. ALLOCATION OF COSTS FOR BLACK START SERVICES

Similar to the treatment of Voltage Support costs, I separate capital and operating costs associated with Black Start from the remainder of production costs. NYPA has followed the approach specified by the NYISO to calculate the embedded cost of Black Start capability for the Niagara and St. Lawrence stations for 2001, and I use this as the basis for my calculations. I use an approach similar to that used for Voltage Support above to develop the Black Start share of gross capital; as with Voltage support, this share of total hydro capital costs should be allocated to Black Start. I understand that NYPA's current capital addition plans for the next several years do not include additions related to Black Start, and so the Black Start capital share is based on existing Black Start equipment only. Beginning with actual 2001 Black Start O&M costs, I project future years' O&M by adjusting for inflation.

As shown in Table 3, for the Test Year, 0.059% of total hydro capital charges should be allocated to Black Start. In addition, $44,265 of O&M expenses should be allocated to Black Start. By 2006, the capital share declines to 0.053% (the Black Start share decreases because of increases in non-Black Start capital), and Black Start O&M increases to $49,160 because of inflation.

C. ALLOCATION OF COSTS FOR REGULATION AND OPERATING RESERVE SERVICES

Since the embedded costs of Regulation and Operating Reserve are handled similarly in this analysis, they are discussed together here. After deducting the costs related to Voltage Support and Black Start, the remaining plant costs are related to serving the capacity and energy requirements of contract customers, including their requirements for Regulation and Operating Reserve.[4] Essentially all of a hydro plant's costs are fixed costs that are related to capacity, not energy output (because the "fuel" is a free, although limited, resource). Thus the allocation of costs among Regulation, Operating Reserve, and generation (energy and capacity) should be based on how much of the plant's capacity is dedicated to each. The capacity I allocate to Regulation and Operating Reserve is related to the hydro allocation of NYPA customers – it is equal to the fraction of NYISO peak that is attributable to Niagara and St. Lawrence contract customers times the NYISO's requirements for Regulation and Operating Reserve (in MW). The NYPA hydro cost of service (net of Black Start and Voltage Support costs deducted above) should be reduced by the proportional Regulation and Operating Reserve requirements to obtain the cost of service to be allocated to generation.

To illustrate, the NYISO requires 255 MW of Regulation for the NYCA as a whole, and it forecasts a peak load of 31,330 MW for 2003 (summer peaking).[5] This implies a Regulation

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[4] In this context, Operating Reserve refers to all classes of Operating Reserve required by the NYISO: 10-minute spinning reserve, 10-minute non-synchronous reserve, and 30-minute reserve. Although the NYISO has different response requirements for each class, for the purposes of this analysis the classes are not distinguished. Hydro generation (unlike many thermal generators) is sufficiently responsive that it can generally provide all classes of Operating Reserve with equal facility.

[5] The NYISO does not publish the amount of Regulation Service it requires. To estimate the Regulation requirement, I used historical hourly data to calculate average amount of Regulation the ISO has held for each hour of the day during the test year. The amount of Regulation held varies significantly from hour to hour, but follows a consistent pattern -- more Regulation is held during the morning and evening ramp periods in

requirement of 0.8% on system peak. Similarly, the NYISO requires 1,800 MW of Operating Reserve, which is 5.7% of peak load.[6] These percentages are applied to NYPA's total summer peak hydro contract demand to get the MW requirement for Regulation and Operating Reserve for Niagara and St. Lawrence. Based on a total of 2,988 MW of demand from contract customers for the NYPA hydro plants during Summer 2002, 24 MW (0.8% of 2,988 MW) is allocated to Regulation, and 172 MW (5.7% of 2,988 MW) is allocated to Operating Reserve. These requirements are divided by the total net dependable capacity of Niagara and St. Lawrence, 3,200 MW, to determine that 0.76% of costs should be deducted for Regulation, and an additional 5.37% of costs should be deducted for Operating Reserve.[7] The remaining 93.87% of cost is allocated to generation. Again, these percentages are applied to the net cost of service after deducting the Voltage Support and Black Start costs calculated above.

In the Test Year, the fractions of net total cost for Niagara and St. Lawrence (capital plus O&M, after deducting Voltage Support and Black Start costs) allocated to Regulation and Operating Reserve are 0.78% and 5.52%, respectively (See Tables 4 and 5). These fractions decline slightly over time to 0.73% and 5.16%, respectively, in 2006. The decrease occurs because the forecasted growth in NYISO peak load implies proportionately lower Regulation and Operating Reserve requirements as a percentage of load.

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which load is changing rapidly, and less in other hours. The 255 MW overall Regulation requirement is based on the average amount of Regulation held during the 12 hours with the highest average Regulation.

6 The NYISO's Operating Reserve requirement is 1.5 times the most severe NYCA operating capability loss. This yields a requirement of 1800 MW. See New York ISO Locational Reserve Requirements, Table 2.

7 The net dependable capacity of Niagara is 2400 MW, and for St. Lawrence it is 800 MW.

V. CONCLUSION

I have identified NYPA hydro embedded costs (capital and operating costs for the Niagara and St. Lawrence facilities) that are associated with the provision of the following ancillary services: Voltage Support, Black Start, Regulation and Operating Reserve. I have determined the annual embedded cost associated with these ancillary services over the time frame encompassing the Test Year (October 2001-September 2002) and for the calendar years 2003 through 2006.

Table 1 shows the results of my analysis, and should be interpreted as follows. First, the annual O&M costs for Voltage Support and Black Start given in Table 1 should be deducted from the O&M component of the total annual hydro cost of service. The remaining O&M costs should be reduced by the O&M share allocated to Regulation and Operating Reserve.[8] The capital component of the total hydro cost of service should first be reduced by the shares for Voltage Support and Black Start, and then the remaining capital costs should be further reduced by the shares for Regulation and Operating Reserve.[9] Equivalently, the last three lines of Table 1 combine the deductions for all four of the ancillary services. To use the results in this format, the O&M component of the total hydro cost of service should be reduced by the dollar reduction for Ancillary Service O&M Cost ($), and that result further reduced by the Ancillary Service O&M Share (%). The capital component of the hydro cost of service should be reduced by the Ancillary Service

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[8] The O&M costs to be allocated to generation are:
{Total O&M $ - (Voltage $ + Black Start $)} * {1 - (Regulation % + Operating Reserve %)}.

[9] The capital costs to be allocated to generation are:
Total Capital $ * {1 - (Voltage % + Black Start %)} * {1 - (Regulation % + Operating Reserve %)}.

Capital Share (%). The remaining amount after deductions for these four ancillary services is the cost on which generation rates (capacity and energy charges) should be based.

Tables

Table 1
EMBEDDED COSTS FOR ANCILLARY SERVICES FOR NIAGARA AND ST. LAWRENCE

		Test Year 10/01 - 9/02	2003	2004	2005	2006
Voltage Support O&M Cost Reduction ($)	[1]	145,271	149,833	153,579	157,419	161,354
Voltage Support Capital Share (%)	[2]	1.15%	1.27%	1.34%	1.41%	1.47%
Black Start O&M Cost Reduction ($)	[3]	44,265	45,650	46,791	47,961	49,160
Black Start Capital Share (%)	[4]	0.059%	0.057%	0.055%	0.054%	0.053%
Regulation O&M Share (%)	[5]	0.78%	0.76%	0.75%	0.74%	0.73%
Regulation Capital Share (%)	[6]	0.78%	0.76%	0.75%	0.74%	0.73%
Operating Reserve O&M Share (%)	[7]	5.52%	5.37%	5.28%	5.22%	5.16%
Operating Reserve Capital Share (%)	[8]	5.52%	5.37%	5.28%	5.22%	5.16%
Ancillary Service O&M Cost ($)	[9]	189,536	195,483	200,370	205,379	210,514
Ancillary Service O&M Share (%)	[10]	6.30%	6.13%	6.03%	5.96%	5.90%
Ancillary Service Capital Share (%)	[11]	7.43%	7.37%	7.34%	7.34%	7.33%

Notes and Sources:
[1]-[2]: Table 2.
[3]-[4]: Table 3.
[5]-[6]: Table 4.
[7]-[8]: Table 5.
[9]: [1]+[3]
[10]: [5]+[7]
[11]: 1 - { 1 - ([2]+[4]) } * { 1 - ([6]+[8]) }

Table 2
EMBEDDED COSTS FOR VOLTAGE SUPPORT FOR NIAGARA AND ST. LAWRENCE

		Test Year 10/01 - 9/01	2003	2004	2005	2006
Voltage Fraction of Gross Capital (Niag. & St. L.)	[1]	**1.15%**	**1.27%**	**1.34%**	**1.41%**	**1.47%**
Voltage O&M Expense : Niagara ($)	[2]	88,071	90,837	93,108	95,435	97,821
Voltage O&M Expense : St. Lawrence ($)	[3]	57,200	58,996	60,471	61,983	63,533
Total Voltage O&M Expense ($)	[4]	**145,271**	**149,833**	**153,579**	**157,419**	**161,354**

Notes and Sources:
[1]: From Workpaper 5.3. Fraction is Beginning-of-Year value (equal to End-of-Year value for previous year).
Test Year equals 25% of 2001 value plus 75% of 2002 value.
[2] and [3]: From Workpaper 2.2.
[4] = [2] + [3].

Table 3

EMBEDDED COSTS FOR BLACK START FOR NIAGARA AND ST. LAWRENCE

		Test Year 10/01 - 9/02	2003	2004	2005	2006
Black Start Fraction of Gross Capital (Niag. & St. L.)	[1]	**0.059%**	**0.057%**	**0.055%**	**0.054%**	**0.053%**
Inflation Factor	[2]		102.5%	102.5%	102.5%	102.5%
Black Start O&M Expense ($)	[3]	**44,265**	**45,650**	**46,791**	**47,961**	**49,160**

Notes and Sources:
[1]: From Workpaper 7. Fraction is Beginning-of-Year value (equal to End-of-Year value for previous year).
Test Year equals 25% of 2001 value plus 75% of 2002 value.
[2] = From Workpaper 1
[3]: 2001= Sum of Training costs for Niagara and St. Lawrence, plus O&M Cost allocated to Black Start from Workpaper 6.
2002 to 2006 =Previous year's Total Black Start O&M Expense, adjusted by Inflation from Workpaper 6.
Test Year = 25% of 2001 value plus 75% of 2002 value.

Table 4
EMBEDDED COSTS FOR REGULATION FOR NIAGARA AND ST. LAWRENCE

		Test Year 10/01 - 9/02	2003	2004	2005	2006
NYCA Peak Load	[1]	30,475	31,330	31,840	32,200	32,560
Total NYCA Regulation Requirement (MW)	[2]	255	255	255	255	255
Required regulation per MW of peak load (MW)	[3]	0.008	0.008	0.008	0.008	0.008
Peak load of all contract customers of Niagara and St. Lawrence (MW)	[4]	2,988	2,988	2,988	2,988	2,988
Required regulation for all contract customers of Niagara and St. Lawrence (MW)	[5]	25	24	24	24	23
Niagara & St. Lawrence Summer Generation Capacity (MW)	[6]	3,200	3,200	3,200	3,200	3,200
Share of regulation for all contract customers of Niagara and St. Lawrence in generation capacity (%)	[7]	0.78%	0.76%	0.75%	0.74%	0.73%

Notes and Sources:
[1]: From Workpaper 8. Test year peak equals 2002 peak.
[2]: From Workpaper 8.
[3] = [2] / [1].
[4]: From Workpaper 8.
[5] = [3] * [4].
[6]: NYPA, "2001 Annual Report".
[7] = [5] / [6].

Table 5
EMBEDDED COSTS FOR OPERATING RESERVE FOR NIAGARA AND ST. LAWRENCE

		Test Year 10/01 - 9/02	2003	2004	2005	2006
NYCA Peak Load	[1]	30,475	31,330	31,840	32,200	32,560
Total NYCA Reserve Requirement (MW)	[2]	1,800	1,800	1,800	1,800	1,800
Required reserve per MW of peak load (MW)	[3]	0.059	0.057	0.057	0.056	0.055
Peak load of all contract customers of Niagara and St. Lawrence (MW)	[4]	2,988	2,988	2,988	2,988	2,988
Required reserve for all contract customers of Niagara and St. Lawrence (MW)	[5]	177	172	169	167	165
Niagara & St. Lawrence Summer Generation Capacity (MW)	[6]	3,200	3,200	3,200	3,200	3,200
Share of required reserve for all contract customers of Niagara and St. Lawrence in generation capacity (%)	[7]	5.52%	5.37%	5.28%	5.22%	5.16%

Notes and Sources:
[1]: From Workpaper 8. Test year peak equals 2002 peak.
[2]: From Workpaper 8.
[3] = [2] / [1].
[4]: From Workpaper 8.
[5] = [3] * [4].
[6]: NYPA, "2001 Annual Report".
[7] = [5] / [6].

Appendix

Appendix: QUALIFICATIONS OF FRANK C. GRAVES

Mr. Graves is a Principal of *The Brattle Group*. He assists utilities in the design and implementation of long-range planning, investment, and operating policies, and he assists their counsel with regulatory compliance and policy review. He has extensive experience with capacity expansion and network modeling, investment and contract prudence reviews, estimation of marginal costs, design and pricing of new services, and financial simulation and valuation techniques. He has testified on the economics of restructuring for retail and wholesale transmission access, power contract interpretations, service unbundling, market entry, and new services before the FERC and state regulatory commissions. He received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

REPRESENTATIVE CONSULTING EXPERIENCE

- The energy and telecom industries have both been plagued by scandals regarding alleged trading and accounting misrepresentations, such as wash trades, manipulations of mark-to-market valuations, premature recognition of revenues, and improper use of off-balance sheet entities. In many cases, this conduct has preceded or caused financial collapse and subsequent shareholder suits. Mr. Graves has lead research on accounting and financial evidence for such misconduct, including event studies of the stock price movements around the time of the contested practices, and reconstruction of accounting and economic justifications for the way asset values and revenues were recorded.

- Several utilities with coal-fired power plants are facing allegations from the U.S. EPA that they have conducted past maintenance on these plants constituting one or more major modifications, thereby triggering New Source Review standards for air quality controls. Mr. Graves has helped one such utility assess limitations on the way in which GADS data can be used retrospectively to quantify comparisons between past actual and projected future emissions. Testimony was presented.

- For the electric utility regulatory commission of Colombia, S.A., Mr. Graves led a study to access the inadequacies in the physical capabilities and economic incentives to manage outages at adequate levels. The *Brattle* team developed minimum reactive power support obligations and supplement reactive power acquisition mechanisms for generators, transmission companies, and distribution companies.

- The increased use of transmission congestion pricing has created interest in merchant transmission facilities. Mr. Graves assisted a developer with testimony on the potential impacts of the proposed line on market competition for transmission services and adjacent generation markets. He also assisted in the design of a system for soliciting and ranking bids to buy tranches of capacity over the line.

- Many regions are reassessing whether the preconditions for retail electric access are truly in place. Mr. Graves assisted a group of industrial customers with a critique of retail restructuring proposals to demonstrate that the locally weak transmission grid made competition among numerous generation suppliers very implausible.

- Recent gas price increases in the U.S. left several gas and electric utilities struggling to counter claims that they should have hedged more of their fuel supplies at times in the past. Mr. Graves has developed testimony to rebut this hindsight criticism and risk management techniques for fuel (and power) procurement for utilities to apply in the future to avoid prudence challenges.

- There is a strong tendency in electric restructuring to impose "provider of last resort" (POLR) transitional supply obligations on distcos. Unfortunately, POLR obligations that are extremely protective of customers harm the development of competitive retail power markets and can impose extreme, viability-threatening costs or risks on distcos. Mr. Graves has developed policy papers and tutorials on this problem for the Edison Electric Institute, and has advised several utilities on the design and valuation of alternative POLR specifications and coverage strategies.

- Wholesale generating companies intuitively realize that there are considerable differences in the financial risk of different kinds of power plant projects, depending on fuel type, length and duration of power purchase agreements, and tightness of local markets. However, they often are unaware of how if at all to adjust the hurdle rates applied to valuation and development decisions. Mr Graves lead a Brattle analysis of risk-adjusted discount rates for generation; very substantial adjustments were found to be necessary.

- As a means of retaining ownership but not control of generation, some utilities have turned to divesting output contracts. Mr. Graves was involved

in the design and approval of such agreements for an entire fleet of generation. The work entailed estimating and projecting cost functions that were likely to track the future marginal and total costs of the units, and analysis of the financial risks the plant operator would bear from the output pricing formula. Testimony on risks under this form of restructuring was presented.

- The U.S. Government is contractually obligated to dispose of spent nuclear fuel at commercial reactors after January 1998, but has not fulfilled this duty. As a result, nuclear facilities that are shutdown or facing full spent fuel pools are facing burdensome costs and risks. Mr. Graves prepared testimony on the incremental costs being borne by three nuclear operating companies with shutdown units as a result of this federal failure to perform.

- A major concern associated with electric utility industry restructuring is whether or not generation markets are adequately competitive to allow complete deregulation of generation prices. Because of the state-dependent nature of transmission transfer capability between regions, itself a function of generation use, the extent of viable competition in the generation market can vary significantly and may be susceptible to market power abuse by dominant suppliers. Mr. Graves has helped one of the largest ISOs in the U.S. develop market monitoring procedures to detect and discourage market manipulations that would impair competition.

- Much attention has been payed to horizontal market power in the electric generation industry, but less so to the possibility of vertical market power, whereby sufficient control of an upstream market creates competitive advantage in a downstream market. It is possible for this problem to arise in fuels, in settings where the likely marginal generation is dependent on one or a very few fuel suppliers who also have economic interests in the local generation market. Mr. Graves has analyzed this problem in the context of the California gas and electric markets and filed testimony to explain the magnitude and manifestations of the problem.

- The glut of generation capacity that helped usher in electric industry restructuring in the US led to asset devaluations in many places, even where no retail access was allowed. In some cases, this has led to bankruptcy, especially of a few large rural electric cooperatives. Mr. Graves assisted one such coop with its long term financial modeling and rate design under its plan

of reorganization, which was approved. Testimony was provided on cost of service justifications for the new generation and transmission prices, as well as on risks to the plan from potential environmental liabilities.

- Regulatory and legal approvals of utility mergers require evidence that the combined entity will not have undue market power and that it will create operating synergies that produce benefits for electric customers. Mr. Graves has assisted several utilities in evaluating potential mergers and acquisitions. He has identified ways in which transmission constraints reduce the number and type of suppliers, creating a risk of anticompetitive impacts unless structural, ownership, and pricing adjustments are put in place. He has also determined which benefits can be attributed to a merger and which can be accomplished without forming the combined organization.

- On behalf of the Electric Power Research Institute (EPRI), Mr. Graves has written a primer on how to define and measure the cost of electric utility transmission capacity for better planning, pricing, and regulatory policies. The text covers the basic electrical engineering of power circuits, utility practices to exploit transmission economies of scale, means of assuring system stability, economic dispatch subject to transmission constraints, and the estimation of marginal costs of transmission. The implications for a variety of policy issues are also discussed.

- A major telecommunications firm was concerned about when and how to reenter the Pacific rim for wireless ventures following the economic collapse of that region in 1997-99. Mr. Graves lead an engagement to identify prospective local partners with a governance structure that made it unlikely for them to divert capital from the venture if markets went soft. He also helped specify contracting and financing structures that create incentives for the venture to remain together should it face financial distress, while offering strong returns under good performance.

- Mr. Graves has assisted several utilities in forecasting market prices, revenues, and risks for generation assets being shifted from regulated cost recovery to competitive, deregulated wholesale power markets. Such studies have facilitated planning decisions, such as whether to divest generation or retain it, and have been used as the basis for quantifying stranded costs associated with restructuring in regulatory hearings. Mr. Graves' work in this

area has helped several utilities develop long term planning models for managing their generation assets in a competitive market.

- Many utilities find the prospects for participation in overseas power markets appealing, because of the similarities to regulatory contracting and pricing that they have experienced in the U.S., prior to restructuring. However, it is clear that there are many new risks associated with operations in a foreign country, related to the stability of its currency, its macroeconomy, its foreign investment policies, and even its political system. Mr. Graves has assisted firms facing these new dimensions to assess the risks, identify strategic advantages, and choose an appropriate, risk-adjusted hurdle rate for the market conditions and contracting terms they will face.

- The value of hydroelectric generation assets in a competitive power market is heavily dependent on operating practices that astutely shift between real power and ancillary services markets, while still observing a host of non-electric hydrological constraints. Mr. Graves has led studies for several major hydro generation owners in regard to forecasting of market conditions and corresponding hydro schedule optimization. He has also designed transfer pricing procedures that create an internal market for diverting hydro assets from real power to system support services firms that do not yet have explicit, observable market prices.

- The natural gas pipeline industry is wedged between competitive gas production and competitive resale of gas delivered to end users. In principle, the resulting basis differentials between locations around the pipeline ought to provide efficient usage and expansion signals, but traditional pricing rules prevent the pipeline companies from participating in the marginal value of their own services. Mr. Graves has worked to develop alternative pricing mechanisms and service mixes for pipelines that would provide more dynamically efficient signals and incentives.

- Power plants often provide a significant contribution to the property tax revenues of the townships where they are located. A common valuation policy for such assets has been that they are worth at least their book value, because that is the foundation for their cost recovery under cost-of-service utility ratemaking. However, restructuring throws away that guarantee, requiring reassessment of these assets. Traditional assessment tests, *e.g.*, based on the replacement costs of comparable assets, can be extremely

misleading, because they do not consider market conditions. Utility property tax assessments must be based on sound concepts of how value is captured in competitive power markets, requiring careful education and presentation to tax assessment boards. Mr. Graves has testified on such matters on behalf of the owners of a small, out-of-market coal unit in Massachusetts.

- The impacts of transmission open access and generation competition on utility financial health are well documented. In contrast, the effects on fuel use have been largely ignored, though there are many reasons to believe that relative fuel use will change, due to revised dispatch, repowerings and retirements, changes in expansion mix, and altered load shapes and load growth under more competitive pricing. For EPRI, Mr. Graves has contributed to a study that projects changes in fuel use within and between ten large power market regions spanning the country under different scenarios for the pace and success of restructuring.

- Several states are moving rapidly on implementing retail access for electric utilities. Mr. Graves has worked with the executive committees of several utilities in designing a regulatory strategy for influencing this transition and developing comprehensive business strategies and integrated planning tools for service unbundling and pricing, incentive ratemaking, corporate reorganization, market forecasting, asset valuation, and risk management.

- Stranded costs and out-of-market contracts from restructuring can affect municipalities and cooperatives as well as investor-owned utilities. Mr. Graves has assisted one debt-financed utility in an evaluation of its possibilities for reorganization, refinancing, and re-engineering to improve financial health and to lower rates. Sale and leaseback of generation, fuel contract renegotiation, targeted downsizing, spinoff of transmission, and new marketing programs were among the many components of the proposed new business plan.

- Mr. Graves has led a gas distribution company in the development of an incentive ratemaking system to replace all aspects of traditional cost of service regulation. The base rates (for non-fuel operating and capital costs) were indexed on a price-cap basis (RPI-X), while the gas and upstream transportation costs allowances were tied to optimal average annual usage of a reference portfolio of supply and transportation contracts. The gas company will also make numerous adjustments to its rate design, *e.g.,*

designing new standby rates so that customer choice will not be distorted by pricing inefficiencies.

- As a means of reducing supply commitment risk, several utilities have solicited offers for power contracts that grant the right but not the obligation to take power at some future date at a predetermined price, in exchange for an initial option premium payment. Mr. Graves has assisted several of these utilities in the development of valuation models for comparing the asking prices to fair market values for option contracts. In addition, he has helped these clients develop estimates of the critical option valuation parameters, such as trend, volatility, and correlations of the future prices of electric power and the various fuel indexes proposed for pricing the optional power. Training seminars on options valuation methods were also presented.

- An electric utility with several out-of-market independent power contracts wanted to determine the value of making those plants dispatchable and to devise a negotiating strategy for restructuring the IPP agreements. Mr. Graves developed a range of forecasts for the delivered price of natural gas to this area of the country through the year 2000. Alternative ways of sharing the potential dispatch savings were proposed as incentives for the IPPs to renegotiate their utility contracts.

- The ability to recover sunk costs of generation assets under open transmission access is of great concern to utilities. Mr. Graves has assisted one electric utility in the design and implementation of a method for forecasting probable capital recovery levels in the regional power market over the coming decade. The approach involves calculating a fixed cost contribution per kWh based on the marginal customer's value of lost load and the hourly loss of load probability, coupled with iterative adjustments to the quantity and mix of generation reserves in the regional pool based on the implied financial viability of each generating unit at the forecasted market prices.

- Mr. Graves has participated as a facilitator and advisor to one electric utility's task force on transmission strategy formulation and service pricing. Of particular concern were how much to unbundle and where to draw the line between generation and transmission functions. The efficiency and cost recovery merits of “nonconforming” rates (not based on embedded cost of service) were weighed against the potential regulatory controversy. Straw-man alternatives reflecting time- or location-of-use in rate design were

mocked up for assessment of competitive position and customer impact. The need to revise existing interconnection contracts to achieve comparability of service was also evaluated.

- For an electric utility considering the conversion of some large oil-fired units to natural gas, Mr. Graves conducted a study of the advantages of alternative means of obtaining gas supplies and gas transportation services. A combination of monthly and daily spot gas supplies, interruptible pipeline transportation over several routes, gas storage services, and "swing" (contingent) supply contracts with gas marketers was shown to be attractive. Testimony was presented on why the additional services of a local distribution company would be unneeded and uneconomic.

- A power engineering firm entered into a contract to provide operations and maintenance services for a cogenerator, with incentives fees tied to the unit's availability and operating cost. When the fees increased due to changes in the electric utility tariff to which they were tied, a dispute arose. Mr. Graves provided analysis and testimony on the avoided costs associated with improved cogeneration performance under a variety of economic scenarios and under several alternative utility tariffs.

- For a division of a large telecommunications firm, Mr. Graves assisted in a cost benchmarking study, in which the costs and management processes for billing, service order and inventory, and software development were compared to the practices of other affiliates and competitors. Unit costs were developed at a level far more detailed than the company normally tracked, and numerical measures of drivers that explained the structural and efficiency causes of variation in cost performance were identified. Potential costs savings of 10-50 percent were estimated, and procedures for better identification of inefficiencies were suggested.

- Mr. Graves has helped several pipelines design incentive pricing mechanisms for recovering their expected costs and reducing their regulatory burdens. Among these have been Automatic Rate Adjustment Mechanisms (ARAMs) for indexation of operations and maintenance expenses, construction-cost variance-sharing for routine capital expenditures that included a procedure for eliciting unbiased estimates of future costs, and market-based prices capped at replacement costs when near-term future expansion was an uncertain but probable need.

- For a major industrial gas user, he prepared a critique of the transportation balancing charges proposed by the local gas distribution company. Those charges were shown to be arbitrarily sensitive to the measurement period as well as to inconsistent attribution of storage versus replacement supply costs to imbalance volumes. The tariff design, a commodity charge on a per-cash-in/cash-out at spot market gas prices with penalties for very deep imbalances, or an incremental storage inventory and withdrawal capacity used on-peak, were shown to be cheaper, more efficient, and less complex to administer. This analysis helped the parties reach a settlement based on the cash-in/cash-out design.

- The Clean Air Act Amendment authorizes electric utilities to trade emission allowances (EAs) as part of their approach to complying with SO_2 emissions reductions targets. For the Electric Power Research Institute (EPRI), Mr. Graves has developed multi-stage planning models to illustrate how the considerable uncertainty surrounding future EA prices justifies waiting to invest in irreversible control technologies, such as scrubbers, until the present value cost of such investments is significantly below that projected from relying on EAs.

- Mr. Graves has contributed to the design and pricing of new, unbundled services on several natural gas pipelines. To identify attractive alternatives, the marginal costs of possible changes in a pipeline's service mix were quantified by simulating the least-cost operating practices subject to the network's physical and contractual constraints. Such analysis helped one pipeline to justify a zone-based rate design for its firm transportation service. Another pipeline used this technique to demonstrate that unintended degradations of system performance and increased costs could ensue from certain proposed unbundlings that were insensitive to system operations.

- For several natural gas pipeline companies, Mr. Graves has evaluated the cost of equity capital in light of the requirements of FERC Order 636 to unbundle and reprice pipeline services. In addition to traditional DCF and risk positioning studies, the risk implications of different degrees of financial leverage (debt capitalization) were modeled and quantified. Aspects of rate design and cost allocation between services that also affect pipeline risk were considered.

- Mr. Graves has assisted in the coordination and leadership of EPRI *Catalyst* planning sessions, two-day seminars held with managers from several departments within the same utility to constructively brainstorm about the critical dimensions of a strategic problem and the options for dealing with it. He has supported both environmental and transmission access seminars.

- For an electric utility with a troubled nuclear plant, Mr. Graves presented testimony on the economic benefits likely to ensue from a proposed reorganization. The plant was to be spun off to a jointly-owned subsidiary that would sell available energy back to the original owner under a contract indexed to industry unit cost experience. This proposal afforded a considerable reduction of risk to ratepayers in exchange for a reasonable, but highly uncertain prospect of profits for new investors. Testimony compared the incentive benefits and potential conflicts under this arrangement to the outcomes foreseeable from more conventional incentive ratemaking arrangements.

- For the World Bank and several investor-owned electric utilities, Mr. Graves has presented tutorial seminars on applying methods of financial economics to the evaluation of power production investments. Recently developed techniques for using option pricing to appraise the value of flexibility (such as arises from fuel switching capability or small plant size) were emphasized. He has applied these methods in estimating the value of contingent contract terms in fuel contracts (such as Gas Inventory Charges, or price caps and floors) for natural gas pipelines.

- Mr. Graves has helped design Gas Inventory Charge (GIC) tariffs for interstate pipelines seeking to reduce their risks of not recovering the full costs of multi-year gas supply contracts. The costs of holding supplies in anticipation of future, uncertain demand were evaluated with models of the pipeline's supply portfolio that reveal how many non-production costs (demand charges, take-or-pay penalties, reservation fees, or remarketing costs for released gas) would accrue under a range of demand scenarios. The expected present value of these costs provided a basis for the GIC tariff.

- For an electric utility seeking to improve its plant maintenance program, Mr. Graves directed a study on the incremental value of a percentage point decrease in the expected forced outage rate at each plant owned and operated by the company. This defined an economic priority ladder for efforts to

reduce outage that could be used in lieu of engineering standards for each plant's availability. The potential savings were compared to the costs of alternative schedules and contracting policies for preventive and reactive maintenance, in order to specify a cost reduction program.

- Mr. Graves performed a review and critique of a state energy commission's assessment of regional natural gas and electric power markets in order to determine what kinds of pipeline expansion into the area was economic. A proposed facility under review for regulatory approval was found to depend strongly on uneconomic bypass of existing pipelines and LDCs. In testimony, modular expansion of existing pipelines was shown to have significantly lower costs and risks.

- Mr. Graves conducted a study on the risk-adjusted discount rate appropriate to a publicly-owned electric utility's capacity planning. Since revenue requirements (the amounts being discounted) include operating costs in addition to capital recovery costs, the weighted average cost of capital for a comparable utility with traded securities may not be the correct rate for every alternative or scenario. The risks implicit in the utility's expansion alternatives were broken into component sources and phases, weighted, and compared to the risks of bonds and stocks to estimate project-specific discount rates and their probable bounds.

- For several electric utilities with generation capacity in excess of target reserve margins, Mr. Graves has designed and supervised market analyses that compared the marginal operating costs of all power plants not needed to meet target reserves for 50 to 100 neighboring utilities. These cost curves were then overlaid on the corresponding curve for the client utility to identify which neighbors were competitors and which were potential customers. The strength of their relative threat or attractiveness could be quantified by the present value of the product of the amount, duration, and differential cost of capacity that was displaceable by the client utility.

- Mr. Graves has specified algorithms for the enhancement of the EPRI EGEAS generation expansion optimization model, to capture the first-order effects of financial and regulatory constraints on the preferred generation mix.

- For a major electric power wholesaler, Mr. Graves developed a framework for estimating how pricing policies alter the attractiveness of capacity expansion alternatives. Traditional cost-recovery pricing rules can significantly distort the choice between two otherwise equivalent capacity plans, if one includes a severe "front end load" while the other does not. Price-demand feedback loops in simulation models and quantification of consumer satisfaction measures were used to appraise the problem. This "value of service" framework has been generalized for the Electric Power Research Institute.

- For a large gas and electric utility, Mr. Graves participated in coordinating and evaluating the design of a strategic and operational planning system. This included computer models of all aspects of utility operations, from demand forecasting through generation planning to financing and rate design. Efforts were split between technical contributions to model design and attention to organizational priorities and behavioral norms with which the system had to be compatible.

- For a major electronic and semiconductor firm, Mr. Graves critiqued and refined a proposed procedure for ranking the attractiveness of research and development projects. Aspects of risk peculiar to research projects were emphasized over the standards used for budgeting an already proven commercial venture.

- For an oil and gas exploration and production firm, Mr. Graves developed a framework for identifying what industry groups were most likely to be interested in natural gas supply contracts featuring atypical risk-sharing provisions. These provisions, such as price indexing or performance requirements contingent on market conditions, are a form of product differentiation for the producer, allowing it to obtain a price premium for the insurance-like services.

- For a natural gas distribution company, Mr. Graves established procedures for redefining customer classes and for repricing gas services according to customers' similarities in load shape, access to alternative gas supplies, expected growth, and need for reliability. In this manner, natural gas service was effectively differentiated into several products, each with price and risk appropriate to a specific market. PC-based software was developed for balancing gas portfolios to customer group demands.

- For a Midwestern electric utility, Mr. Graves extended a regulatory *pro forma* financial model to capture the contractual and tax implications of canceling and writing off a nuclear power plant in mid-construction. This possibility was then appraised relative to completion or substitution alternatives from the viewpoints of shareholders (market value of common equity) and ratepayers (present value of revenue requirements).

- For a corporate venture capital group, Mr. Graves conducted a market-risk assessment of investing in a gas exploration and production company with contracts to an interstate pipeline. The pipeline's market growth, competitive strength, alternative suppliers, and regulatory exposure were appraised to determine whether its future would support the purchase volumes needed to make the venture attractive.

- For a natural gas production and distribution company, he developed a strategic plan to integrate the company's functional policies and to reposition its operations for the next five years. Decision analysis concepts were combined with marginal cost estimation and financial *pro forma* simulation to identify attractive and resilient alternatives. Recommendations included target markets, supply sources, capital budget constraints, rate design, and a planning system. A two-day planning conference was conducted with the client's executives to refine and internalize the strategy.

- Mr. Graves prepared a review of empirical evidence regarding the stock market's reaction to alternative dividend, stock repurchase, and stock dividend policies for a major electric utility. Tax effects, clientele shifting, signaling, and ability to sustain any new policies into the future were evaluated. A one-time stock repurchase, with careful announcement wording, was recommended.

- For the New Mexico Public Service Commission, he analyzed the merits of a corporate reorganization of the major New Mexico gas production and distribution company. State ownership of the company as a large public utility was considered but rejected on concerns over efficiency and the burdening of performance risks onto state and local taxpayers.

- Mr. Graves has analyzed the spatial and temporal patterns of marginal costs on gas and electric utility transmission networks using optimization models of production costs and network flows. These results were used by one

natural gas transmission company to design receipt-point-based transmission service tariffs, and by another to demonstrate the incremental costs and uneven distribution of impacts on customers that would result form a proposed unbundling of services.

PROFESSIONAL MEMBERSHIPS

IEEE Power Engineering Society
Mathematical Association of America
American Finance Association
International Association for Energy Economics
Energy Modeling Forum (Stanford University)

EXPERT TESTIMONY

Direct testimony before the Public Utility Commission of Texas on behalf of Reliant Energy, Inc., Docket No. 26195, July 2002, regarding the appropriateness of Reliant HL&P's gas contracting, purchasing and risk management practices, and standards for assessing HL&P's gas purchases.

Direct and rebuttal testimonies before the Public Utilities Commission of the State of California on behalf of Southern California Edison, Application No. R. 01-10-024, May 1, 2002, and June 5, 2002, regarding Edison's proposed power procurement and risk management strategy, and the regulatory guidelines for reviewing its procurement purchases.

Expert report before the United States District Court, Southern District of Ohio, Eastern Division on behalf of Ohio Edison Company and Pennsylvania Power Company, Civil Action No. C2-99-1181, April 1, 2002, regarding coal plant maintenance projects alleged to trigger New Source Review.

Rebuttal testimony before the Texas Public Utility Commission on behalf of Reliant Resources, Inc., Docket No. 24190, October 10, 2001, regarding the good cause exception to the substantive rules that Reliant Resources, Inc. and the staff of the Public Utility Commission sought in their Provider of Last Resort settlement agreement.

Direct testimony before the Vermont Public Service Board on behalf of Vermont Gas Systems, Inc., Docket No. 6495, April 13, 2001, regarding Vermont Gas System's proposed risk management program and deferred cost recovery account for gas purchases.

Affidavit on behalf of Public Service Company of New Mexico, March 26, 2001, before the Federal Energy Regulatory Commission (FERC) to provide an updated application for market based rates, Docket No. ER96-1551-000.

Affidavit on behalf of the New York State Electric and Gas Corporation, April 19, 2000, before the New York State Public Service Commission, *In the Matter of Customer Billing Arrangements*, Case 99-M-0631.

Expert report before the United States Court of Federal Claims on behalf of Connecticut Yankee Atomic Power Company, *Connecticut Yankee Atomic Power Company, Plaintiff v. United States of America*, No. 98-154 C, June 30, 1999, regarding the damages from non-performance of the U.S. Department of Energy in accepting spent nuclear fuel and high-level waste under the terms of its contract.

Expert report before the United States Court of Federal Claims on behalf of Maine Yankee Atomic Power Company, *Maine Yankee Atomic Power Company, Plaintiff v. United States of America*, No. 98-474 C, June 30, 1999, regarding the damages from non-performance of the U.S. Department of Energy in accepting spent nuclear fuel and high-level waste under the terms of its contract.

Expert report before the United States Court of Federal Claims on behalf of Yankee Atomic Electric Company, *Yankee Atomic Electric Company, Plaintiff v. United States of America*, No. 98-126 C, June 30, 1999, regarding the damages from non-performance of the U.S. Department of Energy in accepting spent nuclear fuel and high-level waste under the terms of its contract.

Prepared direct testimony before the Federal Energy Regulatory Commission on behalf of National Rural Utilities Cooperative Finance Corporation, Inc., *Cities of Anaheim and Riverside, California v. Deseret Generation & Transmission Cooperative*, Docket No. EL97-57-001, March 1999, regarding cost of service for rural cooperatives versus investor-owned utilities, and coal plant valuation.

Expert report and oral examination before the Independent Assessment Team for industry restructuring appointed by the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation, January 1999, regarding the generation of cost of capital under long-term, indexed power purchase agreements.

Oral testimony before the Commonwealth of Massachusetts Appellate Tax Board on behalf of Indeck Energy Services of Turners Falls, Inc., *Turners Falls Limited Partnership, Appellant vs. Town of Montague, Board of Assessors, Appellee*, Docket Nos. 225191-225192, 233732-233733, 240482-240483, April 1998, regarding market conditions and revenues assessment for property tax basis valuation.

Direct and joint supplemental testimony before the Pennsylvania Public Utility Commission on behalf of Pennsylvania Electric Company and Metropolitan Edison Company, No. R-00974009, *et al.*, December 1997, regarding market clearing prices, inflation, fuel costs, and discount rates.

Testimony before the Public Utilities Commission of the State of California on behalf of the Southern California Edison Company, No. 96-10-038, August 1997, regarding anticompetitive implications of the proposed Pacific Enterprises/ENOVA mergers.

Direct testimony before the Kentucky Public Service Commission on behalf of Big Rivers Electric Corporation, No. 97-204, June 1997, regarding wholesale generation and transmission rates under the bankruptcy plan of reorganization.

Affidavit before the Federal Energy Regulation Commission on behalf of the Southern California Edison Company in Docket No. EC97-12-000, March 28, 1997, filed as part of motion to intervene and protest the proposed merger of Enova Corporation and Pacific Enterprises.

Direct, rebuttal, and supplemental rebuttal testimony before the State of New Jersey Board of Public Utilities on behalf of GPU Energy, No. EO97070459, February 1997, regarding market clearing prices, inflation, fuel costs, and discount rates.

Oral direct testimony before the State of New York on behalf of Niagara Mohawk Corporation in *Philadelphia Corporation, et al., v. Niagara Mohawk*, No. 71149, November 1996, regarding interpretation of low-head hydro IPP contract quantity limits.

Oral direct testimony before the State of New York on behalf of Niagara Mohawk Corporation in *Black River Limited Partnership v. Niagara Mohawk Power Corporation*, No. 94-1125, July 1996, regarding interpretation of IPP contract language specifying estimated energy and capacity purchase quantities.

Oral direct testimony on behalf of *Eastern Utilities Associates* before the Massachusetts Department of Public Utilities, No. 96-100 and 2320, July 1996, regarding issues in restructuring of Massachusetts electric industry for retail access.

Affidavit before the Kentucky Public Service Commission on behalf of *Big Rivers Electric Corporation* in PSC Case No. 94-032, June 1995, regarding modifications to an environmental surcharge mechanism.

Rebuttal testimony on behalf of utility in *Eastern Energy Corporation v. Commonwealth Electric Company*, American Arbitration Association, No. 11 Y 198 00352 04, March 1995, regarding lack of net benefits expected from a terminated independent power project.

Direct testimony before the Pennsylvania Public Utility Commission on behalf of Pennsylvania Power & Light Company in *Pennsylvania Public Utility Commission et al. v. UGI Utilities, Inc.*, Docket No. R-932927, March 1994, regarding inadequacies in the design and pricing of UGI's proposed unbundling of gas transportation services.

Direct testimony before the Pennsylvania Public Utility Commission, on behalf of Interstate Energy Company, *Application of Interstate Energy Company for Approval to Offer Services in the Transportation of Natural Gas*, Docket No. A-140200, October 1993, and rebuttal testimony, March 1994.

Direct testimony before the Pennsylvania Public Utility Commission, on behalf of Procter & Gamble Paper Products Company, *Pennsylvania Public Utility Commission v. Pennsylvania Gas and Water*

Company, Docket No. R-932655, September 1993, regarding PG&W's proposed charges for transportation balancing.

Oral rebuttal testimony before the American Arbitration Association, on behalf of Babcock and Wilcox, File No. 53-199-00127-92, May 1993, regarding the economics of an incentive clause in a cogeneration operations and maintenance contract.

Answering testimony before the Federal Energy Regulatory Commission, on behalf of CNG Transmission Corporation, Docket No. RP88-211-000, March 1990, regarding network marginal costs associated with the proposed unbundling of CNG.

Direct testimony before the Federal Energy Regulatory Commission, on behalf of Consumers Power Company *et al.*, concerning the risk reduction for customers and the performance incentive benefits from the creation of *Palisades Generating Company*, Docket No. ER89-256-000, October 1989, and rebuttal testimony, Docket No. ER90-333-000, November 1990.

Direct testimony before the New York Public Service Commission, on behalf of Consolidated Natural Gas Transmission Corporation, *Application of Empire State Pipeline for Certificate of Public Need*, Case No. 88-T-132, June 1989, and rebuttal testimony, October, 1989.

PUBLICATIONS AND PRESENTATIONS

"Regulatory Policy Should Encourage Hedging Programs" (with Steven H. Levine), *Natural Gas*, Volume 19, Number 4, November 2002.

"Measuring Gas Market Volatility - A Survey" (with Paolo Coghe and Manuel Costescu), presented at the Stanford Energy Modeling Forum, Washington, D.C., June 24, 2002.

"Unbundling and Rebundling Retail Generation Service: A Tale of Two Transactions" (with Joseph B. Wharton), presented at the Edison Electric Institute Conference on Unbundling/Rebundling Utility Generation and Transmission, New Orleans, LA, February 25, 2002.

"Provider of Last Resort, Service Hindering Retail Market Development" (with Joseph B. Wharton), *Natural Gas*, Volume 18, Number 3, October 2001.

"Measuring Progress Toward Retail Generation Competition" (with Joseph B. Wharton) Edison Electric Institute E-Forum presentation, May 16, 2001.

"Strategic Management of POLR Obligations" presented at Edison Electric Institute and the Canadian Electricity Association Conference, New Orleans, LA, June 5, 2001.

"POLR and Progress Towards Retail Competition - Can Kindness Kill the Market?" (with Joseph B. Wharton), presented at the NARUC Winter Committee Meeting, Washington, D.C., February 27, 2001.

"What Role for Transitional Electricity Price Protections After California?" presented to the Harvard Electricity Policy Group, 24th Plenary Session, San Diego, CA, February 1, 2001.

"Estimating the Value of Energy Storage in the United States: Some Case Studies" (with Thomas Jenkin, Dean Murphy and Rachel Polimeni) presented by Thomas Jenkin, prepared for the Conference on Commercially Viable Electricity Storage, London, England, January 31, 2001.

"PBR Designs for Transcos: Toward a Competitive Framework" (with Steven Stoft), *The Electricity Journal*, Volume 13, Number 7, August/September 2000.

"Capturing Value with Electricity Storage in the Energy and Ancillary Service Markets" (with Thomas Jenkin, Dean Murphy and Rachel Polimeni) presented at EESAT, Orlando, Florida, September 18, 2000.

"Implications of ISO Design for Generation Asset Management" (with Edo Macan and David A. Andrade), presented at the Center for Business Intelligence's Conference on Pricing Power Products & Services, Chicago, Illinois, October 14-15, 1999.

"Residual Service Obligations Following Industry Restructuring" (with James A. Read, Jr.), presented at the Edison Electric Institute Economic Regulation and Competition Committee Meeting, Longboat Key, Florida, September 26-29, 1999. Also presented at EEI's 1999 Retail Access Conference: *Making Retail Competition Work*, Chicago, Illinois, September 30-October 1, 1999.

"Opportunities for Electricity Storage in Deregulating Markets" (with Thomas Jenkin and Dean Murphy), *The Electricity Journal*, October 1999.

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"Price Caps for Standard Offer Service: A Hidden Stranded Cost" (with Paul Liu), *The Electricity Journal*, Volume 11, Number 10, December 1998.

Mechanisms for Evaluating the Role of Hydroelectric Generation in Ancillary Service Markets (with R.P. Broehm, R.L. Earle, T.J. Jenkin, and D.M. Murphy), Final Report, November 1998, TR-111707 (Palo Alto, CA: Electric Power Research Institute, 1998).

"PJM Market Competition Evaluation White Paper," (with Philip Hanser), prepared for PJM, L.L.C., October, 1998.

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"Pipeline Pricing to Encourage Efficient Capacity Resource Decisions"(with Paul R. Carpenter and Matthew P. O'Loughlin), filed on behalf of Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company, with their comments on *Financial Outlook for the Natural Gas Pipeline Industry*, FERC Docket No. PL98-2-000, February 1998.

"One-Part Markets for Electric Power: Ensuring the Benefits of Competition" (with E. Grant Read, Philip Q Hanser, and Robert L. Earle), *Power Systems Restructuring: Engineering and Economics*, M. Ilić, F. Galiana, and L. Fink, eds. (Boston: Kluwer Academic Publishers, 1998), pp. 243-280.

"Railroad and Telecommunications Provide Prior Experience in 'Negotiated Rates'" (with Carlos Lapuerta), Marketing and Rates, *Natural Gas*, July 1997.

"Considerations in the Design of ISO and Power Exchange Protocols: Procurement Bidding and Market Rules" (with J.P. Pfeifenberger), presented at the Electric Utility Consultants Bulk Power Markets Conference, Vail, Colorado, June 3-4, 1997.

"The Economics of Negative Barriers to Entry: How to Recover Stranded Costs and Achieve Competition on Equal Terms in the Electric Utility Industry" (with William B. Tye), Electric Industry Restructuring, *Natural Resources Journal*, Volume 37, No. 1,Winter 1997.

"Capacity Prices in a Competitive Power Market" (with James A. Read), *The Virtual Utility: Accounting, Technology & Competitive Aspects of the Emerging Industry*, S. Awerbuch and A. Preston, eds. (Boston: Kluwer Academic Publishers, 1997), pages 175-192.

"Stranded Cost Recovery and Competition on Equal Terms" (with William B. Tye), *Electricity Journal*, Volume 9, Number 10, December 1996.

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"Distributed Generation Technology in a Newly Competitive Electric Power Industry" (with Johannes P. Pfeifenberger, Paul R. Ammann, and Gary A. Taylor), presented at the *American Power Conference*, Illinois Institute of Technology, April 10, 1996.

"A Framework for Operations in the Competitive Open Access Environment" (with Marija D. Ilić, Lester H. Fink, Albert M. DiCaprio), *Electricity Journal*, Volume 9, Number 3, April 1996.

"Prices and Procedures of an ISO in Supporting a Competitive Power Market" (with Marija Ilić), presented at the *Restructuring Electric Transmission Conference*, Denver, Colorado, September 27, 1995.

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"Estimating the Social Costs of PUHCA Regulation" (with Paul R. Carpenter), submitted to the Security and Exchange Commission's *Request for Comments on Modernization of the Regulation of Public Utility Holding Companies*, SEC File No. S7-32-93, February 6, 1995.

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"Impacts of Electric Industry Restructuring on Distributed Utility Technology," presented to the Electric Power Research Institute/National Renewable Energy Laboratory/Florida Power Corporation *Conference on Distributed Generation*, Orlando, Florida, August 24, 1994.

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22Jan03

Authority Staff Recommendation
To Audit Committee
and
Buck Consultants Study

123 Main Street
White Plains, New York 10601
914 681.6200

November 19, 2002

To: **Audit Committee Members**
Vice Chairman Frank S. McCullough, Jr.
Trustee Timothy S. Carey

From: **Thomas Concadoro**

Subject: **Year-end 2002 Accounting Adjustments**

In closing the year 2002, we will be proposing to record the following accounting adjustments which will reduce projected net revenues for the year by approximately $99 million. As detailed below, we consider these adjustments to be prudent and appropriate under generally accepted accounting principles.

(1)Retiree Health Benefits ($25 million)

The Authority currently records health and insurance benefits for retirees on a pay-as-you-go basis resulting in an annual charge of $6 million against net revenues. This approach is currently acceptable for government entities. However, we are currently anticipating that the Government Accounting Standards Board will require an accrual accounting approach be implemented by the Authority and other government entities in the year 2006. Commercial entities have been required to apply accrual accounting to retiree health benefits since the early 1990's. Under an accrual approach, the annual charge to expense will increase to $31 million assuming we adopt a 20-year amortization period for prior year accumulated obligations.

The basic assumption underlying the accrual approach is that employees earn their retiree health benefits during their working years. Actuarial methods are applied to project future payments using estimated health care inflation rates. These payments are then discounted using projected earning rates on funds to be utilized to satisfy these obligations. The Actuarial Study utilized by the Authority was developed by Buck Consulting. Underlying assumptions include an initial medical inflation rate of 12% and an earnings rate of 6%. Utilizing this approach, the Authority's financial obligation for future retiree health benefits was $272 million as of December 31, 2001. The current year expense ($31 million) includes the amortization of this prior year liability over 20 years ($25 million;

including interest) and an amount attributed to current year employee service ($6 million). The charge against earnings for this expense is estimated to increase by approximately $2 to $3 million per year over the next 10 years (2003, $33 million; 2004, $35 million etc.) representing interest on the obligation.

ACTUARIAL VALUATION REPORT
AS OF JANUARY 1, 2001
AND JANUARY 1, 2002

NEW YORK POWER AUTHORITY
POSTRETIREMENT BENEFITS OTHER THAN PENSIONS

January 2002

Practicing the art and finance of human resources™
BUCK CONSULTANTS
A Mellon Consulting Company

BUCK CONSULTANTS®
A Mellon Consulting Company
301 Tresser Boulevard, Suite 1110
Stamford, Connecticut 06901-3202

January 15, 2002

Mr. Howard Berg
New York Power Authority
123 Main Street
White Plains, New York 10601

Dear Howard:

This report presents the results of our Actuarial Valuation Report as of January 1, 2001 and January 1, 2002 for the New York Power Authority Postretirement Benefits other than pensions.

The purpose of the valuation is to determine the benefit obligations of NYPA participants and evaluate the GASB 27 standard with respect to the accounting and reporting for postemployment benefits other than pensions (OPEB) compared to the FAS 106 standard. The valuation was based on census data supplied by NYPA, per capita unit costs calculated by Buck Consultants, and the program provisions described in Exhibit B of this report. The valuation was prepared based on actuarial assumptions that reflect NYPA's best estimate of future program experience including an 8.0% discount rate.

The Table of Contents, which immediately follows, outlines the material contained in this report.

Sincerely,

Anthony M. Abbazia, F.S.A.
Principal & Consulting Actuary

Suzanne M. Kidd
Principal & Benefit Consultant

NYPA PRM Report.doc
06928

Buck Consultants, Inc.
203 | 975-0260 Fax 203 | 975-1986

NEW YORK POWER AUTHORITY
POSTRETIREMENT MEDICAL BENEFITS
JANUARY 1, 2001 AND JANUARY 1, 2002 VALUATIONS

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SECTION I

EXECUTIVE SUMMARY

1. At the request of New York Power Authority (NYPA), Buck Consultants has prepared this valuation of postretirement benefits other than pensions as of January 1, 2001 and January 1, 2002. The purpose of the valuation is to determine the benefit obligation of NYPA participants and evaluate the GASB 27 standard with respect to the accounting and reporting for postemployment benefits other than pensions (OPEB) compared to the FAS 106 standard.

2. NYPA provided individual census data for active employees, current retirees and covered spouses, (including surviving spouses). A summary of the data is presented in Section II.

3. Exhibit A outlines the full set of actuarial assumptions and methods used in the valuation. The per-capita medical plan unit costs were developed by Buck Consultants using the current pre-Medicare unit costs, the plan provisions described in Exhibit B and the Buck manual pricing program.

4. Exhibit B outlines the plan provisions for Salaried and Union employees used in the valuation.

5. Exhibit C contains a comparison of the FAS 106 accounting standard and the GASB 27 accounting standard and also shows the major differences between the two accounting standards.

6. The Liability Summary is presented in Section III. A summary of the principal results of the valuation as of January 1, 2002 is as follows:

	January 1, 2002
Valuation Data	
Number of active participants	1,542
Number of retirees and widows	1,000
Number of spouses of retirees	582
Liabilities (000's)	
Active Participants	$ 93,623
Retirees and Widows	$ 68,079
Spouses of retirees	$ 45,646
Total	$ 207,348

7. The valuation results are presented in Section III. A summary of the options available for a January 1, 2002 versus January 1, 2001 adoption date is as follows:

($000)	January 1, 2002	January 1, 2001
Annual Cost excluding one-time charges		
FAS 106 - 20 year amortization	$ 31,225	$ 29,320
FAS 106 – immediate recognition	$ 20,858	$ 19,567
GASB 27 – 10 year level dollar amortization	$ 35,489	$ 33,317
GASB 27 – 40 year level dollar amortization	$ 21,976	$ 20,605
GASB 27 – 40 year level percent amortization	$ 14,498	$ 13,571

8. The Governmental Accounting Standards Board continues to work on their Other Post-Employment Benefits project. While the provisions are expected to be similar to GASB 27, some of the items they are debating include frequency of valuations, relief for very small plans, and financial statement disclosures. They currently expect to issue an Exposure Draft in June 2002 and they are pushing to meet this deadline because a Board member's term expires June 30, 2002. Assuming the Board issues an Exposure Draft in June, a final statement will be expected a year later with an effective date at least two years after that. The earliest effective date would be January 1, 2006.

As you can see, earlier adoption will help reduce the impact of implementation. However, if NYPA does not intend to fund the obligation, earlier adoption will complicate your books before your peers face the same issues. As the GASB option is more flexible than the FASB option, we would recommend either waiting for the Exposure Draft or adopting GASB 27.

SECTION II

MEMBER DATA

	Salaried	IBEW	Teamsters	UWUA	Total
Active Members					
Number	906	568	0	68	1,542
Total Pay	$69,675,722	$32,871,480	$0	$4,087,929	$106,635,131
Average Age	47.42	46.26	0.00	47.63	47.00
Average Service	14.58	16.71	0.00	16.65	15.46
Average Pay	$76,905	$57,872	$0	$60,117	$69,154
Retirees and Widows					
Number	582	362	12	44	1,000
Average Age	68.58	69.25	63.67	62.21	68.48
Total Life Insurance	$14,205,947	$6,344,902	$180,120	$660,000	$21,408,877
Spouses					
Number	330	220	12	20	582
Average Age	63.95	64.89	61.75	61.55	64.18

SECTION III

LIABILITY SUMMARY

January 1, 2002

	Salaried	IBEW	Teamsters	UWUA	Total
Active					
Medical Benefits	$ 46,299,525	$ 26,817,889	$ 0	$ 3,471,618	$ 76,589,032
Part B Reimbursements	7,608,691	4,616,436	0	635,953	12,861,080
Life Insurance	3,325,462	739,535	0	107,424	4,172,421
Total	$ 57,233,678	$ 32,173,860	$ 0	$ 4,214,995	$ 93,622,533
Retirees and Widows					
Medical Benefits	$ 29,977,811	$ 18,527,396	$ 596,009	$ 3,155,320	$ 52,256,536
Part B Reimbursements	5,005,842	2,914,105	110,598	381,014	8,411,559
Life Insurance	5,224,477	1,954,393	45,458	186,612	7,410,940
Total	$ 40,208,130	$ 23,395,894	$ 752,065	$ 3,722,946	$ 68,079,035
Spouses					
Medical Benefits	$ 21,704,771	$ 15,604,996	$ 868,345	$ 1,672,392	$ 39,850,504
Part B Reimbursements	3,294,559	2,175,186	120,467	205,339	5,795,551
Total	$ 24,999,330	$ 17,780,182	$ 988,812	$ 1,877,731	$ 45,646,055
Total Liability	$ 122,441,138	$ 73,349,936	$ 1,740,877	$ 9,815,672	$ 207,347,623
Projected Benefit Payments	$ 4,602,997	$ 2,905,442	$ 96,918	$ 342,900	$ 7,948,257

SECTION IV

VALUATION RESULTS

Table 1

January 1, 2002 Adoption Date

FAS106 Accounting Methodology with 20 Year Straight Line Amortization

Reconciliation of Funded Status as of January 1, 2002

	Salaried	IBEW	Teamsters	UWUA	Total
Accumulated Postretirement Benefit Obligation (APBO)	$ (65,207,460)	$ (41,176,076)	$ (1,740,877)	$ (5,600,677)	(113,725,090)
Retirees	(17,034,751)	(8,026,111)	0	(1,561,557)	(26,622,419)
Actives - Eligible to Retire	(40,198,927)	(24,147,749)	0	(2,653,438)	(67,000,114)
Actives - Not Eligible to Retire					
Total APBO	$ (122,441,138)	$ (73,349,936)	$ (1,740,877)	$ (9,815,672)	(207,347,623)
Fair Value of Plan Assets	0	0	0	0	0
Funded Status	$ (122,441,138)	$ (73,349,936)	$ (1,740,877)	$ (9,815,672)	$ (207,347,623)
Unrecognized Prior Service Cost	0	0	0	0	0
Unrecognized Net (Gain) or Loss	0	0	0	0	0
Unrecognized Transition Obligation	122,441,138	73,349,936	1,740,877	9,815,672	207,347,623
(Accrued) / Prepaid Postretirement Benefit Cost	$ 0	$ 0	$ 0	$ 0	$ 0

Net Periodic Postretirement Benefit Cost for 2002

	Salaried	IBEW	Teamsters	UWUA	Total
Service Cost (EOY)	$ 2,934,597	$ 1,491,515	$ 0	$ 161,557	$ 4,587,669
Interest Cost	9,611,171	5,751,777	135,393	771,538	16,269,879
Return on Assets	0	0	0	0	0
Amortization of					
Unrecognized Prior Service Cost	0	0	0	0	0
Unrecognized Net (Gain) or Loss	0	0	0	0	0
Unrecognized Transition Obligation	6,122,057	3,667,497	87,044	490,784	10,367,381
Net Periodic Postretirement Benefit Cost for 2002	$ 18,667,825	$ 10,910,789	$ 222,437	$ 1,423,879	$ 31,224,929

SECTION IV

VALUATION RESULTS

Table 2

January 1, 2002 Adoption Date

FAS106 Accounting Methodology with Immediate Recognition

Reconciliation of Funded Status as of January 1, 2002

	Salaried	IBEW	Teamsters	UWUA	Total
Accumulated Postretirement Benefit Obligation (APBO)					
Retirees	$ (65,207,460)	$ (41,176,076)	$ (1,740,877)	$ (5,600,677)	(113,725,090)
Actives - Eligible to Retire	(17,034,751)	(8,026,111)	0	(1,561,557)	(26,622,419)
Actives - Not Eligible to Retire	(40,198,927)	(24,147,749)	0	(2,653,438)	(67,000,114)
Total APBO	$ (122,441,138)	$ (73,349,936)	$ (1,740,877)	$ (9,815,672)	(207,347,623)
Fair Value of Plan Assets	0	0	0	0	0
Funded Status	$ (122,441,138)	$ (73,349,936)	$ (1,740,877)	$ (9,815,672)	$ (207,347,623)
Unrecognized Prior Service Cost	0	0	0	0	0
Unrecognized Net (Gain) or Loss	0	0	0	0	0
Unrecognized Transition Obligation	0	0	0	0	0
(Accrued) / Prepaid Postretirement Benefit Cost	$ (122,441,138)	$ (73,349,936)	$ (1,740,877)	$ (9,815,672)	$ (207,347,623)

Net Periodic Postretirement Benefit Cost for 2002

	Salaried	IBEW	Teamsters	UWUA	Total
Service Cost (EOY)	$ 2,934,597	$ 1,491,515	$ 0	$ 161,557	$ 4,587,669
Interest Cost	9,611,171	5,751,777	135,393	771,538	16,269,879
Return on Assets	0	0	0	0	0
Amortization of					
Unrecognized Prior Service Cost	0	0	0	0	0
Unrecognized Net (Gain) or Loss	0	0	0	0	0
Unrecognized Transition Obligation	0	0	0	0	0
Net Periodic Postretirement Benefit Cost for 2002	$ 12,545,768	$ 7,243,292	$ 135,393	$ 933,095	$ 20,857,548
Immediate Recognition of APBO	122,441,138	73,349,936	1,740,877	9,815,672	207,347,623
Total Cost for 2002	$ 134,986,906	$ 80,593,228	$ 1,876,270	$ 10,748,767	$ 228,205,171

SECTION IV

VALUATION RESULTS

Table 3

January 1, 2002 Adoption Date

GASB 27 Accounting Methodology with 10 Year Level Dollar Amortization

Determination of Amortization of Unfunded Liability as of January 1, 2002

	Salaried	IBEW	Teamsters	UWUA	Total
Accumulated Postretirement Benefit Obligation (APBO)					
Retirees	$ (65,207,460)	$ (41,176,076)	$ (1,740,877)	$ (5,600,677)	(113,725,090)
Actives - Eligible to Retire	(17,034,751)	(8,026,111)	0	(1,561,557)	(26,622,419)
Actives - Not Eligible to Retire	(40,198,927)	(24,147,749)	0	(2,653,438)	(67,000,114)
Total APBO	$ (122,441,138)	$ (73,349,936)	$ (1,740,877)	$ (9,815,672)	(207,347,623)
Fair Value of Plan Assets	0	0	0	0	0
Unfunded Liability	$ (122,441,138)	$ (73,349,936)	$ (1,740,877)	$ (9,815,672)	$ (207,347,623)
Amortization Over 10 Year Period (BOY)	16,895,685	10,121,577	240,224	1,354,467	28,611,953

Annual Required Contribution (ARC)

	Salaried	IBEW	Teamsters	UWUA	Total
Normal Cost (BOY)	$ 2,717,220	$ 1,381,032	$ 0	$ 149,590	$ 4,247,842
Amortization Payment (BOY)	16,895,685	10,121,577	240,224	1,354,467	28,611,953
Total Cost (Beginning of Year)	$ 19,612,905	$ 11,502,609	$ 240,224	$ 1,504,057	$ 32,859,795
Interest to End of Year	1,569,032	920,209	19,218	120,325	2,628,784
Total ARC	$ 21,181,937	$ 12,422,818	$ 259,442	$ 1,624,382	$ 35,488,579

SECTION IV

VALUATION RESULTS

Table 4

January 1, 2002 Adoption Date

GASB 27 Accounting Methodology with 40 Year Level Dollar Amortization

Determination of Amortization of Unfunded Liability as of January 1, 2002

	Salaried	IBEW	Teamsters	UWUA	Total
Accumulated Postretirement Benefit Obligation (APBO)	$ (65,207,460)	$ (41,176,076)	$ (1,740,877)	$ (5,600,677)	(113,725,090)
Retirees	(17,034,751)	(8,026,111)	0	(1,561,557)	(26,622,419)
Actives - Eligible to Retire	(40,198,927)	(24,147,749)	0	(2,653,438)	(67,000,114)
Actives - Not Eligible to Retire					
Total APBO	$ (122,441,138)	$ (73,349,936)	$ (1,740,877)	$ (9,815,672)	(207,347,623)
Fair Value of Plan Assets	0	0	0	0	0
Unfunded Liability	$ (122,441,138)	$ (73,349,936)	$ (1,740,877)	$ (9,815,672)	$ (207,347,623)
Amortization Over 40 Year Period (BOY)	9,507,346	5,695,498	135,176	762,170	16,100,190

Annual Required Contribution (ARC)

	Salaried	IBEW	Teamsters	UWUA	Total
Normal Cost (BOY)	$ 2,717,220	$ 1,381,032	$ 0	$ 149,590	$ 4,247,842
Amortization Payment (BOY)	9,507,346	5,695,498	135,176	762,170	16,100,190
Total Cost (Beginning of Year)	$ 12,224,566	$ 7,076,530	$ 135,176	$ 911,760	$ 20,348,032
Interest to End of Year	977,965	566,122	10,814	72,941	1,627,842
Total ARC	$ 13,202,531	$ 7,642,652	$ 145,990	$ 984,701	$ 21,975,874

SECTION IV

VALUATION RESULTS

Table 5

January 1, 2002 Adoption Date

GASB 27 Accounting Methodology with 40 Year Level Percent of Pay Amortization

Determination of Amortization of Unfunded Liability as of January 1, 2002

	Salaried	IBEW	Teamsters	UWUA	Total
Accumulated Postretirement Benefit Obligation (APBO)					
Retirees	$ (65,207,460)	$ (41,176,076)	$ (1,740,877)	$ (5,600,677)	(113,725,090)
Actives - Eligible to Retire	(17,034,751)	(8,026,111)	0	(1,561,557)	(26,622,419)
Actives - Not Eligible to Retire	(40,198,927)	(24,147,749)	0	(2,653,438)	(67,000,114)
Total APBO	$ (122,441,138)	$ (73,349,936)	$ (1,740,877)	$ (9,815,672)	(207,347,623)
Fair Value of Plan Assets	0	0	0	0	0
Unfunded Liability	$ (122,441,138)	$ (73,349,936)	$ (1,740,877)	$ (9,815,672)	$ (207,347,623)
Amortization Over 40 Year Period (BOY)	5,418,786	3,246,193	77,045	434,405	9,176,429

Annual Required Contribution (ARC)

	Salaried	IBEW	Teamsters	UWUA	Total
Normal Cost (BOY)	$ 2,717,220	$ 1,381,032	$ 0	$ 149,590	$ 4,247,842
Amortization Payment (BOY)	5,418,786	3,246,193	77,045	434,405	9,176,429
Total Cost (Beginning of Year)	$ 8,136,006	$ 4,627,225	$ 77,045	$ 583,995	$ 13,424,271
Interest to End of Year	650,880	370,178	6,164	46,720	1,073,942
Total ARC	$ 8,786,886	$ 4,997,403	$ 83,209	$ 630,715	$ 14,498,213

SECTION IV

VALUATION RESULTS

Table 6

January 1, 2001 Adoption Date

FAS106 Accounting Methodology with 20 Year Straight Line Amortization

Reconciliation of Funded Status as of January 1, 2001

	Salaried	IBEW	Teamsters	UWUA	Total
Accumulated Postretirement Benefit Obligation (APBO)					
Retirees	$ (64,304,587)	$ (40,625,338)	$ (1,697,221)	$ (5,483,898)	(112,111,044)
Actives - Eligible to Retire	(15,899,846)	(7,491,129)	0	(1,449,333)	(24,840,308)
Actives - Not Eligible to Retire	(34,705,285)	(21,080,293)	0	(2,318,377)	(58,103,955)
Total APBO	$ (114,909,718)	$ (69,196,760)	$ (1,697,221)	$ (9,251,608)	(195,055,307)
Fair Value of Plan Assets	0	0	0	0	0
Funded Status	$ (114,909,718)	$ (69,196,760)	$ (1,697,221)	$ (9,251,608)	$ (195,055,307)
Unrecognized Prior Service Cost	0	0	0	0	0
Unrecognized Net (Gain) or Loss	0	0	0	0	0
Unrecognized Transition Obligation	114,909,718	69,196,760	1,697,221	9,251,608	195,055,307
(Accrued) / Prepaid Postretirement Benefit Cost	$ 0	$ 0	$ 0	$ 0	$ 0

Net Periodic Postretirement Benefit Cost for 2001

	Salaried	IBEW	Teamsters	UWUA	Total
Service Cost (EOY)	$ 2,717,220	$ 1,381,032	$ 0	$ 149,590	$ 4,247,842
Interest Cost	9,027,580	5,431,474	132,302	727,842	15,319,198
Return on Assets	0	0	0	0	0
Amortization of					
Unrecognized Prior Service Cost	0	0	0	0	0
Unrecognized Net (Gain) or Loss	0	0	0	0	0
Unrecognized Transition Obligation	5,745,486	3,459,838	84,861	462,580	9,752,765
Net Periodic Postretirement Benefit Cost for 2001	$ 17,490,286	$ 10,272,344	$ 217,163	$ 1,340,012	$ 29,319,805

SECTION IV

VALUATION RESULTS

Table 7

January 1, 2001 Adoption Date

FAS106 Accounting Methodology with Immediate Recognition

Reconciliation of Funded Status as of January 1, 2001

Accumulated Postretirement Benefit Obligation (APBO)	Salaried	IBEW	Teamsters	UWUA	Total
Retirees	$ (64,304,587)	$ (40,625,338)	$ (1,697,221)	$ (5,483,898)	(112,111,044)
Actives - Eligible to Retire	(15,899,846)	(7,491,129)	0	(1,449,333)	(24,840,308)
Actives - Not Eligible to Retire	(34,705,285)	(21,080,293)	0	(2,318,377)	(58,103,955)
Total APBO	$ (114,909,718)	$ (69,196,760)	$ (1,697,221)	$ (9,251,608)	(195,055,307)
Fair Value of Plan Assets	0	0	0	0	0
Funded Status	$ (114,909,718)	$ (69,196,760)	$ (1,697,221)	$ (9,251,608)	$ (195,055,307)
Unrecognized Prior Service Cost	0	0	0	0	0
Unrecognized Net (Gain) or Loss	0	0	0	0	0
Unrecognized Transition Obligation	0	0	0	0	0
(Accrued) / Prepaid Postretirement Benefit Cost	$ (114,909,718)	$ (69,196,760)	$ (1,697,221)	$ (9,251,608)	$ (195,055,307)

Net Periodic Postretirement Benefit Cost for 2001

	Salaried	IBEW	Teamsters	UWUA	Total
Service Cost (EOY)	$ 2,717,220	$ 1,381,032	$ 0	$ 149,590	$ 4,247,842
Interest Cost	9,027,580	5,431,474	132,302	727,842	15,319,198
Return on Assets	0	0	0	0	0
Amortization of					
Unrecognized Prior Service Cost	0	0	0	0	0
Unrecognized Net (Gain) or Loss	0	0	0	0	0
Unrecognized Transition Obligation	0	0	0	0	0
Net Periodic Postretirement Benefit Cost for 2001	$ 11,744,800	$ 6,812,506	$ 132,302	$ 877,432	$ 19,567,040
Immediate Recognition of APBO	114,909,718	69,196,760	1,697,221	9,251,608	195,055,307
Total Cost for 2002	$ 126,654,518	$ 76,009,266	$ 1,829,523	$ 10,129,040	$ 214,622,347

SECTION IV

VALUATION RESULTS

Table 8

January 1, 2001 Adoption Date

GASB 27 Accounting Methodology with 10 Year Level Dollar Amortization

Determination of Amortization of Unfunded Liability as of January 1, 2001

Accumulated Postretirement Benefit Obligation (APBO)	Salaried	IBEW	Teamsters	UWUA	Total
Retirees	$ (64,304,587)	$ (40,625,338)	$ (1,697,221)	$ (5,483,898)	(112,111,044)
Actives - Eligible to Retire	(15,899,846)	(7,491,129)	0	(1,449,333)	(24,840,308)
Actives - Not Eligible to Retire	(34,705,285)	(21,080,293)	0	(2,318,377)	(58,103,955)
Total APBO	$ (114,909,718)	$ (69,196,760)	$ (1,697,221)	$ (9,251,608)	(195,055,307)
Fair Value of Plan Assets	0	0	0	0	0
Unfunded Liability	$ (114,909,718)	$ (69,196,760)	$ (1,697,221)	$ (9,251,608)	$ (195,055,307)
Amortization Over 10 Year Period (BOY)	15,856,423	9,548,479	234,200	1,276,632	26,915,734

Annual Required Contribution (ARC)

	Salaried	IBEW	Teamsters	UWUA	Total
Normal Cost (BOY)	$ 2,515,944	$ 1,278,734	$ 0	$ 138,509	$ 3,933,187
Amortization Payment (BOY)	15,856,423	9,548,479	234,200	1,276,632	26,915,734
Total Cost (Beginning of Year)	$ 18,372,367	$ 10,827,213	$ 234,200	$ 1,415,141	$ 30,848,921
Interest to End of Year	1,469,789	866,177	18,736	113,211	2,467,913
Total ARC	$ 19,842,156	$ 11,693,390	$ 252,936	$ 1,528,352	$ 33,316,834

SECTION IV

VALUATION RESULTS

Table 9

January 1, 2001 Adoption Date

GASB 27 Accounting Methodology with 40 Year Level Dollar Amortization

Determination of Amortization of Unfunded Liability as of January 1, 2001

Accumulated Postretirement Benefit Obligation (APBO)	Salaried	IBEW	Teamsters	UWUA	Total
Retirees	$ (64,304,587)	$ (40,625,338)	$ (1,697,221)	$ (5,483,898)	(112,111,044)
Actives - Eligible to Retire	(15,899,846)	(7,491,129)	0	(1,449,333)	(24,840,308)
Actives - Not Eligible to Retire	(34,705,285)	(21,080,293)	0	(2,318,377)	(58,103,955)
Total APBO	$ (114,909,718)	$ (69,196,760)	$ (1,697,221)	$ (9,251,608)	(195,055,307)
Fair Value of Plan Assets	0	0	0	0	0
Unfunded Liability	$ (114,909,718)	$ (69,196,760)	$ (1,697,221)	$ (9,251,608)	$ (195,055,307)
Amortization Over 40 Year Period (BOY)	8,922,544	5,373,011	131,786	718,372	15,145,713

Annual Required Contribution (ARC)

	Salaried	IBEW	Teamsters	UWUA	Total
Normal Cost (BOY)	$ 2,515,944	$ 1,278,734	$ 0	$ 138,509	$ 3,933,187
Amortization Payment (BOY)	8,922,544	5,373,011	131,786	718,372	15,145,713
Total Cost (Beginning of Year)	$ 11,438,488	$ 6,651,745	$ 131,786	$ 856,881	$ 19,078,900
Interest to End of Year	915,079	532,140	10,543	68,550	1,526,312
Total ARC	$ 12,353,567	$ 7,183,885	$ 142,329	$ 925,431	$ 20,605,212

SECTION IV

VALUATION RESULTS

Table 10

January 1, 2001 Adoption Date

GASB 27 Accounting Methodology with 40 Year Level Percent of Pay Amortization

Determination of Amortization of Unfunded Liability as of January 1, 2001

Accumulated Postretirement Benefit Obligation (APBO)	Salaried	IBEW	Teamsters	UWUA	Total
Retirees	$ (64,304,587)	$ (40,625,338)	$ (1,697,221)	$ (5,483,898)	(112,111,044)
Actives - Eligible to Retire	(15,899,846)	(7,491,129)	0	(1,449,333)	(24,840,308)
Actives - Not Eligible to Retire	(34,705,285)	(21,080,293)	0	(2,318,377)	(58,103,955)
Total APBO	$ (114,909,718)	$ (69,196,760)	$ (1,697,221)	$ (9,251,608)	(195,055,307)
Fair Value of Plan Assets	0	0	0	0	0
Unfunded Liability	$ (114,909,718)	$ (69,196,760)	$ (1,697,221)	$ (9,251,608)	$ (195,055,307)
Amortization Over 40 Year Period (BOY)	5,085,474	3,062,389	75,113	409,442	8,632,418

Annual Required Contribution (ARC)

	Salaried	IBEW	Teamsters	UWUA	Total
Normal Cost (BOY)	$ 2,515,944	$ 1,278,734	$ 0	$ 138,509	$ 3,933,187
Amortization Payment (BOY)	5,085,474	3,062,389	75,113	409,442	8,632,418
Total Cost (Beginning of Year)	$ 7,601,418	$ 4,341,123	$ 75,113	$ 547,951	$ 12,565,605
Interest to End of Year	608,113	347,290	6,009	43,836	1,005,248
Total ARC	$ 8,209,531	$ 4,688,413	$ 81,122	$ 591,787	$ 13,570,853

SECTION V

OVERVIEW OF ACTUARIAL ASSUMPTIONS AND METHODS

1. Exhibit A outlines the full set of actuarial assumptions and methods used in our valuation. The per-capita medical plan unit costs were developed based on paid claim experience for 1999, 2000, and partial-year 2001 as well as premium equivalent rates for 2001.

2. The establishment of the current per capita unit costs of medical coverage is an important step in the measurement process. Cost rates should reflect the actual differences in the cost of covering individuals reflecting their ages, whether or not they are covered by Medicare and the plan of benefits under which they have coverage. The 2001 per capita unit costs used in the valuation were derived primarily from the claim experience and premium rates provided by NYPA.

3. The Company provided POS and HMO premium rates by medical plan for 2001. Claims data were available separately for salaried versus hourly retirees and covered dependents and separately for individuals under and over age 65. Valuation census data were used to determine underlying enrollments and per capita costs. The claim rates were adjusted from a paid to an incurred basis and trended to the middle of 2001.

INCREASES IN FUTURE MEDICAL PLAN COSTS

4. Increases in medical plan benefit costs occur for several reasons. Some are directly related to medical cost inflation while others are a function of plan provisions or changing demographics. The valuation explicitly models the effects of plan provisions such as deductibles and cost-sharing, changing demographics by age distribution, and medical cost inflation on covered expenses.

5. As each individual ages, chances are that health declines and incurred medical expenses increase. Based on experience studies for large corporate clients and on statistics published by the government, the valuation explicitly reflects age-related morbidity as indicated in Exhibit A.

EXHIBIT A

OUTLINE OF ACTUARIAL ASSUMPTIONS AND METHODS

VALUATION DATE: January 1, 2001 and January 1, 2002.

ACTUARIAL COST METHOD: Projected unit credit with benefits attributed on a level basis from date of hire until date of full eligibility for expected benefits.

DISCOUNT RATE: 8.0% per annum, compounded annually.

RETURN ON PLAN ASSETS: N/A

SEPARATIONS FROM EMPLOYMENT: Representative values of the assumed annual rates of withdrawal, disability, death, and retirement are as follows:

	Annual Rate of			
	Withdrawal		Disability	
Age	Not Vested	Vested	Ordinary	Accidental
25	.1161	.0171	.0014	.0001
30	.0957	.0171	.0014	.0001
35	.0856	.0181	.0014	.0003
40	.0750	.0166	.0020	.0006
45	.0653	.0153	.0034	.0009
50	.0604	.0141	.0048	.0012
55	.0599	.0105	.0057	.0011
60	.0561	.0105	.0065	.0007
65	.0523	.0105	.0070	.0006
70	--	--	--	--

	Annual Rate of Death	
Age	Male	Female
25	.0005	.0003
30	.0006	.0003
35	.0009	.0005
40	.0012	.0007
45	.0022	.0010
50	.0039	.0017
55	.0061	.0025
60	.0092	.0042
65	.0156	.0071

Age	Annual Rate of Retirement Regular*
55	.20
56	.10
57	.10
58	.10
59	.10
60	.15
61	.20
62	.40
63	.25
64	.30
65	.40
66	.30
67	1.00

* An additional 20% is added to the rate when participant reaches 30 years of service.

DEATHS AFTER RETIREMENT: According to the 1983 Group Annuity Mortality Table.

SALARY INCREASES: The assumed annual rates of future salary increase is 4.50%.

UNIT COSTS: The 2001 assumed annual average per-capita incurred medical unit costs at age 65 are as follows:

	Pre-Medicare	Post-Medicare
Salaried		
HMO	$ 2,968	N/A
POS	$ 3,184	N/A
Indemnity	$ 8,941	$ 2,272
Union		
HMO	$ 2,984	N/A
POS	$ 4,195	N/A
Indemnity	$ 8,526	$ 1,975*

* Pre-91 IBEW retirees drug coverage increases unit cost shown by $79.

SUBSTANTIVE PLAN: The current medical plan features are as follows:

- Deductible: Deductibles are assumed to increase periodically at the ultimate Health Care Cost Trend Rate to reflect increases in costs.

- Out-of-Pocket Maximum (excluding the deductible): The out-of-pocket maximum is assumed to increase periodically at the ultimate Health Care Cost Trend Rate to reflect increases in costs.

- Retiree Contribution: No contribution is required for medical benefits. Union participants are required to contribute half of the premium rate for life insurance coverage.

AGE-RELATED MORBIDITY: To allow for the incidence of increased cost of medical benefits with age, our per capita unit costs are adjusted per year of age. A sample of the increase in gross eligible charges by year of age was assumed to be:

Age	Annual Increase
50-54	3.2%
55-59	3.4
60-64	3.7
65-69	3.2
70-74	2.4
75-79	1.8
80-84	1.3
85+	0.0

HEALTH CARE COST TREND RATES: Representative values of future expected increases in net medical charges are as follows:

Year	Increase
2002	12.0%
2003	11.2
2004	10.4
2005	9.7
2006	8.9
2007	8.1
2008	7.3
2009	6.6
2010	5.8
2011+	5.0

MEDICARE COORDINATION: Medicare is assumed to remain the primary payor for retirees and spouses over age 65. The portion of Medicare eligible charges is assumed to remain constant in the future.

MEDICAL PLAN ENROLLMENT AND DEPENDENT ASSUMPTION: Reported data were used to identify current covered retirees, spouses and surviving spouses. Reported data for active employees currently eligible to retire were used to determine the following assumptions for future retirees:

	Coverage Election		
		Of Those Electing Coverage	
	Waived	Single	Family
Men	0%	25%	75%
Women	0%	25%	75%

Husbands are assumed to be three years older than their wives.

MEDICAL PLAN ENROLLMENT AND SPOUSAL ASSUMPTION: Reported data were used to identify current married actives. Married participants were assumed to elect family coverage.

MISCELLANEOUS: The valuation was prepared on an ongoing plan basis.

EXHIBIT B

Summary of Benefit Provisions

Retirement Program	**As in effect January 1, 2001**
Eligibility	Age 55 and 10 years of service.
Coverages available	Medical Plan benefits, Medicare Part B Reimbursement, and Life Insurance benefit.

Salaried Employees

I. Medical

		Premier Plan	
		In Network	Out of Network
Deductible	Individual:	None	$160
	Employee plus one:	None	$320
	Family:	None	$480
Coinsurance		100% After Minimal copayments	80% of R&C in excess of the deductible

Out-of-Pocket Maximum	Individual:	$600
	Family:	$900
Hospitalization	Annual deductible:	$ 0
	Emergency room copayment:	$ 0
Prescription Drug Copayments	Generic:	$ 5
	Brand:	$10
	Mail Order:	$ 0
Lifetime Maximum	$1,000,000	
Retiree Contributions	None	

II. Medicare Part B Reimbursement — Paid by NYPA

III. Life Insurance

Benefit	40% of salary, minimum $20,000, maximum $50,000.
Retiree Contributions:	None

UWUA Employees

I. Medical

		In Network	Out of Network
Deductible	Individual:	None	$175
	Family:	None	$525
Coinsurance		100% After Minimal copayments	80% of R&C in excess of the deductible

Out-of-Pocket Maximum	Family:	$700
Hospitalization	Annual deductible:	$ 0
	Emergency room copayment:	$ 0
Prescription Drug Copayments	Generic:	$ 2
	Brand:	$ 2 or $ 8
	Mail Order:	$ 0
Lifetime Maximum	$1,000,000	
Retiree Contributions	None	

II. Medicare Part B Reimbursement — Paid by NYPA

III. Life Insurance

Benefit — $25,000

Retiree Contributions: One half of the monthly premium as follows:

Union	Rate per thousand
UWUA	$1.08

IBEW Employees

I. Medical

Deductible	Individual:	$100	
	Family:	$300	
Coinsurance		80% of R&C in excess of the deductible	
Out-of-Pocket Maximum	Individual:	$475	
Hospitalization	Annual deductible:	$ 0	
	Emergency room copayment:	$ 0	
		Post '91	Pre '91
Prescription Drug Copayments	Generic:	$ 0	$1
	Brand:	$ 2 or $ 8	$1
	Mail Order:	$ 0	$0
Lifetime Maximum	$1,000,000		
Retiree Contributions	None		

II. Medicare Part B Reimbursement — Paid by NYPA

III. Life Insurance

Benefit — $25,000

Retiree Contributions: — One half of the monthly premium as follows:

Union	Rate per thousand
IBEW	$1.73

Teamster Union Employees

I. Medical

Deductible	Individual: Family:	$140 $420
Coinsurance		80% of R&C in excess of the deductible
Out-of-Pocket Maximum	Individual:	$500
Hospitalization	Annual deductible: Emergency room copayment:	$ 0 $ 0
Prescription Drug Copayments	Generic: Brand: Mail Order:	$ 0 $ 2 or $ 8 $ 0
Lifetime Maximum	$1,000,000	
Retiree Contributions	None	

II. Medicare Part B Reimbursement — Paid by NYPA

III. Life Insurance

Benefit	$25,000	
Retiree Contributions:	One half of the monthly premium as follows:	
	Union	Rate per thousand
	Teamsters	$1.0

EXHIBIT C

Comparison of FAS 106 and GASB 27

Item	GASB 27	FAS 106	Comparison
Actuarial Funding Method	Entry Age, Frozen Entry Age, Attained Age, Frozen Attained Age, Projected Unit Credit, Aggregate	Projected Unit Credit	GASB provides more options and allows you to change methodology while FAS 106 is rigid
Cost Determination	**Annual Required Contribution (ARC)** Normal Cost – value of accrual of benefits attributable to the current year, plus Amortization Cost – amortization of unfunded liabilities over selected period. The period can be as long as 40 years (declining to 30 over the next 10 years) or as short as 10 years. The amortization method includes principal and interest and can be either level dollar or level percent of pay. If the employer contribution is not equal to the ARC, adjustments to the cost are required	**Net Periodic Post Retirement Benefit Cost** Service Cost – value of accrual of benefits attributable to the current year, plus Interest Cost – one year's interest on the liability adjusted for benefit payments, plus Amortization of Transition Obligation – straight line amortization of unfunded obligation at transition over 20 years unless the employer elects to take a one-time accounting charge at transition, plus Amortization of Prior Service Cost – straight line amortization of effect of plan changes over average working lifetime, plus Amortization of Gains and Losses – minimum amortization on a straight line basis of unrecognized gains and losses in excess of 10% of the liability over average working lifetime, plus Expected Return on Assets – a credit equal to the expected long term rate of return on assets multiplied by the assets adjusted for contributions and benefit payments. In an unfunded plan, this component is zero.	GASB is more flexible than FASB The Service Cost and Normal Cost components are equivalent if using the same actuarial method. The GASB amortization includes both principal and interest in a single number. The FASB method separates interest from principal which leads to faster amortization (higher cost) when using the same period. In addition, FASB requires a shorter period (less than 12 years) for future changes than allowable for GASB. FASB's lone advantage is that minor gains and losses (less than 10% of the liability) do not impact cost.

Comparison of FAS 106 and GASB 27

(Continued)

Item	GASB 27	FAS 106	Comparison
Transition Amortization	10 – 40 year amortization of unfunded liability (principal and interest) on a level dollar or level percent of pay	20 year amortization on a straight line basis with interest reflected in the Interest Cost. Immediate recognition is available for principal amount.	Unless immediate recognition is desirable, GASB is much more flexible.
Amortization of Prior Service Cost	Impact of plan changes on liability is amortized the same as the Transition amount. Often combined into one base. Total amortization amount must be within acceptable range.	Amortization on a straight line basis over average working lifetime with interest reflected in the Interest Cost.	GASB is more flexible and generally produces a lower cost.
Amortization of Gains and Losses	Gains and Losses are amortized the same as the Transition amount. Often combined into one base. Total amortization amount must be within acceptable range.	Minimum amortization on a straight line basis of unrecognized gains and losses in excess of 10% of the liability over average working lifetime with interest reflected in the Interest Cost.	FASB ignores minor fluctuations in cost while GASB requires an immediate adjustment to cost.
Settlements, Curtailments, and Termination Benefits	Generally, the change in liability is amortized similar to a plan amendment. A change in employer structure (transaction) might be treated differently.	Settlements and Curtailments trigger immediate recognition of items that previously would have been amortized (transition amounts, prior service costs, and gains and losses). The change in liability for Termination Benefits is immediately recognized and for a Curtailment might be immediately recognized.	A Settlement is a transaction where the liability is discharged for a price like an annuity purchase. A Curtailment is the termination of a significant number of employees or the ceasing of the accrual of benefits for a significant number of employees. Termination Benefits are special or contractual benefits paid in certain situations like an early retirement window.

From: Abbazia Anthony M [mailto:tabbazia@buckconsultants.com]
Sent: Sunday, November 17, 2002 3:42 PM
To: Berg, Howard; Chin, Thomas
Cc: Kidd Suzanne M
Subject: 6% Valuation Results and Headcount Projection

Attached are two files with (1) the Valuation Results using a 6% discount rate and 20, 25, and 30 year amortization periods and (2) a Headcount Projection for 25 years.

<<2002 NYPA FAS 106 - 6% to NYPA.xls>> <<Headcounts - to NYPA.xls>>

We owe you a cover letter for the responses to PWC's comments.

Please let me know if you would like to discuss these results,

Tony Abbazia
Consulting Actuary
Buck Consultants
281 Tresser Boulevard
6th Floor
Stamford, CT 06901
tabbazia@buckconsultants.com
Phone 203.352.1614
Fax 203.967.3139

VALUATION RESULTS

January 1, 2002

Determination of Unfunded Liability as of January 1, 2002

Accumulated Postretirement Benefit Obligation (APBO)	Salaried	IBEW	Teamsters	UWUA	Total
Retirees	$ (80,999,780)	$ (49,730,981)	$ (2,191,210)	$ (7,057,725)	(139,979,696)
Actives - Eligible to Retire	(21,702,485)	(10,177,754)	0	(1,970,046)	(33,850,285)
Actives - Not Eligible to Retire	(58,216,795)	(35,153,143)	0	(3,887,868)	(97,257,806)
Total APBO	$ (160,919,060)	$ (95,061,878)	$ (2,191,210)	$ (12,915,639)	(271,087,787)
Fair Value of Plan Assets	0	0	0	0	0
Unfunded Liability	$ (160,919,060)	$ (95,061,878)	$ (2,191,210)	$ (12,915,639)	$ (271,087,787)

GASB 27 Accounting Methodology with 20 Year Level Dollar Amortization

Annual Required Contribution (ARC)

	Salaried	IBEW	Teamsters	UWUA	Total
Normal Cost (BOY)	$ 4,009,194	$ 2,050,003	$ 0	$ 221,123	$ 6,280,320
Amortization Payment (BOY)	13,235,525	7,818,800	180,226	1,062,306	22,296,857
Total Cost (Beginning of Year)	$ 17,244,719	$ 9,868,803	$ 180,226	$ 1,283,429	$ 28,577,177
Interest to End of Year	1,034,683	592,128	10,814	77,006	1,714,631
Total ARC	$ 18,279,402	$ 10,460,931	$ 191,040	$ 1,360,435	$ 30,291,808

GASB 27 Accounting Methodology with 25 Year Level Dollar Amortization

Annual Required Contribution (ARC)

	Salaried	IBEW	Teamsters	UWUA	Total
Normal Cost (BOY)	$ 4,009,194	$ 2,050,003	$ 0	$ 221,123	$ 6,280,320
Amortization Payment (BOY)	11,875,632	7,015,452	161,709	953,159	20,005,952
Total Cost (Beginning of Year)	$ 15,884,826	$ 9,065,455	$ 161,709	$ 1,174,282	$ 26,286,272
Interest to End of Year	953,090	543,927	9,703	70,457	1,577,177
Total ARC	$ 16,837,916	$ 9,609,382	$ 171,412	$ 1,244,739	$ 27,863,449

GASB 27 Accounting Methodology with 30 Year Level Dollar Amortization

Annual Required Contribution (ARC)

	Salaried	IBEW	Teamsters	UWUA	Total
Normal Cost (BOY)	$ 4,009,194	$ 2,050,003	$ 0	$ 221,123	$ 6,280,320
Amortization Payment (BOY)	11,028,863	6,515,228	150,178	885,195	18,579,464
Total Cost (Beginning of Year)	$ 15,038,057	$ 8,565,231	$ 150,178	$ 1,106,318	$ 24,859,784
Interest to End of Year	902,283	513,914	9,011	66,379	1,491,587
Total ARC	$ 15,940,340	$ 9,079,145	$ 159,189	$ 1,172,697	$ 26,351,371

NYPA: Total Headcounts

Year	Current Retirees, Spouses and Widows	Future Retirees, Spouses and Widows	GRAND TOTAL
2002	1,564	59	1,623
2003	1,528	186	1,714
2004	1,490	317	1,807
2005	1,451	450	1,901
2006	1,409	597	2,006
2007	1,366	745	2,111
2008	1,322	877	2,199
2009	1,276	998	2,274
2010	1,230	1,112	2,342
2011	1,181	1,221	2,402
2012	1,131	1,326	2,457
2013	1,082	1,427	2,509
2014	1,031	1,503	2,534
2015	981	1,548	2,529
2016	928	1,567	2,495
2017	878	1,577	2,455
2018	828	1,568	2,396
2019	777	1,536	2,313
2020	727	1,497	2,224
2021	679	1,462	2,141
2022	632	1,420	2,052
2023	585	1,367	1,952
2024	540	1,304	1,844
2025	496	1,237	1,733
2026	455	1,172	1,627